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Underground Injection Control Program Class VI Well for Geological Sequestration of Carbon Dioxide

Well #3
Permit Application - Revised

Archer Daniels Midland Company

Decatur, Illinois

August 2022

Contents

1. Executive Summary

1.1 Introduction

The Archer Daniels Midland (ADM) Company ("Operator") proposes an underground injection project at its agricultural products and biofuels production facility located in Decatur, Illinois. The goal of this injection project is to add an additional underground injection well to accept and retain industrial-scale volumes of carbon dioxide (CO2) for permanent geologic sequestration. Two pre-existing Carbon Capture and Sequestration (CCS) wells with associated equipment have previously been constructed and operated at the facility.

Carbon Capture and Sequestration Well #3 (CCS#3) is to begin injection upon permit approval at an approximate rate of 3,300 metric tons per day (MT/day). At least 1.1 million MT will be injected annually.

The proposed sequestration site at the ADM facility will be supplied with nearly pure CO2 from ADM or 3rd party systems, including but not limited to:

- Allam Combustor flue gas
- Oxy-combustion boiler flue gas
- CO_2 from ADM's various ethanol and cogeneration facilities, including but not limited to Decatur, IL; Clinton, IA; and Cedar Rapids, IA

Sensitive, Confidential, or Privileged Information [redacted] Following cessation of the operational period, ADM proposes a post-injection monitoring and site closure period of 10 years.

The transmission system that will service CCS#3 consists of a pipeline that transports the compressed CO2 to the sequestration site, approximately 1 mile from the surface facility. The sequestration site associated with the new well will consist of the new CCS#3 injection well, with associated equipment, and one additional verification well (Well VW#3) to monitor the sequestered CO2.

The proposed sequestration site at the ADM facility will be supplied with nearly pure CO2 from various processes as outlined in Section 8.6 CO2 stream characteristics.

ADM will leverage the knowledge and experience gained from existing site CCS operations to design, construct, and operate the CO2 collection, compression, dehydration, and injection facility capable of delivering and sequestering over 1 million MTs per year of CO2 in CCS#3 into the Mt. Simon.

The construction phase of the project is expected to last 18-24 months, allowing the commissioning and operation of the new well facilities to occur beginning in January 2025.

1.2 Injection Plan

The proposed mass to be injected is to be approximately 3,300 MT/day of supercritical CO2. A cumulative CO2 mass of 14.3 million tons is projected over approximately twelve years of operation and injection is scheduled to begin in January 2025. Injection rates will be metered and are projected to remain continuous during the injection period.

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During the period prior to injection, assessment of perforation strategies and subsequent modeling will take place to further predict the behavior of the CO2 plume based on the data collected during the CCS#3 injection well installation. Permeability-thickness and the injectivity of several sub-intervals (layers) within the Mt. Simon will be quantified and assessed, to more fully understand the impact of lower permeability interval(s) within the Mt. Simon on the distribution of the buoyant CO2 plume.

1.3 Injection Fluid

Information pertaining to composition, quantity, origin and other data of the proposed CO2 streams are presented in 8.6 CO2 stream characteristics.

CCS#3 will be operated at a maximum daily injection rate of 3,300 MT/day and average annual average injection rate of 1.1 MT/year from the combined CO2 sources addressed in Section 8.6, with injection beginning in January 2025. The total injection mass, over the life of the well, is anticipated to be at least 14.3 million MT.

2. General Information

2.1 Applicant and Site Information

Applicant:	Archer Daniels Midland Company – Corn Processing
USEPA Identification No.	ILD984791459
IEPA Identification No.	1150155136
Facility Contact:	Mr. Jason Stahr, Plant Manager
Mailing Address:	4666 Faries Parkway Decatur, IL 62526
Phone:	217-451-6330

Injection Well Location:

CCS#3 (proposed):
39° 52' 12.936'' N, -88° 52' 49.188'' W
South center of Section 33
Township 17N, Range 3E (Whitmore Township)
Decatur, Macon County Illinois

Site Information:

County:	Macon
SIC Codes:	2046 – wet corn milling 2869 – industrial organic chemicals, ethanol 2075 – soybean oil mills 2076 – vegetable oil mills
Owner/Operator:	Archer Daniels Midland Company – Corn Processing 4666 Faries Parkway Decatur, IL 62526
Operator Status:	Private
Phone:	1-800-637-5843
Indian Lands:	The site is not located on Indian lands.

Existing Environmental Permits:

NPDES	Industrial Storm Water Permit IL0061425
UIC	IL-115-6A-0001 IL-115-6A-0002
RCRA	None
Other	Various air permits, including Title V Clean Air Act Permit (#96030038)

Other	Sanitary District of Decatur Pre-Treatment, Permit #200

Nature of Business:

ADM is a manufacturer of biodiesel, ethanol, soybean oil and meal, corn sweeteners, flour, and other value-added food and feed ingredients.

2.2 Cross-Reference Table to Class VI Injection Well Rules

See APPENDIX F: Cross-Reference Table of Class VI Injection Well Rules (40 CFR Subpart H) for list of regulations and how this application meets applicable requirements.

2.3 List of Abbreviations Used in this Application

2D two-dimensional
3D three-dimensional
ADM Archer Daniels Midland
aka also known as
AoR area of review
API American Petroleum Institute
bbls barrels
BGL below ground level
BHA bottom hole assembly
BHCT bottom hole circulating temperature
BHST bottom hole static temperature
BOD basis of design
BOP blow out preventer
bpm barrels per minute
B-T gauge Bourdon-tube gauge
BTC buttress thread & coupling
BTU British thermal unit
C Celsius
CaCl2 calcium chloride
CaCO3 calcium carbonate
CBL cement bond log
CCS carbon capture and sequestration
cf cubic feet
cf/sk cubic feet per sack
CFR Code of Federal Regulations
cm centimeter(s)
CO2 carbon dioxide
cp centipoises (viscosity unit)
csg casing
cu capture units
D&CWOP Drill and complete well on paper
e.g. for example
EMR electronic memory recorder
EOR enhanced oil recovery
EOT end of tubing
est. estimate
etc. et cetera
EUE external upset end
F Fahrenheit
FIT formation integrity test
FEED front end engineering design
FOT fall-off test

FS	full scale
ft	foot or feet
ft/hr	feet per hour
ft/min	feet per minute
gal/sk	gallons per sack
g/L	grams per liter
gpm	gallons per minute
GR	gamma ray
H2S	hydrogen sulfide
HAZOP	Hazard and Operability Study
hp	horsepower
hr(s)	hour(s)
IBDP	Illinois Basin – Decatur Project
IBOP	inside blowout preventer
ID	inside diameter
IEPA	Illinois Environmental Protection Agency
IL-ICCS	Illinois – Industrial Carbon Capture and Sequestration
in.	inch(es)
ISGS	Illinois State Geological Survey
KB	kelly bushing (depth referenced to)
KCl	potassium chloride
km	kilometer(s)
L (l)	liter(s)
Lb (lbs)	pound (pounds)
Lb/ft (lbm/ft)	pounds per foot
Lb/sk	pounds per sack
LCM	lost circulation material
LTC	long thread & coupling
M (m)	meter(s)
m/hr	meters per hour
MASIP	maximum allowable surface injection pressure
MDT	modular dynamic tester
mD	millidarcy (millidarcies)
MD	measured depth
meV	milli electronvolts
mg/L	milligrams per liter
MFC	multi-finger caliper
MGSC	Midwest Geologic Sequestration Consortium
MI	move in
mi.	miles
mL	milliliter
mmscf	million standard cubic feet
MO	move out
Mol.	mole
MOSDAX	modular subsurface data acquisition system

µPa	microPascal
MPa	MegaPascal
MSL	mean sea level
MT	metric tonnes
MT/day	metric tonnes per day
MVA	monitoring, verification, and accounting
N2	nitrogen (atmospheric)
NaCl	sodium chloride
N/A	not applicable
ND	nipple down
NPDES	National Pollution Discharge Elimination System
NRC	Nuclear Regulatory Commission
NU	nipple up
O2	oxygen (atmospheric)
OD	outside diameter
Pa	Pascal (pressure unit)
P&A	plugging and abandonment
P&ID	Piping & Instrument Diagram
PBTD	Plug back total depth
PCSD	Process Control Strategy Diagram
PFD	process flow diagram
PFO	pressure fall off
PISC	post-injection site care
POOH	pull out of hole
Poz	pozzolan
ppg	pounds per gallon
ppb	parts per billion
ppf	pounds per foot
ppm	parts per million
ppmv	parts per million by volume
ppmwt	parts per million by weight
psi	pounds per square inch
psia	pounds per square inch atmospheric
psig	pounds per square inch gauge
psi/ft	pounds per square inch per foot
PV	plastic viscosity
QA	quality assurance
QHSE	quality, health, safety, and environment
Qty	quantity
RCC	Richland Community College
RD	rig down
RU	rig up
RST	reservoir saturation tool
RSTPro	trademark reservoir saturation tool
S (sec)	seconds

SCS	Schlumberger Carbon Services
SCMT	slim cement mapping tool
sk(s)	sack(s)
SIP	surface injection pressure
SP	spontaneous potential
SPF	slots per foot
SRPG	surface-readout pressure gauge
SRTs	step rate tests
SS	stainless steel
STC	short thread & coupling
TBD	to be determined
tbg	tubing
TD	total depth
TDS	total dissolved solids
TEC	tri-ethylene glycol
TIH	trip in hole
TIW	Texas Iron Works (pressure valve)
TOH	trip out of hole
TVD	true vertical depth
UIC	underground injection control
US DOE	United States Department of Energy
USEPA	United States Environmental Protection Agency
USDW	underground source of drinking water
USGS	United States Geological Survey
USIT	ultrasonic imaging tool
V (v)	volt
VFD	variable frequency drive
VSP	vertical seismic profile
WFL	water flow log
WOC	wait on cement

3. Site Geologic Characterization

3.1 Regional geology and geologic structure

Sensitive, Confidential, or Privileged Information [redacted] Figure 3.1-2 displays the petrophysical results of the Mt Simon Formation at CCS#1. The facies of the Lower Mt. Simon are a mixture of several depositional environments that include subaqueous coast, subaerial coast, lagoon, river, plain, and eolian plain (Freiburg J. T., 2016). The Lower Mt. Simon is divided into three subunits (B, A-Upper, A-Lower).

STRATIGRAPHIC COLUMN OF THE ILLINOIS BASIN

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Figure 3.1-1: Stratigraphic Column for the Illinois Basin (ISGS, 2011)

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Figure 3.1-2: Petrophysics at CCS#1 (gamma ray, porosity, and permeability).

References

Freiburg, J. T. (2014). A Depositional and Diagenetic Characterization of the Mt . Simon Sandstone at the Illinois Basin - Decatur Project Carbon Capture and Storage Site , Decatur , Illinois , USA, 73.

Freiburg, J. T. (2016, 05 17). *Current Research on the Mt. Simon Geology; Refining the Lower Mt. Simon Depositional Interpretation.* Retrieved from http://www.sequestration.org/resources/PAGMay2016Presentations/04-Freiburg_IBDP_PAG_2016_Mt-Simon.pdf: http://www.sequestration.org/resources/PAGMay2016Presentations/04-Freiburg_IBDP_PAG_2016_Mt-Simon.pdf

ISGS. (2011). *Stratigraphic Column for the Illinois Basin .*

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Smith, V. L., & Leetaru, H. E. (2014). *2D Seismic Reflection Data across Central Illinois.* Schlumberger Carbon Services.

3.2 Faults and fractures

There is very low risk for faulting or fracturing near the CCS#3 well to impact the arrestment properties of the confining zone at the site. In addition to characterization of the site geology that supports the sealing properties of the cap rocks, during the injection phase of the project to date wherein CO2 was managed in the Mt. Simon at the nearby CCS#1 and CCS#2 wells (beginning in 2012), no loss of containment has occurred and no microseismic events occurred above the injection zone. Faulting does not and will not contribute to lack of containment because:

- In the area, no faulting could be identified on the original 3D seismic processing, and no faults were evident on the newly interpreted 2D seismic lines (Knox 501, Knox 601, Knox 101) as described in Section 3.1. Seismic line Knox 501 passes near to well CCS#3.
- The faults interpreted to be present based on the reprocessed 3D seismic at IDBP to the west of CCS#3 all show very small vertical displacement (throw). Additionally, the faults that may be present in the upper Mt. Simon also are projected to have minimal horizontal offset (<10 feet). None of the faults cut the overlying Eau Claire confining zone. It should be noted that these inferred faults show little correlation to the location of microseismic events recorded during the IBDP project.
- Microseismic events suggest that fractures may be present in the Precambrian, Argenta and lowest units of the Mt. Simon zone, however these zones are well below the confining zone.

No faults were interpreted on the original 3D or 2D seismic. Fault interpretation in this area is very difficult as the faults have small offsets that are well below the resolution of the seismic data. In the Mt. Simon interval, the seismic wavelengths are approximately 200 feet, and offsets of at least ¼ wavelength (50 feet) are typically required for reliable fault interpretation. The seismic used for the CCS#1 and CCS#2 permits did not exhibit any offsets in the seismic signatures to indicate faulting, and no faults were visible on the 2D seismic lines used to extend the structural surfaces for the model used in the reservoir simulation of CCS#3.

3.2.1 Interpreted faults near CCS#1 and CCS#2 based on reprocessed 3D seismic data

Recent reprocessing of the 3D seismic cube was performed to boost the upper frequency band of the 3D seismic data, resulting in a crisper image of the injection zone and the Precambrian basement. The continuity observed in the original seismic section (yellow box in the lower panel of Figure 3.2-1) was disrupted by the frequency boosting (in the upper panel, Figure 3.2-1). After the higher frequencies were boosted in the 3D cube, an edge detection algorithm was applied to the reprocessed data, which identified discontinuities in the 3D seismic that may be attributed to depositional changes or may be related to faulting. The next step was to apply an Ant-tracking algorithm to the edge detection cube to planarize these discontinuities. When constrained by a stereonet filter, Ant-tracking will produce only near-vertical features that imply faulting. However, there is significant uncertainty associated with the use of this algorithm, based on this seismic quality, to identify faults so the location of any features interpreted as faults is suspect. Also, the manual interpretation performed using the Ant-track cube as a guide is a subjective process, and interpretations can vary significantly between interpreters.

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Figure 3.2-1 – Original seismic processing (bottom panel) and 2019 reprocessing (top panel). Note the lateral continuity of the Mt. Simon C in the yellow box on the bottom panel, as compared to the disruption in the seismic signature in the yellow box on the upper panel.

During injection at IBDP, almost 5000 microseismic events were detected (a full discussion in Section 3.8) If faults were to exist, it is expected these would overly the microseismic clusters. **Figure 3.2-**Figure 3.2-2 shows the microseismic events recorded at IBDP, and the interpreted faults (where they intersect the Precambrian horizon). However, Figure 3.2-2 shows there is little correlation between the event clusters and the fault interpretations.

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Figure 3.2-2 – Association of interpreted faults and microseismic events at IBDP. The surface is the Precambrian basement, the white lines represent the intersection of the interpreted faults from the 3D with the Precambrian, and the blue points are the recorded microseismic events. There are several linear clusters of events which show a low degree of correlation with the interpreted faulting.

3.2.2 Fractures implied by microseismic recorded at IBDP

Of nearly 5000 microseismic events recorded at IBDP, the majority occurred in the Precambrian basement, with some occurring in the Argenta and Lower Mt. Simon formations. Figure 3.2-3 shows a cross section of the microseismic events, and a histogram of the depth of the microseismic events below the confining zone. Of the thousands of events shown, all buty two occurred over 900 feet below the base of the confining zone, indicating that these events occurred deep within the section, most originating in Precambrian basement. While occurrence may be associated with Precambrian faults/fractures, the occurrence is limited to deep basement with no events occurring near or above the confining zone.

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Figure 3.2-3 – Cross section through IDBP from Dando, 2021 (a) and histogram of the depth below the confining zone for microseismic events (b). The cross section shows the majority of microseismic events occur in the Precambrian, with some in the Argenta and Lower Mt. Simon. The histogram shows the depth of events below the Eau Claire shale.

3.3 Injection and confining zone characteristics

3.3.1 Variogram Analysis

The porosity logs acquired from the four wells used in modeling provided relatively high vertical resolution regarding effective porosity at each well; however, without using other data, little was known about the porosity values between the wells. To complete geological modeling, it was necessary to interpolate the data from the wells into the interwell space in a way that represented the geological setting. Variogram analysis was used to evaluate the geological setting, and it was used to interpolate the effective porosity of the formations in the interwell space based on the measured log data. Variograms are often determined from well data; however, due to the limited number of well logs available at the site, this analysis could not be completed in a statistically valid way on only four well data set. To complete the modeling, variogram analysis was completed based on the upscaled 2019 Porosity Cube (Figure 3.3-1) because it has a high horizontal sampling rate. The 2019 Porosity Cube was only processed for the Eau Claire Shale down to the upper section of the Precambrian. The upscaling process used an averaging algorithm to define one porosity cube value for each model cell. This provided a way to calculate a series of zone-specific parameters, which included a variogram map, major azimuth, range, sill, nugget, and function types (Figure 3.3-1 and 3.3-2**Figure 3.3-**). The quantified variogram parameters that were generated for each formation are explained below and shown in Table 3.3-1:

- **Variogram map**: In variogram analysis, deciding on the direction of the variogram is one of the first decisions that must be made. This was completed using variogram maps (Figure 3.3-2). Theoretically, the direction of maximum continuity (major direction) and direction of minimum continuity (minor direction) are found after the variograms are calculated in all possible directions (from 0 degree to 359°). Then, the ones that show minimum and maximum range are selected as the variograms that represent the minor and major directions.
    - The major direction defines the direction where the sample points have the strongest correlation. The azimuth angle of this major direction can be changed interactively by editing the direction in the search cone. Azimuth angle is specified as the clockwise angle from the north (in degrees).
    - The minor search direction is perpendicular to the major direction.
- **Range**: The range describes where the variogram model reaches its plateau (i.e., the separation distance where there is no longer any change in the degree of correlation between pairs of data values). The range is specific in each direction for the model variogram. A large range means greater continuity and a small range means less continuity. The larger the range, the smaller the heterogeneity. Major and minor ranges were extracted from the highly horizontal sampled 2019 Porosity Cube, and the vertical range was taken from the well log analyses.
- **Sill:** The sill is the semi-variance where the separation distance is greater than the range (on the plateau). This describes the variation between two unrelated samples.
- **Nugget:** The nugget is the semi-variance where the separation distance is zero.
- **Variogram types**: Different methods (variogram types) exist. The types used in this project were:
    - Spherical: The curve is linear at shorter distances and then makes a sharp transition to a flat sill.
    - Exponential: The curve has an exponential behavior, with a rapid variation at shorter distances.

Table 3.3-1. Variogram parameters extracted from the 2019 Porosity Cube and well logs

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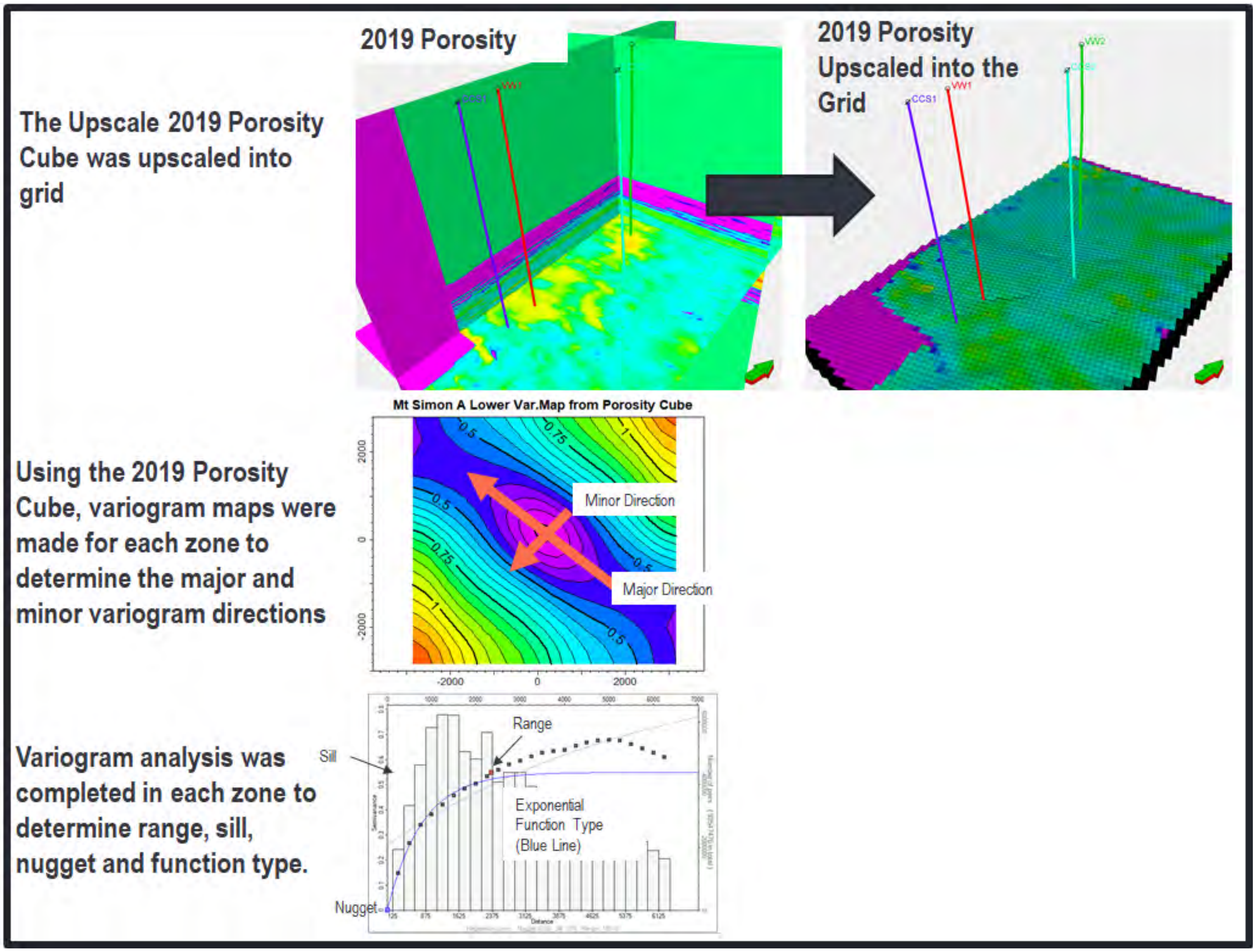

Figure 3.3-1. Steps used to generate the mini grid for geostatistical extraction.

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Figure 3.3-2: Variogram maps extracted from the 2019 Porosity Cube.

3.3.2 Petrophysical Modeling of Effective Porosity and Permeability Interpolation

The effective porosity logs from the four wells used in modeling provided high vertical resolution at each well; however, little was known about the porosity values between the wells. Using the variogram analysis described in Section 3.3.1, the 2019 Porosity Cube was used to guide the petrophysical modeling of effective porosity. This was used because there is a correlation of seismic inversion properties (porosity and acoustic impedance, AI) with the well log properties (porosity and AI). Seismic inversion requires a relationship to be defined between the AI observed in the 3D seismic survey and the total porosity in the well logs. The relationship is then used to transform the 3D acoustic impedance (AI) volume into a porosity volume (2019 Porosity Cube). A reliable correlation between the porosity well log and the 2019 Porosity Cube was found.

Effective porosity and permeability were interpolated using the above-described geostatistics. Because of the presence of reservoir and non-reservoir facies types, the porosity and permeability were modeled separately within each zone and facies type. Cokriging was used to take advantage of the covariance between the effective porosity logs and the 2019 Porosity Cube. This method is appropriate here because the primary data (effective porosity logs) has high vertical resolution but is not present between wells; the related secondary data (2019 Porosity Cube) lacks high vertical resolution but has abundant horizontal sampling between the wells. Using this relationship, in 2020, a more-reliable reservoir model was developed because it capitalizes on the strengths of both the high vertical resolution well log with the higher horizontal sampling seismic data. A plot of the upscaled porosity versus the porosity cube is shown to have a reasonable correlation coefficient of 0.81; therefore, the porosity cube can be used as a reliable cokriging variable (Figure 3.3-3**Figure 3.3-**). Using the geostatistics from each formation from the variogram analysis, permeability was cokriged using Gaussian random function simulation (GRFS) against the effective porosity property (Figure 3.3-3). Cokriging was used to take advantage of the known covariance between effective porosity and permeability.

Synthetic logs were extracted from the geocellular model at the proposed CCS#3 well location (Figure 3.3-4). Increased porosity and permeability are predicted in the Mt. Simon A Upper and Lower formations.

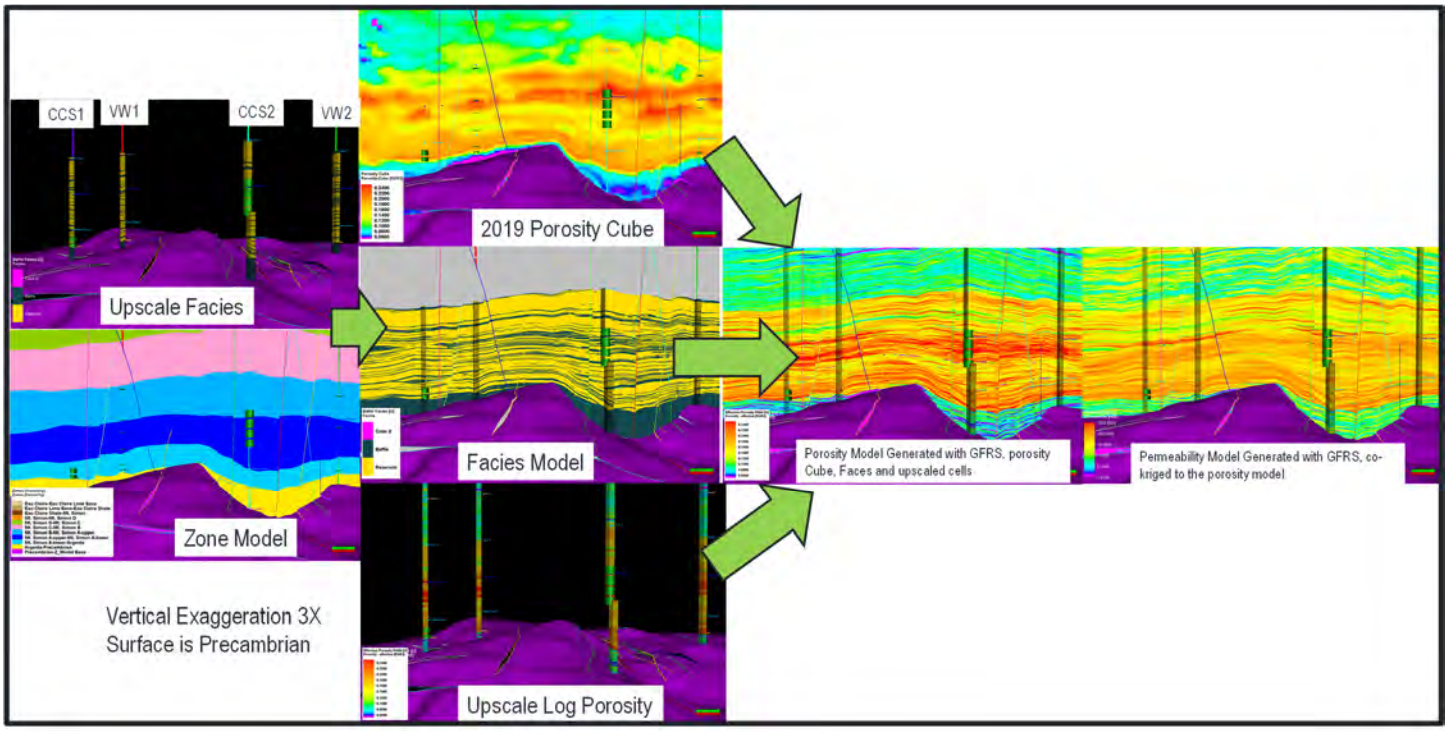

Figure 3.3-3: Property model workflow.

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Figure 3.3-4: Synthetic facies, porosity, and permeability at the proposed CCS#3 well location extracted from the 3D model.

References

Freiburg, J. T. (2014). *A Depositional and Diagenetic Characterization of the Mt . Simon Sandstone at the Illinois Basin - Decatur Project Carbon Capture and Storage Site ,* Decatur , Illinois , USA, 73.

Freiburg, J. T. (2016, 05 17). *Current Research on the Mt. Simon Geology; Refining the Lower Mt. Simon Depositional Interpretation.* Retrieved from http://www.sequestration.org/resources/PAGMay2016Presentations/04-Freiburg_IBDP_PAG_2016_Mt-Simon.pdf: http://www.sequestration.org/resources/PAGMay2016Presentations/04-Freiburg_IBDP_PAG_2016_Mt-Simon.pdf

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Smith, V. L., & Leetaru, H. E. (2014). *2D Seismic Reflection Data across Central Illinois.* Schlumberger Carbon Services.

3.4 Hydrologic and hydrogeologic Information

As with the currently permitted CCS1 and CCS2 Class VI injection wells, the CCS3 Class VI well targets an injection zone in the Cambrian Mt. Simon Sandstone of the Illinois Basin (see coordinates above under Section 2.1). Geologic and hydrologic information on the injection and confining zones was collected during the drilling and testing of the nearby injection wells CCS#1 and CCS#2, as well as the two deep monitoring wells VW#1 and VW#2. Data from an ISGS database of core sample data and additional core sample analyses from sites within approximately 30–80 miles of the injection wells were also used. Wireline log results from CCS#2 and VW#2 and core analyses from VW#2 were compared to data collected from CCS#1 and the ISGS database. The results show good agreement with respect to porosity, permeability, lithology, thickness, and other geologic characteristics, validating the local site geology and hydrogeology. Regarding the formations of interest, Table 3.4-1 details information collected during the construction of the sites four deep wells.

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The Mt. Simon Sandstone is the first formally recognized sedimentary unit overlying the Precambrian granitic basement rock. Based on local site data, the formation tops at 5,537 ft and has an average thickness is 1,586 ft. The depositional environment of the Mt. Simon has "commonly been interpreted to be a shallow, sub-tidal marine environment," based on surface study of the upper Mt. Simon or studies of Wisconsin or Ozark Dome outcrops. However, based on core sample and log analysis from the site's existing wells, and verified from pre-injection testing on CCS#2 and VW#2, the upper Mt. Simon is interpreted to have been deposited "in a tidally influenced system similar to the reservoirs used for natural gas storage in northern Illinois," while the basal 600 ft (the target injection zone) represents an "arkosic sandstone that was originally deposited in a braided river-alluvial fan system." In this lower zone, "abundant amounts" of secondary porosity occur due to the dissolution of feldspar grains. A sedimentary interval known as the "pre-Mt. Simon" is present at the base of the Mt. Simon, bounded by a disconformity (between the Mt. Simon and the pre-Mt. Simon). The pre-Mt. Simon is lithologically similar to the Mt. Simon but with significantly lower porosity and permeability than the overlying Mt. Simon (Freiburg et. al., 2014).

Directly overlying the Mt. Simon Sandstone is the Cambrian Eau Claire Formation. This formation tops at 5,027 ft and has an average thickness of 511 ft. The Eau Claire consists of a basal shale layer overlain by very fine-grained limestone interbedded with thin siltstone layers. The Eau Claire serves as a confining zone for gas storage projects elsewhere in the Illinois Basin. Two other regional shale units are identified as secondary and tertiary confining zones are the Ordovician Maquoketa Formation and the Devonian New Albany Shale, respectively. Although these units protect the locally used sources of underground drinking water, they lie above the designated lowermost USDW.

Only limited data and modeling results are available on ground water flow in the deep Illinois Basin, which is based on modeling results from Gupta and Bair (1997). Flow patterns in the Mt. Simon are "influenced by the geologic structure with flow away from arches such as the Kankakee Arch and toward the deeper parts of the Illinois Basin." In the model, an initial fluid pressure of 3,205 psi (at elevation -6,345 ft MSL), an initial temperature of 112ºF (at elevation - 5,365 ft MSL; gradient 1ºF/ft), and an initial salinity of 200,000 ppm were used. MSL is defined as mean sea level. Like other areas with humid climates (Freeze and Cherry, 1979), the water table in central Illinois is expected to reflect the elevation of the land surface. Steady-state ground water flow modeling for the IBDP site indicates that shallow ground water flows toward the east and southeast toward the Sangamon River and Lake Decatur. Figure 3.4-1 maps the observed head in the Mt Simon and details the location of the proposed injection well.

The lowermost USDW is the Ordovician St. Peter Sandstone. This unit starts at 3,261 ft and has an average thickness of 184 ft. Based on five years of data generated by the annual fluid sampling conducted at GM#2, the TDS of the groundwater ranges between 9,000-10,000 mg/l. Because of the formation depth and high TDS, the St Peter is not currently exploited as a local source of drinking water.

References

Freiburg, J. T. (2014). A Depositional and Diagenetic Characterization of the Mt . Simon Sandstone at the Illinois Basin - Decatur Project Carbon Capture and Storage Site. Decatur, Illinois, USA.

Gupta, N. & Bair, E.S. (1997). Variable-density flow in the mid-continent Basins and Arches region of the United States. *Water Resources Research,* v. 33, n. 8.

Freeze, R. A. and Cherry, J. A. (1979). Groundwater. *Prentice-Hall.*

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Figure 3.4-1. Observed head in the Mt. Simon Sandstone. The red dot represents the location of the Decatur IL CO_2 storage site (potentiometric surface = 76 m/249 ft above mean sea level).

3.5 Geochemical Data and Compatibility of CO_2

The Mt. Simon formation water is dominated by Na-Ca-Cl type chemistry and has total dissolved solids (TDS) around 195 g/L (Labotka et al, 2015). Geochemical modeling was used to predict the effects of the geochemical reactions of supercritical CO_2 with Mt. Simon Sandstone and the formation water (Berger et al., 2009). It was predicted that illite and glauconite would dissolve initially, followed by precipitation of kaolinite and smectite. The study concluded that the volume of pore space would not be significantly altered (Berger et al., 2009) and no compatibility problems, such as a major reduction in injection-formation permeability resulting from chemical precipitates, are expected.

Carroll et al. (2013) conducted a combined experimental and modeling study using Mt. Simon Sandstone and Eau Claire Shale samples under CO_2 storage conditions. The study showed that dissolution of illitic clays and K-feldspar, and precipitation of montmorillonite, amorphous silica, and kaolinite, are the major reaction paths initiated by addition of CO_2. Significant increase in Fe concentration was noticed after CO_2 is introduced, with iron-bearing clays interpreted to be the source of Fe release. The authors suggest that these reactions could alter reservoir and seal permeability by clogging pores and fracture networks. However, the effects of dissolution and precipitation on petrophysics are two sided. Dissolution of the iron clays could increase porosity and permeability locally and promote long-term mineral trapping of CO_2 as Fe carbonates, while precipitation of Fe-carbonates, clays and hydroxides could reduce reservoir and seal permeability by clogging pores and fracture networks.

A recent flow-through experiment study (Dávila, et al., 2020) using a Mt. Simon core sample from the IBDP site coupled with reactive transport modeling also showed changes in flow properties induced by mineral reactions. Rock-water reactions similar to those identified by Carroll, et.al, are documented, including dissolution of K-feldspar, calcite, minor illite and pyrite combined with the precipitation of montmorillonite, mesolite, muscovite, and alunite. Particularly, calcite dissolution at the inlet of the core sample was clearly noted, leading to increased porosity at the inlet. However, overall permeability of the across the core sample decreased at the end of the flow experiment.

Overall, these site-specific studies show similar geochemical reaction pathways to the previous studies from other sedimentary reservoirs and seals. The effects on rock properties, though somewhat varied at the core scale, do not show significant differences from previous studies. Therefore, because previous and current (2020) studies are in general agreement, it is not expected that injection of CO_2 into the proposed CCS#3 well would lead to drastic geochemical reactions within the reservoir and seal that compromise injectivity and long-term security.

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3.6 Geomechanical and Petrophysical Information

3.6.1 Formation Pressure

Fluid sampling and testing were conducted in August 2015 in the VW#2, including in-situ measurements of formation pressure and temperature, and the collection of eight fluid samples at five depths. A temperature log was run in the CCS#2 in 2015. Formation pressure was 3,200 psi at 6,980 KB with a pressure gradient of 0.46 psi/ft. The pressure ranged from 2,626 psi at 5,848 KB to 3,211 psi at 7,041 KB. The formation pressure gradient for the CCS#3 was assumed to be the same without additional data.

3.6.2 Rock Strength

The 1-dimensional (1D) mechanical earth model (MEM) uses log data, core data, pressure, and stress measurements to construct a calibrated model of the rock properties and stresses at the wellbore (Plumb, et al, 2000). With the abundance of data acquired for this project, the 1D MEM properties were well constrained. Three wells; CCS#1, VM#1, VM#2 were evaluated using the 1D MEM workflow (Lee et al., 2014). The average static Young's Moduli in the Mt. Simon and Eau Claire are 4.5 and 5.0 MPsi based on log analysis. The average Poisson's Ratios in these zones were 0.12 and 0.21, respectively. Rock strength testing from laboratory analysis in the Eau Claire Shale from the CCS#1 recorded Unconfined Compressive Strength (UCS) values of 10,986 psi, an internal friction angle of 42.9º, and cohesion of 2,395 psi. The Mt. Simon in the CCS#1 had Unconfined Compressive Strength (UCS) values of 3,247 psi, an internal friction angle of 37.9º, and cohesion of 793 psi.

3.6.3 In-Situ Stress

The in-situ stress field consists of three components: vertical, minimum horizontal, and maximum horizontal. The overburden/vertical stress is determined by integrating the density of the rock with depth. The horizontal stresses are estimated using the poro-elastic stress model which assumes that the rocks are a semi-infinite poro-elastic medium subjected to overburden and horizontal strain loadings (Higgins et al., 2008). The results are summarized in Table 3.6-1. The stress regime is strike-slip ($\sigma_{Hmax} > \sigma_V > \sigma_{hmin}$) with localized normal faulting ($\sigma_V > \sigma_{Hmax} > \sigma_{hmin}$) for intervals with relatively low elastic moduli. This is consistent with earthquake source mechanisms in other parts of Illinois which indicates dominate strike slip stress regime (Lahann et al., 2017). The maximum horizontal stress direction is N68^{o}E based on the drilling induced fractures and breakout orientation. This direction is also consistent with the fast shear azimuth from the dipole shear log.

Table 3.6-1. In-situ stress from 1D MEMs – CCS#1, VM#1, VM#2 (Lee et al., 2014)

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3.6.4 Confining Zone Integrity

Caprock integrity was examined using the in-situ stress and rock mechanical properties from the 1D MEMs for CCS#1, VM#1, and VM#2. The formation was assumed to be intact since no faults were interpreted from 2D and 3D seismic data. Using the geomechanical properties as described above, stress state in the Eau Claire Shale is below the Coulomb failure line both at the initial state and after CO2 injection (Figure 3.6-1). The stress path moves toward the shear failure line after CO2 injection, but the magnitude of stress change is small and the caprock is still within the stable region with minimum risk of shear failure. A pore pressure increase of 650psi was assumed in this analysis, which represents the highest pressure increase directly below Eau Claire Shale from reservoir simulation. Poroelasticity was not accounted for in this analysis. Both assumptions make this analysis more conservative for shear failure evaluation. No tensile failure is expected in the caprock as well due to the high fracture gradient in Eau Claire Shale. A more detailed analysis on the caprock integrity can be performed if small-scale fractures or faults below the current seismic resolution are identified in the future.

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Figure 3.6-1. Stress state in the Eau Claire Shale is below the Coulomb failure line both at the initial state (black dots) and after CO2 injection (grey dots). p' – effective mean stress, q – deviatoric stress. Dark black line represents in failure line using rock strength properties from core analysis in Eau Claire Shale as described in previous section. Two light-colored lines represent failure lines using p10 and p90 rock strength values from log analysis. Poroelasticity was not accounted for, and thus this represents a more conservative evaluation.

3.6.5 Fracture/Fault Stability Analysis

Clusters of microseismic events were observed in pre-Cambrian, Argenta and lowest units of the Mt. Simon away from the wellbores during and after of the CCS#1 and CCS#2 injection periods. Based on the working assumption that microseismic events are caused by incremental failure along pre-existing critically stressed zones of weakness, a total of 12 zones of discontinuity were identified and modeled as fault planes (Lee et al., 2014). These pre-existing weakness zones exist near or at their critical stress rate, and a small variation in injection pressure can result in strain relief along these zones. The finite element model (FEM) combines previous model properties to determine rock strain change with associated change in pressure and generates synthetic microseismic events. These synthetic events compared well with the measured microseismic events for both location and occurrence (Figure 3.6-2). The use of seismic moment to estimate the length of seismogenic slip planes in the local subsurface suggests that faults large enough to produce felt seismicity are unlikely to be present at or near the Decatur site. (Williams-Stroud et.al., 2020).

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Figure 3.6-2. Location of modelled microseismic events (yellow) and measured microseismic events (red). (Lee et al., 2014)

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3.7 Injection & confining zone mineralogy, petrology, and lithology

3.7.1 Mt Simon Sandstone

The Cambrian Mt. Simon Sandstone is a transgressive terrestrial to shallow marine sequence deposited in the proto-Illinois and Illinois basins, and the Michigan and Appalachian basins (Kolata and Nelson, 1990). Depositional environments in the Mt. Simon are highly variable; the numerous interpretations include shallow-marine, deltaic, fluvial, eolian, sabkha, and coastal (Driese et al., 1981; Hagadorn et al., 2002; Fischietto, 2009; Bowen et al., 2011; Freiburg et al., 2014). At the storage site, the Mt Simon Sandstone is over 457 m (1500 ft thick) and can be divided into an upper, middle, and lower unit. The formation consists of well sorted, fine- to coarse-grained sandstone, poorly sorted conglomerates, and minor siltstones and mudstones.

Stratigraphic and petrographic analysis of the whole cores and sidewall cores from three project wells, CCS#1, VW#1, and VW#2, provides detailed site-specific data (Leetaru & Freiburg, 2014; Freiburg et al., 2014). The Lower Mt. Simon contains four major facies originating in various depositional environments that include subaqueous coast, subaerial coast, lagoon, river, plain, and eolian plain (Leetaru & Freiburg, 2014; Freiburg et al., 2016). Major lithologies include fine- to coarse-grained sandstone and granule to pebble conglomerates that are interbedded with low- porosity and permeability, siltstones and mudstones.

The Middle Mt Simon exhibits two distinct lithofacies. The lower facies is composed dominantly of maroon to dark brown subarkose arenite and quartz arenite, interbedded with thin mudstones and wackes (sandstones with clay matrix). This facies also contains planar to cross-bedded coarse-grained poorly sorted sandstones and granule to pebble conglomerates with trace amounts of lithics and clay minerals. The upper facies consists dominantly of quartz arenite and lesser amounts of quartz wacke and occasional thin laminae of allogenic green clay. Hematite cements, in the form of Leisigang bands, are common in both the top and bottom facies (Leetaru & Freiburg, 2014).

The upper Mt Simon Sandstone comprises two interbedded litho-facies (Leetaru & Freiburg, 2014). The first facies is composed of mudstones and pink arkose wacke and subarkose arenites. Sandstones are commonly well cemented with clay and authigenic feldspar. The second facies is comprised of tan to white quartz arenites which are commonly mottled, homogenous, planar, or crossbedded.

XRD data show the predominate mineral phase in the Mt Simon sandstone is quartz, generally over 70%, followed by minor amounts of potassium feldspar (up to 20%) and clay (up to 15%), and small to trace amounts of plagioclase, calcite, siderite, ankerite, dolomite, pyrite, barite, fluorapatite, and hematite. (Freiburg et al., 2014). The most common clays within the Mt. Simon are illite and mixed layered illite-smectite, with small fractions of chlorite and kaolinite (Freiburg et al., 2014). Clay occurs as grain coatings on both quartz and feldspar grains, as pore filling and cement, and as bedded detrital laminae. Iron oxides, primarily hematite and goethite, commonly occur as grain coats, Liesegang bands, residues in stylolites, and at unconformity surfaces within the Mt. Simon (Bowen et al., 2011;

Freiburg et al., 2014). Authigenic clays appear most commonly near weathered feldspar grains and casts of dissolved feldspar grains, indicating that the feldspars may be one possible source of the authigenic clays (Bowen et al., 2011).

The highest reservoir quality occurs in the unconsolidated to partially consolidated, coarser grained quartz arenite and subarkosic sandstone in the Lower Mt. Simon, which exhibits preserved, excellent, primary porosity. Porosity is further enhanced by secondary porosity derived from feldspar dissolution. Some mineral grains are coated by thin layer of clay which prevents quartz overgrowths. Authigenic quartz is the most common cement in the Mt. Simon and is the most significant factor of porosity reduction, along with consolidation (Freiburg et al., 2014).

3.7.2 Eau Claire Shale

The primary seal for the Mt Simon carbon sequestration reservoir is the overlying Eau Claire formation which is approximately 152 m (500 ft) thick at the storage site. Within the Eau Claire Formation is deposited within a tidally influenced, shallow marine depositional environment with four major facies, including (Unit A) intertidal mixed sand/mud flats and tidal channels of the foreshore environment; (Unit B) subtidal deposits of the offshore transition zone; (Unit C) subtidal deposits of the upper shoreface environment; and (Unit D) subtidal mixed carbonate/siliciclastic deposits (Palkovic, 2015). At the proposed site, the lower part of the Eau Claire formation consists of gray to dark gray, highly laminated, fissile shale to silty shale with abundant siltstone beds. The upper part consists of very fine-grained dolomitic limestone interbedded with thin siltstone layers (Leetaru & Freiburg, 2014).

The mineralogy varies widely throughout the Eau Claire. Quartz, K-feldspar, and clays are the most common minerals and comprises the majority of the mineral makeup for most lithologies. Small amounts of plagioclase, calcite, siderite, ankerite, dolomite, and pyrite are commonly present (Palkovic, 2015). The predominant clay minerals are mixed layered illite/smectitie, illite, with small amounts of kaolinite and chlorite. Glauconite is also detected (Leetaru & Freiburg, 2014; Palkovic, 2015).

The mineral phases in the reservoir and seal are all common minerals found in sedimentary rocks. Their reactivity with CO2-rich formation water has been extensively examined by rock-water-CO2 reaction experiments and geochemical simulation. Additionally, a number of field projects of large-scale CO2 injection into sedimentary rock formations with similar mineral compositions have been conducted during the last decades. Due to the relatively low mineral reaction kinetics, no drastic rock-water-CO2 interactions which could pose threats to the viability of the injection projects have been documented. Therefore, we do not expect compatibility issues with the mineral composition at the proposed injection site.

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3.8 Seismic history, seismic sources, and seismic risk

While injection at CCS#1 from 2012-2014 was associated with clear induced microseismic activity, injection at CCS#2 has not resulted in any increase in activity despite no significant change in the scale and quality of active receiver networks used (Dando, et.al., 2021). Monitoring began 18 months prior to injection to record background microseismicity, during this period only 8 local events were detected that were not associated with anthropogenic activity. These eight events ranged in magnitude from -2.16 to -1.52 (Bauer, et.al., 2016).

During injection at CCS#1 from 2014-2017, an average of 4 microseismic events per day were detected for a total of 4,747 events (Bauer, et.al., 2016). Induced microseismicity at CCS#1 started two months after injection began, and by 6 months post injection the activity decreased from around 50-200 events per month to around 20 per month – see Figure 3.8-1(a). Ninety-four percent of the events were less than magnitude 0, and only two events were above magnitude 1 at 1.07 and 1.17 (Bauer, et.al., 2016). Approximately half of the microseismic events were in the Precambrian with the rest in the Mt. Simon and Argenta. Events were grouped into four clusters that tended to follow a northeasterly trend or nearly the direction of S_{HMax}. Microseismic events were not considered large enough to endanger caprock integrity (Bauer, et.al., 2016).

Injection began at CCS#2 in April 2017, and through November 2019 there were only 220 microseismic events located during the injection period, even though CO_2 was being injected at 1.7 times the CCS#1 injection rate (Stanek, et.al., 2020) (Figure 3.8-1**Figure 3.8-**(a)). The reduction in event rate is credited with a shallower injection interval depth, further from the crystalline Precambrian basement and the deepest Mt. Simon that accommodated a significant portion of microseismic events during CCS#1 injection. Induced microseismicity was not considered significant for CCS#2 because many of the injection events were in the same clusters as for CCS#1, and the rate of events detected did not change from the period between CCS#1 and CCS#2 and after injection began at CCS#2.

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Figure 3.8-1 - Event count timeline (a) and magnitude histogram (b) of all events (Stanek, et.al., 2020; Dando, et.al., 2021). From the timeline, the events (mainly occurring in the Precambrian basement) dropped off significantly after injection ceased at CCS#1. The number of events did not noticeably increase with the commencement of injection at CCS#2.

Figure 3.8-2 shows the microseismic events recorded at the IDBP site through June 2018. The events tend to lie in well-defined clusters, and the moment magnitudes for these events are all below the threshold where an event can be felt at the surface. The cross section shown in Figure 3.8-3 shows all recorded events and well locations along a direction perpendicular to S_{HMax}. The events fall almost exclusively in the Precambrian basement, with some events also occurring in the lower Mt. Simon and Argenta formations.

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Figure 3.8-2 - Locations of 5037 microseismic events recorded during injection period of CCS#1 and CCS#2 (December 2011 – June 2018). The events are colored by Moment Magnitude. The blue line represents the position of the cross section in Figure 3.8-3.

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Figure 3.8-3 – Cross section with all wells and microseismic events projected to the plane (shown in blue in Figure 3.8-2). Note most of the events are in the Precambrian basement.

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3.9 Air and Soil Gas Monitoring

At the Decatur CCS site, CO_2 air monitoring is conducted at any well that penetrates the Eu Claire seal formation. Currently CCS#1, CCS#2, VW#1, and VW#2, have CO2 air monitoring at the well site. CO2 air monitoring will be conducted at CCS#3 and VW#3. Because there are no other wells within the AoR that penetrate the injection zone seal formation, no additional air monitoring is planned.

Soil gas and flux monitoring networks were initiated for the Decatur CCS project site in 2009 for the IBDP Project (CCS#1) and 2012 for the IL-ICCS Project (CCS#2). The soil flux monitoring network consisted of approximately 70 soil flux collars installed within the project area and were co-located with approximately 50 soil gas nests. Monitoring of these networks continued through 2015 collecting about six years of background and operational data (during CCS#1 injection period 2011-2014).

Soil CO2 flux was measured on a monthly basis. Soil gas was sampled on a quarterly basis and analyzed using gas chromatography for CO2, N2, O2 and light hydrocarbons (C1 to C6). In addition, selected samples were be analyzed for isotope composition δ13C, δ18O and radiocarbon (Δ14C) of CO2 to help determine the source of CO2 in the soil. In addition, background concentrations were measured to determine statistical variations of CO2 with respect to sample temperature, seasonal variations, diurnal variations and other factors. Soil gas samples were initially collected on a monthly basis and were reduced to quarterly after sufficient baseline information was collected to characterize the seasonal variability in gas composition and isotopic signatures. All analytical results have been archived and are available to the USEPA upon request.

Because sufficient baseline and operational data has been generated for the Decatur CCS Site and no statistical changes were observed during the injection period for CCS#1 and the pre-injection period for CCS#2, no further soil gas or flux monitoring is planned at this time.

3.10 Facies changes in the injection or confining zone

When the reservoir simulations began in 2008, there were challenges with history matching between the observed data and the simulation results. The history matching helped refine the geomodel by using the discrepancies between the observed and the simulated CO2 migration to highlight regions of the geomodel that required modification. These model modifications were changes to structure and property distribution (porosity and permeability) that were not clear or had been uncertain earlier.

In the 2018 model update, adding baffle facies layers became necessary for history matching. These baffle facies are areas of relatively lower porosity and relatively lower permeability barriers, which were interpreted layers within the Mt. Simon Formation. When the reservoir simulations were run, the baffle layers were used as discontinuous barriers to CO2 and pressure migration. On the well logs, these baffles have been interpreted to occur in intervals where the porosity and permeability are low. From this log interpretation, the baffles were not always continuous between wells (dark green baffles with yellow reservoir on track 6 of Figure 3.10-1). Some baffles could be correlated from well to well and some could not. The justification for adding these baffle facies into the model was as follows:

- The first recognized influence of layered baffles was the pressure reactions at VW#1 during the CCS#1 injection, with the highest formation pressure increases of about 5.1% in the lowest three gauges, highs of only about 1.7% increase in gauge 4, and less formation pressure increases in higher gauges. Also, CO2 was detected in VW#1 at Zone 3 and lower but not at Zone 4 and higher.
- When CCS#2 injection began in the lowest perforation, a higher-pressure response occurred at the CCS#1 injection interval than was modeled. This indicates there may be a preferential pathway from CCS#2 to CCS#1; however, such a high-pressure response at VW#1 compared to the previous modeled response did not occur, suggesting a different degree of connection between CCS#2 to CCS#1 and CCS#2 to VW#1. A directional preferential pathway was seen by CCS#2 pressure response first arriving at VW#1 far before VW#2 which is closer to CCS#2.
- The pressure response at VW#2 (Zone 2) indicated that reservoir interval including VW#2 (Zone 2) and CCS#2 might be locally confined by the low-permeability baffles.
- Although the Mt. Simon A-Lower was believed to be undifferentiated, repeat pulsed neutron logs at VW#1 show that high-permeability sand packages and interlayered low-porosity and low-permeability layers (baffles) strongly control vertical CO2 plume geometry at distance from the injector.
- These observed preferential pathways/flow barriers suggested that strong heterogeneity (porosity and permeability) exists in the reservoir. Adding the baffle facies allowed for better history matching results in all the simulation scenarios.

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Figure 3.10-1. Petrophysics, completions, and baffle facies interpretation on low-porosity and low-permeability layers.

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3.11 Injection zone storage capacity

For the injection scenarios lateral extent of plume is mapped and area of plume calculated at year 2038 (end of injection) and fifty year after injection stops in year 2088. Figure 3.11-1 show the plume for each case superimposed on satellite image.

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Figure 3.11-1. 40Mt injection. Image on the left represents the plume extent at the end of injection in year 2038. Image on the right represents the plume extent in year 2088. Plume covers an area of 2.95 and 3.45 square mile respectively.

The targeted injection zone is a vertical interval of 195 ft mainly within the Mt. Simon reservoir's A Upper Unit (See Figure 3.11-2). The injection zone has an effective porosity of approximately 0.15 ft^3/ft^3 (15%). During the injection period 40 million metric ton of CO_2 will be stored in this formation. The horizontal spacial extent of the plume is approximately 118.2 million ft^2. Based on the projected average reservoir pressure and temperature of 3,800 psia and 120°F respectively, the CO_2 has a specific volume of 0.0189 ft^3/lb. Ignoring solubilization of CO_2 in the brine, the injected free phase CO_2 will have a bulk volume of approximately 1.7 million ft^3. Multiplying the effective porosity by the injection interval and spacial extent of the plume, the reservoir has a pore space volume of approximately 3.46 Million ft^3. Therefore approximately 48% of the available pore space is being used by the CO_2. When considering the Mt Simon Sandstone as a complete storage unit and fully utilizing this unit for injection. Figure 3.11-3 shows that the reservoir is 1,490 ft in thickness and has an average porosity of 12.9%. The capacity of the formation within the spacial extent of the plume is approximately 22.8 million ft^3. Therefore, the proposed injection volume would use approximately 7.3% of the available pore space.

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Figure 3.11-2: Injection well completion diagram showing the model's effective porosity and permeability.

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Figure 3.11-3: Reproduced layers of the geologic model and average porosity/permeability values, as identified by ADM based on log analysis, along with the approximate screened intervals of CCS #1 and CCS #2.

3.12 Confining zone integrity

The median porosity of the Eau Claire Formation is 4.7%, based on information from an ISGS database of UIC well core samples. Pre-injection testing in CCS#2 and VW#2 indicated very small pore sizes based on CMR data, resulting in generally very low permeability. During pre-operational testing, ADM collected 33 horizontal and 3 vertical whole core samples, and 2 rotary sidewall core samples, all from VW#2. Three hundred fifty-one (351) core plugs were drilled from the whole core collected from VW#2 and were suitable for routine core property measurements. The rock properties derived from these samples were primarily used to validate and calibrate the ELAN petrophysical model based on well logs. While no core samples were taken from the shale zone of the Eau Claire A at VW#2, 36 plugs of the upper interval Eau Claire C (very fine sandstone, microcrystalline limestone, and siltstone) were available for testing. Of the plugs tested for vertical permeability, the average permeability was 0.036 mD. While no core samples were taken from the shale zone of the Eau Claire A at CCS#1, 12 plugs of the lower portion of the upper interval Eau Claire B/C (very fine sandstone, microcrystalline limestone, and siltstone) were available for testing. Average horizontal permeability for these sidewall rotary core samples was determined to be 0.000344 mD. However, the vertical permeability of the actual shale interval is expected to be much lower because vertical permeability of plugs "is generally lower than horizontal permeability and shale permeability is generally much lower than sandstone, limestone, and siltstone." Based on the analysis of log results from CCS#1 and confirmed by well logs in CCS#2, the Eau Claire, extending from the top of the Mt. Simon to -4,545 ft MSL (-5,227 ft KB), is described as having "only a few small intervals of less than a few feet that have any permeability greater than 0.1 mD," which do not appear to be continuous.

ADM also cited a median permeability value of 0.000026 mD from the ISGS UIC core database. In addition, based on a set of core samples from a site approximately 80 miles to the north of the proposed Class VI location, of the 110 analyses conducted, most were in the range of < 0.001 to 0.001 mD, with five in the range of 0.100 to 0.871 mD (the maximum value in the data set). This indicates that even the more permeable beds in the Eau Claire Formation are expected to be relatively tight and tend to act as sealing lithologies.

A "mini-frac" field test was used to determine in-situ fracture pressure in the confining zone. Fracture pressure results (from four short-term injection/fall-off test periods, 15 to 60 minutes each) ranged from 5,078 to 5,324 psig, corresponding to a fracture gradient ranging from 0.93 to 0.98 psi/ft in the Eau Claire shale zone which significantly greater than the fracture gradient of 0.715 psi/ft in Mt Simon. As maximum injection pressure is limited at 90% of the fracture pressure gradient at Mt Simon formation, Eau Claire will not be exposed to pressures which could create induced fractures.

4. Area of Review (AoR) Delineation and Corrective Action Plan

4.1 Conceptual site model

The Midwest Geological Sequestration Consortium's (MGSC) Illinois Basin-Decatur Project (IBDP) started injecting CO2 through CCS#1 injector well at the bottom section of Mt. Simon sandstone formation in November 2011. In November 2014, IBDP reached its goal of injecting one million metric of CO_2. The Illinois Industrial Carbon Capture and Storage (ICCS), led by ADM, expanded the site's CO_2 injection and storage capability with the objective to inject up to one million metric tons per year through CCS#2 injector well.

During the course of both projects, an extensive data set established through various monitoring activities. The data obtained includes but not exclusive of injector's bottomhole pressure (BHP), multi-zone pressure data from in-zone verification wells VW#1 and VW#2, spinner data, i.e. injection profile logs and reservoir saturation tools (RST) from both injectors. These datasets allowed calibration of various reservoir parameters including intrinsic permeabilities, relative permeabilities, wellbore skin values, vertical to horizontal permeability ratios, and rock compressibility. These calibrations allow the model to be updated periodically to improve the accuracy between the model predictions versus the actual result.

The previous studies compiled by Zaluski & Lee (2018, 2020) describes the steps taken to create the history matched (calibrated) model. The calibrated model includes the injection data acquired until June 2021. The dynamic model includes the entire Mt. Simon and the overlying seal (the Eau Claire), spanning a 40 × 40 mile area. The final reservoir model was represented by a 247 × 247 × 110 grid in a Cartesian system with 247 grid points in the x-direction, 247 grid points in the y- direction, and 110 grid points in the z-direction, for a total of 6,710,990 grid points.

Description of Software

ECLIPSE 300 is a compositional finite-difference solver that is commonly used to simulate hydrocarbon production and has various other applications including carbon capture and storage modeling. The CO2STORE module accounts for the thermodynamic interactions between three phases: an H2O-rich phase (i.e., 'liquid'), a CO2-rich phase (i.e., 'gas'), and a solid phase, which is limited to several common salt compounds (e.g. NaCl, CaCl2, and CaCO3). Mutual solubilities and physical properties (e.g. density, viscosity, enthalpy, etc.) of the H2O and CO2 phases are calculated to match experimental results through a range of typical storage reservoir conditions, including temperature ranges between 12°C-100°C and pressures up to 60 MPa. Details of this method can be found in Spycher & Pruess (2005). Additional assumptions governing the phase interactions throughout the simulations are as follows:

- The salt components may exist in both the liquid and solid phases.
- The CO2-rich phase (i.e., 'gas') density is obtained by using the Redlich-Kwong equation of state. The model was accurately tuned and modified as further described below (Redlich and Kwong, 1949).
- The brine density is first approximated as pure water then corrected for salt and CO_2 concentration by using Ezrokhi's method (Zaytsev & Aseyev, 1992).

•The CO2 gas viscosity is calculated per the methods described by Vesovic et al. (1990) and Fenghour et al. (1998).

The gas density was obtained using a modified Redlich-Kwong equation of state following a method developed by Spycher and Pruess (2005, 2009), where the attraction parameter is made temperature dependent.

The transition between liquid CO_2 and gaseous CO_2 can lead to rapid density changes of the gas phase; the simulator uses a narrow transition interval between the liquid and gaseous density to represent the two phase CO2 region.

Because the compression facility controls the CO_2 delivery temperature to the injection well between 80°F and 120°F, the temperature of the injectate will be comparable to the reservoir formation temperature within the injection interval. Therefore, the simulations were carried out based on isothermal operating conditions. With respect to time step selection, the software algorithm optimizes the time step duration based on specific convergence criteria designed to minimize numerical artifacts. For these simulations, time step size ranged from 8.64x101 to 8.64x105 seconds or 0.001 to 10 days. In all cases, the maximum solution change over a time step is monitored and compared with the specified target. Convergence is achieved once the model reaches the maximum tolerance where small changes of temperature and pressure calculation results occur on successive iterations. New time steps are chosen so that the predicted solution change is less than a specified target.

Field Development Plan

In this study, the calibrated model was used to evaluate a new development strategy that comprises of reactivating CCS#1 injector and drilling a new injector well CCS#3.

During its operational period, CCS#1 injector injected over 55 ft. interval at the bottom of Mt. Simon formation in the interval identified as Mt. Simon A-lower. CCS#2 is currently injecting in the interval identified as Mt Simon A-upper and Mt. Simon B which overlay the Mt. Simon A-lower. The development strategy evaluated in this study comprises of re-completing CCS#1 in Mt. Simon A-upper and Mt. Simon B, continuing injection in CCS#2 through its existing completions and targeting Mt. Simon A-upper and Mt. Simon with the new CCS#3 injector well. The location of CCS#3 was determined by ADM can be seen in the Figure 4.1-1.

Sensitive, Confidential, or Privileged Information

[redacted]

Figure 4.1-1. Injector and Verification well locations. CCS#3 is the planned location for the new injector. All other represents the actual locations.

Injection interval of each well can be seen in Figure 4.1-2. All the new proposed injection intervals in CCS#1 and CCS#3 remains deeper than the CCS#2 injection interval. This in return do not alter the upper most perforated interval depth and hence the critical pressure used to define pressure driven Area of Review (AoR). Therefore, the threshold pressure which was used for CCS#2 permitting is still valid for AoR identification and will be further explained in Section 4.2.

Sensitive, Confidential, or Privileged Information

[redacted]

Figure 4.1-2. Existing and proposed injection interval. The perforations in the bottom part of CCS#1 were used as part of IBDP project. The proposed perforations are located in Mt. Simon A Upper zone and shallower compared to the perforations that exist in CC#2 injectors. Similarly, the proposed CCS#3 injector has perforated intervals in Mt. Simon A Upper and Mt Simon B zones deeper compared to the perforations at CCS#2 injector.

Simulation Results

In the simulation, the primary constraint on maximum injection rate is defined by the maximum allowable injection pressure. A step rate test at CCS#1, in the interval of -7,025 ft KB to -7,050 ft KB was conducted to estimate the fracture pressure of the injection zone. The result from the uppermost perforation of CCS#1 (-7,025 ft KB) was 5,024 psig, corresponding to a fracture gradient of 0.715 psi/ft. 90% of the fracturing pressure was calculated at the top of the shallowest perforated interval and used in the simulations as the maximum allowable injection pressure. The second parameter that constraints the injection is the maximum injection rate allowed for each well and scenario. The final constraint is applied at the field level. Each scenario has a target field injection rate over the injection period. For second and third cases the target field injection rate is smaller than the sum of the maximum allowed injection rate defined at well level. This configuration allows wells to compensate for each other within the allowable rate and pressure constraints.

As can be seen in Figure 4.1-3, in bottomhole pressure and injection rate plots all three wells can inject the target injection rate without reaching maximum allowable injection pressure. The cumulative injection for CCS#1, CCS#2 and CCS#3 are 10.1, 16.4 and 14.3 million tonnes, respectively.

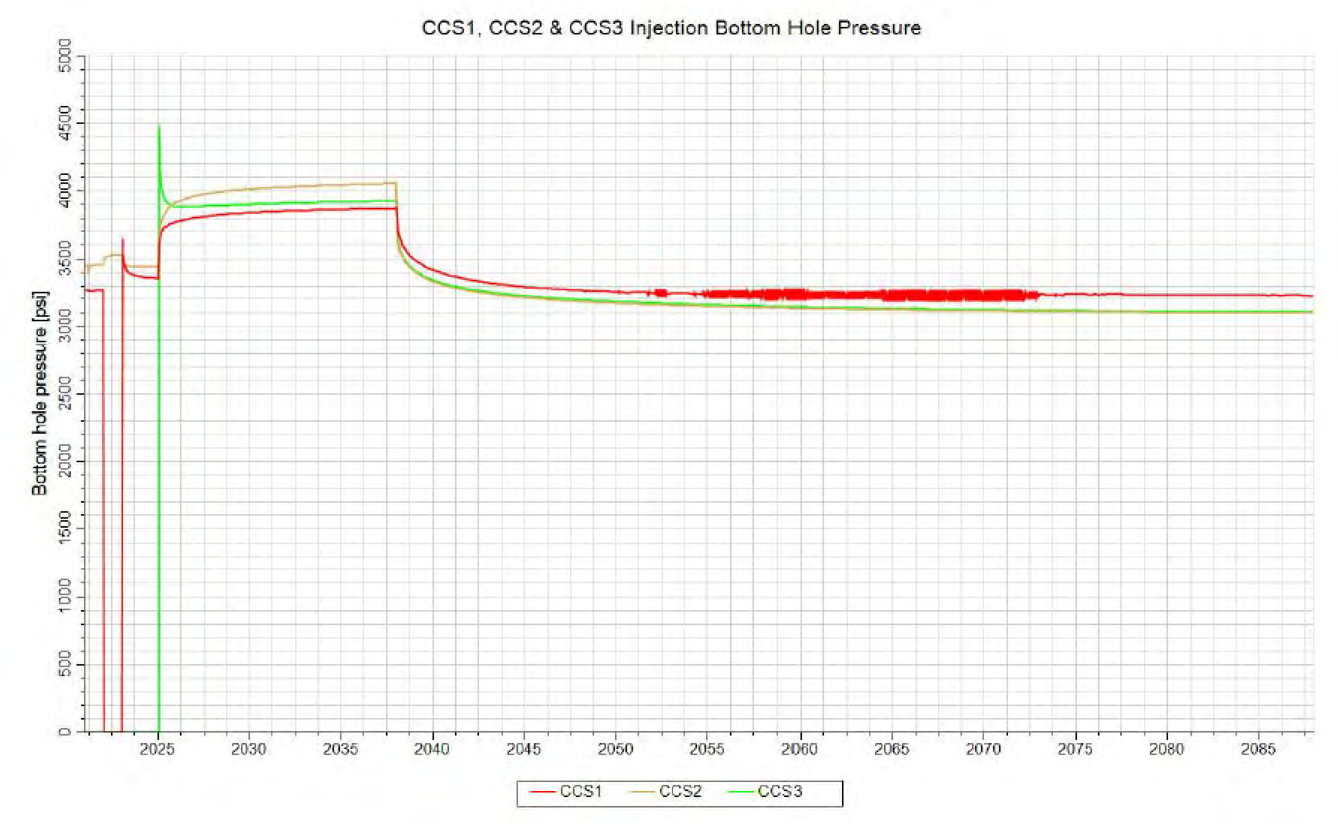

Figure 4.1-3. Injector bottomhole pressure for 40 Million ton injection scenario.

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4.2 Computational AoR delineation model

4.2.1 Pressure Delineation Model

To delineate the pressure front, the minimum or critical pressure (Pi,f) necessary to reverse flow direction between the lowermost USDW and the injection zone—and thus cause fluid flow from the injection zone into the formation matrix—must be calculated.

Based on the Method 1 provided in the May 2013 UIC Program Class VI Well Area of Review and Evaluation and Corrective Action Guidance document, the increase in pressure that may be sustained in the injection zone is given by:

$$\Delta P_{if} = P_u + \rho_i g \cdot (z_u - z_i) - P_i$$

Pi = is the initial pressure in the injection zone,

Pu = initial pressure of the lowermost USDW,

ρi = fluid density of the injection zone,

ρu = fluid density of the lowermost USDW, g = acceleration due to gravity,

zu = elevation of the lowermost USDW and

zi = elevation of the injection zone.

The values that were used in the calculations can be found in the Table 4.2-1. The pressure of USDW in St Peter formation obtained from ground water monitoring well GM#2 downhole pressure gauge. Zone two downhole pressure gauge at VW#2 was used to determine Mt Simon reservoir pressure. Water densities in Mt Simon and St Peter was obtained from ground water samples from VW#2 and GM#2 respectively. Formation depths are taken at CCS#2 injector as the shallowest injection interval is located in this well.

Units	Description (units)	CCS#2
P_u	Pressure in the St Peter USDW (Pa)	Sensitive, Confidential, or Privileged Information [redacted]
P_u	St Peter Fluid head (m)	
	St Peter Level of Fluid (m)	
P_i	Pressure in the Mt Simon (Pa)	
P_i	Mt Simon Fluid head (m)	
	Mt Simon Level of Fluid (m)	
$p_{i\,brine}$	Mt Simon brine density (kg/m3)	
$p_{u\,water}$	St Peter water density (kg/m3)	
g	gravity (m/s2)	
z_u	**St Peter Depth (ft)**	
z_u	St Peter Depth (m)	
z_i	**Mt Simon Reference Depth (ft)**	
z_i	Mt Simon Reference Depth (m)	

Table 4.2-1. Parameter space and values that were used to calculate critical pressure which is used to identify pressure induced Area of Review, per May 2013 UIC Program Class VI Well Area of Review and Evaluation and Corrective Action Guidance document.

The corresponding Pi,f value is calculated as negative 28.2 psi and indicates that Mt Simon is over pressured with respect to St Peter formation which is the deepest USDW in the region. Therefore, as suggested in the guidance document, Method 2 was used to estimate pressure front based on the displacing fluid initially present in the borehole, assuming (1) hydrostatic conditions and (2) initially linearly varying densities in the borehole and constant density once the injection zone fluid is lifted to the top of the borehole (i.e., uniform density approach). The threshold pressure increase (ΔPc) may be calculated by:

$$\Delta P_c = \frac{1}{2} \cdot g \cdot \xi \cdot (z_u - z_i)^2$$

Where ξ is a linear coefficient defined by;

$$\xi = \frac{\rho_i - \rho_u}{z_u - z_i}$$

The corresponding critical pressure value calculated to be 90.4 psi. As suggested in the UIC Program Class VI Well Area of Review and Evaluation and Corrective Action Guidance document, some over-pressurization within the injection zone may be allowable without causing sustained fluid leakage, owing to the density differential between the injection zone and USDW. If the value of ΔPc using Method 2 is greater than the absolute value of ΔPi,f using Method 1, the difference in magnitude between the two is used as an estimate of the allowable pressure increase. Hence, using this approach allows 62.2 psi pressure increase in the injection interval and anything more should be within the area of review.

4.2.2 Reservoir Modeling Results

The 62.2 psi pressure front was extracted from the simulation results for the three volumetric sensitivity cases discussed further in Section 4.2.3. Simulation results evaluated on yearly basis during the injection period until the year 2038 and every 5 years thereafter. In 40Mt, in 2043, 62.2 psi pressure front reaches its maximum extend. In Below, in Figure 4.2.2-1, maximum extent of the 62.2 psi pressure front can be seen in teal with a radius of 8.1 miles.

Figure 4.2.2-1. Maximum extent of the 62.2 psi pressure front for 40 Mt injection scenarios with a radius of 8.1 miles. 40 Mt injection is the planned injection scenario.

4.2.3 Sensitivity Discussion

To determine the sensitivity of model projections to input parameters, an analysis was conducted to estimate plume size as a function of total injected volume. Figures 1 through 3 present modeled CO_2 plumes corresponding to total injected volumes of 40, 50 and 60 million tons during the projected operational lifetime. As summarized in Table 2, a 50% increase in injected volume results in about a 15 to 20% increase in equivalent plume radius.

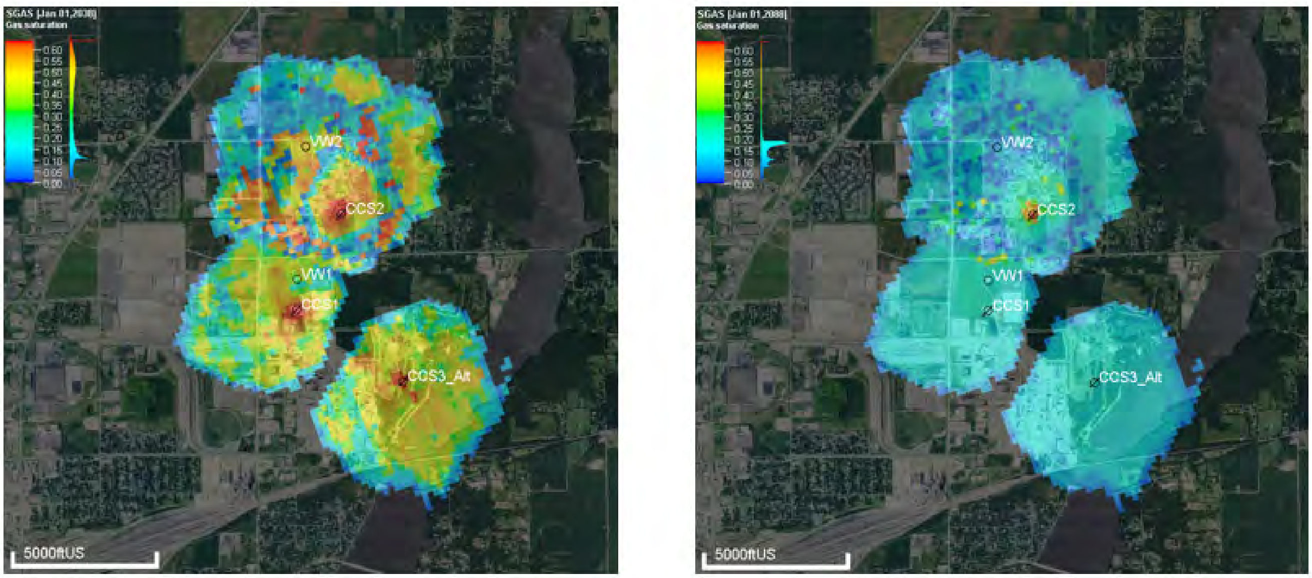

Figure 4.2.3-1. Case 1 – 40Mt injection. Image on the left represents the plume extent at the end of injection in year 2038. Image on the right represents the plume extent in year 2088. Plume covers an area of 2.95 and 3.45 square mile respectively.

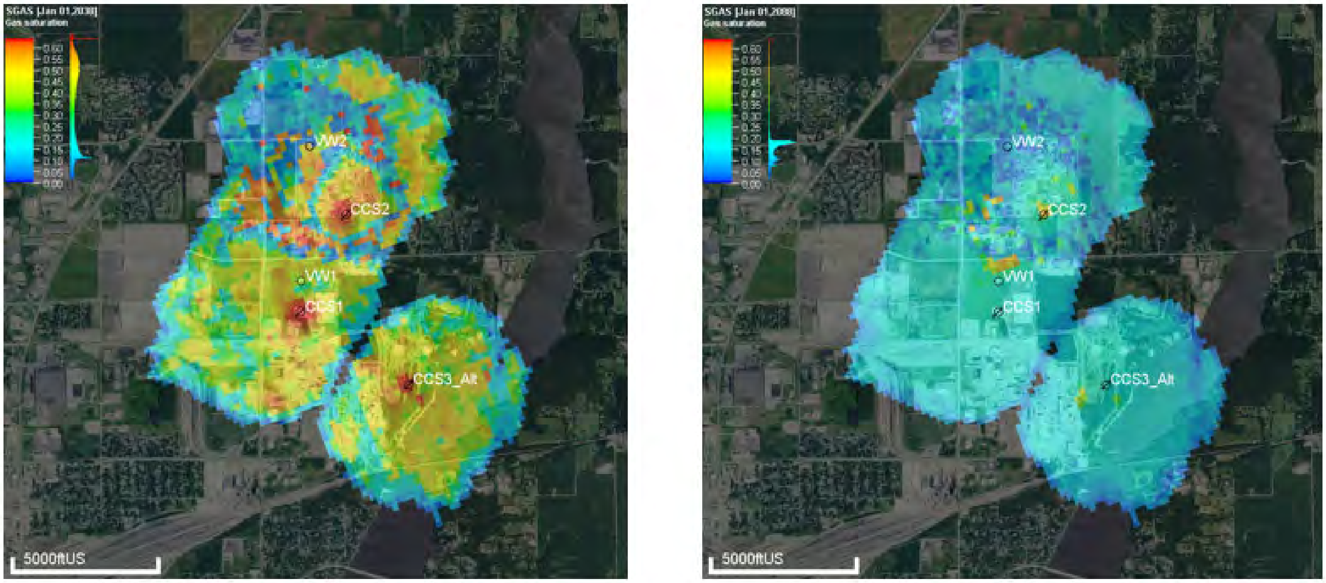

Figure 4.2.3-2. Case 2 – 50Mt injection. Image on the left represents the plume extent at the end of injection in year 2038. Image on the right represents the plume extent in year 2088. Plume covers an area of 4.30 and 4.83 square mile respectively.

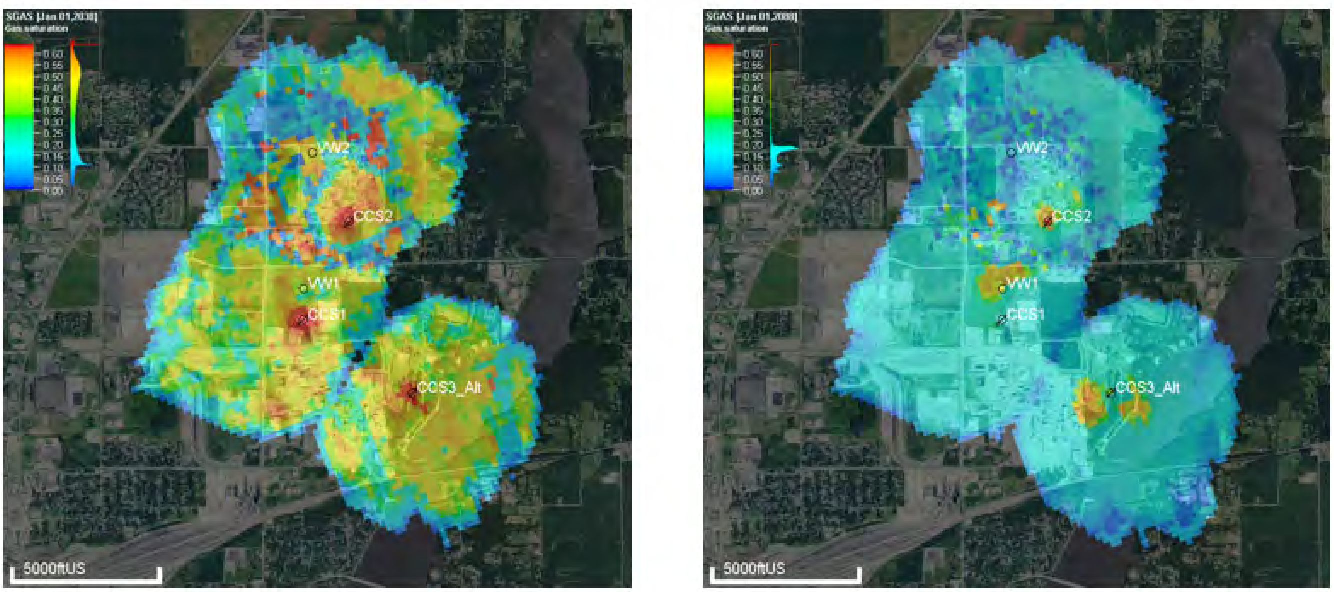

Figure 4.2.3-3. Case 3 – 60Mt injection. Image on the left represents the plume extent at the end of injection in year 2038. Image on the right represents the plume extent in year 2088. Plume covers an area of 4.35 and 4.96 square mile respectively.

Year	Plume Area (mi2)		
	40Mt	50Mt	60Mt
2037	4.20	4.81	5.44
2088	4.57	5.25	6.01

Table 4.2.3-1. Plume Area

Year	Equivalent Circle Radius (mi)		
	40Mt	50Mt	60Mt
2038	1.16	1.24	1.32
2088	1.21	1.29	1.38

Table 4.2.3-2. Equivalent Plume Radius

Predicted pressure-rise demonstrates similar sensitivity to injected volume. In 40Mt and 50Mt injection cases, in 2043, 62.2 psi pressure front reaches its maximum extend. In 60Mt injection case pressure front reaches its maximum extent in 2048; 10 years after injection ceases in 2038. Figure 4.3.2-4 presents the 62.2-psi AoR boundaries for the same 3 cases of projected rate. As shown, a 50% increase in injected volume will extend the AoR radius by approximately 20%. Post-injection pressure behavior is similar for all rate assumptions, with the cone of influence predicted for each of the 3 sensitivity cases reducing to less than 1% of its maximum size over a 50-year post-injection timeframe.

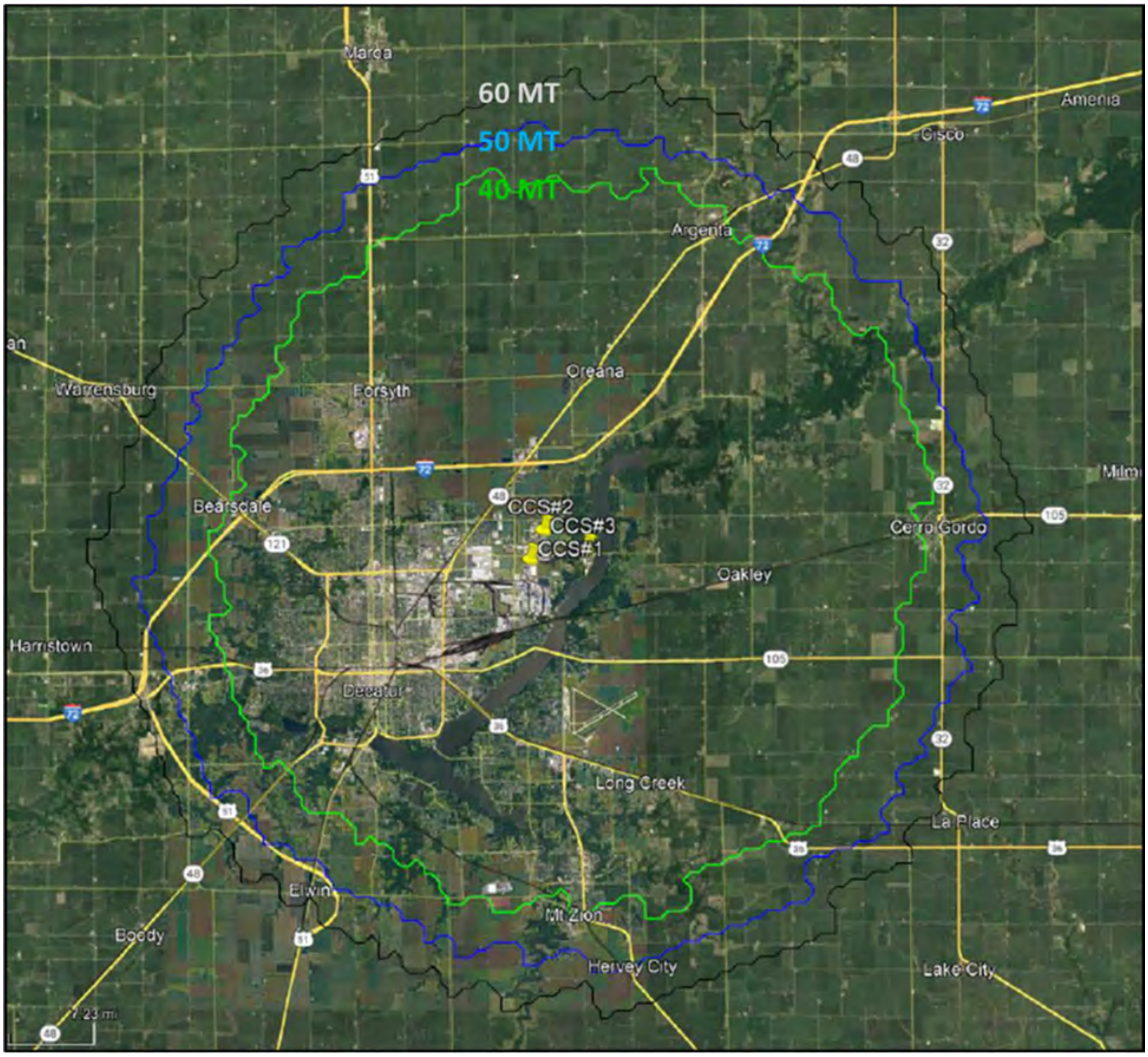

Figure 4.2.3-4: AoR Boundary vs Total Injected Volume

In addition, variations in primary reservoir parameters (permeability and thickness) have similar impacts on projected plume behavior as changes in rate. Based on supplementary modeling, increasing the thickness by a factor of 50% reduces plume radius by approximately 20% while permeability has a much smaller effect.

Relatively large changes to major model input parameters result in limited changes to predications. In fact, the level of characterization for the site and for the probable injection rates/volumes is more accurate than these very generalized sensitivity examples that have been presented for illustration purposes. The proposed testing and monitoring program will allow for comparison and tracking of plume and pressure development throughout the life of the project.

Maximum Allowable Bottomhole Pressure – 50 Million Tonnes Scenario

All three wells can inject the target field injection rate without reaching the maximum allowed bottomhole pressure. As can be seen in the injection rate plot, CCS#1 and CCS#3 - being two edge wells – inject at maximum allowable rate as CCS#2 being in between the two wells gets impacted by the pressure interference. In this case, the cumulative injection for CCS#1, CCS#2 and CCS#3 are 19.1, 12.1 and 18.8 million tonnes, respectively.

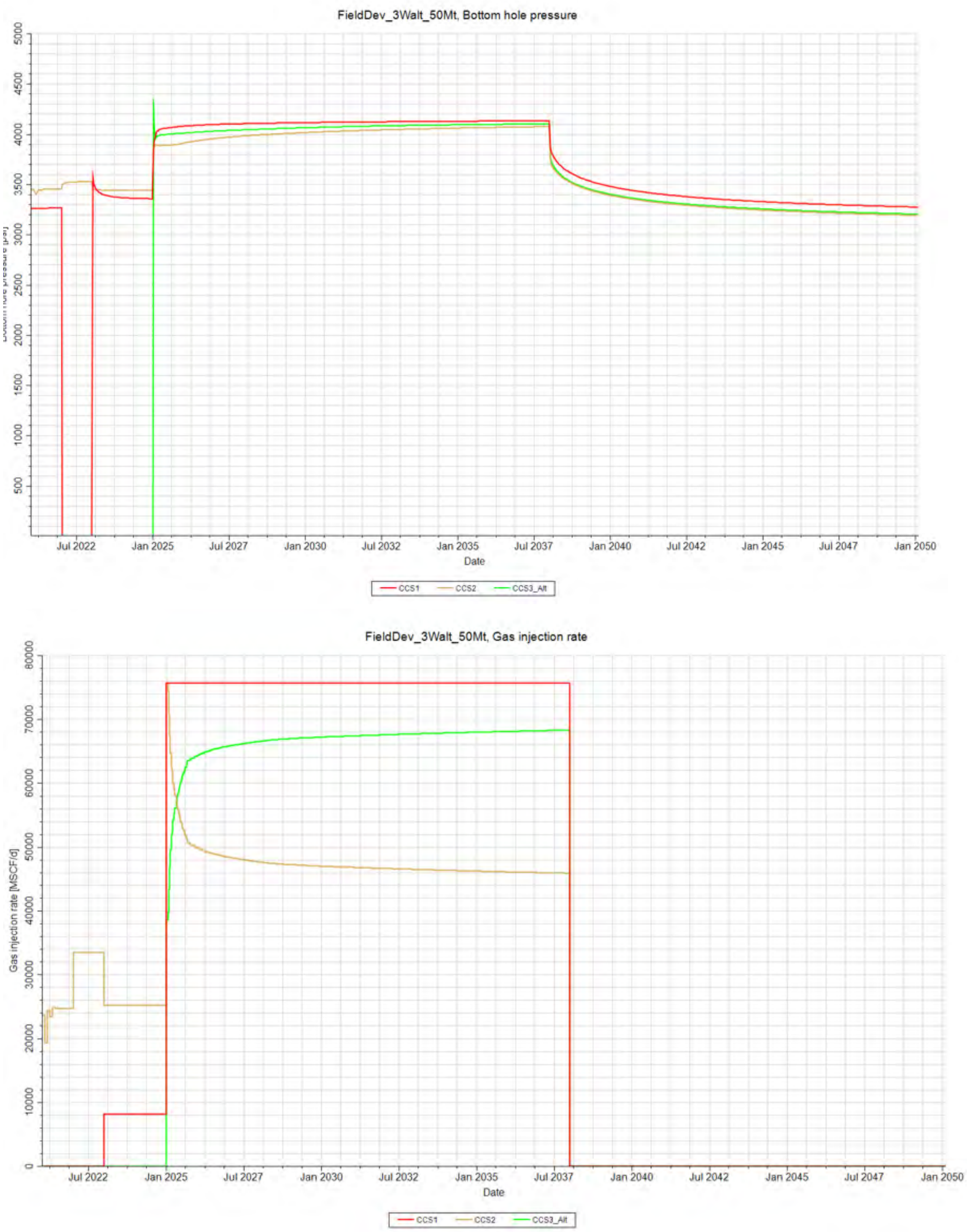

Figure 4.2.3-5. Injector bottomhole pressure and injection rate profiles for 50 Million ton injection scenario.

<u>Maximum Allowable Bottomhole Pressure – 60 Million Tonnes Scenario</u>

All injectors behave in similar manner as in 50 million tons scenario. All three wells can inject the target field injection rate without reaching the maximum allowed bottomhole pressure. As can be seen in the injection rate plot, CCS#1 and CCS#3 inject at maximum allowable rate and CCS#2 injects the remaining required rate to achieve field target injection rate. In this case, the cumulative injection for CCS#1, CCS#2 and CCS#3 are 21.4, 17.5 and 21.1 million tonnes, respectively.

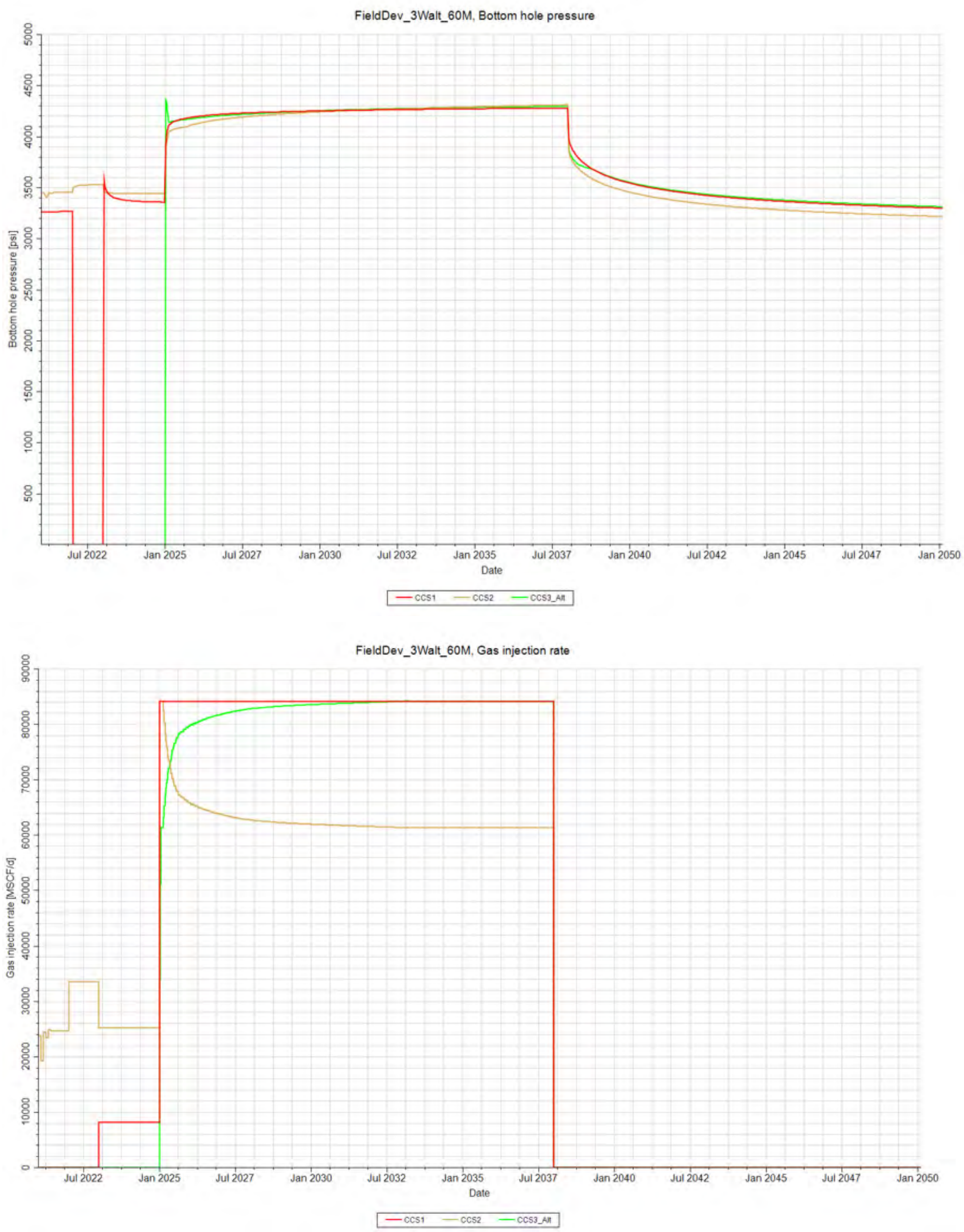

Figure 4.2.3-6. Injector bottomhole pressure and injection rate profiles for 60 Million ton injection scenario.

The table below summarizes the injection rate, simulated maximum injection pressure, maximum allowable pressure for each well and each case.

	Max Simulated Pressure, psi			Max Allowed
	Case 1	Case 2	Case 3	Injection Pressure
CCS1	3,880	4,140	4,270	4,527
CCS2	4,065	4,065	4,320	4,389
CCS3	3,915	4,110	4,300	4,367

Table 4.2.3-3. Maximum simulated bottomhole injection pressures for each well and scenario and maximum allowed bottomhole pressures for each well.

4.3 Artificial penetrations within the AoR

The AOR is presented in Figures B.1 and B.2 in Appendix B and was calculated based on CCS#1, CCS#2 [redacted] those associated with the Illinois Basin Decatur Project (IBDP) and Illinois Industrial Carbon Capture and Storage (IL-ICCS) projects, as described below], no wells were identified from public records that penetrate the confining zone within the AoR.

4.3.1 Tabulation of Wells within the AoR

<u>Wells within the AoR</u>

The only known wells within the AoR which currently penetrate the caprock (Eau Claire Formation) are wells associated with the IBDP and IL-ICCS projects:

- The IBDP injection well, CCS#1 (which is currently permitted as a Class VI well in its post-injection phase and will be used as a monitoring well during the IL-ICCS project).
- The IBDP verification well, VW#1 (which will continue to be used as a monitoring well during the IL-ICCS project).
- The IL-ICCS injection well, CCS#2.
- The IL-ICCS verification well, VW#2.

Tables B.1 and B.2 in Appendix B present a tabulation of publicly available data for oil and gas and water wells within the AoR, respectively. Figures 1 and 2 in Appendix B present the location of oil and gas and water wells within the AoR, respectively. Available records for each well without a listed total depth were evaluated. Based on the information gathered which indicates none of the oil/gas or water wells with available data penetrate the confining zone, it is assumed that wells without a listed total depth are [redacted]

There are ten oil and gas wells located within approximately 2.4 km (1.5 miles) of the CCS well location. The closest well to CCS is located in the northeast quarter of Section 5, T16N, R3E (API number

121150061800), was drilled as a gas well in 1933, and was -27 m (-88 ft KB) deep. There is no publicly available plugging and abandonment record for this well, but it was likely collecting naturally occurring methane from the Quaternary sediments. The other 9 wells are located in Section 5, T16N, R3E or Section 28 and Section 29, T17N, R3E. The deepest of these oil wells is API number 121152369400, located in the northeast quarter of Section 34. This well was drilled into the Ordovician and was -905 m KB (-2,970 ft KB) deep. In summary, ten oil and gas wells occur within 1.5 miles of the CCS#3 well location, but none penetrate the confining zone.

Wells Penetrating the Confining Zone

With the exception of the injection and verification wells previously detailed, there are no known wells within the area of review that penetrate deeper than -1,049 m KB (-3,440 ft KB). The depth to the top of the upper confining zone (Eau Claire Formation) at CCS#1 is -1,538 m KB (-5,047 ft KB), and a similar depth is expected at CCS#3. Therefore, there are only four known wells that currently penetrate into the uppermost confining zone within the AOR: the IBDP wells CCS#1 and VW#1, and the IL-ICCS wells CCS#2 and VW#2.

If any of these wells are taken out of service during the life of the project, ADM will provide information to EPA to confirm that they have been properly plugged to ensure USDW protection pursuant to requirements at 40 CFR Part 146. If any additional wells that penetrate the confining zone are identified (e.g., if the AoR is re-delineated to cover a larger area as the result of an AoR reevaluation), ADM will complete corrective action as needed pursuant to 40 CFR 146.84(d).

4.3.2 Plan for Site Access

This is not applicable because no corrective action is required at this time.

4.3.3 Justification of Phased Corrective Action

This is not applicable because no corrective action is required at this time.

4.4 AoR and Corrective Action Plan

ADM will take the following steps to evaluate project data and, if necessary, reevaluate the AoR. AoR reevaluations will be performed during the injection and post-injection phases. ADM will:

1. Review available monitoring data and compare it to the model predictions. ADM will analyze monitoring and operational data from the injection well (CCS#2), proposed injection well (CCS #3), the monitoring and geophysical wells, other surrounding wells, and other sources to assess whether the predicted CO_2 plume migration is consistent with actual data. Monitoring activities to be conducted are described in the Testing and Monitoring Plan (Section 9 of this permit application) and the PISC and Closure Plan (Section 11 of this permit application). Specific steps of this review include:

    a. Reviewing available data on the position of the CO_2 plume and pressure front (including pressure and temperature monitoring data and RST saturation and seismic survey data). Specific activities will include:

        i. Correlating data from time-lapse RST logs, time-lapse VSP surveys, and other seismic methods (e.g., 3D surveys) to locate and track the movement of the CO_2 plume. A good correlation between the data sets will provide strong evidence in validating the model's ability to represent the storage system. Also, 2D and 3D seismic surveys will be employed to determine the plume location as described in the Testing and Monitoring Plan and/or the PISC and Site Closure Plan (as applicable).

        ii. Reviewing downhole reservoir pressure data collected from various locations and intervals using a combination of surface and downhole pressure gauges.

    b. Reviewing ground water chemistry monitoring data taken in the shallow (i.e., in Quaternary and/or Pennsylvanian strata) monitoring wells, the St. Peter, and the Ironton-Galesville to verifying that there is no evidence of excursion of carbon dioxide or brines that represent an endangerment to any USDWs.

    c. Reviewing operating data, e.g., on injection rates and pressures, and verifying that it is consistent with the inputs used in the most recent modeling effort.

    d. Reviewing any geologic data acquired since the last modeling effort, e.g., additional site characterization performed, updates of petrophysical properties from core analysis, etc. Identifying whether any new data materially differ from modeling inputs/assumptions.

2. Compare the results of computational modeling used for AoR delineation to monitoring data collected. Monitoring data will be used to show that the computational model accurately represents the storage site and can be used as a proxy to determine the plume's properties and size. ADM will demonstrate this degree of accuracy by comparing monitoring data against the model's predicted properties (i.e., plume location, rate of movement, and pressure decay). Statistical methods will be employed to correlate the data and confirm the model's ability to accurately represent the storage site.

3. If the information reviewed is consistent with, or is unchanged from, the most recent modeling assumptions or confirms modeled predictions about the maximum extent of plume and pressure front movement, ADM will prepare a report demonstrating that, based on the monitoring and operating data, no reevaluation of the AoR is needed. The report will include the data and results demonstrating that no changes are necessary.

4. If material changes have occurred (e.g., in the behavior of the plume and pressure front, operations, or site conditions) such that the actual plume or pressure front may extend beyond the modeled plume and pressure front, ADM will re-delineate the AoR. The following steps will be taken:

    a. Revising the site conceptual model based on new site characterization, operational, or monitoring data.

    b. Calibrating the model in order to minimize the differences between monitoring data and model simulations.

    c. Performing the AoR delineation as described the Computational Modeling Section of this AoR and Corrective Action Plan.

5. Review wells in any newly identified areas of the AoR and apply corrective action to deficient wells. Specific steps include:

    a. Identifying any new wells within the AoR that penetrate the confining zone and provide a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion.

    b. Determining which abandoned wells in the newly delineated AoR have been plugged in a manner that prevents the movement of carbon dioxide or other fluids that may endanger USDWs.

c. Performing corrective action on all deficient wells in the AoR using methods designed to prevent the movement of fluid into or between USDWs, including the use of materials compatible with carbon dioxide.

6. Prepare a report documenting the AoR reevaluation process, data evaluated, any corrective actions determined to be necessary, and the status of corrective action or a schedule for any corrective actions to be performed. The report will be submitted to EPA within one year of the reevaluation. The report will include maps that highlight similarities and differences in comparison with previous AoR delineations.

7. Update the AoR and Corrective Action Plan to reflect the revised AoR, along with other related project plans, as needed.

4.4.1 AoR Reevaluation Cycle

ADM will reevaluate the above described AoR every five years during the injection and post-injection phases.

In addition, monitoring and operational data will be reviewed periodically (likely annually) by ADM during the injection and post-injection phases. Given inconclusive results in the CCS#2 step-rate test, ADM will modify their monitoring and reporting schedule to collect and review data more regularly during the first six months of the injection phase. Specifically, pressure and seismic results will be reviewed on a monthly basis to identify any deviations from expected conditions (see Section 3 of this permit application for more detail). The reservoir flow model will be history matched against the observed parameters measured at the monitoring wells. Pressure will be monitored as described in the Testing and Monitoring Plan. The time lapse pressure monitoring data will be compared to the model predicted time lapse pressure profiles. ADM will provide a brief report of this review to the UIC Program Director and discuss the findings.

If data suggest that a significant change in the size or shape of the actual CO_2 plume as compared to the predicted CO_2 plume and/or pressure front is occurring or there are deviations from modeled predictions such that the actual plume or pressure front may extend vertically or horizontally beyond the modeled plume and pressure front, ADM will initiate an AoR reevaluation prior to the next scheduled reevaluation. Such deviations may be evidenced by the results of direct or indirect monitoring activities including MIT failures or loss of MI; observed pressure and saturation profiles; changes in the physical or chemical characteristics of the CO_2; any detection of CO_2 above the confining zone (e.g., based on hydrochemical/physical parameters); microseismic data indicating slippage in or near the confining zone or microseismic data within the injection zone that indicates slippage and propagation into the confining zone; or arrival of the CO_2 plume and/or pressure front at certain monitoring locations that diverges from expectations, as described below.

4.4.2 Trigger for AoR Reevaluations Prior to the Next Scheduled Reevaluation

Unscheduled reevaluation of the AoR will be based on quantitative changes of the monitoring parameters in the deep monitoring wells, including unexpected changes in the following parameters: pressure, temperature, neutron saturation, and the deep ground water (> 3,000 ft below KB) constituent concentrations indicating that the actual plume or pressure front may extend beyond the modeled plume and pressure front. These changes include:

- *Pressure:* Changes in pressure that are unexpected and outside three (3) standard deviations from the average will trigger a new evaluation of the AoR.

- *Temperature*: Changes in temperature that are unexpected and outside three (3) standard deviations from the average will trigger a new evaluation of the AoR.

- *RST Saturation:* Increases in CO_2 saturation that indicate the movement of CO2 into or above the confining zone will trigger a new evaluation of the AoR unless the changes are found to be related to the well integrity. (Any well integrity issues will be investigated and addressed.)

- *Deep ground water constituent concentrations*: Unexpected changes in fluid constituent concentrations that indicate movement of CO_2 or brines into or above the confining zone will trigger a new evaluation of the AoR unless the changes are found to be related to the well integrity. (Any well integrity issues will be investigated and addressed.)

- *Exceeding Fracture Pressure Conditions*: Pressure in any of the injection or monitoring wells exceeding 90 percent of the geologic formation fracture pressure at the point of measurement. This would be a violation of the permit conditions. The Testing and Monitoring Plan (Section 9 of this permit application) and the operating procedures in Section 8 of this permit application provides discussion of pressure monitoring and specific procedures that will be completed during the injection start-up period.

- *Exceeding Established Baseline Hydrochemical/Physical Parameter Patterns:* A statistically significant difference between observed and baseline hydrochemical/physical parameter patterns (e.g., fluid conductivity, pressure, temperature) immediately above the confining zone. The Testing and Monitoring Plan (Section 8 of this permit application) provides extended information regarding how pressure, temperature, and fluid conductivity will be monitored.

- *Compromise in Injection Well Mechanical Integrity*: A significant change in pressure within the protective annular pressurization system surrounding each injection well that indicates a loss of mechanical integrity at an injection well.

- *Seismic Monitoring Identification of Subsurface Structural Features*: Seismic monitoring data that indicates the presence of a fault or fracture in or near the confining zone or a fault or fracture within the injection zone that indicates propagation into the confining zone. The Testing and Monitoring Plan provides extended information about the microseismic monitoring network.

An unscheduled AoR reevaluation may also be needed if it is likely that the actual plume or pressure front may extend beyond the modeled plume and pressure front because any of the following has occurred:

- Seismic event greater than M3.5 within 8 miles of the injection well;
- If there is an exceedance of any Class VI operating permit condition (e.g., exceeding the permitted volumes of carbon dioxide injected); or
- If new site characterization data changes the computational model to such an extent that the predicted plume or pressure front extends vertically or horizontally beyond the predicted AoR.

ADM will discuss any such events with the UIC Program Director to determine if an AoR reevaluation is required.

If an unscheduled reevaluation is triggered, ADM will perform the steps described at the beginning of this section.

5. Financial Responsibility Plan

Estimates are based on prices incurred for similar work and reflect the current pricing environment. The cost summary presented in Section 5.6 applies both inflation and cost discounting assumptions based on the expected project timeline.

5.1 Area of Review and Corrective Action Cost Estimate

As outlined in Appendix B of the permit application, the area of review (AOR) refers to the maximum area extent of the effected injection reservoir in which Mt. Simon pressure will exceed a critical pressure and have the potential to hypothetically drive fluids upwards into the lowermost USDW (St. Peter formation) if a vertical pathway is present. The AOR is based on results from current numerical modeling and is subject to change if operational measurements deviate significantly from modeled predictions. However, no known deep penetrating wells were found to exist within the AOR. Based on this review, no cost has been assigned for corrective action since no pathways for leakage were found to exist.

5.2 Injection Well Plugging and Site Reclamation Estimate

Plugging costs for the three injection wells will be incurred at the end of their respective operational period. A series of cement plugs will be placed to seal the entire wellbore, and the well will be capped and covered below ground level. Table 5.2-1 presents an approximate breakdown of total estimated cost based on the procedures provided in Section 10.

TABLE 5.2-1

COST SUMMARY FOR INJECTION WELL PLUGGING / SITE RECLAMATION

Activity	No. Wells	Cost/Well	Subtotal
Sensitive, Confidential, or Privileged Information [redacted]			
		Total Estimated Cost for P&A / Site Reclamation:	**$2,325,000**

5.3 Post-Injection Site Care Cost Estimate

Post-injection monitoring extends the use of the verification wells (VWs) and geophysical monitoring wells (MWs) by means of the operational testing and monitoring plan described in Section 9 of the permit application. Monitoring activities, locations and frequencies are summarized in Table 5.3-1. Monitoring costs assume that VW #3 is installed as a single wellbore with multi-zone sampling capacity. In the event VW #3 is installed as a system of multiple, smaller-diameter wellbores, incremental sampling costs are expected to be negligible.

TABLE 5.3-1
COST SUMMARY FOR POST-INJECTION MONITORING

Activity	Tested Wells	Frequency	Cost/Test	Total No. of Tests	Subtotal (10-yr)
Sensitive, Confidential, or Privileged Information [redacted]					
				Total Estimated Cost for Post-Injection Monitoring:	**$2,650,000**

5.4 Site Closure Cost Estimate

The site closure costs summarized in Table 5.4-1 include plugging and reclamation activities for all VWs and MWs (the procedure is identical to that described in Section 5.2 for injection wells). The VWs extend to the approximate depth of injection wells but have a smaller diameter, which significantly reduces the volume of cement and time required for plugging. The GWs are installed to the base of the St. Peter formation, which is approximately half the depth of injection and verification wells. Site closure estimates assume VW #3 existing as a single wellbore; multiple, smaller-diameter wellbores would likely incur the same total plugging cost.

TABLE 5.4-1

COST SUMMARY FOR SITE CLOSURE

Activity	No. Wells	Cost/Well	Subtotal
Sensitive, Confidential, or Privileged Information [redacted]			
		Total Estimated Cost for Site Closure:	**$2,970,000**

5.5 Emergency and Remedial Response Cost Estimate

The primary sources of risk evaluated in the current plan are similar to the risk categories utilized in the previously approved CCS#2 permit. For the current evaluation, additional consideration was given to surface equipment. In this site-wide financial risk assessment, Monte-Carlo analysis was used to calculate an expected net present value (NPV) of financial liability based on the probability and expected cost of risk events occurring over the 15-year operational and 10-year post operational periods. Probabilities for each event were assigned primarily based on a 2007 risk assessment report submitted as part of the FutureGen Environmental Impact Statement (FutureGen, Contract No. DE-AT26-06NT42921). Table 5.5-1 summarizes the range of probabilities estimated in the FutureGen report for each respective risk event and used as part of the input values for this evaluation.

TABLE 5.5-1

ANNUAL PROBABILITIES OF RELEVANT CCS RISK EVENTS

Risk Event	Event Description	Annual Frequency of Failure (Single Item)	
		Low Estimate	High Estimate
1	Pipeline Rupture	Sensitive, Confidential, or Privileged Information [redacted]	
2	Pipeline Puncture		
3	Wellhead Equipment Rupture		
4	Upward rapid leakage through CO_2 injection well		
5	Upward slow leakage through CO_2 injection well		
6	Upward rapid leakage through deep oil & gas wells		
7	Upward slow leakage through deep oil & gas wells		
8	Leaks due to undocumented deep wells, high rate		
9	Leaks due to undocumented deep wells, low rate		
10	Upward rapid leakage through caprock		
11	Upward slow leakage through caprock		
12	Release through existing faults		
13	Release through induced faults		

Each Monte-Carlo simulation observation assigns random event probabilities using uniform distributions based on the respective low and high estimates shown in this table. The resulting probabilities are then multiplied by the number of relevant items: events 1-5 apply to three CO_2 injection wells, events 6-7 are applied to approximately 100 oil and gas wells within the project's area-of review (AOR), and the remaining events are interpreted as project-wide risks with a multiplier of 1.

If an event occurs in a particular Monte-Carlo realization based on the probability distribution and the multiplier for the potential number of events from the process described above, it is then randomly assigned a cost using triangular distributions, with most-likely estimates corresponding to the values provided in the previously approved CCS#2 Emergency and Remedial Response Plan (ERRP). The CCS#3 ERRP presented in Section 12 is modeled after the approved CCS#2 ERRP. In addition to the peak of the distribution, low and high-estimates for each of the triangular distributions are estimated (Appendix A provides additional information on the characteristics of triangular distributions). Table 5.5-2 summarizes the distribution parameters used for each risk event (low, most-likely, and high estimates).

TABLE 5.5-2

REMEDIATION COST PARAMETERS FOR RISK EVENTS

Event	Event Description	Event Cost (Triangular Distribution)		
		Low	Most Likely	High
1	Pipeline Rupture	Sensitive, Confidential, or Privileged Information [redacted]		
2	Pipeline Puncture			
3	Wellhead Equipment Rupture			
4	Upward rapid leakage through installed well			
5	Upward slow leakage through installed well			
6	Upward rapid leakage through transecting wells			
7	Upward slow leakage through transecting wells			
8	Leaks due to undocumented deep wells, high rate			
9	Leaks due to undocumented deep wells, low rate			
10	Upward rapid leakage through caprock			
11	Upward slow leakage through caprock			
12	Release through existing faults			
13	Release through induced faults			

Using the defined probability and cost distributions, the Monte-Carlo simulation creates thousands of viable scenarios that project annual liability costs over a 25-year timeframe (15 years operational and 10 post-operational). Future payments are discounted at a rate of 2.0% and incorporate an annual inflation rate of 2.5%. Figure 5.5-1 illustrates the final distribution of total project liability based on the aggregate results of 100,000 simulations. The Monte Carlo analysis was used to generate an expected value of $5.34 million based on the results from all modeled outcomes. The input for the Monte-Carlo analysis is consistent with both risk events and costs used in the previously approved CC2 financial assurance documentation.

Sensitive, Confidential, or Privileged Information

[redacted]

Figure 5.5-1. Distribution of Emergency & Remedial Response Net-Present Value

5.6 Cost Summary

Cost estimates detailed in Sections 5.1 through 5.5 were adjusted to net present values using the same method described in the emergency and remedial response section (future costs were inflated assuming an annual inflation rate of 2.5% and discounted at a rate of 2.0%). Table 5.6-1 summarizes the pre-adjusted and adjusted cost totals for the five cost categories.

TABLE 5.6-1

FINANCIAL ASSURANCE COST SUMMARY

Category	Pre-adjusted	Adjusted NPV
Sensitive, Confidential, or Privileged Information [redacted]		
	Total Financial Assurance Required:	**$14,344,000**

6. Well Construction Details

6.1 Well Hole Diameters and Injection Intervals

The open hole diameters and injection intervals for CCS#3 are described below in Table 6.1-1.

Table 6.1-1: CCS#3 preliminary open hole diameters and depth intervals

Name of Interval	Approximate Depth Interval (feet)	Open Hole Diameter (inches)	Comment
Surface	Sensitive, Confidential, or Privileged Information [redacted]	[redacted]	To bedrock
Intermediate	[redacted]	[redacted]	To primary seal
Long	[redacted]	[redacted]	To total depth

6.2 Casing Specifications

The casing specifications for CCS#3 are described below in Table 6.2-1.

Table 6.2-1: CCS#3 preliminary casing specifications

Name of Interval	Approximate Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Threaded)	Thermal Conductivity @ 77°F (BTU/ft.hr. °F)
Surface[1]	Sensitive, Confidential, or Privileged Information [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Intermediate[2]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Long[3] (carbon)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Long[3] (chrome)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Note 1: Surface casing will be 350 ft of 20 inch casing. After drilling a 26" hole to approximately 350' true vertical depth (TVD) or at least 50 ft into the bedrock below the shallow groundwater, 20", 94 ppf, H40, short thread and coupling (STC) casing will be set and cemented to surface. Coupling outside diameter is ~21 inches.

Note 2: Intermediate casing will be 5,300 ft of 13.375-inch casing. After a shoe test or formation integrity test (FIT) is performed, a 17.5" hole will be drilled to approximately 5,300' TVD or approximately 50' into the Eau Claire Shale (primary seal formation). The 13.375-inch long thread and coupling (LTC) or buttress thread and coupling (BTC) casing will be set and cemented to surface. Coupling outside diameter is ~14.375-inches.

Note 3: Long string casing consists of two sections: 1) 0-5,000 ft of 9.625-inch, API CS casing and 2) 5,000- 7,250 ft of 9.625-inch, API 13Cr alloy casing. After a shoe test is performed and the integrity of the casing is tested, a 12.25-inch hole will be drilled to approximately 7,500' TVD or through the Mt. Simon, where the long string casing will be set and cemented in two stages using CO2 resistant cement in the bottom (tail) section. Coupling outside diameter is ~10.625-inches for the upper CS section and ~10.485-inches for the lower 13Cr section.

6.3 Tubing Specifications

The tubing specifications for CCS#3 are described below in Table 6.3-1.

Table 6.3-1: CCS#3 Preliminary tubing Specifications

Name	Depth Interval (feet)[1]	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Threaded	Burst strength (psi)	Collapse strength (psi)
Injection tubing[2,3,4]	[redacted] Sensitive, Confidential, or Privileged Information							

Note 1: The tubing length will be finalized after the location of the perforations are selected and the packer location determined. The final tubing design may change subject to availability and/or pending results of reservoir analysis. The well casing design does allow for a larger tubing than 5 ½" if required.

Note 2: Maximum allowable suspended weight based on joint strength of injection tubing. Specified yield strength (weakest point) on tubular and connection is 306,000 lbs.

Note 3: Weight of expected injection tubing string (axial load) in air (dead weight) will be 88,200 lbs.

Note 4: Thermal conductivity of tubing @ 77°F will be 16 BTU / ft.hr.°F.

The injection well will be plugged back from the bottom with at least 80 feet of cement or with a sufficient volume to prevent the injection fluid from coming directly in contact with the Precambrian granite basement through the wellbore. Figure 6.3-1 below displays a CCS#3 well schematic showing surface and subsurface well details.

Sensitive, Confidential, or Privileged Information

[redacted]

Figure 6.3-1: CCS#3 Well Schematic

6.4 Tubing and Packer Pressure Gauge and Compatibility

The pressure and temperature gauge will be installed at the packer at approximate depth of 6350 ft. Tubing and packer materials will be compatible with fluids with which the materials may be expected to come into contact and will meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director.

7. Pre-Injection/Operational Testing Plan

The testing activities at the CCS#3 Well described in this Section are restricted to the pre-injection phase. Testing and monitoring activities during the injection and post-injection phases are described in the Testing and Monitoring Plan, along with other non-well related pre-injection baseline activities such as geochemical monitoring.

The pre-injection operational testing plan presented herein addresses the requirements of 40 CFR Section 146.87 (a-f):

- Deviation checks during drilling (a)(1)
- Logging required before installation of surface casing and long string casing (a)(2)(3)
- Tests to demonstrate internal and external mechanical integrity (a)(4)(5)
- Proposed coring program (b)
- Proposed fluid sampling program, including those to assess the chemical characteristics of the injection and confining zones (c)(d)
- Tests to verify hydrogeologic conditions in the injection and confining zone and determine fracture pressure(d)(e)

7.1 Tests during well drilling/construction

ADM will perform logging, surveys and tests to determine or verify the depth, thickness, porosity, permeability, lithology, and formation fluid salinity in all relevant geologic formations. These tests shall include:

- Deviation checks that meet the requirements of 40 CFR 146.87(a)(1);
- Logs and tests before and upon installation of the surface casing that meet the requirements of 40 CFR 146.87(a)(2);
- Logs and tests before and upon installation of the long-string casing that meet the requirements of 40 CFR 146.87(a)(3);
- Tests to demonstrate internal and external mechanical integrity that meet the requirements of 40 CFR 146.87(a)(4); and
- Any alternative methods that are required by and/or approved by the Director pursuant to 40 CFR 146.87(a)(5).

7.1.1 Deviation Checks

The subsurface and surface design (casing, cement, and wellhead designs) meets the requirements to appropriately manage CO_2, the preserve mechanical integrity during injection operations and to sustain the integrity of the caprock to ensure CO_2 remains in the Mt. Simon. For reasons such as equipment or supply availability, or changes to the supplemental monitoring program, the final well design may vary but will meet or exceed requirements in terms of strength and CO_2 compatibility.

The injection well is planned to be drilled with an inclination of 5° degrees or less. During drilling, the wellbore trajectory will be tracked and surveyed every 1,000 feet to reduce the risk of interception with adjacent wellbores.

7.1.2 Mechanical Integrity Testing and Logging During and after Casing Installation

Wireline logging is an important tool that will be used to identify many characteristics of the formations encountered during drilling and for demonstrating mechanical integrity of the well. The logs discussed in this section are summarized in Table 7.1.2-1, and will apply to proposed injection wells CCS#3.

Mechanical integrity testing and logging are described below. ADM will provide a schedule for all testing and logging to the permitting agency at least 30 days in advance of conducting the first such tests and/or logs.

7.1.2.1 Historic Logs

Table 7.1.2-1 presents a summary of the previous geophysical logs collected in the CCS and VW wells. The logging programs for the two CCS wells were similar. CCS#1 and 2 both had, at a minimum, triple combo logs (gamma ray, spontaneous potential, caliper, resistivity, bulk density, and neutron porosity) performed on all sections of each well. All casing strings had either a cement bond log (CBL) or ultrasonic CBL performed to confirm the quality of cement behind each string of casing. The intermediate and long string sections of the wells had logging programs conducted that included triple combo logs as well as dipole sonic, formation micro-imaging (fracture finder), spectral gamma ray, and nuclear magnetic resonance as part of the suite of open hole logs. Logs from CCS#1 added the modular dynamics tester and the versatile seismic imager for the long string section. Logs from CCS#2 added the Litho-Scanner (Lithology Scanner) performed on the long string section. Triple combo logs were performed in wells VW#1 and 2. The logging suite performed on the CCS wells presents a comprehensive geophysical analysis of the injection zone, confining zone, and overlying formations. A summary of the geologic characterization is provided in Section 3. Site Geologic Characterization of this application document.

Table 7.1.2-1. Log Summary: Existing Site Wells

Well Name	Log Vendor	Log Title	Date Run	Depth Interval (MD ft. KB)
Sensitive, Confidential, or Privileged Information [redacted]		GR, CAL, SP, Resistivity, RHOB, NPHI	3/9/2009	Sensitive, Confidential, or Privileged Information [redacted]
		Variable Density CBL		
		GR, CAL, SP, Resistivity, RHOB, NPHI	4/5/2009	
		Sonic Scanner and FMI	4/5/2009	
		CMR, ECS, HNGS	4/5/2009	
		MSCT	4/5/2009	
		Ultrasonic Cement Imaging		
		GR, CAL, SP, Resistivity, RHOB, NPHI	4/26/2009	
		Sonic Scanner and FMI	4/26/2009	
		CMR, ECS, HNGS	4/26/2009	
		MSCT	4/26/2009	
		MDT	4/26/2009	
		VSIT	4/26/2009	
		Ultrasonic Cement Imaging		
		Variable Density CBL		
		Pressure/Temperature Log		
		Thermal Neutron Decay (Formation Sigma) Log		
		Multi-Finger Caliper Log		
		CCL and Perforation Record		
		Injection Fullbore Spinner Logs		
		[redacted]	[redacted]	
		GR, Resistivity, NPHI, SlimPulse	1/12/2015	
		CAL, DSLT, GPIT	1/12/2015	
		CBL	1/16/2015	
		GR, CAL, SP, Resistivity, RHOB, NPHI	5/3/2015	
		Sonic Scanner, FMI, CAL, GPIT	5/3/2015	
		ECS, HNGS	5/3/2015	
		Variable Density CBL	5/31/2015	
		Isolation Scanner Cement Evaluation	5/31/2015	
		Isolation Scanner Casing Integrity	5/31/2015	
		GR, CAL, SP, Resistivity, RHOB, NPHI	5/29/2015	
		Sonic Scanner, FMI, CAL, GPIT	5/29/2015	
		CMR, Litho Scanner, HNGS	5/29/2015	
		MSCT	5/29/2015	

Well Name	Log Vendor	Log Title	Date Run	Depth Interval (MD ft. KB)
Sensitive, Confidential, or Privileged Information [redacted]	[redacted]	Multi-finger Imaging Tool	6/10/2015	Sensitive, Confidential, or Privileged Information [redacted]
[redacted]	[redacted]	Variable Density CBL	6/10/2015	[redacted]
[redacted]	[redacted]	Isolation Scanner Cement Evaluation	6/10/2015	[redacted]
[redacted]	[redacted]	Isolation Scanner Third Interface Echo	6/10/2015	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	GR, SP, Resistivity, RHOB, NPHI, Sonic		[redacted]
[redacted]	[redacted]	CBL and/or Cement Imaging		[redacted]
[redacted]	[redacted]	GR, CAL, Resistivity, RHOB, NPHI		[redacted]
[redacted]	[redacted]	Sonic Scanner		[redacted]
[redacted]	[redacted]	GR, CAL, Resistivity, RHOB, NPHI		[redacted]
[redacted]	[redacted]	Sonic Scanner		[redacted]
[redacted]	[redacted]	MDT	10/25/2010	[redacted]
[redacted]	[redacted]	XPT (Pressure Express Tool)	11/17/2010	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	GR, CAL, Resistivity, RHOB, NPHI	10/8/2012	[redacted]
[redacted]	[redacted]	Sonic Scanner	10/8/2012	[redacted]
[redacted]	[redacted]	GR, CAL, Resistivity, RHOB, NPHI	10/31/2012	[redacted]
[redacted]	[redacted]	Sonic Scanner	10/31/2012	[redacted]
[redacted]	[redacted]	XPT (Pressure Express Tool)	10/31/2012	[redacted]
[redacted]	[redacted]	RST		[redacted]

7.1.2.2 Proposed Surface Casing Logs

Table 7.1.2-2 presents the proposed log suite for CCS#3. Each open hole section (prior to setting each casing string) will be logged with multiple suites to fully characterize the geologic formations (reservoirs and seals). At a minimum, all wireline runs will have resistivity, spontaneous potential (SP), gamma ray (GR) and caliper logs.

Table 7.1.2-2. Proposed Logging for CCS#3

Log Type (Open Hole or Cased Hole)	Log Run Title	Hole Section
Open Hole	GR, SP, Resistivity, Caliper	Surface
Cased Hole	Radial Cement Bond Log	Surface
Cased Hole	Temperature Log	Surface
Open Hole	GR, SP, Resistivity, Caliper	Intermediate
Open Hole	Bulk Density, Neutron Porosity	Intermediate
Open Hole	Sonic	Intermediate
Cased Hole	Radial Cement Bond Log or Ultrasonic Cement Bond Log	Intermediate
Cased Hole	Temperature Log	Intermediate
Open Hole	Spectral GR, SP, Resistivity, Caliper	Long String
Open Hole	Bulk Density, Neutron Porosity	Long String
Open Hole	Sonic	Long String
Open Hole	Nuclear Magnetic Resonance	Long String
Open Hole	Fracture Finder	Long String
Cased Hole	Radial Cement Bond Log or Ultrasonic Cement Bond Log	Long String
Cased Hole	Temperature Log	Long String

With the exception of the 20” surface casing, a cement bond log (CBL) with radial capability and/or ultrasonic cement imaging logs will be run on all casing strings. In addition to cement evaluation data, ultrasonic imaging logs will provide baseline casing thickness and internal radius measurements. The long string casing internal diameter will be baselined by running a multi-finger caliper (MFC) log. Follow-up MFC logs will be performed in the event the injection tubing is removed during a well recompletion.

Regarding the surface casing, due to the large casing size, a cement bond log with radial imaging is not practical and when performed typically yield ambiguous results. To achieve good cement mechanical integrity, the best practice indicators are returning excess clean cement to the surface during cement displacement, having minimal cement fallback after completing cement displacement, and successfully passing a casing shoe test.

Based on previous experience with CCS#1 and CCS#2, hydraulic stimulation of the injection zone is not expected but an acid matrix stimulation to reduce perforation skin damage may be necessary. To reduce the risk of formation damage during well perforation, the operator will employ a static or dynamic underbalanced techniques.

After the well is cased, pre-injection testing will be performed to provide well specific data for the reservoir model. During these tests, P/T gauges will be deployed near the perforated interval while the pressure fall-off and step rate tests are performed. The final perforating scheme will be based on interpretation of the test results.

After installation of the 5-1/2" injection tubing, a baseline temperature and pulse neutron (PN) type logs will be run. These logs will be compared to subsequent timelapse logs to inform the operator about the accumulation and movement of CO2 behind the wellbore and the state of the well's mechanical integrity. The PN logs will provided information about the location and vertical movement of CO_2 near the wellbore. This allows the operator to monitor the movement of CO_2 within the injection zone and above the seal formation. Both logging techniques will be used to demonstrate the mechanical integrity of the well.

7.1.2.3 Proposed Mechanical Integrity Testing

After setting and cementing the casing, a radially capable cement imaging log will be run to evaluate the cement bonding between the casing and the reservoir. Next, the casing string will undergo a one-hour pressure test at 750 psig and will pass if the pressure loss is less than 3%. After passing these tests, the well will be perforated and completed with 5.5-inch tubing and packer assembly. After well completion, the tubing/casing annulus will undergo a one-hour pressure test. As mentioned above, a baseline pulse neutron log will be run. Repeat PN logs can be run if anomalous temperature data indicates a need for further analysis. Monitoring the distributed temperature system (DTS) data across the top of the Mt. Simon Sandstone formation, as well as the porous zones above the seal, will be used to validate the integrity of the completion. Table 7.1.2-3 below is a summary of MITs and pressure fall-off tests to be performed prior to injection.

Table 7.1.2-3 Summary of MITs and Pressure Fall-Off Test to be Performed Prior to Injection

Class VI Rule Citation	Rule Description	Test Description	Program Period
[40 CFR 146.89(a)(1)]	MIT – Internal	Annulus Pressure Test	Prior to Operation
[40 CFR 146.87(a)(4)]	MIT – External	Temperature Log	Prior to Operation
[40 CFR 146.87(e)(1)]	Testing prior to operating	Pressure Fall-off Test	Prior to Operation

7.2 Injection zone characterization and core sampling

ADM will provide a schedule for all testing and logging, including coring events, to the permitting agency at least 30 days in advance of conducting the first such tests and/or logs. Logging is described in Section 7.1, above.

7.2.1 Historic injection zone fluid characterization and core sampling

The following historic information is provided to provide background data pertinent to establishing the proposed core and injection zone sampling and analysis at CCS#3.

7.2.1.1 Historic Fluid Sampling

This section discusses the historic fluid sampling that has been conducted in CCS#1 and CCS#2 to characterize the Eau Claire (confining zone) and Mt. Simon (injection zone). The previous sampling and analysis of the fluid of the injection zone included fluid temperature, pH, conductivity, reservoir pressure, and static fluid level. In addition, total dissolved solids (TDS), fluid chemistry, density, and viscosity of the fluid in the injection zone were performed. The fluid samples were collected using Schlumberger's Modular Formation Dynamics Tester (MDT). Sampling of CCS 1 and CCS 2 were completed using the MDT tool at several depths within the Mt. Simon. Average fluid parameters of the injection zone are included in Table 7.2.1-1. These were collected using the MDT at multiple points in the injection zone. Using the fluid parameters from Table 7.2.1-1 , an estimated static fluid level for the injection reservoir was calculated to be 249.5 feet above mean sea level (AMSL). Explanation of the historical analyses and results are discussed in more detail in previous permit applications and completion reports.

Table 7.2.1-1. Average Injection Zone Fluid Parameters

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Historic information pertaining to physical characteristics of the injection and confining zone can be derived from log and core data and are discussed below.

7.2.1.2 Historic Well Coring Programs

Thorough coring programs, utilizing both conventional whole core and rotary sidewall core and including wide-ranging analytical suites, were performed at CCS#1, CCS#2, VW#1, VW#2, and GM#2. While the focus on coring and analysis was the confining and injection zones in VW#2 and CCS#2, core-related information on overlying formations was also gathered in VW#1, CCS#1, and GM#2. A total of approximately 1,268 feet of whole core was recovered between the five wells, the bulk of which was captured in VW#1 (700 feet) and VW#2 (392 feet). Recovered sidewall core samples from the two injection wells and two verification wells totaled 400 samples. Of these 400 samples, 174 sidewalls were from VW#1, 62 sidewalls were from CCS#1, 69 sidewalls were from VW#2, and 95 sidewalls were from CCS#2. A summary of the core collected in these wells is presented in Appendix D and is discussed in more detail below.

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7.2.2 Proposed Coring and Fluid Sampling Program

This section addresses the pre-operational sampling proposed by ADM to ensure that sufficient characterization of the subsurface at CCS#3 is performed in addition to satisfying Class VI regulations. These requirements include injection and confining zone physical and chemical characteristics including coring and formation fluid sampling. Subpart (f) of §146.87 requires 30 day notice of any logging or testing of the Class VI well to the Director so that the Director has the opportunity to witness well activities.

7.2.2.1 Proposed Coring Program

The coring program and analysis that ADM performed at CCS#1, CCS#2, VW#1, and VW#2 provides extensive characterization of various formations, particularly the confining zone and injection zone, as described in Section 7.2.1. Appendix D provides more detail on the core data collected in these wells. The data provided from the site wells included both whole core and sidewall core focusing on the confining zone and injection zone. The testing in the existing core included routine core analysis (porosity, permeability, grain density, fluid saturations, and lithology descriptions), mercury injection capillary pressure, geomechanics, x-ray diffraction, quantitative evaluation of minerals by scanning electron microscopy, focused ion beam electron microscopy, tight rock analysis, total organic carbon content, nuclear magnetic resonance, pulse decay permeability, laser grain size analysis, CT scanning, and thin sections.

The coring program for CCS#3 will include at least 90 feet of whole core within the confining zone (Eau Claire) and injection zone (Mt. Simon), as well as potential sidewall coring within select formations, as necessary based on open hole logging results. Routine core and geomechanical analysis will be performed on recovered core, as applicable. Data will be correlated with openhole geophysical well logs from the wells, and compared to core sample results obtained from previous wells.

7.2.2.2 Proposed Fluid Sampling Program

Although sufficient data has been acquired from the reservoir from the two injectors already installed and tested at the site, prior to any well testing in a newly drilled well a sample of the formation fluid from the injection zone will be collected to measure the pH, conductivity, physical, chemical, static fluid level and other characteristics to satisfy §146.87 (c) and (d)(3), and to determine whether the CO_2 plume has reached any newly drilled injector (CCS#3) during the time of completion. These data are also important in the analysis of the initial pressure falloff test. Collection of these data, and previous reservoir sampling in combination with temperature and pressure logs noted in Section 7.4 Injection and confining zone formation testing , will satisfy §146.87 (c).

Well sampling will be conducted to satisfy regulations stated in Section 7.2. While a similar method of sample collection via wireline used to sample CCS#1 and CCS#2 is expected, the detailed procedure will depend on borehole conditions encountered during operations, as well as equipment and personnel availability experienced near the time of completion of the well. Detailed procedures outlining the expected sampling and subsequent analysis will be submitted in accordance with federal regulations and guidance prior to implementing a specific sampling procedure in the field.

7.3 Fracture pressure and downhole hydrogeologic testing of conditions

Specific regulatory requirements exist as permitting standards for testing and data collection associated with new wells. As presented at §146.82 (c), (d) and (e), the following are among the data that must be acquired for any new Class VI Injection well:

> (c) The owner or operator must record the fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone(s).
>
> (d) At a minimum, the owner or operator must determine or calculate the following information concerning the injection and confining zone(s):

(1) Fracture pressure;…

(e) Upon completion, but prior to operation, the owner or operator must conduct the following tests to verify hydrogeologic characteristics of the injection zone(s):

(1) A pressure fall-off test; and

(2) A pump test; or

(3) Injectivity tests.

CCS#3 is a new well that may be installed at the site in the future and hence must comply with requirements at §146.87 (c), (d) and (e) (see Section 7.2 for the proposed fluid sampling and coring program). Data obtained as part of previous injection and monitoring requirements at the site are relevant to data acquisition to be collected from any new site wells. Historic activities are summarized in Section 7.3.1, which supports the proposed CCS#3 data collection activities presented in Section 7.3.2

7.3.1 Historic testing

This section discusses the historic testing that has been conducted in CCS#1 and CCS#2 to characterize the Eau Claire (confining zone) and Mt. Simon (injection zone).

The well testing performed in both injection wells at the ADM site consisted of a pressure build-up falloff test (FOT) and a step rate test (SRT). The well testing performed in CCS#1 and 2 are presented in Table 7-6. As presented in previous and forthcoming sections, historical sampling and testing activities conducted to characterize the subsurface at the site were comprehensive. No pressure transient testing was conducted in the VM wells.

7.3.1.2 Historic Reservoir Testing

Well testing in the two injection wells CCS#1 and CCS#2 included an initial FOT and an SRT. A description of tests performed at each injection well is discussed in greater detail below and summarized in Table 7-6.

Table 7-6. Testing Summary: Existing Site Wells

Activity	Well	Formation	Depth (feet KB)	Comment
Pressure of Reservoir	Sensitive, Confidential, or Privileged Information [redacted]			
Pressure Step Rate				
Pressure Falloff				

<u>CCS 1 Test History</u>

Three FOTs of varying duration were conducted in September and October 2009 as part of the initial completion of CCS#1. FOT involve two parts. During the first portion of the falloff tests, the reservoir was stressed by injecting fluid at a (traditionally) relatively stabilized rate, causing an increase in reservoir pressure. During the second portion of the test, injection was stopped and the well shut-in while the reservoir pressure monitored as it decayed and approached near-static condition.

The initial perforations in the CCS#1 injection interval were from 7,025 to 7,050 feet KB. To conduct initial reservoir testing, water, treated with a clay-stabilizing potassium chloride (KCl) substitute, was injected at rates of between 1.5 to 2.0 barrels per minute (bpm) (63 to 84 gallons per minute [gpm]) for approximately two hours. A 19.5 hour pressure falloff period followed this injection period.

After this test, the perforations were acidized and an SRT was conducted by pumping at increasing rate steps to observe a change of the well injectivity. Following the SRT, treated water was injected at a rate of 3.1 bpm (130 gpm) for five hours. After this period of relatively stable injection, the well was shut in and pressure was monitored for approximately 45 hours as a second FOT.

A third FOT was conducted after additional perforations were made in the well and subsequently stimulated with acid. These additional perforations, totaling 30 feet, were from 6,982 to 7,012 feet KB. The perforated zone received a second acid treatment. For the third FOT, treated water was injected at an increasing rate of 3.1 to 4.2 bpm (130 to 176 gpm) over 6.5 hours and then at 4.2 bpm (176 gpm) for an additional 6.5 hours. After this 13-hour period of injection, the well was shut in and pressure was monitored for 105 hours.

Analysis of the pressure transient data using analytical simulations was performed by Schlumberger. These analyses resulted in a projected reservoir permeability-thickness of 13,875 md-ft. Based on an average effective injection zone thickness of 75 feet, a permeability of 185 millidarcies (md) was calculated.

Analysis of the SRT, performed by Schlumberger, estimated a fracture propagation pressure of 4,966 psi at the bottomhole gauge depth of 6,891 feet KB resulting in a gradient of 0.72 psi/ft. This analysis was performed graphically by plotting the pressure at the end of each step versus rate. The intersection of lines before and after a pressure sensitive threshold was used to estimate the fracture pressure. This approach is an industry standard method for estimating conservative values.

Copies of the pressure transient data and analyses were presented to EPA in previous reports and are available upon request.

The confining zone testing included a "mini-frac" using Schlumberger's MDT tool across a 2.8-foot interval of the Eau Claire centered on 5,435 feet KB. The fracture pressure measured from the tool ranged from 5,078 to 5,324 psig, which corresponds to fracture gradients of 0.93 to 0.98 psi/ft for the Eau Claire (confining zone).

CCS#2 Test History

An SRT and two FOTs were performed in July 2015 as part of the initial completion of CCS#2.

The SRT was performed following the perforation of four separate intervals (6,630 to 6,670 ft KB, 6,680 to 6,725 ft KB, 6,735 to 6,775 ft KB, and 6,787 to 6,825 ft KB) at a density of 4 shots per foot (SPF) for a total perforation interval of 163 feet. The initial injection period consisted of multiple increasing injection rates from 2 bpm to 8 bpm (6.28 hours), followed by a 16.3 hour falloff, then an injection period of 6 bpm for 8.4 hours prior to a final 157 hour falloff period. The fluid injected was 8.33 ppg water.

This data was analyzed by Schlumberger and was reported in an Injection-Falloff Analysis dated August 24, 2015. Schlumberger's Report Summary stated:

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The FOT and spinner log data from the long term injection test at the end of the pressure transient sequence were collected and analyzed. Spinner log data from Schlumberger's Production Log Advisor report dated August 12, 2015 showed that during the long-term injection test, a total of 47.1 feet of the perforations were taking fluid in the upper 34 feet of the Mt. Simon, with 59% of the flow (and the lowermost 8.6 feet) taking 35% of the flow. The pressure falloff test analysis indicated a permeability thickness of 19,118 md-feet.

Copies of the pressure transient data and analyses were presented to EPA in previous reports and are available upon request.

7.3.2 Proposed CCS#3 testing program

This section addresses the pre-operational testing proposed by ADM to ensure that sufficient characterization of the subsurface at CCS#3 is performed and to satisfy Class VI regulations. These requirements include those addressed in Section 7.2 (e.g. injection and confining zone physical, chemical, and fluid characteristics) as well as fracture pressure determination and well testing located in §146.87(d)(1) and (e). ADM will provide 30 day notice of any logging or testing of the Class VI well to the Director so that the Director has the opportunity to witness well activities.

7.3.2.1 Well Testing - Injection Zone

After CCS#3 has been cased and perforated and fluid sampling has been complete, an SRT will be performed to obtain a confirmatory estimate of the fracture pressure of the injection zone. Subsequent wells will not be subjected to an SRT upon completion unless irregular data is obtained from the third injection well. It is noted that the existing Class VI program offers the following discussion regarding the use of additional site SRT data, and similar practices are proposed for new injectors:

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7.3.2.2 Well Testing - Confining Zone

As discussed in Section 7.3.2.2, a "mini-frac" using the MDT tool was used to estimate the fracture gradient of the confining zone in CCS 1 and CCS 2. In addition, dipole sonic data are available through the confining zone to estimate the geomechanics. If the results of CCS#3 geophysical well logging conducted through the confining zone indicate that conditions are similar to the results found using previous logging conducted at CCS 1 and 2, then no additional testing of the confining zone is proposed for CCS#3. Dipole sonic logs will be correlated to existing well logs with similar results and can also be used to infer the representativeness of the CCS 1 and 2 MDT “mini-frac” results.

7.4 Injection and confining zone formation testing

CCS#3 is a new well that may be installed at the site in the future and hence must comply with requirements at §146.87 (a), (b) and (e). Data obtained as part of previous injection and monitoring requirements at the site are relevant to data acquisition to be collected from any new site wells and are summarized in Tables 7.1.2-1, 7.1.2-2, and 7.1.2-3. Historic activities are summarized in Section 7.3.1, which supports the proposed CCS#3 data collection activities presented in Section 7.3.2 because a significant quantity of data has already been obtained to characterize the site during previous testing that supports the proposed CCS#3 program.

7.5 Quality Assurance Surveillance Plan (QASP)

The QASP is provided in APPENDIX C: Quality Assurance and Surveillance Plan which meets relevant requirements under 40 CFR 146.90

8. Site Operating Plan

8.1 Injection rate

The CCS#3 injection well will be operated at rates that will result in an annual average injection rate of approximately 1.1 MT/year. Injection is projected to begin in January 2025.

The injection well is intended to be operated continuously (24 hour per day, 7 days a week, and 365 days per year). The injection rate will vary between 0 and 3,300 MT per day and may vary due to equipment maintenance, mechanical inspection, and testing subject to § 146.89 and § 146.90.

8.2 Maximum injection pressure

Except during stimulation, ADM will ensure that injection pressure does not exceed 90 percent of the fracture pressure of the injection zone(s) so as to ensure that the injection does not initiate new fractures or propagate existing fractures in the injection zone(s). In no case shall injection pressure initiate fractures or propagate existing fractures in the confining zone or cause the movement of injection or formation fluids into a USDW. The maximum injection pressure is included in Table 8.2-1 below.

Table 8.2-1 Well Operating Conditions

PARAMETER/CONDITION	LIMITATION	UNIT
Maximum Injection Pressure - Surface	*	psig
Minimum Annulus Pressure	100	psig
Minimum Annulus Pressure/Tubing Differential (directly above and across packer)	100	psig

*To be determined based on 0.6435 psi/ft multiplied by as-built depth.

The operational injection pressure is estimated to be between 2,100 and 2,300 psi. The higher pressure would be a result of lower Mt. Simon injectivity parameters. These pressure estimates are based on the design surface compression capacity of 3,300 MT per day.

8.3 CO_2 volume

The proposed sequestration site at the ADM facility will be supplied with nearly pure CO2 from the following areas:

- Allam Combustor flue gas
- Oxy-combustion boiler flue gas
- CO_2 from ADM's various ethanol and cogeneration facilities, including Decatur, IL; Clinton, IA; and Cedar Rapids, IA

The details of these CO2 streams are presented in 8.6 CO2 stream characteristics.

The CCS#3 will be operated at a maximum daily injection rate of 3,300 MT/day and injection will result in an average annual average injection rate of approximately 1.1 MT/year from the above combined sources. Injection is expected to begin in January 2025. The total injection volume over the life of the well is expected to be at least 14.3 million MT.

8.4 Annulus pressure

8.4.1 Regulatory Requirements

Except during workovers or times of annulus maintenance, ADM will maintain on the annulus a pressure that exceeds the operating injection pressure as specified in 40 CFR 146.88(c), unless the Director determines that such requirement might harm the integrity of the well or endanger USDWs.

ADM will fill the annulus between the tubing and the long string casing in a liquid-filled condition using a non-corrosive fluid approved by the Director. As previously discussed in this document, an inhibited brine is to be used as the annulus fluid for the CCS#3 well.

8.4.2 Casing, Tubing, Annulus Pressure, Average and Maximum

Because the injection tubing will be set in a packer above the injection interval within the Mt. Simon, the casing-tubing annulus space above the packer will be isolated from the CO2 stream. A constant surface annulus pressure of 400 to 500 psig and at least 100 psig across the packer will be utilized during injection. The average and maximum annulus pressure are anticipated being about the same; however, fluctuations in pressure are anticipated from changes in ambient surface temperature and injection tubing pressure.

All other annulus spaces (one between surface casing and intermediate casing, and one between intermediate casing and long string casing) will have cement to surface. Consequently, the pressures of these annular spaces will be at atmospheric pressure at surface and will not be monitored.

8.5 Well stimulation procedures

8.5.1 Regulatory Requirements

This section is intended to address the standards presented in cited materials as follows:

"If well stimulation is planned, describe the stimulation fluids and procedures to ensure that stimulation will not fracture the confining zone, affect well integrity, or otherwise allow injection of formation fluids to endanger USDWs". EPA Guidance "Underground Injection Control (UIC) Program Class VI Well Construction Guidance", Section 4.1, provides supporting information.

- § Part 146.82(a)(9): [the owner or operator shall submit pursuant to §146.91(e), and the director shall consider the following:] Proposed stimulation program, a description of stimulation fluids to be used and a determination that stimulation will not interfere with containment.
- § 146.88 (a): Except during stimulation, the owner or operator must ensure that injection pressure does not exceed 90 percent of the fracture pressure of the injection zone(s) so as to ensure that the injection does not initiate new fractures or propagate existing fractures in the injection zones(s). In no case may injection pressure initiate fractures in the confining zones(s) or cause movement of injection or formation fluids that endangers a USDW.
- § 146.91 (d) (2) and (e): [Owners or operators must notify the director in writing 30 days in advance of]: Any planned stimulation activities, other than stimulation for formation testing conducted under § 146.82. (e): regardless of whether a state has primary enforcement responsibility, owners or operators must submit all required reports, submittals, and notifications under subpart h of this part to EPA in an electronic format approved by EPA.

The purpose of this Section is to satisfy applicable regulatory requirements presented in § 146.82(a), 146.88(a), and 146.91(d). More specifically, the Section addresses a description of the proposed stimulation programs that may be implemented, a description of stimulation fluids that may be used, and a determination that stimulation plans will not interfere with containment. Because flexibility is required to ensure that the owner/operator may select an appropriate stimulation approach depending on conditions that may develop in the future and because EPA is required to review and approve these approaches prior to implementation, this plan includes multiple methodologies for EPA review and approval. The mandatory 30-day notice that will be provided by the operator may include any of the described methods, depending upon circumstances, that would produce the desired outcome. By providing details about potential stimulation options as part of the permit application in a single plan, EPA is informed of the possible proposed approaches, and may review and approve them as part of the permit authorization, well in advance of any specific stimulation program proposal.

The purpose of any stimulation treatment is to enhance injectivity that is observed at initial conditions or remediate injection capacity restrictions that develop after a well is placed in service. Impediments to optimum injection capacity can be associated with native and induced flow path restricting materials, such as: clay fragments, mineral scales, metallic sulfide or oxide particulates, relative permeability blockages, oil emulsions, and other materials carried into the injection intervals or induced by the injected CO_2 or formed as a result of reactions within the formation.

Prior to completion of any new well or implementation of stimulation on an existing well, ADM will provide a 30-day notice of the specific stimulation methods proposed for completion of the new well based on conditions encountered during drilling and testing. After completion, if injection monitoring or analyses indicate a flow restriction that is either within the well bore or in the near well bore injection formation interval(s), ADM will provide specific proposed remedial stimulation actions with at least 30-days prior notice. The notifications will include the proposed operational tasks and method(s) that will be implemented to conduct stimulation, and the detailed chemical formulation (final selections and volumes) for stimulation when chemical stimulation is proposed.

8.5.2 Stimulation Programs or Methods and Description of Stimulation Fluids

8.5.2.1 Chemical Stimulation Methods

Chemical stimulation methods can involve injection of fluids with no fluid recovery (i.e. Bullhead Stimulation), matrix treatment with fluid recovery, or direct chemical injection with the carbon dioxide injectate. The following sections describe these methods and present fluids that may be used as part of the described methods.

Bullhead Stimulation

Bullhead Stimulation is a stimulation method whereby fluids are injected to enhance injectivity or solubilize flow restrictions, with no fluid recovery. It can be accomplished in injection wells by pumping treatment fluids into an injection formation and ultimately displacing the treatment fluids or flushing them out of the wellbore and into the formation with no recovery back to surface. The chemical stimulant may be preceded by volumes of treated water or other fluids and subsequently followed by enough treated water to displace the stimulation chemicals into the injection zone. For the purpose of these proposed methods, treatment is conducted below the permitted bottom hole pressure for well operations so that no new fractures are created. The displacement may be in stages to allow the stimulation chemicals time to soak at the targeted depth. Variations for delivering the chemical treatment to the targeted intervals include:

- Pumping the chemicals and stimulants down the injection tubing. Site equipment or temporary pumping equipment may be used for injection.
- Placing the chemicals and stimulants at or near the targeted interval(s) by running coiled tubing inside of the injection tubing and pumping the chemicals through the coiled tubing. This option may also include using various nozzles on the coiled tubing string to jet water or chemicals at specific perforated intervals to enhance the chemical contact and mechanical washing.

- Pulling the injection tubing and running a work string or coiled tubing string to pump the chemicals to the targeted interval(s). This placement method may also include running isolation packers to focus the chemical injection on specific intervals.

Matrix Treatment with Fluid Recovery

Matrix treatment stimulation involves the injection of fluids to solubilize flow restrictions, as well as with reverse flow to recover spent chemicals and solubilized fines and other materials. Chemicals are pumped into the formation with all or partial recovery by flowing fluids back out of the well bore. This method is preferred when the treatment is expected to mobilize significant mass of particulates or solid materials that need to be removed from the formation porosity to optimize injection. The chemicals may be preceded by volumes of treated water and may be followed by additional volumes of treated water. In some cases where significant solids are present, initial treatment steps may involve attempts to recover solids from the well and near wellbore porosity by backflowing, jetting with coiled tubing, swabbing, or otherwise producing the well so that less treatment chemical is then required to address immobile plugging materials.

The same methods of placement listed in the bullets, above, under Bullhead Stimulation would be options for Matrix Treatment with fluid recovery. The principal recovery method would be to utilize the previously injected carbon dioxide as the media to flow the spent chemicals and flush water back out of the well. This would require installing temporary separation equipment at surface to flow the well back under controlled conditions and remove the particulate laden spent treatment fluids prior to venting the carbon dioxide.

If extensive fluid volumes are used, the well may be amenable to recovering fluid by:

- Swabbing of the well to recover the fluids that have been pumped down the injection string or a work string of jointed pipe.
- Jetting fluids out with nitrogen gas or carbon dioxide gas when working with coiled tubing or a work string.

Direct Chemical Injection with the Carbon Dioxide Injection

The introduction of solubilizing or scale prevention agents in a fluid system carried by the carbon dioxide injection fluid may be used to solubilize or prevent formation of materials that would impede injection flow paths. This method could be implemented on either a continuous or batch basis.

Direct chemical injection with carbon dioxide injection would be appropriate when it is necessary to dissolve minor amounts of particulates or to introduce scale inhibitors into the injection intervals. Chemicals are typically not recovered.

Description of Fluid System Components that may be Proposed for Chemical Stimulation.

Proposed chemical stimulation formulations may contain a variety of primary fluids and additives to address various conditions that might be encountered. When new well completion or remediation requirements are identified and vendors are selected, specific fluid details, including concentrations and volumes, will be provided with the 30-day notice. Treatment chemicals and additives would be expected to include one or more of the following chemical agents or categories, or suitable equivalents:

1. Inorganic acid solutions such as:
    - hydrochloric acid
    - hydrofluoric acid in combination with hydrochloric acid

2. Inorganic basic solutions such as:
    - sodium hydroxide
    - ammonium solutions and conjugal salts there of
    - sodium hypochlorite solutions and conjugal salts there of

3. Oxidizing agents such as:
    - Sodium hypochlorite solutions
    - Chlorine dioxide solutions
    - Sodium chlorite solutions
    - Sodium chlorate solutions

4. Organic acids such as
    - Citric acid
    - Acetic acid
    - Formic acid
    - Sulfamic acid

5. Combinations of inorganic and organic acids as listed in 1. Inorganic acid solutions and 4. Organic acids

6. Alternating stages of acids listed in 1. Inorganic acid solutions or 4. Organic acids or both with oxidizers listed in 3. Oxidizing agents.

7. Chelating agents, as a direct treatment chemical or in combination with acids listed in 1. Inorganic acid solutions and/or 4. Organic acids, such as:

- Citric acid and salts thereof
- Acetic acid and salts thereof
- Nitrilotriacetic acid (NTA)
- Ethylene diamine tetra-acetic acid, EDTA
- Hydroxyl ethylene diamine triacetic acid, HEDTA
- Glutamic acid-N,N-diacetic acid, GLDA
- Tetrakis(hydroxymethyl)phosphonium sulfate, THPS

8. Acid inhibitors, particularly in common with acids listed in 1. Inorganic acid solutions. There are numerous commonly utilized chemical additives applied to minimize the corrosion of metal well components. Some general categories are:
    - Quaternary amine compounds
    - Imadazoline compounds
    - Pyridine compounds
    - And many others
9. Surfactants, in common with acids listed in 1. Inorganic acid solutions, bases listed in 2. Inorganic basic solutions, and organic acids listed in 4. Organic acids.
10. Organic solvents to mitigate hydrocarbon contamination that could inhibit acid penetration, such as:
    - Xylene
    - Toluene
    - Naphtha
    - Terpenes

11. Mutual solvents to enhance the dispersion and effectiveness of any organic solvents that are applied, such as
    - Ethylene Glycol MonoButyl Ether, EGMBE
    - Various alcohols

12. Scale inhibitors to reduce scale formation from reactions with the fluids introduced during the stimulation or from the subsequent CO_2 injection. There are many specifically designed scale

inhibitor chemistry formulations that might be applied depending on the expected scaling potential. The two primary general categories are:

- Polymeric – typically long chain polymers with carboxylic or acrylic functional groups
- Phosphonate - organic phosphorous bearing compounds that are specifically designed and fabricated to prevent scale formation

13. Clay stabilizers – salts or chemicals specifically applied to prevent the native clays in the formation from fragmenting and releasing pore blocking particulates. Examples include:
    - Inorganic salts, particularly potassium chloride, sodium chloride, calcium chloride, ammonium chloride, and magnesium chloride; but other salts might be used.
    - Temporary clay stabilizers; typically, organic amine type compounds with relatively low molecular weight intended to bind with ion-exchange sites on the clays to prevent the clays from fragmenting. Examples include:
        - Tetramethylammonium chloride, TMAC
        - Choline chloride
        - Other substances that are utilized to stabilize clays to prevent damage through ion-exchange induced clay fragmentation
    - Permanent clay stabilizers; typically, long chain cationic or nonionic polymers that bridge across multiple ion-exchange sites on the clay structure to provide longer term fragmentation prevention. There are many polymeric chemistries applied for this purpose, with polyamines being one common example.

14. Diverting agents – materials used to temporarily block off intervals that retain high injectivity so that stimulation chemicals are focused into intervals that are less permeable or more impaired. These might include:
    - Rock salt; conveyed into the well bore as a slurry with the salt crystals suspended in salt brine. The salt brine may be treated with gelling agents such as guar polymer or xanthan gum to produce higher viscosity and salt carrying capacity.
    - Water soluble solids with low acid solubility, such as benzoic acid flakes, encapsulated citric acid, or other bridging agents that can be dissolved after stimulation chemical placement is completed by flushing with water or injected carbon dioxide.
    - Soluble ball sealers that are made of materials that will dissolve over time in carbon dioxide solution or injected water and/or brine.
    - Insoluble rubber ball sealers that would need to be removed from the well through flow back or other mechanical methods for recovery.

- Polymeric substances that are formulated to provide temporary restrictions and then "break down" or dissolve with time and temperature.

15. Biologic control agents, or biocides. When large volumes of flush water are used before or after a chemical stimulation, treatment of the fluids to prevent contaminating the well bore with undesirable microbes may be appropriate. Numerous chemical alternatives are available as EPA registered biocides and may be used as additives to reduce undesirable biological activity. A few examples are:
    - Quaternary amine compounds,
    - Sodium hypochlorite,
    - Chlorine dioxide,
    - Dazomet, and
    - Other alternatives, depending on the anticipated microbial control requirement and confirmation that the biocidal agent(s) are compatible with the proposed chemical stimulation.

8.5.2.2 Mechanical Stimulation Methods

In addition to chemical stimulation, mechanical stimulation of the well may be pursued independently, or in concert with the chemical methods described earlier in this section. Mechanical methods that might be used include perforation, propellant stimulant, and backflow methods as described below.

Perforation

Perforation or re-perforation, with or without supplemental propellant assistance may be proposed during initial completion and remedial stimulation operations. Initial well completions will commonly incorporate perforations to connect the well bore to the targeted injection intervals. In some cases, ADM may propose to utilize propellant assisted perforating tools to enhance the connectivity through the steel casing and cement sheath to the formation. Analytical data may indicate near-wellbore flow restrictions that are best remediated with mechanical penetration. Any re-perforating, with or without propellant assistance, will be proposed to EPA with detailed procedures in the 30-day advance notification.

Propellant assistance is accomplished by various suppliers using slightly different methods to obtain the same basic objective, i.e., to provide a short duration, high energy gas pulse to further extend the perforation tunnels created by the shape charges. (Enhanced Energetics Kraken-enhanced Perforating Flow Performance Tests, API RP19B Section 4 Test Results – 2020).

Propellant Stimulation

Propellant stimulation may be used to induce or enhance flow paths in the injection zone, with flow paths confined to approximately the height of the propellant gun. Direct propellant stimulation may be proposed to create flow paths through the damaged or restricted formation sections. This may be particularly effective when analytical data indicate that flow restriction extends past the wellbore face or the initial perforation channel to moderate depths into the formation, (i.e.,5 to 15 feet). Various studies and modeling efforts have been performed by private and governmental agencies to confirm that propellant stimulations create or stimulate flow paths into the targeted formation intervals with nominal vertical growth; verifying that there is no risk of confinement layer breach when guns depths are restricted to appropriate distances below the top of the injection zone. (SPE 8934 1980; Enhanced Energetics – Gas Gun – Vertical Containment, (undated); Letter of Determination, Natural Resources Agency of California Department of Conservation, Division of Oil, Gas, & Geothermal Resources, Dated 4/12/2019).

Deployment for initial perforation, re-perforation, re-perforation with propellant assistance, or propellant stimulation alone is commonly done with conventional electric line, coiled tubing e-line, and/or jointed tubing conveyed methods. Any of these methods might be proposed depending upon the scope of the stimulation and well operating conditions. When performing remedial work, the stimulation might be performed with the well full of liquid kill weight fluid or with the well full of injected carbon dioxide.

Backflow

Fluids can be produced from an injection well by backflow, used to reverse the direction of flow, thereby mobilizing fines that are plugging near wellbore pore spaces and perforation channels. This material can then settle into the rathole below the completion, or some minor smaller particulate may be produced back to surface if sufficient energy is available to overcome well hydrostatics and friction to sustain velocity needed to carry solids back to the surface.

To backflow a CO2 injector, safety issues associated with a controlled CO2 release from the wellhead to the atmosphere will be addressed and the wellhead area prepared for operations. Preparations will include assessment of: wellhead temperature and pressure, weather, and air quality monitoring; communications; PPE; and suitable exclusion areas. After equipment is tested and necessary monitoring is enabled, valves at the wellhead are opened to allow CO2 to be produced from the well, thereby reversing flow direction from the injection reservoir downhole. Controlled CO2 production will be monitored to ensure safe production operations and to allow the calculation of the volume of CO2 produced. At the end of the proscribed production period (15 to 30 minutes), valves will be closed slowly in stages to manage temperature effects and minimize the potential for shocks to the well from instantaneous shut-in.

An example well flow back procedure that has previously been provided by ADM to EPA is attached in Appendix E. This is provided as an example only and will be customized for each proposed flow back operation or use of flow back in conjunction with other stimulation methods. Other types of stimulation notices will include similar detailed plans for the proposed activities.

Well flowback operations may be followed by mechanical methods of solids removal from the rathole, such as jetting with coiled tubing, that will also be detailed in the 30- day notification to EPA.

Other Activities

All the above methods may be proposed to enhance original injectivity upon the initial well completion and may also be used to remediate injectivity restrictions. When injection rates vs injection pressure is below expectations, EPA will be notified when the operator proposes to investigate injection restrictions using common physical and analytical methods such as:

- Collecting bottom hole samples with sampling equipment conveyed into the well bore by wireline, slickline, or coiled tubing, with follow up analytical testing as appropriate for the sample and treatments under consideration,
- Performing injection profile logging activities with thermal measurement instruments, acoustic measurements instruments, or mechanical spinner tools to pinpoint the focus intervals for the stimulation, and
- Injection and fall-off testing to assess overall skin damage.

Standard procedures will be followed with respect to job safety and monitoring for all field operations. The 30 day notice to EPA for proposed operations will include:

- Listing of pre-job planning and assignments,
- Methods and practices for well control to prevent uncontrolled emissions or loss of well control,
- Methods for estimating, recording, and reporting any controlled emissions,
- When the proposed action involves ceasing injection and performing maintenance activities, the detailed work procedures will include:
    - approaches for shutting-in and securing the well for the proposed activities
    - specific actions to be performed
    - detail of all chemicals and concentrations that will be applied
    - detail for all tools, such as propellant enhanced perforating guns, coiled tubing equipment with jetting type wash nozzle, etc. that may be utilized
    - procedures to secure the well after stimulation activities

  - any post stimulation evaluation procedures that are proposed
  - procedures to return the well to injection service after stimulation
- When stimulation is proposed while the well is still injecting, the notice will include
  - detail for all chemicals and concentrations that will be applied
  - monitoring and control mechanisms that will be utilized to perform the chemical injection
  - methods to evaluate the chemical performance and adjust chemical dosing, as appropriate

  and,
- Job specific personnel training requirements.

The flow back procedure in Appendix E provides an example of the prior planning, well control procedures, and other job specific safety and environmental protection control practices that will be detailed and employed with all stimulation activities. Such safety plans are not considered UIC permit requirements, but are provided herein for general informational purposes. These procedures are subject to change without advanced notice based on vendors selected to complete various field operations, the type of field actions undertaken to accomplish well stimulation, and the nature of potential chemical and physical hazards identified for personnel.

8.5.3 Determination that Stimulation will not Interfere with Containment

Stimulation of the permitted injection interval will take place at depths below the top of the permitted injection interval and are not projected to have an impact on the confining layer. Mechanical operations such as perforating will be vertically separated from the casing at the top of the permitted injection zone by a minimum of 10 feet. Chemical additives will be injected into perforations below the base of the confining zone and will not be in contact with the rock matrix above the base of the confining zone formations. This will be accomplished by injecting limited treatment volumes at controlled pressures.

Routine chemical stimulation will be conducted at sustained bottom hole pressures that remain below 90% of the established fracture initiation pressures for the well/interval being stimulated. This practice will satisfy the requirement that “In no case may injection pressure initiate fractures in the confining zones(s) or cause movement of injection or formation fluids that endangers an Underground Source of Drinking Water USDW” (40 CFR Part 146.88).

Stimulation chemical treatments will be conducted in a manner to ensure that chemical treatments are isolated to the injection interval. For example:

- When treating through either the injection tubulars or a work string, the annular pressure will be monitored to confirm that chemicals are contained below the upper packer or other down hole isolation tools.

- All chemical treatments will be selected for chemical compatibility with the placement method. For example, mineral acids will be treated with chemical inhibitors to prevent any significant corrosion damage to the tubing string that conveys the chemical. In addition, chemical systems will be selected to avoid damage to the down hole packer sealing elements and other seals within the injection system that might be exposed to the chemicals.

Propellant stimulations will only be utilized well below the top of the injection zone. Established studies indicate that propellant stimulations have only nominal height growth above the propellant tool depth so restricting the use of propellant well below the top of the injection interval will assure that no fractures are created into the confining layer.

8.6 CO_2 stream characteristics

The injection stream is high purity CO_2 with trace levels of other constituents. The details of these CO_2 streams are presented in the tables below.

Table 8.6-1. CO_2 Stream Characteristics

Component	Wt. %
Carbon Dioxide	> 93.8%
Nitrogen	< 4.0%
Oxygen	< 1.0%
Water	< 250 ppmw
Hydrocarbons	< 5.0%
Sulfur Species	Report

The CO_2 streams included in this application are typically greater than 99.9% pure CO_2. It is saturated with water vapor at 100°F and at slightly greater than atmospheric pressure. Common impurities (in amounts typically less than 200 ppm by volume) are nitrogen, oxygen, methanol, acetaldehyde and hydrogen sulfide.

8.7 Injection Well Operating Requirements

ADM will install, continuously operate, and maintain an automatic alarm and an automatic shut-off system or, at the discretion of the Director, down-hole shut- off systems, or other mechanical devices that provide equivalent protection; and successfully demonstrate the functionality of the alarm system and shut-off system prior to the Director authorizing injection, and at a minimum of once every twelfth month after the last approved demonstration.

Testing to demonstrate functionality will involve subjecting the system to simulated failure conditions. ADM will provide notice in an electronic format 30 days prior to running the test and will provide the Director or their representative the opportunity to attend. The test will be documented using either a mechanical or digital device which records the value of the parameter of interest, or by a service company job record. A final report including any additional interpretation necessary for evaluation of the testing will be submitted.

The injection well operating requirements are previously covered in Sections 8.1, 8.2, and 8.4.

8.7.1 Precautions to Prevent Well Blowouts

ADM will maintain on the well a pressure which will prevent the return of the injection fluid as specified in Section 8.4 to the surface. The well bore will be filled with a high specific gravity fluid during workovers to maintain a positive (downward) gradient and/or a plug shall be installed which can resist the pressure differential. A blowout preventer will be installed and kept in proper operational condition whenever the wellhead is removed to work on the well. ADM will follow procedures such as those below to assure that a backflow or blowout does not occur:

- Limit the temperature and/or corrosivity of the injectate; and
- Develop procedures necessary to assure that pressure imbalances do not occur.

8.7.2 Circumstances Under Which Injection Must Cease

Injection will cease when any of the following circumstances arises:

1. Failure of the well to pass a mechanical integrity test;
2. A loss of mechanical integrity during operation;
3. The automatic alarm or automatic shut-off system is triggered;
4. A significant unexpected change in the annulus or injection pressure;
5. The Director determines that the well lacks mechanical integrity; or
6. ADM is unable to maintain compliance with any permit condition or regulatory requirement and the Director determines that injection should cease.

If any of the above circumstances arise, ADM will immediately cease injection and shut-in the well as outlined in Section 12. Emergency and Remedial Response Plan.

9. Testing and Monitoring Plan

This Testing and Monitoring Plan describes how ADM will monitor the CCS#3 site pursuant to 40 CFR 146.90. In addition to demonstrating that the well is operating as planned, the carbon dioxide plume and pressure front are moving as predicted, and that there is no endangerment to USDWs, the testing and monitoring data will be used to validate and adjust the geological models used to predict the distribution of the CO2 within the storage zone to support AoR reevaluations and a non-endangerment demonstration to support closure.

9.1 CO_2 stream analysis

ADM will analyze the CO2 stream during the operation period to yield data representative of its chemical and physical characteristics and to meet the requirements of 40 CFR 146.90(a).

Sampling will take place each calendar quarter.

ADM will analyze each CO_2 gas stream for the constituents identified in Table 9.1-1 using the methods listed.

Table 9.1-1. Summary of analytical parameters for CO2 gas streams.

Parameters	Analytical Methods (1)
Oxygen	ISBT 4.0 (GC/DID) GC/TCD
Nitrogen	ISBT 4.0 GC/DID GC/TCD
Carbon Monoxide	ISBT 5.0 Colorimetric ISBT 4.0 (GC/DID)
Oxides of Nitrogen	ISBT 7.0 Colorimetric
Total Hydrocarbons	ISBT 10.0 THA (FID)
Methane	ISBT 10.1 GC/FID)
Acetaldehyde	ISBT 11.0 (GC/FID)
Sulfur Dioxide	ISBT 14.0 (GC/SCD)
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)
Ethanol	ISBT 11.0 (GC/FID)
Carbon Dioxide	ISBT 2.0 Caustic absorption Zahm-Nagel ALI method SAM 4.1 subtraction method (GC/DID) GC/TCD

9.1.1 Sampling Methods

CO_2 stream sampling will occur in the compressor building after the last stage of compression and prior to flowline conveyance to the injection wellhead. A sampling station will be installed with the ability to purge and collect samples into a container that will be sealed and sent to the authorized laboratory.

All sample containers will be labeled with durable labels and indelible markings. A unique sample identification number and sampling date will be recorded on the sample containers.

9.1.2 Laboratory to be Used/Chain of Custody Procedures

Samples will be analyzed by a third party laboratory using standardized procedures for gas chromatography, mass spectrometry, detector tubes, and photo ionization. The sample chain-of- custody procedures described in Section B.3 of the QASP will be employed.

9.2 Mechanical integrity and corrosion testing

To meet the requirements of 40 CFR 146.90(c), ADM will monitor well materials during the operation period for loss of mass, thickness, cracking, pitting, and other signs of corrosion at surface to ensure that the well components meet the minimum standards for material strength and performance.

This monitoring will occur once per calendar quarter.

ADM will monitor corrosion using the corrosion coupon method and collect samples according to the description below.

9.2.1 Sample Description

Samples of material used in the construction of the compression equipment, pipeline and injection well which come into contact with the CO_2 stream will be included in the corrosion monitoring program either by using actual material and/or conventional corrosion coupons. The samples consist of those items listed in Table 9.2.1-1 below. Each coupon will be weighed, measured, and photographed prior to initial exposure (see “Sample Handling and Monitoring” below).

Table 9.2.1-1. List of Equipment Coupon with Material of Construction.

Equipment Coupon	Material of Construction
Pipeline	CS A106B
Long String Casing (Surface - 4,800’)	Carbon Steel
Long String Casing (4,800’ – TD)	Chrome Alloy
Injection Tubing	Chrome alloy
Wellhead	Chrome alloy

Packers 1	Chrome alloy

9.2.2 Sample Exposure

Each sample will be attached to an individual holder (Figure 2a) and then inserted in a flow- through pipe arrangement (Figure 2b). The corrosion monitoring system will be located downstream of all process compression/dehydration/pumping equipment (i.e., at the beginning of the pipeline to the wellhead). To accomplish this, a parallel stream of high pressure CO_2 will be routed from the pipeline through the corrosion monitoring system and then back into a lower pressure point upstream in the compression system. This loop will operate any time injection is occurring. No other equipment will act on the CO_2 past this point; therefore this location will provide sufficiently representative exposures of the samples to the CO_2 composition, temperature, and pressures that will be seen at the wellhead and injection tubing. The holders and location of the system will be included in the pipeline design and will allow for continuation of injection during sample removal.

Figure 2a. Coupon Holder.

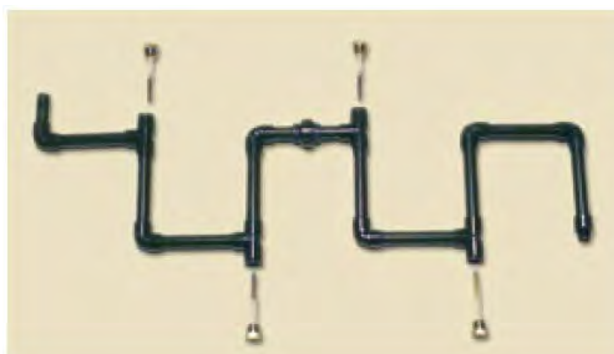

Figure 2b. Flow-through Pipe Arrangement.

9.2.3 Sample Handling and Monitoring

The coupons will be handled and assessed for corrosion using the American Society for Testing and Materials (ASTM) G1-03, Standard Practice for Preparing, Cleaning, and Evaluating Corrosion Test Specimens (ASTM 2011). The coupons will photographed, visually inspected with a minimum of 10x power, dimensionally measured (to within 0.0001 inch), and weighed (to within 0.0001 gm).

9.3 Pressure fall-off testing

ADM will perform pressure fall-off tests during the injection phase as described below to meet the requirements of 40 CFR 146.90(f).

At a minimum, pressure fall-off testing will be performed:

- During injection in year 5 of operation; and
- At least every 5 years during the remainder of the injection period.

ADM will conduct pressure fall-off testing according to the procedures below.

9.3.1 Pressure Fall-off Test Procedure

Each pressure falloff test will include a period of injection followed by a period of no-injection or shut-in. Normal injection using the stream of CO_2 captured from the ADM facility will be used during the injection period preceding the shut-in portion of the falloff tests. The normal injection rate is estimated to be maximum 3,300 MT/day. Prior to the falloff test, a constant rate will be maintained. If this rate causes relatively large changes in bottomhole pressure, the rate may be decreased. Injection will have occurred for multiple years prior to this test, but there may have been injection interruptions due to operations or testing. At a minimum, one week of relatively continuous injection will precede the shut-in portion of the falloff test; however, several months of injection prior to the falloff will likely be part of the pre- shut-in injection period and subsequent analysis. This data will be measured using a surface readout downhole gauge so a final decision on test duration can be made after preliminary evaluation of the data takes place. The gauges may be those used for day-to-day data acquisition or a pressure gauge will be conveyed via electric line (e-line).

To reduce the wellbore storage effects attributable to the pipeline and surface equipment, the well will be shut-in at the wellhead nearly instantaneously with direct coordination with the injection compression facility operator. Because surface readout will be used and downhole recording memory restrictions will be eliminated, data will be collected at five second intervals or more frequently for the entire test. The shut-in period of the falloff test will be at least four days or longer until adequate pressure transient data are collected to allow meaningful interpretation of the data. Because surface readout gauges will be used, the shut-in duration can be determined in real-time. A report containing the pressure falloff data and interpretation of the reservoir ambient pressure will be submitted to the permitting agency within 90 days of the test. Pressure sensors used for this test will be the wellhead sensors and a downhole gauge for the pressure falloff test. Each gauge will be of a type that meets or exceeds ASME B 40.1 Class 2A (0.5% accuracy across full range). Wellhead pressure gauge range will be 0-4,000 psi. Downhole gauge range will be 0-10,000 psi.

9.4 Groundwater quality monitoring

The purpose of the groundwater monitoring plan is to evaluate potential carbon dioxide (CO2) migration and/or native fluid displacement from the injection zone or other water quality changes that may lead to endangerment of USDWs. ADM will monitor three separate zones during operation to meet the requirements of 40 CFR 146.90(d).

9.4.1 Identification of Monitored Intervals

The groundwater monitoring plan focuses on the following zones:

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[redacted]

Sensitive, Confidential, or Privileged Information

[redacted]

Table 9.4.2-1 and Table 9.4.3-1 show the planned direct and indirect monitoring methods, locations, and frequencies for groundwater quality monitoring above the confining zone. ADM will also monitor in the Mt. Simon Sandstone (the injection zone). Monitoring in this layer will be to track the CO_2 plume and is described in Section 9.5.

9.4.2 Direct Monitoring Methods

ADM will employ direct monitoring methods such as pressure and temperature monitoring and fluid sampling on a monthly or annual basis. Table 9.4.2-1 summarizes the planned locations and frequencies of all applicable direct monitoring methods.

Table 9.4.2-1. Summary of Direct Monitoring Methods

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
Sensitive, Confidential, or Privileged Informa [redacted]	Fluid Sampling	Sensitive, Confidential, or Privileged Information [redacted]		Baseline; Quarterly during Year 1 & 2; Semi-annual thereafter
	Temperature Monitoring (DTS)			Continuous**; recorded hourly
				Continuous**; recorded hourly
				Continuous**; recorded hourly
	Fluid Sampling			Baseline; Annual
				Baseline; Annual
				Baseline; Annual
	Pressure Monitoring			Monthly
				Monthly
				Monthly
	Temperature Monitoring (DTS)			Continuous**; recorded hourly
				Continuous**; recorded hourly
				Continuous**; recorded hourly
	Pressure Monitoring			Monthly
				Monthly
				Monthly
	Temperature Monitoring (DTS)			Continuous**; recorded hourly
				Continuous**; recorded hourly
				Continuous**; recorded hourly
				Baseline; Annual

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
	Fluid Sampling	[redacted]		Baseline; Annual
				Baseline; Annual

Notes:

* indicates applicable if the proposed well is drilled in the future. Sample location estimated based off offset information, subject to change after drilling.

**Continuous temperature and pressure monitoring (DTS) will be satisfied with a minimum 5 minute sampling and at least hourly recording. If the continuous monitoring is unavailable, the well can continue to operate by performing pressure and temperature monitoring every 4 hours.

9.4.3 Indirect Monitoring Methods

ADM will continue to employ indirect monitoring methods such as wireline logging and seismic monitoring. Table 9.4.3-1 summarizes the planned locations and frequencies of all applicable indirect monitoring methods.

Table 9.4.3-1. Summary of Indirect Monitoring Methods

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
[redacted]	Pulse Neutron/RST Logging	[redacted]		Baseline, Bi-Annual
				Baseline, Bi-Annual
				Baseline, Bi-Annual
				Baseline, Bi-Annual
				Baseline, Bi-Annual
				Baseline, Bi-Annual
	Pulse Neutron/RST Logging			Baseline, Bi-Annual
				Baseline, Bi-Annual
				Baseline, Bi-Annual
				Baseline, Bi-Annual
				Baseline, Bi-Annual
				Baseline, Bi-Annual
				Baseline, Bi-Annual
				Baseline, Bi-Annual

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
	Pulse Neutron/RST Logging	Sensitive, Confidential, or Privileged Information [redacted]		Baseline, Bi-Annual
				Baseline, Bi-Annual
				Baseline, Bi-Annual
				Baseline, Bi-Annual
	Passive seismic			Continuous**; processed monthly
	Time-lapse 3D surface seismic			5-Year

Notes:

* indicates applicable if the proposed well is drilled in the future

**Continuous recording of passive seismic data is processed on a monthly basis to determine if seismic events over M1.0 occurred within the AoR. The passive seismic monitoring system at borehole and surface seismic stations is owned and operated by USGS.

9.4.4 Analytical and Field Parameters for Groundwater Samples

Sampling will be performed as described in Section B.2 of the Quality Assurance Sampling Plan (QASP); this section of the QASP describes the groundwater sampling methods to be employed, including sampling SOPs (Section B.2.a/b), and sample preservation (Section B.2.g). Sample handling and custody will be performed as described in Section B.3 of the QASP. Quality control will be ensured using the methods described in Section B.5 of the QASP.

Table 9.4.4-1. Summary of Fluid Sampling Constituents and Analytical Methods

Target Formation	Parameters	Analytical Methods [1]
Sensitive, Confidential, or Privileged Information [redacted]	**Cations:** Ca, Fe, K, Mg, Na, and Si	ICP-OES, EPA Method 6010B
	Anions: Br, Cl, F, NO3, and SO4	Ion Chromatography, EPA Method 300.0
	Dissolved CO_2	Coulometric titration, ASTM D513-11
	Total Dissolved Solids	Gravimetry; APHA 2540C
	Alkalinity	APHA 2320B
	pH (field)	EPA 150.1
	Specific conductance (field)	APHA 2510
	Temperature (field)	Thermocouple
	Cations: Ca, Fe, K, Mg, Na, and Si	ICP-OES, EPA Method 6010B
	Anions: Br, Cl, F, NO3, and SO4	Ion Chromatography, EPA Method 300.0
	Dissolved CO2	Coulometric titration, ASTM D513-11
	Isotopes: δ13C of DIC	Isotope ratio mass spectrometry
	Total Dissolved Solids	Gravimetry; APHA 2540C
	Water Density (field)	Oscillating body method
	Alkalinity	APHA 2320B
	pH (field)	EPA 150.1
	Specific conductance (field)	APHA 2510
	Temperature (field)	Thermocouple
	Cations: Ca, Fe, K, Mg, Na, and Si	ICP-OES, EPA Method 6010B
	Anions: Br, Cl, F, NO3, and SO4	Ion Chromatography, EPA Method 300.0
	Dissolved CO2	Coulometric titration, ASTM D513-11
	Isotopes: δ13C of DIC	Isotope ratio mass spectrometry
	Total Dissolved Solids	Gravimetry; APHA 2540C
	Water Density (field)	Oscillating body method
	Alkalinity	APHA 2320B
	pH (field)	EPA 150.1

Target Formation	Parameters	Analytical Methods [1]
	Specific conductance (field)	APHA 2510
	Temperature (field)	Thermocouple

Note 1: ICP = inductively coupled plasma; MS = mass spectrometry; OES = optical emission spectrometry; GC-P = gas chromatography - pyrolysis. An equivalent method may be employed with the prior approval of the UIC Program Director.

9.5 CO_2 plume and pressure front tracking

9.5.1 Direct Monitoring Methods

<u>Monitoring of Temperature and Pressure</u>

In-situ pressure measurements will be recorded in all active injection wells. Pressure data will be collected via downhole pressure gauges located near the base of the Eau Claire Formation (the confining zone) in addition to the Ironton-Galesville Sandstone located directly above the Eau Claire formation. Temperature will be monitored in all active injection wells throughout each wellbore. This monitoring well be conducted for as long as remains practical utilizing a fiber-optic, dynamic temperature survey (DTS) to be installed during the installation of each well.

Significant variance between actual measured and predicted pressure/temperature (P/T) data will indicate that a re-calibration of the numerical model is warranted. Review and revisions to the model and subsequently the area of review (AoR) and the monitoring program supported by simulations generated with the model will be conducted on a minimum frequency of once every 5-years during operations to incorporate any subsequent changes in model predictions.

<u>Addition of Verification Well #3 (VW #3)</u>

The approved testing and monitoring program submitted in 2017 incorporated two verification wells (VW#1 and VW #2) to monitor plume front and associated pressures as a result of injection into CCS#1 and CCS#2. The proposed VW#3 is located south of all three CCS locations.

The addition of CCS#3 and the use of the existing two site wells (CCS#1 and CCS#2) for continued injection service will increase the volume of CO_2 injection introduced into the injection zone and will extend both the area over which pressure rise and CO_2 saturation will occur within the injection zone. Pressure will be impacted by cumulative operation of all wells completed in the same injection interval. These effects will increase the size of the existing AoR and the altered distribution of fluids, and one verification well will be added appropriate for confirmatory monitoring. Figure 9.5.1-1 presents the current and proposed configuration of the well development at the site and Figure 9.5.1-2 shows the wells superimposed on a satellite image for reference. Figure 9.5.1-3 is an enhanced view showing the potential location for VW#3. The optimal VW#3 location was selected based on the regulatory guidelines described above.

1) With regard to down-gradient orientation, current modeling indicates that the down-gradient gravity effects are not significant enough to meaningfully influence plume drift during the operational period (Figure 9.5.1-4 presents the extent of the CO_2 plume growth at specified time horizons). Based on these modeling predictions, direct monitoring in VW #2, in addition to indirect seismic methods, are projected to be sufficient for tracking potential plume migration to the north and providing useful data for future model comparison and calibration.

2) Based on Figure 9.5.1-4, the CO_2 plume is predicted to eclipse the new VW #3 location during the operational period. Pressure impacts will be able to be measured earlier than probable arrival time of concentration changes that will occur later in the life of the operation. These changes will be influenced by allocation between injectors and total volume actually injected into the well system. A more substantial distance from offset injectors to the VW #3 location as compared with the offset between prior injector-verification well pairs will allow for more elapsed time to pass before higher concentration CO_2 is projected to encounter the location. Tuning the model to the closer offset existing well pairs and to these data will enhance the ability to verify that larger-scale and longer-term model projections are meaningful. In addition to pressure monitoring in an area closer to proposed future injector locations than the existing VW- 1 and VW#2, fluid samples taken in the Mt Simon at VW-3 will provide an additional means to validate modeled CO_2 concentration vs. distance in another direction that will be impacted by the altered distribution of injectate based on the addition of injection locations.

3) The current orientation of VW #1 and VW #2 allow for direct monitoring to the immediate north of the injection centroid. From an aerial perspective, plume migration and associated pressure rise that develop to the south cannot be as effectively evaluated from the existing 2-well monitoring array. The addition of VW #3 will enhance the ability to characterize fluid and pressure migration in the injection zone by allowing acquisition of data in an opposite azimuth relative to the existing verification wells.

Figures 9.5.1-4 and 9.5.1-5 illustrate model projections of pressure and plume front relative to the VW #3 location. As shown in these figures, the selected VW #3 location provides a useful additional monitoring location that will generate data later in the progression of the plume and pressure front development than VW #1 and 2. VW #1 is in a location such that it provided valuable data regarding the behavior of the reservoir close to the original completion layer in VW #1 and can be re-used to provide confirmation of behavior close to CCS#1 due to injection into any recompletion of CCS#1. In addition to satisfying the general regulatory guidelines and technical objectives, the selected location of VW #3 offers suitable surface access for drilling, testing and future maintenance/workover operations. The three-well VW network is sufficient to provide spatial and temporal resolution of plume and pressure development within the multi-well CCS system to be operated at the ADM site.

VW #3 installation will take place with or after installation of the next injector at the site. Additional CCS wells are not anticipated to trigger the need for further VW well installation; monitoring of site pressure and plume development will be accomplished through monitoring with the distributed three-well VW system in addition to the monitoring of each active injector.

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[redacted]

Figure 9.5.1-1. Orientation of ADM Injection and Monitoring Wells (Coordinate View)

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[redacted]

Figure 9.5.1-2. Orientation of ADM Injection and Monitoring Wells (Surface View)

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[redacted]

Figure 9.5.1-3. Planned Surface Location of Verification Well #3

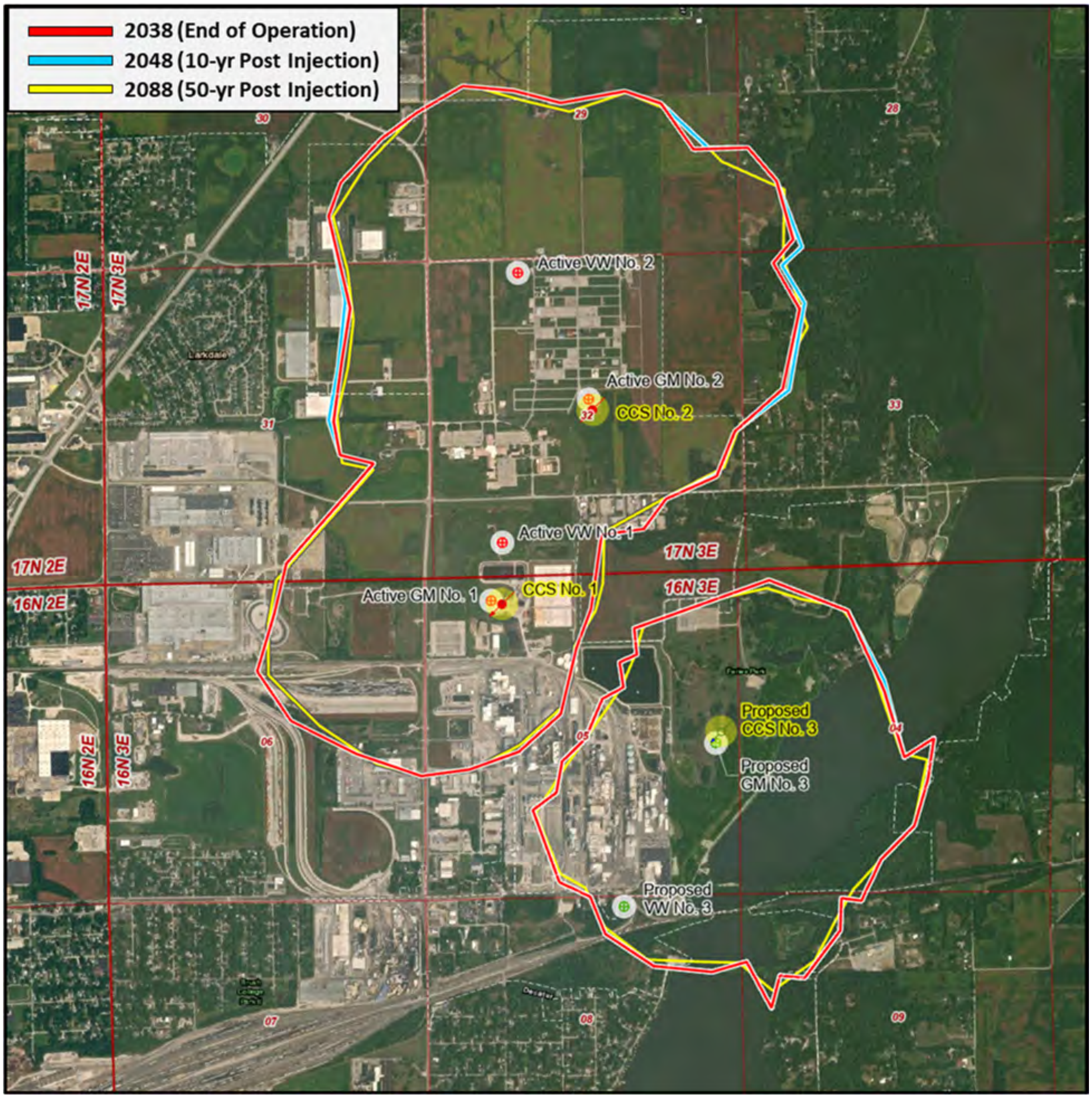

Figure 9.5.1-4. Verification Well #3 Proximity to Projected Plume Arrival

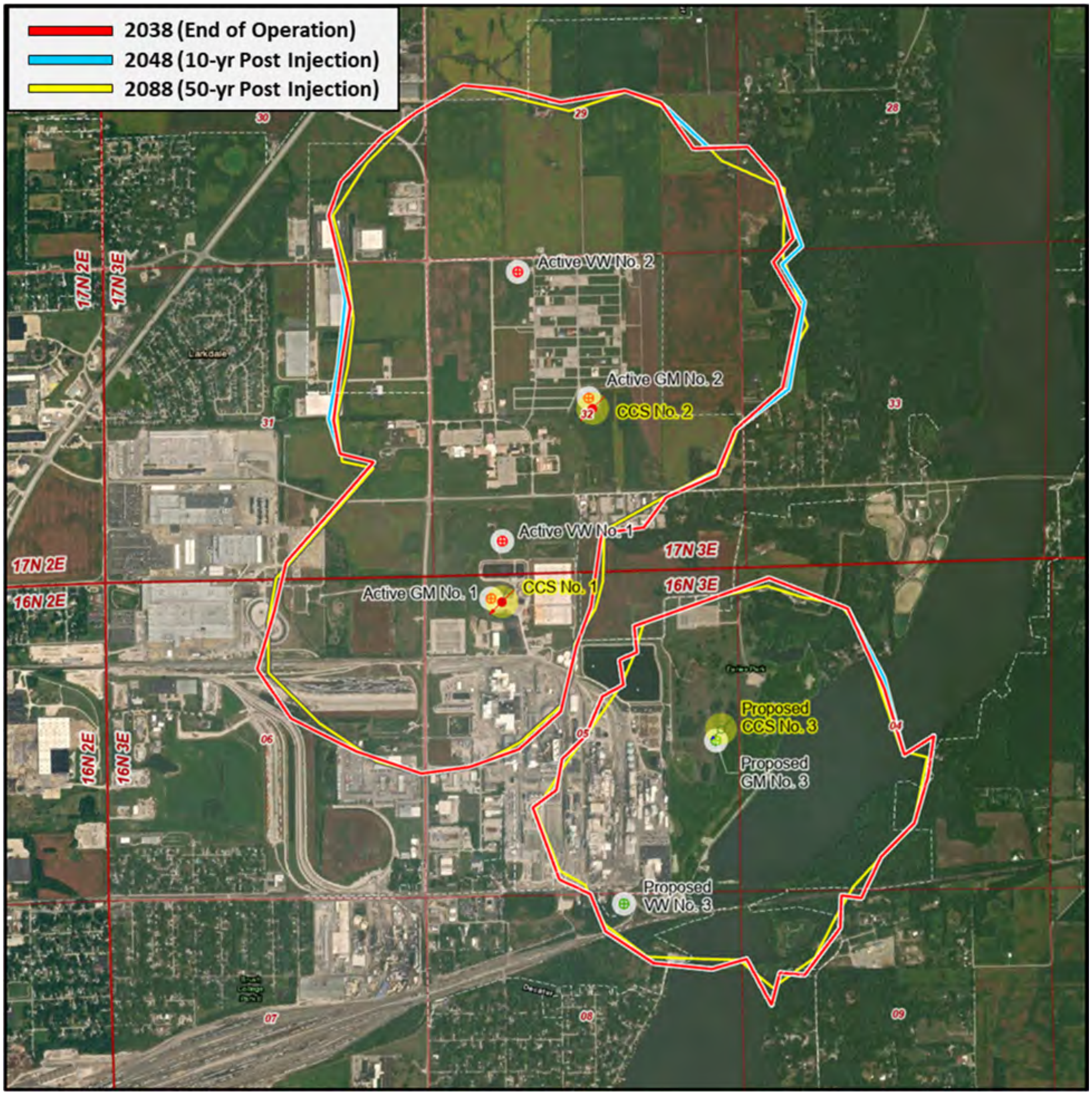

Figure 9.5.1-5. Verification Well #3 Proximity to AOR Boundary

Annual Fluid Sampling

Following baseline fluid sampling and analysis, fluid sampling will be conducted on an annual basis in all monitoring-verification wells. Initial samples will be taken via packer-isolated sliding sleeves located adjacent to the Ironton-Galesville Sandstone or suitable equivalent method if complications are encountered with the equipment and within the Mt. Simon Formation below the lower-most packer. Each sample interval will be analyzed for the constituents listed in Table 9.5.2-1 to document baseline fluid chemistry and to detect changes in fluid chemistry that could result from the movement of brine or CO_2 from the storage interval through the overlying confining zone and other formation.

Table 9.5.2-1. Summary of Fluid Sampling Constituents and Analytical Methods

Parameters	Analytical Methods [1]
Cations: Ca, Fe, K, Mg, Na, and Si	ICP-OES, EPA Method 6010B
Anions: Br, Cl, F, NO3, and SO4	Ion Chromatography, EPA Method 300.0
Dissolved CO2	Coulometric titration, ASTM D513-11
Isotopes: δ13C of DIC	Isotope ratio mass spectrometry
Total Dissolved Solids	Gravimetry; APHA 2540C
Water Density (field)	Oscillating body method
Alkalinity	APHA 2320B
pH (field)	EPA 150.1
Specific conductance (field)	APHA 2510
Temperature (field)	Thermocouple

By conducting the planned sampling initially and at specified monitoring frequencies, it is expected that baseline conditions can be documented, natural variability in conditions can be characterized, and unintended brine or CO_2 migration could be detected if it occurred. Sufficient data will be collected to demonstrate that the effects of CO_2 injection are limited to the permitted injection zone comprised of the Mt. Simon formation. Table 9.5.2-2 summarizes the planned locations and frequencies of all applicable direct monitoring methods.

Table 9.5.2-2. Summary of Direct Monitoring Methods

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
Sensitive, Confidential, or Privileged In [redacted]	Pressure Monitoring	Sensitive, Confidential, or Privileged Information [redacted]		Monthly
				Monthly
				Monthly
	Temperature Monitoring (DTS)			Continuous**; recorded hourly
				Continuous**; recorded hourly
				Continuous**; recorded hourly
	Fluid Sampling			Baseline; Annual
				Baseline; Annual
				Baseline; Annual

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
Sensitive, Confidential, or Privileged In [redacted]	Pressure Monitoring	Sensitive, Confidential, or Privileged Information [redacted]		Continuous**; recorded hourly
				Continuous**; recorded hourly
				Continuous**; recorded hourly
				Monthly
				Monthly
				Monthly
	Temperature Monitoring (DTS)			Continuous**; recorded hourly
				Continuous**; recorded hourly
				Continuous**; recorded hourly
				Baseline; Annual

	Fluid Sampling	Sensitive, Confidential, or Privileged Information [redacted]	Baseline; Annual
			Baseline; Annual

Note:

* indicates applicable if the proposed well is drilled in the future

**Continuous temperature and pressure monitoring (DTS) will be satisfied with a minimum 5 minute sampling and at least hourly recording. If the continuous monitoring is unavailable, the well can continue to operate by performing pressure and temperature monitoring every 4 hours.

9.5.2 Indirect Monitoring Methods

Wireline Logging

Both pulse-neutron and reservoir-saturation logs will be conducted initially and once every two years in all active injection and verification wells. Baseline conditions will be established in any new wells drilled by conducting initial logging as part of new well completions. At a minimum, initial logging will be conducted from surface to TD and subsequent logging will be conducted over intervals sufficient to establish changing conditions. Analysis of logging data will provide a means to complement and verify the results obtained from the fluid sampling program, specifically regarding any potential migration of CO_2 into and/or above the confining zone.

Seismic Monitoring

Time-lapse seismic surveys will be conducted at 5-year intervals during the operational period and used as a broad-scale means to attempt to track the migration of the subsurface CO_2 plume. Data collection has previously been conducted at the site outside any potential plume boundary. In the future, similar areas will be surveyed and the area expanded if reservoir modeling data and verification well monitoring indicate a need for expanded data acquisition to ascertain the leading edge of the plume. Analysis of subsequent seismic survey data will provide a supplemental method for assisting with validating the numerical model forecasts as they pertain to maximum plume extent and distribution. In addition, ADM will continue to operate its current passive-seismic monitoring system or a suitable equivalent replacement system, with the ability to detect seismic events exceeding M1.0 within the AOR. Table 9.5.2-1 summarizes the methods and locations of the planned indirect monitoring program.

Table 9.5.2-1. Summary of Indirect Monitoring Methods

Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
Pulse Neutron/RST Logging	Sensitive, Confidential, or Privileged Information [redacted]		Baseline, Bi-Annual
			Baseline, Bi-Annual
			Baseline, Bi-Annual
			Baseline, Bi-Annual
			Baseline, Bi-Annual
			Baseline, Bi-Annual
Passive seismic			Continuous**; recorded monthly
Time-lapse 3D surface seismic			5-Year

Note: * indicates ap [redacted]

**Continuous recording of passive seismic data is processed on a monthly basis to determine if seismic events over M1.0 occurred within the AoR. The passive seismic monitoring system at borehole and surface seismic stations is owned and operated by USGS.

9.6 Testing and monitoring plan QASP

A quality assurance and surveillance plan (QASP) for all testing and monitoring activities pursuant to 40 CFR 146.90(k) is provided in APPENDIX C: Quality Assurance and Surveillance Plan.

9.7 Reporting Requirements

The following details the reporting and recordkeeping requirements as it relates to CCS#3.

9.7.1 Electronic Reporting

Electronic reports, submittals, notifications and records made and maintained by the permittee under this permit will be in an electronic format approved by EPA. The permittee will electronically submit all required reports to the Director at the following website or via a suitable alternative method as may be instructed by EPA: *https://gsdt.pnnl.gov/*

9.7.2 Semi-Annual Reports

ADM will submit semi-annual reports containing:

(a) Any significant changes to the physical, chemical, and other relevant characteristics of the carbon dioxide stream from the proposed operating data;
(b) Monthly average, maximum, and minimum values for injection pressure, flow rate and daily volume, temperature, and annular pressure;
(c) A description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit;
(d) A description of any event which triggers the shut-off systems based on permit operational alarm value setpoints required pursuant to 40 CFR 146.88(e), and the response taken;
(e) The monthly volume and/or mass of the carbon dioxide stream injected over the reporting period and the volume and/or mass injected cumulatively over the life of the project;
(f) Monthly annulus fluid volume added or produced; and
(g) Results of the monitoring required in the Testing and Monitoring Plan, including:
    (i) A tabulation of: (1) daily maximum injection pressure, (2) daily minimum annulus pressure, (3) daily minimum value of the difference between simultaneous measurements of annulus and injection pressure, (4) daily volume, (5) daily maximum flow rate, and (6) average annulus tank fluid level; and
    (ii) Graph(s) of the monitoring as required, or of daily average values of these parameters. The injection pressure, injection volume and flow rate, annulus fluid level, annulus pressure, and temperature shall be submitted on one or more graphs, using contrasting symbols or colors, or in another manner approved by the Director; and
(h) Results of any additional monitoring identified in the Testing and Monitoring Plan.

9.7.3 24-Hour Reporting

ADM will report to the Director any permit noncompliance which may endanger human health or the environment and/or any events that require implementation of actions in the Emergency and Remedial Response Plan. Any information shall be provided orally within 24 hours from the time the permittee becomes aware of the circumstances. Such verbal reports shall include, but not be limited to the following information:

- Any evidence that the injected carbon dioxide stream or associated pressure front may cause an endangerment to a USDW, or any monitoring or other information which indicates that any contaminant may cause endangerment to a USDW;
- Any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs;
- Any triggering of the shut-off system required (i.e., down-hole or at the surface);
- Any failure to maintain mechanical integrity;
- Pursuant to compliance with the requirement at 40 CFR 146.90(h) for surface air/soil gas monitoring or other monitoring technologies, if required by the Director, any release of carbon dioxide to the atmosphere or biosphere; and
- Actions taken to implement appropriate protocols outlined in the Emergency and Remedial Response Plan.

A written submission to document any required 24-hour reporting shall be provided to the Director in an electronic format within five days of the time the permittee becomes aware of the circumstances described in Section 9.7.3. The submission shall contain a description of the noncompliance and its cause; the period of noncompliance, including exact dates and times, and, if the noncompliance has not been corrected, the anticipated time it is expected to continue as well as actions taken to implement appropriate protocols outlined in the Emergency and Remedial Response Plan; and steps taken or planned to reduce, eliminate and prevent recurrence of the noncompliance.

9.7.4 Reports on Well Tests and Workovers

Report, within 30 days, the results of:

- Periodic tests of mechanical integrity;
- Any well workover or stimulation;
- Any other test of the injection well conducted by the permittee if required by the Director; and
- Any test of any monitoring well required by this permit.

9.7.5 Advance Notice Reporting

- Well Tests – ADM will give at least 30 days advance written notice to the Director in an electronic format of any planned workover, stimulation, or other well test.
- Planned Changes – ADM will give written notice to the Director in an electronic format, as

soon as practical, of any planned physical alterations or additions to the permitted injection facility other than minor repair/replacement or maintenance activities. An analysis of any new injection fluid shall be submitted to the Director for review and written approval at least 30 days prior to injection; this approval may result in a permit modification.

- Anticipated Noncompliance – ADM will give advanced written notice to the Director in an electronic format of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements.

9.7.6 Additional Reports

- Compliance Schedules – Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this permit will be submitted in an electronic format by ADM no later than 30 days following each schedule date.
- Transfer of Permits – This permit is not transferable to any person except after notice is sent to the Director in an electronic format at least 30 days prior to transfer and the requirements of 40 CFR 144.38(a) have been met. Pursuant to requirements at 40 CFR 144.38(a), the Director will require modification or revocation and reissuance of the permit to change the name of the permittee and incorporate such other requirements as may be necessary under the SDWA.
- Other Noncompliance – ADM will report in an electronic format all other instances of noncompliance not otherwise reported with the next monitoring report. The reports shall contain the information listed in Section 9.7.3 above.
- Other Information – When ADM becomes aware of failure to submit any relevant facts in the permit application or that incorrect information was submitted in a permit application or in any report to the Director, ADM will submit such facts or corrected information in an electronic format within 10 days in accordance with 40 CFR 144.51(l)(8).
- Report on Permit Review – Within 30 days of receipt of this permit, ADM will certify to the Director in an electronic format that he or she has read and is personally familiar with all terms and conditions of this permit.

9.7.7 Records

ADM will retain records and all monitoring information, including all calibration and maintenance records and all original chart recordings for continuous monitoring instrumentation and copies of all reports required by this permit (including records from pre-injection, active injection, and post-injection phases) for a period ofat least 10 years from collection.

ADM will maintain records of all data required to complete the permit application form for this permit and any supplemental information (e.g. modeling inputs for AoR delineations and reevaluations, plan modifications) submitted under 40 CFR 144.27, 144.31, 144.39, and 144.41; information used to develop the demonstration of the alternative post-injection site care timeframe; and the site closure report for a period of at least 10 years after site closure.

ADM will retain records concerning the nature and composition of all injected fluids until 10 years after site closure.

Records of monitoring information shall include:

- The date, exact place, and time of sampling or measurements;
- The name(s) of the individual(s) who performed the sampling or measurements;
- A precise description of both sampling methodology and the handling of samples;

- The date(s) analyses were performed;
- The name(s) of the individual(s) who performed the analyses;
- The analytical techniques or methods used; and
- The results of such analyses.

10. Well Plugging Plan

10.1 Facility Information

Facility Name: Archer Daniels Midland
CCS#1 Permit: IL-115-6A-0002
CCS#2 Permit: IL-115-6A-0001
CCS#3 Permit: TBD

Facility Contact: Mr. Jason Stahr, Plant Manager
4666 Faries Parkway, Decatur, IL
(217) 424-5750, jason.stahr@adm.com

Well Location: Decatur, Macon County, IL;
CCS#1: 39º 52’ 37.06469”, -88º 53’ 36.25685”
CCS#2: 39º 53’ 09.32835”, -88º 53’ 16.68306”
CCS#3 (Proposed): 39° 52' 12.936'' N, -88° 52' 49.188'' W

Injection well plugging will be conducted according to the procedures provided in this section, which are consistent with previously approved procedures and submittals provided to US EPA Region 5 by ADM in May of 2016. Note that the plugging plan is generally the same for each well in approach, but are subject to minor variation based on construction specifics such as depth and to variation based on the well conditions at the end of the life of each well.

Upon completion of the active injection phase of the project, or at the end of the life of the respective CCS injection well, the well will be plugged and abandoned to meet the requirements of 40 CFR 146.92. The plugging procedure and materials are designed and will be implemented to prevent any unwanted fluid movement, to resist the corrosive aspects of carbon dioxide/water mixtures, and to protect any USDWs. Annual testing or information derived during plugging operations may indicate the need for revisions to this plugging plan. Significant revisions will be submitted to the UIC Program Director.

10.2 Summary

After injection has ceased, the well to be plugged will be flushed with a kill weight brine fluid. A minimum of three tubing volumes will be injected without exceeding maximum bottomhole injection pressure specified by permit. Bottom hole pressure measurements will be made using wireline or slickline conveyed tools and the well will be logged and pressure tested to evaluate Part I mechanical integrity (inside) and Part II external mechanical integrity (outside) of the casing prior to plugging. If a loss of mechanical integrity is discovered, the agency will be consulted regarding findings, and the well will be repaired as necessary to allow plugging consistent with regulatory requirements prior to proceeding with the plugging operations.

A detailed plugging procedure is provided below. Well construction and completion activities are designed to bring cement to surface on all casing strings. No casing will be retrieved at plugging.

After injection is terminated permanently, the injection tubing and packer will be removed. After the tubing and packer are removed, the casing will be circulated clean, or fluids displaced into the injection interval, and the balanced-plug placement method will be used to plug the well by cementing the long-string casing to surface. If, after flushing, the tubing and packer cannot be released, a tubing cutter will be used to cut off the tubing above the packer and the packer will be left in the well, the well will be flushed, and the cement retainer method will be used for plugging the injection formation below the packer.

All of the casing strings will be cut off at least 4 feet below the surface, below the plow line. A blanking plate with the required permit information will be welded to the top of the cutoff casing at the conclusion of the plugging process.

10.3 Planned Tests or Measures to Determine Bottom-hole Reservoir Pressure

ADM will record static bottom hole formation pressure using a down hole pressure gauge and calculate kill fluid density based on final ambient monitoring pressure measurements.

10.4 Planned External Mechanical Integrity Test(s)

ADM will conduct at least one of the tests in Table 10.2-1 to verify external MI prior to plugging the injection well as required in 40 CFR 146.92(a).

Table 10.2-1. External MIT Methods

Test Type	Means of Testing
Temperature Log	Along wellbore using DTS or wireline well log
Noise Log	Wireline Well Log
Oxygen Activation Log	Wireline Well Log

10.5 Information on Cement Plugs

The cement(s) formulated for plugging will be compatible with the carbon dioxide stream that has historically been injected into the well at the conclusion of the well life. The cement formulation and required certification documents will be submitted to the agency with the final well plugging plan to be submitted with the notice to plug the well. ADM will report the wet density of the cement and will retain duplicate samples of the cement used for each plug. Figure 10.5-1 presents a typical plugging schematic. Table 10.5-2 discusses the details of the cement plugs to be included for each well and utilizes CCS#2 for its example calculations and volumes; similar information will be provided for CCS#3 once final well installation information is available.

Sensitive, Confidential, or Privileged Information

[redacted]

Figure 10.5-1. Proposed Plugging Schematic

Table 10.5-2. Cement Plug Details (CCS#2 Example)

	Plug #1	Plug #2
Diameter of Casing in Which Plug Will be Placed (in)	Sensitive, Confidential, or Privileged Information [redacted]	
Depth to Bottom of Tubing or Drill Pipe (ft)		
Sacks of Cement to be Used (per plug)		
Slurry Volume to be Plumped (ft^3)		
Slurry Weight (lb/gal)		
Calculated Top of Plug (ft)		
Bottom of Plug (ft)		
Type of Cement		
Method of Emplacement		

10.3 Narrative Description of Plugging Procedures

In compliance with 40 CFR 146.92(c), ADM will do the following:

1. Notify the regulatory agency at least 60 days before plugging the well and provide updated plugging plan, if applicable.

2. Confirm the mechanical integrity of the well by performing one of the permitted external mechanical integrity tests presented in the table under "Planned External Mechanical Integrity Test(s)" above.

3. Move-in Rig onto well and rig up (RU). All CO_2 pipelines will be marked and noted with rig supervisor prior to field work.

4. Conduct and document a safety meeting specifying requirements based on conditions noted at the well prior to plugging mobilization.

5. RU wireline or slickline equipment and required pressure control and run-in well to datum depth or suitable equivalent to record bottom hole pressure using down hole gauge. RD slickline. Calculate required kill fluid density.

6. Check pressures on the vertical run of the tree to verify wellhead equipment is sufficient for plugging activities.

7. Test the pump and lines to a minimum of 2,500 psi. Fill tubing with kill weight brine (minimum 9.5 ppg or greater, as determined by bottom hole pressure measurement). Bleeding off occasionally may be necessary to remove all gas from the system. Test casing annulus to a minimum of 1,000 psi and monitor as in annual MIT. If there is pressure remaining on tubing, rig-up equipment to pump down tubing and inject minimum of two tubing volumes of kill weight brine. Monitor tubing and casing pressure for 1 hour. If both casing and tubing are dead then nipple up (install) blowout preventers (NU BOPs). Monitor casing and tubing pressures.

8. If the well is not dead or the pressure cannot be bled off of tubing, RU slickline and set plug in lower profile nipple below packer. Circulate tubing and annulus with kill weight fluid until well is dead. After well is dead, nipple down (ND) tree, NU BOPs, and perform a function test. BOP's should have appropriately sized single pipe rams on top and blind rams in the bottom ram for tubing. Test pipe rams and blind rams to 250 psi low, 3,000 psi high. Test annular preventer to 250 psi low and 3,000 psi high. Test all TIW valves (pressure control valve), BOP choke and kill lines, and choke manifold to 250 psi low and 3,000 psi high. NOTE: Make sure casing valve is open during all BOP tests. After testing BOPs pick up tubing string and unlatch seal assembly from seal bore. Rig slick line and lubricator back to well and remove X- plug from well. Rig to pump via lubricator and circulate until well is dead. During this process, annulus fluid may be bullheaded into the formation or circulated out of the well.

9. Pull out of hole with tubing laying it down. NOTE: Ensure that the well is over-balanced and add kill brine as needed to maintain fluid-filled well.

10. Pull seal assembly, pick up workstring, and trip in hole (TIH) with the packer retrieving tools. Latch onto the packer and pull out of hole laying down same.

    Contingency: If unable to pull seal assembly, RU electric line and make cut on tubing string just above packer. Note: Cut must be made above packer at least 5-10 ft MD. If unable to pull the packer, pull the work string out of hole and proceed to next step. If problems are noted, update cement remediation plan (if needed) and execute prior to plugging operations.

11. TIH with work string to tagged total depth (TD). Note that the tagged TD might be shallower than the original TD due to fill. The work string should be worked as deep as safely possible. Keep the hole full at all times. Circulate the well with fluid of sufficient weight to maintain static equilibrium and prepare for cement plugging operations.

12. The lower section of the well from the top of the confining zone to the bottom of the plug will be plugged using CO_2 resistant cement (Schlumberger Evercrete or suitable equivalent) which, in the case of CCS#2, is from TD at approximately 7,100 ft to a depth approximately 1,000 ft above the top of the Eau Claire formation (at approximately 4,000 ft KB). This initial stage of plugging will be accomplished by placing consecutive 500-foot balanced plugs in the casing. Using a cement slurry with a density of 15.9 ppg and a yield of 1.11 cf/sk, approximately 1,431 sacks (sx) of cement will be required. Note, the values used in these calculations are derived from Schlumberger's Evercrete mix. Actual cement volume will depend upon plug back total depth and wellbore fill that determine total plug length. It is anticipated that at 6-7 plugs of 500 feet in length will be necessary to complete the first stage. No more than two plugs will be set before cement is allowed to develop sufficient compressive strength (per data from testing on the specific cement blend). Top depth of the plug will be verified by setting the work string down onto the plug. Wait on cement for a minimum of 20 hours prior to proceeding with second stage of plugging above the confining zone to surface

13. After the first stage of cementing is complete, circulate the well and ensure it is in balance. Tag cement to verify depth and place work string just above the top of cement. For plugging of long-string casing above the confining zone, mix and spot 500 ft balanced plug in 9 5/8-inch casing (approximately 180 sx Class A/H mixed at 15.9 ppg with yield 1.18 cu ft/sk). Pull out of plug and reverse circulate work string.

14. Repeat this operation until a total of 8 additional plugs have been set. If plugs are well balanced then the reverse circulation step can be omitted until after every third plug. Lay down work string while pulling from well. At the end of the day, pull approximately 10 stands and rack back in derrick and reverse tubing before shutting down for night.

15. After waiting overnight, trip back in hole and tag plug and continue. After seven plugs have been set pull work string from well and shut in for 12 hours. Trip in hole with work string and tag cement top. Calculate volume for final plug. Pull work string back out of well.

16. ND BOPs and cut all casing strings below plow line (minimum 4 feet below ground level or per local policies/standards and ADM requirements).

17. Trip in well and set final cement plug. Total of approximately 1,443 sx total cement to be used in all plugs above 4,000 feet.

18. Lay down all work string, etc. Rig down all equipment and move out. Clean cellar to where a plate can be welded onto casing stub with well name onto lowest casing string at 4 feet, or as per permitting agency directive.

The procedures described above are subject to modification during execution, as necessary, to ensure implementation of a plugging operation that protects worker safety and effectively protects USDWs. Any significant modifications due to unforeseen circumstances will be reported to the agency during field operations and documented in the plugging report. Completed plugging forms, records and lab information will be supplied to the regulatory agency as required by permit. The plugging report will be certified as accurate by ADM and the plugging contractor, and shall be submitted to the agency within 60 days after plugging is completed.

11. Post-Injection Site Care and Site Closure Plan

This Post-Injection Site Care and Site Closure (PISC) plan describes the activities that ADM will perform to meet the requirements of 40 CFR 146.93. ADM will monitor groundwater quality and track the position of the carbon dioxide plume and pressure front for 10 years after the cessation of injection. ADM will not cease post-injection monitoring in accordance with the approved PISC Plan until site closure has been authorized by the Director pursuant to 40 CFR 146.93(b)(3). Following authorization for site closure, ADM will plug all monitoring wells, restore the site to its original condition, and submit a Site Closure report and associated documentation.

11.1 Pressure differential and position of the CO2 plume and pressure front

Figure 11.1-1 represents the predicted extent of the AoR pressure front at the end of operation, 5-years post-injection and at the end of the 10-year PISC timeframe. This map is a summary of the AoR delineation modeling results submitted in Section 4 of this CCS#3 application in 2022 per 40 CFR 146.84. At the onset of the post-injection period it is expected that the CO_2 plume will continue to expand to a small degree as the system reaches pressure equilibrium, with a maximum CO_2 plume occurring approximately 5-years post-injection. The size of the pressure front, defined by the shrinking cone of influence as reservoir pressures decline, will decrease. As shown in Figure 11.1-1, the AoR is contracting toward the injection well locations prior to the end of the 10-year PISC timeframe. Based on modeling forecasts, the pressure-induced cone of influence (the pressure change that defines the permit AoR) is projected to dissipate to less than 1% of its maximum size by 2088.

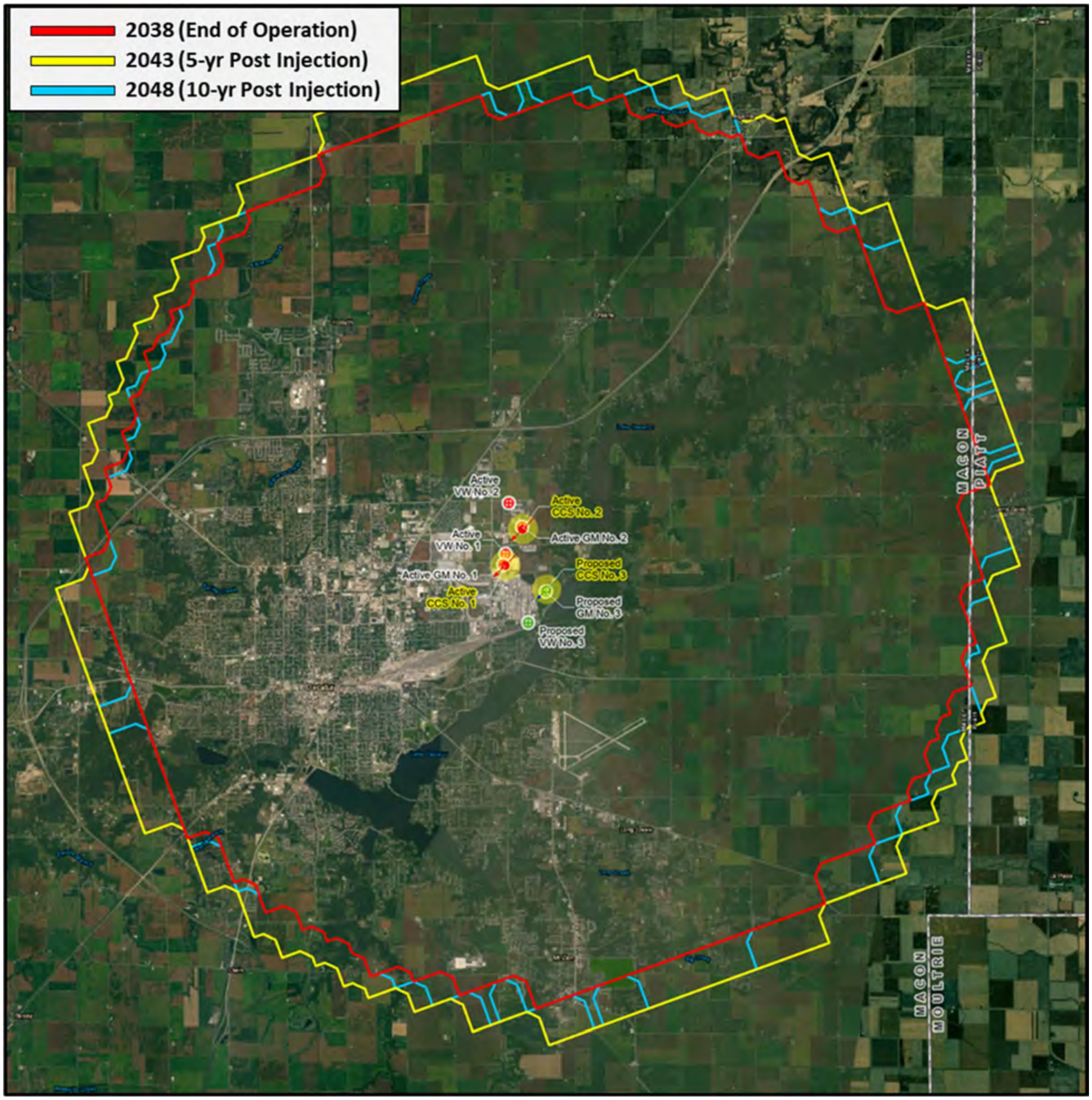

Figure 11.1-1. Modeled Extent of CO_2 Plume (End of Operation, 5-Years and 10-Years Post-Injection)

Similarly, Figure 11.1-2 is a summary of modeling results presented in Section 4 of this document. It depicts the modeled extent of the plume boundary at the end of operation, the end of the 10-year PISC timeframe and for comparison purposes also shows the minimal changes that occur at 50-years post injection as compared with the end of the PISC period. Based on modeling results, no significant post-operational plume drift is expected and the plume is predicted to reach its near-maximum size by the end of the 10-year PISC period.

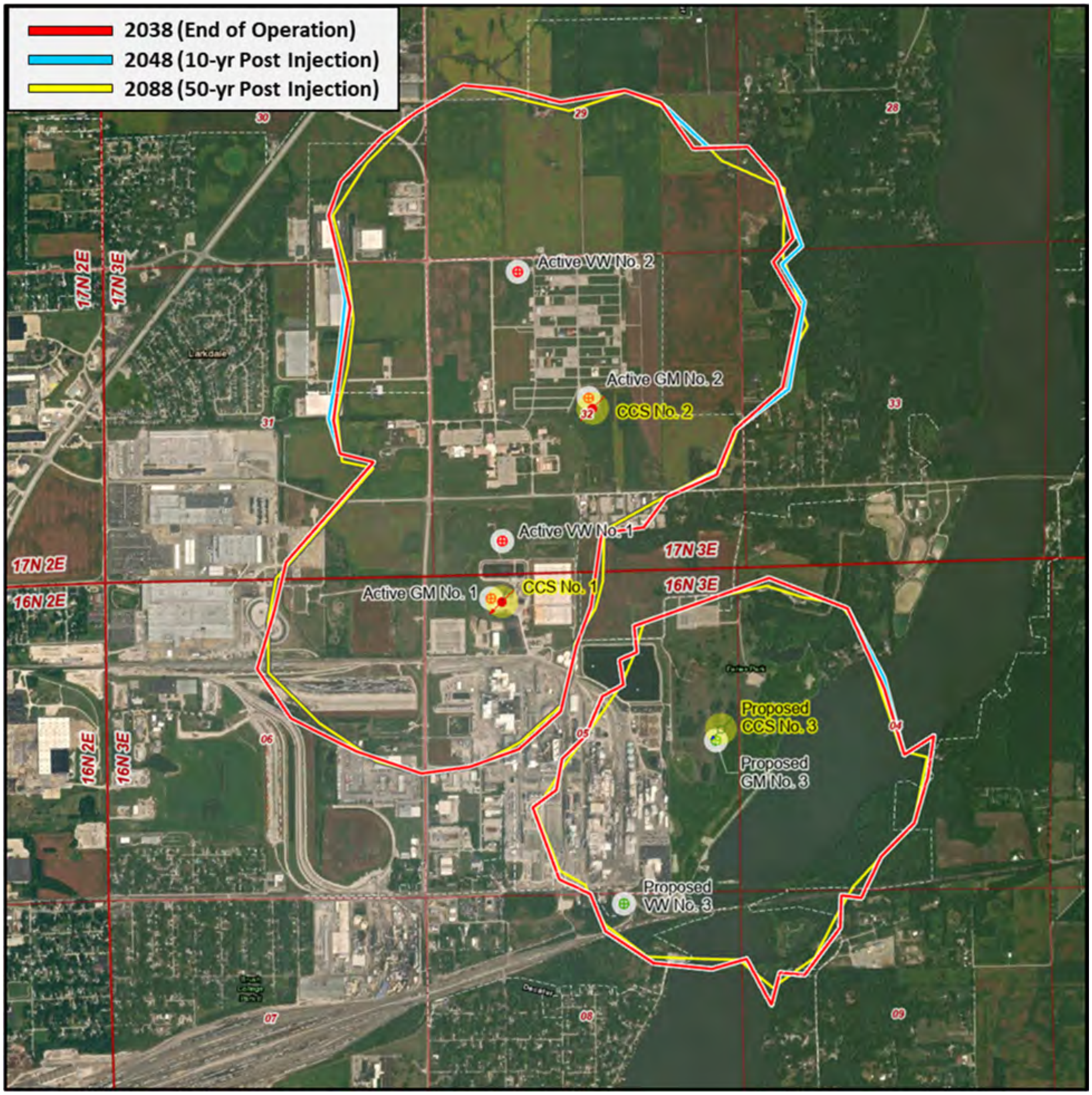

Figure 11.1-2. Modeled Extent of CO_2 Plume (End of Operation, 10-Years and 50-Years Post-Injection)

11.2 Post-injection phase monitoring plan

11.2.1 Groundwater Quality Monitoring

Tables 11.2.1-1 and 11.2.1-2 present the direct and indirect monitoring methods, locations, and frequencies for groundwater quality monitoring that are planned above the confining zone in the Quaternary and/or Pennsylvanian strata, in the St. Peter Formation, and for the Ironton-Galesville Sandstone. All of the existing and proposed monitoring wells are located on ADM property. Table I.3 identifies the parameters to be monitored and the analytical methods ADM will employ.

Fluid sampling will provide direct evidence regarding the presence or absence of CO2 and/or altered geochemistry that is associated with CO2 movement. Temperature monitoring will provide evidence to determine if fluid passing a monitored location has changed the original temperature of the monitored interval and pressure monitoring will provide evidence if sufficient fluid movement has occurred into a deep strata that has resulted in an induced pressure gradient at the monitored location.

Table 11.2.1-1. Post-Injection Phase Direct Groundwater Monitoring Above Confining Zone

Target Formation	Monitoring Activity	Monitoring Location	Frequency: Year1	Frequency: Years 2-3	Frequency: Years 4-9	Frequency: Year 10
[redacted]	Fluid Sampling	[redacted]	Annual	Annual	Annual	Annual
	Distributed Temperature Sensing (DTS)		Monthly	None	None	None
	Fluid Sampling		Annual	Annual	Annual	Annual
	Pressure/Temperature Monitoring		Monthly	Monthly	None	None
	DTS		Monthly	None	None	None
	Fluid Sampling		Annual	Annual	Annual	Annual
	Pressure/Temperature Monitoring		Monthly	Monthly	Annual	Annual
	DTS		Monthly	None	None	None

Table 11.2.1-2. Post-Injection Phase Indirect Groundwater Monitoring Above Confining Zone

Target Formation	Monitoring Activity	Monitoring Location	Frequency to Year 10
Sensitive, Confidential, or Privileged Information [redacted]	Pulse-Neutron/RST Logging	Sensitive, Confidential, or Privileged Information [redacted]	Years 1,3,5,7, and 10
[redacted]	Pulse-Neutron/RST Logging	[redacted]	Years 1,3,5,7, and 10
[redacted]	Pulse-Neutron/RST Logging	[redacted]	Years 1,3,5,7 ,and 10

Table 11.2.1-3. Summary of Analytical and Field Parameters for Groundwater Samples [1]

Parameters	Analytical Methods
Quaternary/Pennsylvanian	
Cations: Ca, Fe, K, Mg, Na, and Si	ICP-OES EPA Method 6010B
Anions: Br, Cl, F, NO_3, and SO_4	Ion Chromatography EPA Method 300.0
Dissolved CO_2	Coulometric titration, ASTM D513-11
Total Dissolved Solids	Gravimetry; APHA 2540C
Alkalinity	APHA 2320B
pH (field)	EPA 150.1
Specific conductance (field)	APHA 2510
Temperature (field)	Thermocouple
St. Peter	
Cations: Ca, Fe, K, Mg, Na, and Si	ICP-OES EPA Method 6010B
Anions:	Ion Chromatography

Br, Cl, F, NO_3, and SO_4	EPA Method 300.0
Dissolved CO_2	Coulometric titration, ASTM D513-11
Isotopes: δ^{13}C of DIC	Isotope ratio mass spectrometry
Total Dissolved Solids	Gravimetry; APHA 2540C
Water Density (field)	Oscillating body method
Alkalinity	APHA 2320B
pH (field)	EPA 150.1
Specific conductance (field)	APHA 2510
Temperature (field)	Thermocouple
Parameters	**Analytical Methods**
Ironton-Galesville	
Cations: Ca, Fe, K, Mg, Na, and Si	ICP-OES EPA Method 6010B
Anions: Br, Cl, F, NO_3, and SO_4	Ion Chromatography EPA Method 300.0
Dissolved CO_2	Coulometric titration, ASTM D513-11
Isotopes: δ^{13}C of DIC	Isotope ratio mass spectrometry
Total Dissolved Solids	Gravimetry; APHA 2540C
Water Density (field)	Oscillating body method
Alkalinity	APHA 2320B
pH (field)	EPA 150.1
Specific conductance (field)	APHA 2510
Temperature (field)	Thermocouple

Note 1: ICP = inductively coupled plasma; MS = mass spectrometry; OES = optical emission spectrometry; GC-P = gas chromatography - pyrolysis. An equivalent method may be employed with prior approval of the Director.

Sampling will be performed as described in section B.2 of the QASP; this section of the QASP describes the groundwater sampling methods to be employed, including sampling SOPs (section B.2.a/b), and sample preservation (section B.2.g).

- Sample handling and custody will be performed as described in section B.3 of the QASP.
- Quality control will be ensured using the methods described in section B.5 of the QASP.

11.2.2 Carbon Dioxide Plume and Pressure Front Tracking

ADM will employ direct and indirect methods to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure within the injection formation as specified. Table 11.2.2-1 presents the direct and indirect methods that ADM will use to monitor the CO_2 plume evolution in the injection zone, including the activities, locations, and frequencies ADM will employ. ADM will conduct fluid sampling and analysis to detect changes in groundwater in order to directly monitor the presence or absence of the carbon dioxide plume at a monitored location. Arrival time of the plume and concentrations detected will be compared to simulations to validate the model projections. The parameters to be analyzed as part of fluid sampling in the Mt. Simon (and associated analytical methods) are presented in Table 11.2.2-2. Sufficient changes in chemical constituents will be analyzed to determine if they provide evidence of plume location. Indirect plume monitoring will be employed using pulsed neutron capture/reservoir saturation tool (RST) logs to monitor CO_2 saturation and these data will be integrated with 3D surface seismic surveys as practical to determine if changing density results in sufficient seismic signatures to track plume movement in the subsurface. Quality assurance procedures for seismic monitoring methods are presented in Section B.9 of the QASP.

Table 11.2.2-1. Post-Injection Phase Plume Monitoring [1,2]

Target Formation	Monitoring Activity	Monitoring Location	Frequency to Year 10
Direct Plume Monitoring			
Sensitive, Confidential, or Privileged Information [redacted]	Fluid Sampling	Sensitive, Confidential, or Privileged Information [redacted]	Annual
Indirect Plume Monitoring			
Sensitive, Confidential, or Privileged Information [redacted]	Pulse-Neutron/RST Logging		Years 1,3,5,7 ,and 10
	3D Seismic Survey		Year 1 and Year 10

Table 11.2.2-2. Summary of analytical and field parameters for fluid sampling in the Mt. Simon

Parameters	Analytical Methods (1)
Water Density (field)	Oscillating body method
Alkalinity	APHA 2320B
pH (field)	EPA 150.1
Specific conductance (field)	APHA 2510
Temperature (field)	Thermocouple
Mt. Simon	
Cations: Ca, Fe, K, Mg, Na, and Si	ICP-OES EPA Method 6010B
Anions: Br, Cl, F, NO_3, and SO_4	Ion Chromatography EPA Method 300.0
Dissolved CO_2	Coulometric titration, ASTM D513-11
Isotopes: $\delta^{13}C$ of DIC	Isotope ratio mass spectrometry
Total Dissolved Solids	Gravimetry; APHA 2540C
Water Density (field)	Oscillating body method
Alkalinity	APHA 2320B
pH (field)	EPA 150.1
Specific conductance (field)	APHA 2510
Temperature (field)	Thermocouple

Note 1: ICP = inductively coupled plasma; MS = mass spectrometry; OES = optical emission spectrometry; GC-P = gas chromatography - pyrolysis. An equivalent method may be employed with the prior approval of the Director.

Table 11.2.2-3 presents the direct and indirect methods that ADM will use to monitor the pressure front, including the activities, locations, and frequencies ADM will employ. ADM will deploy pressure/temperature monitors and distributed temperature sensors to directly monitor the position of the pressure front. Passive seismic monitoring using a combination of borehole and surface seismic stations to detect local events over M1.0 within the AoR will also be performed.

Table 11.2.2-3. Post-Injection Phase Pressure Front Monitoring

Target Formation	Monitoring Activity	Monitoring Location	Frequency: Year 1	Frequency: Years 2-3	Frequency: Years 4-9	Frequency: Year 10
Direct Pressure-front Monitoring						
[redacted]	Pressure/Temperature Monitoring	[redacted]	Monthly	Monthly	Monthly	Monthly
			Monthly	Monthly	Annual	Annual
	DTS		Monthly	None	None	None
Other Monitoring						
[redacted]	Passive Seismic		Continuous**; processed monthly	Continuous**; processed monthly	Continuous**; processed monthly	Continuous**; processed monthly

**Continuous recording of passive seismic data is processed on a monthly basis to determine if seismic events over M1.0 occurred within the AoR. The passive seismic monitoring system at borehole and surface seismic stations is owned and operated by USGS.

11.3 Alternative PISC timeframe

ADM will conduct post-injection monitoring for 10 years following the cessation of injection operations in CCS#3, consistent with the demonstrated and approved alternative timeframe pursuant to 40 CFR 146.93(c)(1), for CCS#1 and CCS#2. ADM requests a 10-year alternative post-injection care time period for CCS#3 based on the computational modeling conducted to delineate the AoR; predictions of plume migration, pressure decline, and carbon dioxide trapping; site-specific geology; well construction; and the distance between the injection zone and the nearest USDWs. Modeling results are summarized in previous portions of this section and described in more detail in Section 4 of this application. Site specific conditions that satisfy the alternative timeframe requirements listed in § 146.93(c)(1) and (2) are described in the following paragraphs. Note that the specific section for each criterion in the CFR is listed in square brackets, [ ].

- [§146.93(c)(1)(i)] The results of computational modeling of the project (Section 4 of this application) show that the sequestered CO_2 will not migrate above the Mt. Simon Sandstone.

- [§146.93(c)(1)(ii)] The modeling demonstrates that formation fluids will not be forced into any USDWs; and/or the timeframe for pressure decline to pre-injection pressures. Consistent with the map presented in Figure 11.1-1, Figure 11.3-1 presents the modeled bottomhole pressures projected over time at the CCS#1, CCS#2 and CCS#3 locations. Pressure values are normalized to a depth of 6,000' SSTVD. Figure 11.3-1 illustrates that bottomhole pressures are projected to decline significantly over the first several years post-injection. At the end of the 10-year PISC timeframe, more than 90% of the pressure decline that will occur is observed in the wells. Pressure rise in the injection zone has dissipated significantly by the end of the 10-year PISC period.

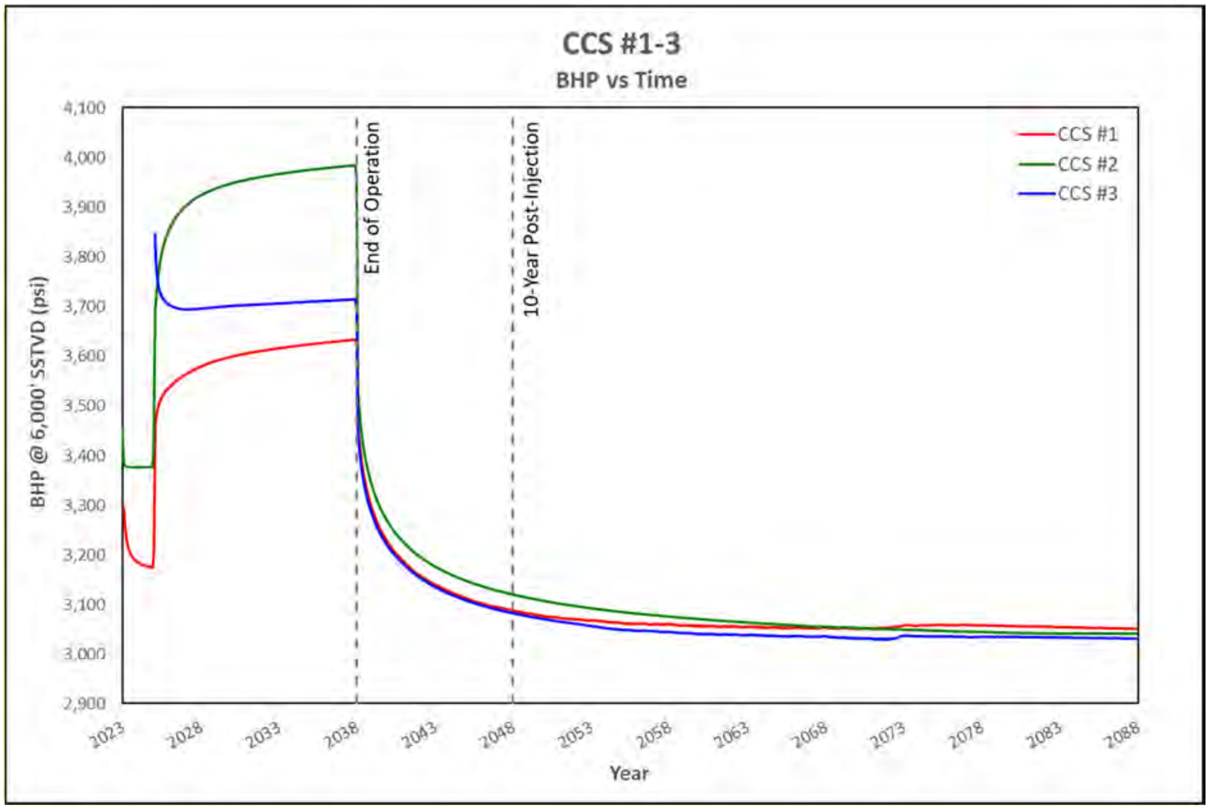

Figure 11.3-1. Modeled Extent of AOR Boundary (End of Operation, 5-Years and 10-Years Post-Injection)

- [§146.93(c)(1)(ii)] The hydrogeologic and seismic characterization for the project site indicates that the Eau Claire Formation, the primary seal above the Mt. Simon, does not contain any faults and has permeability sufficiently low to impede CO_2 migration to overlying formations.

- [§146.93(c)(1)(iii), the predicted rate of carbon dioxide plume migration within the injection zone and predicted time frame for cessation of migration is addressed in Section 4 of this application. Based on the modeled plume areas summarized in Figure 11.1-2, the equivalent plume radius (assuming circular areas and no initial plume) grows at an average of approximately 400 ft/year during the later portion of injection operations. During the initial ten years of post-injection equilibration, the rate of plume expansion reduces to an average of approximately 33 ft/year. Following the 10-year PISC timeframe, the rate of expansion continues to decrease and becomes negligible by 50 years post-injection.

- [146.93(c)(1)(iv-vi) addresses the description of processes that result in carbon dioxide trapping including immobilization by capillary trapping, dissolution and mineralization and the predicted rate of trapping, as well as the site-specific studies supporting these mechanisms. Section 3.11 addressed expected mineralogical reactions and associated studies associated with CO2 injection. The section concludes that it is not expected "that injection of CO2 into the proposed well would lead to drastic geochemical reactions within the reservoir and seal that compromise injectivity and long-term security", and does not call for CO2 immobilization as a trapping mechanism. The alternative timeframe is well justified by modeled pressure decline. As indicated above and shown in Figure 11.3-1, at the end of the 10-year PISC timeframe, more than 90% of the pressure decline that will occur is observed in the wells. Pressure rise in the injection zone has dissipated significantly by the end of the 10-year PISC period.

- [§146.93(c)(1)(viii) and (ix)] Potential conduits for hypothetical CO_2 migration above the Mt. Simon are limited to the ADM injection and verification wells, all of which will be constructed, monitored, and plugged in a manner that will minimize the potential for any such migration and meet the requirements of 40 CFR Part 146. There are no other potential vertical pathways out of the Mt. Simon injection zone within the AoR at the end of the operating life and pressures at the injection wells are projected to have declined to within approximately 10% of the maximum pressure rise experienced during operations by the end of the 10-year PISC period.

- [§146.93(c)(1)(x)] The Mt. Simon Sandstone is nearly 7,000 feet below the lowermost USDW, and there are three confining formations (New Albany Shale, Maquoketa Formation, Eau Claire Formation) between the injection zone and the lowermost USDW. If, based on results of operational monitoring the EPA requires post-injection monitoring beyond the ten-year timeframe outlined in this plan, the operator will work with the Director to establish the monitoring activities, frequency, and duration of the PISC period.

Sections 3 and 4 present the information that satisfies the requirements set forth in §146.93(c)(2) regarding predictive models used, parameter determination including analyses, tests, and estimation techniques, model calibration, modeling assumptions, and modeling uncertainty. The same parameters, modeling techniques, and geologic characterization were presented to support approval of the CCS#2 alternative 10-year time period. In addition to historical injection, this application addresses additional CO_2 injection into all three wells (including the CCS#3 well) over a 12-year initial operating period.

ADM will conduct the monitoring described under "Groundwater Quality Monitoring" and "Carbon Dioxide Plume and Pressure Front Tracking" sections presented above and report the results as described under the "Schedule for Submitting Post-Injection Monitoring Results." This will continue until ADM demonstrates, based on monitoring and other site-specific data, that no additional monitoring is needed to ensure that the project does not pose an endangerment to any USDWs, per the requirements at 40 CFR 146.93(b)(2) or (3).

If any of the information upon which this demonstration was based changes or the measured behavior of the system varies significantly from modeled predictions, e.g., as a result of an AoR reevaluation, ADM may update this PISC and Site Closure Plan pursuant to 40 CFR 146.93(a)(4). ADM will update the PISC and Site Closure Plan, within six months of ceasing injection or demonstrate that no update is needed and as necessary during the duration of the PISC timeframe.

11.4 Non-endangerment demonstration criteria

Prior to authorization of site closure, ADM will submit a demonstration of non-endangerment of USDWs to the Director, per 40 CFR 146.93(b)(2) or (3).

To make the non-endangerment demonstration, ADM will issue a report to the Director. This report will make a demonstration of USDW non-endangerment based on the evaluation of the site monitoring data used in conjunction with the project computational model. The report will detail how the non-endangerment demonstration uses site-specific conditions to confirm and demonstrate non-endangerment. The report will include (or appropriately reference): all relevant monitoring data and interpretations upon which the non-endangerment demonstration is based, model documentation and all supporting data, and any other information necessary for the Director to review the analysis. The report will include the following components:

Summary of Existing Monitoring Data

A summary of all previous monitoring data collected at the site, pursuant to the Testing and Monitoring Plan (Section 9 of this application) and this PISC and Site Closure Plan, including data collected during the injection and PISC phases of the project, will be submitted to help demonstrate non-endangerment. Data submittals will be in a format acceptable to the Director [40 CFR 146.91(e)], and will include a narrative explanation of monitoring activities, including the dates of all monitoring events, changes to the monitoring program over time, and an explanation of all monitoring infrastructure that has existed at the site. Data will be compared with baseline data collected during site characterization [40 CFR 146.82(a)(6) and 146.87(d)(3)].

Comparison of Monitoring Data and Model Predictions and Model Documentation

The results of computational modeling used for AoR delineation and for demonstration of the alternative PISC timeframe will be compared to monitoring data collected during the operational and the PISC periods. The data will include the results of time-lapse temperature and pressure monitoring, groundwater quality analysis, passive seismic monitoring, and geophysical surveys (i.e. logging, operating-phase VSP, and 3D surface seismic surveys) used to update the computational model and to monitor the site. Data generated during the PISC period will be used to show that the computational model accurately represents the storage site and can be used as a proxy to determine the properties of the plume including the plume size. ADM will demonstrate that the accuracy of the model is sufficient by comparing the monitoring data obtained during the PISC period against the performance of the system as predicted by the model (i.e. plume location, rate of movement, and pressure decay). Statistical methods will be employed to correlate the data and confirm the capability of the model to accurately represent the storage site. The validation of the computational model with the significant set of monitoring data will be a significant element to support the non-endangerment demonstration. Justification that the conclusions of the model are meaningful will be presented based on the validation efforts. Further, the validation of the model over the areas, and at the points, where direct data collection has taken place will help to ensure confidence in the model for those areas where surface infrastructure preclude geophysical data collection and where direct observation wells cannot be placed.

Evaluation of Carbon Dioxide Plume

ADM will use a combination of time-lapse RST logs, time-lapse VSP surveys, and other seismic methods (2D or 3D surveys) to locate and track the extent of the CO_2 plume. Figures 11.4-1 through 11.4-3 present examples of how the data may be correlated against the model prediction. In Figure 11.4-1, a series of RST logs are compared against the model's predicted plume vertical extent at a specific point location at a specified time interval. If a good correlation between the two data sets can be established it will be used to provide validation of the model's ability to represent the storage system. Similarly, Figure 11.4-2 illustrates an example of how the time-lapse VSPs can be compared against the predicted spatial extent of the plume at a specified time interval. Limited 2D and 3D seismic surveys will be employed to attempt a determination of the plume location at specific times. The data produced by these activities will be compared against the model using statistical methods to validate the ability of the model to accurately represent the storage site. Figure 11.4-3 presents an example of how the data from time-lapse 3D seismic surveys may be correlated against model predictions.

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Figure 11.4-1. Comparison of the time-lapse RST logs against the predicted vertical extent of the plume at a specific time interval during the operational and PISC timeframes.

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[redacted]

Figure 11.4-2. Comparison of the time-lapse VSPs against the predicted spatial extent of the plume at specific time intervals during the operational and PISC timeframes.

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[redacted]

Figure 11.4-3. Comparison of the time-lapse surface 3D against the predicted spatial extent of the plume at specific time intervals during the operational and PISC timeframes.

Evaluation of Mobilized Fluids

In addition to carbon dioxide, mobilized fluids may pose a risk to USDWs. These include native fluids that are high in TDS and therefore may impair a USDW, and fluids containing mobilized drinking water contaminants (e.g., arsenic, mercury, hydrogen sulfide). The geochemical data collected from monitoring wells will be used to demonstrate that no mobilized fluids have moved above the confining formations that act as the seal or caprock. If no such fluids are detected during the PISC period, declining pressure gradients will be limited in potentially moving the fluids as pressures are coming to equilibrium by the end of the PISC; therefore, such fluids would not pose a risk to USDWs. In order to demonstrate non-endangerment, ADM will compare the operational and PISC period samples from layers above the injection zone, including the lowermost USDW, against the pre-injection baseline samples. This comparison will support a demonstration that no significant changes in the fluid properties of the overlying formations have occurred and that no mobilized formation fluids have moved through the sealing formation. This validation of seal integrity will help demonstrate that the injectate and/or mobilized fluids would not represent an endangerment to any USDWs. Additionally, RST logs will be used to monitor the concentrations of the reservoir fluids in the observation zone above the primary overlying Eau Claire Shale seal.

Evaluation of Reservoir Pressure

ADM will also support the demonstration of non-endangerment to USDWs by showing that, during the PISC period, the pressure within the Mt. Simon has rapidly decreased toward pre-injection static reservoir pressure values. Because the increased pressure during injection is the primary driving force for fluid movement that may endanger a USDW, the decay in the pressure differentials will provide strong justification that the injectate does not pose a risk to any USDWs.

ADM will monitor the downhole reservoir pressure at various locations and intervals using a combination of surface and downhole pressure gauges. The measured pressure at a specific depth interval will be compared against the pressure predicted by the computational model. Agreement between the actual and the predicted values will help validate the accuracy of the model and further demonstrate non-endangerment.

Evaluation of Passive Seismic Data

Finally, passive seismic monitoring will be used to help further demonstrate seal formation integrity. ADM will provide seismic monitoring data showing that no seismic events have occurred that would indicate fracturing or fault activation near or through the seal formation. This validation of seal integrity will provide further support for a demonstration that the CO_2 plume is no longer capable of posing endangerment to any USDWs. Figure 11.4-4 illustrates how these data could be presented. This figure shows a subset of locatable microseismic events occurring during part of the IBDP project operational period. This figure shows that a majority of the microseismic events measured occurred below the Eau Claire seal formation indicating that no fracturing or fault activation was possible within this formation. This provided additional verification of the Eau Claire formation integrity and indicates that to date the response to the imposed fluid pressures due to injection are confined to the vicinity of the injection zone and below.

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[redacted]

Figure 11.4-4. Visual representation showing the microseismic activity occurring during the injection and post-injection periods (figure provided by IBDP project)

11.5 Monitoring well plugging and site closure plan

ADM will conduct site closure activities to meet the requirements of 40 CFR 146.93(e), as described below. ADM will submit a final Site Closure Plan and notify the permitting agency at least 120 days prior of its intent to close the site. Once the permitting agency has authorized closure of the site, ADM will: plug the injection well(s), monitoring and verification well(s), and geophysical well(s); restore the site and move out all equipment; and submit a site closure report to the Director. The activities, as described below, present the planned activities consistent with the approved PISC for CCS#2. A final Site Closure Plan will be submitted to the Director for approval with the notification of the intent to close the site. Details regarding plugging of the CCS#3 injection well is included in Section 10.

11.5.1 Plugging the Verification Monitor Wells

A detailed verification well plugging procedure is provided below. All casing in these wells are designed to be cemented to surface and no casing will be retrieved at plugging.

<u>Type and Quantity of Plugging Materials, Depth Intervals</u>

The cements used for plugging will be tested in a lab prior to plug placement and both wet and dry samples will be collected during plugging for each plug to ensure quality of the plugs. All of the casing strings will be cut off at least 4 feet below the surface, below the plow line. A blanking plate with the required permit information will be welded to the top of the cutoff casing at the end of the plugging process.

Volume Calculations

Volumes will be calculated for each wellbore environment at the time of plugging based on desired plug diameter and length required. The methodology employed will be to:

1) Choose the following:
    a. Length of the cement plug desired.
    b. Desired setting depth of base of plug.
    c. Amount of spacer to be pumped ahead of the slurry.
2) Determine the following:
    a. Number of sacks of cement required.
    b. Volume of spacer to be pumped behind the slurry to balance the plug.
    c. Plug length before the pipe is withdrawn.
    d. Length of mud freefall in drill pipe.
    e. Displacement volume required to spot the plug.

Plugging Procedure

At the end of the serviceable life of a verification well, or when it is determined that plugging is appropriate, the well will be plugged and abandoned. In summary, the plugging procedure will consist of flushing the well with a kill weight brine fluid, conducting a final external MIT, removing all components of the completion system and then placing cement plugs along the entire length of the well. Prior to placing the cement plugs, the final MIT will consist of running casing inspection and temperature logs or suitable equivalents to confirm external mechanical integrity. If a loss of integrity is discovered, then a plan to repair using the cement squeeze method will be prepared and submitted to the agency for review and approval.

The following is an example of a detailed plugging procedure provided for VW#2 in the CCS#2 approved PISC, noting that all depths, cement volumes/sacks and other well-specific data are provided by example and will be modified to reflect actual well conditions. The same approved procedures are proposed for each of the VW wells at the site including proposed VW#3.

1. Move in workover unit with pump and tank.
2. Record bottom hole pressure using down hole instrumentation and calculate kill fluid density. Pressure test annulus as per historic annual mechanical integrity testing (MIT) requirements.
3. Fill both tubing strings with kill weight brine as calculated from bottomhole pressure measurement (expected approximately 9.5 ppg).
4. Nipple down well head and nipple up blow-out preventers (BOPs).
5. Remove completion equipment from well. If the packer cannot be removed from the well, modify plans to cut off tubing and plug through the packer.

6. Keep hole full with workover brine of sufficient density to maintain well control.
7. Log well with cement bond log (CBL), temperature, and casing inspection log or suitable equivalent techniques to confirm external mechanical integrity.
8. Pick up work string and trip in hole to PBTD.
9. Circulate two wellbore volumes to ensure that uniform density fluid is in the well.
10. The lower section of the well will be plugged using CO_2 resistant cement from TD at approximately 7,150 feet to approximately 800 feet above the top of the Eau Claire formation (to approximately 4,200 ft). This will be accomplished by placing plugs in 500-foot increments. Using a density of 15.9 ppg slurry with a yield of 1.11 cf/sk, approximately 347 sacks of cement will be required (to incorporate a safety factor, 416 sacks are assumed: 2,950 ft X .1305 cu ft/ft x 1.2 excess / 1.11 cf/sk = 416 sacks). Actual cement volume will depend upon actual weight of the casing within the plugged zone. This will require at least six plugs of 500 feet in length. No more than two plugs will be set before cement is allowed to set and plug depths will be verified by setting work string down onto the plug.
11. Pull approximately ten stands of tubing (~600 ft) out and shut down overnight to wait on cement curing.
12. After appropriate wait on cement period based on hole conditions, trip in hole and tag the plug. Resume plugging procedure as before and continue placing plugs until the last plug reaches the surface.
13. Nipple down BOPs.
14. Remove all well head components and cut off all casings below the plow line.
15. Finish filling well with cement from the surface if needed. Total of approximately 465 sacks total cement used in all remaining plugs above 4,200 feet (4200 ft X .1305 cu ft/ft /1.18 cu ft/sk = 465 sks). Cement calculations based on using Class A cement from 4200 ft back to surface with a density of 15.6 ppg and a yield of 1.18 cu ft /sk. Lay down all work string, etc. Clean cellar to where a plate can be welded with well name onto lowest casing string at least 4 feet below ground level, or as per permitting agency directive.
16. If required, install permanent marker back to surface on which all pertinent well information is inscribed.
17. Backfill cellar.
18. Rig down workover unit and move out all equipment. Haul off all workover fluids for proper disposal.
19. Reclaim surface to normal grade and reseed location.
20. Complete plugging forms and send in with charts and all lab information to the regulatory agency. Plugging report shall be certified as accurate by ADM and shall be submitted within 60 days after plugging is completed.

Note: 7,150 ft 5 ½” 17 #/ft (7150 ft X .1305 cu ft/ft = 933 cu ft) casing requires an estimated 933 cubic feet of cement to fill 14 plugs. An excess factor of 20% is to be used, as practical, for plugging the lowermost 3,000 ft of the wellbore to account for cement that might be lost to the formation, so total material used would be 423 sacks of EverCRETE CO_2 resistant cement (or equivalent) and 442 sack Class A/H cement.

Figure 11.5.1-1 presents an example well plugging schematic prepared for VW#2, which would be generally applicable to VW#3 noting that final plugging design will be dependent upon local geologic and other conditions at the time of plugging.

Figure 11.5.1-1. Generic Plugging Schematic – Verification Well Based on VW#2

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11.5.2 Plugging the Geophysical Well(s)

At the end of the serviceable life of the well, or when plugging is determined to be appropriate, the geophysical well(s) will be plugged and abandoned. The following is an example of a detailed plugging procedure provided for GM#2 in the CCS#2 approved PISC, noting that all depths, cement volumes/sacks and other well-specific data are provided by example and will be modified to reflect actual well conditions:

1. Notify the permitting agency at least 60 days prior to plugging the well.
2. Remove monitoring equipment from well bore. Well will contain fresh water or a mixture of fresh water and native St. Peter formation water.
3. Nipple down well head and connect cement pump truck to casing. Establish injection rate with fresh water. Mix and pump 247 sacks Class A cement (15.9 ppg). Slow injection rate to ½ bbl/min as cement starts to enter St. Peter perforations. Continue squeezing cement into formation until a squeeze pressure of 500 psi is obtained. Monitor static cement level in casing for 12 hours and fill with cement if needed to top out. Plan to have 50 sacks additional cement above calculated volume on location to top out if needed. (To incorporate a safety factor, 255 sacks are assumed: 3,450 ft X 0.0873 cu ft/ft /1.18 cu ft/sk = 255 sacks.)
4. After cement cures, cut off all well head components and cut off all casings at least 4 feet below ground surface (below the plow line).
5. Install permanent marker at surface, or as required by the permitting agency.
6. Reclaim surface to normal grade and reseed location.

Figure 11.5.2-1 presents a generalized GM#3 plugging schematic based on GM#2, noting that the specific depths, formation tops, etc., will be specific to the GM#3 location and conditions encountered at the time of plugging.

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Figure 11.5.2-1. Generic Plugging Schematic- Geophysical Monitoring Wells based on GM #2

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11.5.3 Planned Remedial/Site Restoration Activities

To restore the site to its pre-injection condition following site closure, ADM will be guided by the state rules for plugging of wells located on leased property under The Illinois Oil and Gas Act: Title 62: Mining Chapter I: Department of Natural Resources - Part 240, Section 240.1170 - Plugging Fluid Waste Disposal and Well Site Restoration.

The following steps will be taken:

1. The free liquid fraction of the plugging fluid waste will be removed from any pits and disposed of in accordance with state and federal regulations (e.g., injection or in above ground tanks or containers pending disposal) prior to restoration. The remaining plugging fluid wastes shall be disposed of by on-site burial.
2. All plugging pits shall be filled and leveled in a manner that allows the site to be returned to original use with no subsidence or leakage of fluids, and where applicable, with sufficient compaction to support farm machinery.
3. All drilling and production equipment, machinery, and equipment debris shall be removed from the site.
4. Casing shall be cut off at least four (4) feet below the surface of the ground, and a steel plate welded on the casing or a mushroomed cap of cement approximately one (1) foot in thickness shall be placed over the casing so that the top of the cap is at least three (3) feet below ground level.
5. Any drilling rat holes shall be filled with cement to no lower than four (4) feet and no higher than three (3) feet below ground level.
6. The well site and all excavations, holes and pits shall be filled and the surface leveled.

Site Closure Report

A site closure report will be prepared and submitted within 90 days following site closure, documenting the following:

- Plugging of the verification and geophysical wells (and the injection well if it has not previously been plugged) as specified at 40 CFR 146.92,
- Location of any sealed injection well on a plat of survey that has been submitted to the local zoning authority, with a copy of the plat provided to the Regional Administrator of EPA Region 5,
- Notifications to state and local authorities as required at 40 CFR 146.93(f)(2),
- Records regarding the nature, composition, and volume of the injected CO_2, and
- Post-injection monitoring records.

ADM will record a notation to the property deed on which the injection well was located that will indicate the following:

- That the property was used for carbon dioxide sequestration,
- The name of the local agency to which a plat of survey with injection well location was submitted, as well as the EPA Region Office to which is was submitted
- The volume of fluid injected,
- The formation(s) into which the fluid was injected, and
- The period over which the injection occurred.

The site closure report will be submitted to the permitting agency and maintained by the operator for a period of 10 years following site closure. Additionally, the operator will maintain the records collected during the PISC period for a period of 10 years after which these records will be delivered to the Director.

11.6 Quality Assurance and Surveillance Plan (QASP)

The Quality Assurance and Surveillance Plan is presented in Appendix C.

12. Emergency and Remedial Response Plan

ADM has prepared an Emergency and Remedial Response Plan (ERRP) in accordance with 40 CFR 146.94. This ERRP is being updated to include the proposed CCS#3 and updated AOR. It is being submitted as a separate attachment in the GSDT tool.

APPENDICIES

APPENDIX A: Financial Responsibility Documents

8.0 APPENDIX

To assess the financial assurance requirements[1] associated with the ADM Decatur CCS development, Petrotek combined UIC subject matter expertise with Monte Carlo modeling. The utility of a Monte Carlo approach is that it eliminates reliance on a deterministic value for future events as well as the implied certainty of those events occurring, no matter their likelihood. As has been established from prior evaluations used to assess risks associated with Class I Hazardous Injection wells, occurrence of failures is extremely rare[2,3]. Accounting for both random occurrence and stringent well construction criteria mandated by the US Environmental Protection Agency (EPA), along with using available data regarding occurrences of failure and their mechanisms, the ability to produce a single estimate of the probability of an event occurring is impractical and is likely to be erroneous[2]. Therefore, a statistical method rather than a deterministic method has been used in this evaluation to assign probabilities of outcomes that could result in costs that require financial assurance.

Monte Carlo evaluation involves stochastic modeling to define the probable liability; rather than determining a value from a single future event, Monte Carlo models thousands of discrete scenarios, each regarding a possible circumstance at any point in the future.

Monte Carlo modeling has been used for decades with wide applicability, including the evaluation environmental risk[4], with extension to CCS[5]. Monte Carlo methods have also been used extensively to provide risk estimates for the EPA[2]. The Monte Carlo method being used for the Decatur project in particular follows methodologies similar to those that have been used in the past[6,7], and also adheres to EPA guidance[8].

For the purposes of this assessment, the Monte Carlo analysis was conducted in a step-wise manner. A list of risk event groups was generated, along with their individual probability of occurrence, distribution of costs if the event occurred, and a specified time frame. For each discrete scenario, the Monte Carlo model assigns a random probability for each risk event, within each event's provided range, for each year. The cost of each risk event for each year would then be determined from its cost distribution. Total cost would then be determined by summing the costs of each individual risk event for every year, then adjusting subsequent years to a present value. The process would be repeated 100,000 times to simulate a large set of outcomes. From the 100,000 different scenarios, a distribution of possible costs is generated, from which an expected value of the liability cost can be ascertained.

8.1 Risk Scenario Identification

Multiple frameworks exist to identify the potential risks and hazards from the operation of a CCS project[9], most with a global perspective. The potential risks collated for the Decatur CCS project were identified using multiple, specific sources[10,11,12,13,14,15]. However, for relevancy each risk is required to be discrete and independent unto itself, as well as relevant to ADM's project and the area in and around Decatur. For example, Quintessa Ltd., a UK based consultancy with sponsorship from the EU, generated a thorough list of over 140 different possible features, events, and processes (FEP) to assess the specific risk and performance of CCS projects[10]. This list was consulted to determine the potential relevancy and applicability of a FEP to the ADM CCS operation.

Cross-referencing was then completed with the dataset of risks provided in the environmental impact statement (EIS) created for the FutureGen CCS project[11]. FutureGen was a consortium of entities with the bulk of funding from the Department of Energy (DOE). The list of risks provided by the FutureGen EIS were generated through research of historical oil, gas, and pipeline operations throughout the United States with relevancy to handling CO2. This list of applicable risk factors was then compared with risk factors previously used to quantify the financial assurance for the ADM CCS-2 well in previously approved submittals. The final list of risks, based on this review, was then utilized for the Decatur Monte Carlo analysis:

1. **Pipeline Rupture**. Encompasses the total rupture of a pipeline due to accidental causes or intentional sabotage, during which CO2 will be released in the area local to the project as well as the surrounding vicinity.

2. **Pipeline Puncture**. Encompasses a range of scenarios to describe a hole in the pipeline, most of which are a low level of risk and cost and are easy to repair but which would cause the release of CO2 at surface. Includes a wide range of the rate of leakage, the causes of which could be due to accident or intentional sabotage.

3. **Wellhead Equipment Failure (either slow or catastrophic)**. Encompasses the accidental or intentional sabotage of a wellhead used for the injection or monitoring purposes of the project but which would allow the release of CO2 at surface. Causes are found at the extremes, through either slow corrosion or the catastrophic failure of an accidental nature or from impact, such as from a vehicle or airplane.

4. **Leakage (rapid and slow) through installed wells (injection, monitor)**. Encompasses the leakage of CO2 through loss of integrity of installed wells. Causes are wide, but inclusive of improper initial installation or through continuous physical or chemical processes. The assumption with this risk is that eventually CO2 or other fluids would escape the injection zone by means of these wells.

5. **Leakage (rapid and slow) through currently existing wells that transect through the injection of confining zone, either active or plugged**. Encompasses artificial penetrations within the areal extent of the CO2 plume. Includes historical oil and gas wells with a wide range of installation or plugging practices, some of which may be unable to withstand the elevated pressure within the plume or contact with the injected CO2 and would subsequently allow CO2 or other fluids to escape the injection zone.

6. **Leakage (rapid and slow) through undocumented wells which may transect through the injection or confining zone**. Similar to the risk event associated with

existing wells that transect the injection or confining zone, this risk event assumes that there may be wells that transect either zone, but which are unaccounted for and will be in contact with the elevated pressure of the plume or injected CO2 at some point in the future and would allow the leakage of CO2 or other fluids into adjacent strata.

7. **Leakage (rapid and slow) through the seal(s) adjacent to the injection zone through means other than existing or created wells, faults, or fractures**. Encompasses those risks which would cause injected CO2 or other fluids to leak through the caprock and into adjacent strata. The range is large, but includes a combination of elevated pressures beyond the mechanical strength of the rock coupled with thermal changes, physical changes and chemical changes which would allow the CO2 to escape. Also includes those risks associated with a seismic event not associated with the injection of CO2.

8. **Leakage through existing and assessed faults**. The risk scenario in which injected CO2 or other fluids would escape the injection zone through existing faults, whether they are open or sealed.

9. **Leakage through induced faults**. The risk scenario in which CO2 or other fluids escape the injection zone through pressure induced faulting or seismic events associated with the injection of the CO2.

The list provided in the financial assurance discussion includes the same nine risks, albeit in discrete form, such that rapid and slow leaking scenarios are differentiated for each risk, so that there are 13 total risk factors indicated[13] and used as model input.

It should be noted that each of the assumed risks will incorporate different time frames. Risks associated with surface equipment will be no longer be a relevant factor once the injection period is complete. Additionally, after injection has stopped and associated wells are plugged to regulatory standards, by definition they will no longer be a factor contributing to ongoing risk. Within the injection zone, the induced pressure caused by the injection of the CO2 into the Mt. Simon will dissipate over time; it will be the highest at the point that injection is ceased and will be the highest proximal to the injection wellbores. Over time, as the pressure dissipates, the risk of a pressure-induced leak or failure decreases as well.

The rapid and slow leakage qualifiers denote the rate at which CO2 would hypothetically have the potential to leak from the injection zone into adjacent strata, with the possibility of continuing into overlying aquifers or underground sources of drinking water (USDW). A slow leak includes scenarios wherein transfer of a given volume of CO2 may take a longer period of time to occur, whereas a rapid leak indicates the loss of a given volume extremely quickly if not catastrophically.

8.2 Risk Scenario Probability of Occurrence

Each identified risk was individually assigned a distribution of annual probability of occurrence. Since the outcome of the analysis is highly dependent on the probability of each risk scenario occurring, a deterministic probability would introduce bias into the analysis, whereas using a distribution for the probability alleviated this bias. Likewise, although the EPA stipulates criteria for the proper construction of injection wells which are intended to reduce the probability of a risk event occurring[3], such standards and practices do not completely eliminate all risk and low probabilities still exist of an event occurring. Additionally, each risk can have any form of causation, and a distribution of probability of occurrence can take this into account. For modeling purposes, risk causation scenarios are innumerable, so professional judgement must be utilized to provide a range of probabilities for each scenario[16].

As previously indicated, research has been done to investigate potential failure mechanisms (observed to date) for some of the limited number of Class I Hazardous Injection Wells and carbon sequestration projects located in the US and throughout the world. This work provides useful and relevant information regarding the probability distributions for different risk scenarios below ground (regarding injection and monitor well failures, leakage, and faulting)[2,3,11,12,17]. Above ground, pipeline and treatment equipment data sets exist for probability estimation within the United States and elsewhere[18,19,20,21,22,23].

For the risk scenarios previously collated and identified as relevant to the Decatur facility, the assumed probabilities of occurrence for each are noted in Table 1.

Table 1. Risk Event Probabilities of Occurrence.

Risk Event	Event Description	Annual Frequency of Failure (Single Item)	
		Low Estimate	High Estimate
1	Pipeline Rupture	Sensitive, Confidential, or Privileged Information [redacted]	
2	Pipeline Puncture		
3	Wellhead Equipment Failure		
4	Upward rapid leakage through Installed well		
5	Upward slow leakage through Installed well		
6	Upward rapid leakage through deep transecting wells		
7	Upward slow leakage through deep transecting wells		
8	Leaks due to undocumented deep wells, high rate		
9	Leaks due to undocumented deep wells, low rate		
10	Upward rapid leakage through caprock		
11	Upward slow leakage through caprock		
12	Release through existing faults		
13	Release through induced faults		

Petrotek

These probabilities mirror those found in the FutureGen EIS, but also incorporate a distribution instead of a deterministic forecast of probability.

For some of the risk scenarios, the probability of occurrence is only inclusive of installed equipment, such as the pipeline or an injection well; for the remainder, the risk is relevant to the whole project and is impacted by the volume of CO2 injected, any stray constituents, the increase in pressure caused by injection, and the reservoir area over which the pressure will be increased compared to in-situ conditions. For the latter case, risks are modeled for the volume of CO2 injected, the leakage mechanism, and the volume of leakage as well as impacted strata or leakage effects on the surface, human, wildlife, or environment. For those which encompass individual components such as injection or monitor wells, the risks must be multiplied by the number of wells, installed or previously existing[24,25]. Table 2 outlines the number of items for each risk category relevant to the Decatur site and project.

Table 2. Number of Items per Risk Scenario.

Risk Event	Event Description	Number of Items
1	Pipeline Rupture	3
2	Pipeline Puncture	3
3	Wellhead Equipment Failure	9
4	Upward rapid leakage through Installed well	9
5	Upward slow leakage through Installed well	9
6	Upward rapid leakage through deep transecting wells	100
7	Upward slow leakage through deep transecting wells	100
8	Leaks due to undocumented deep wells, high rate	1
9	Leaks due to undocumented deep wells, low rate	1
10	Upward rapid leakage through caprock	1
11	Upward slow leakage through caprock	1
12	Release through existing faults	1
13	Release through induced faults	1

8.3 Risk Scenario Cost Distribution

Each risk scenario identified as relevant was assigned a triangular distribution of representative costs in the event that the risk scenario occurred. Because each risk event has a range of probability of occurrence, the severity of the effects when the risk event occurs is also modeled with a distribution. As such, for each risk scenario, a minimum cost, maximum cost, and most likely cost was stipulated to generate the triangular distribution of the severity.

From the stipulated triangular distribution for a risk event, the probability density and cumulative density functions can be generated. In the event that the risk scenario occurs, the probability of occurrence would then directly translate to the associated cost of that occurrence. Likewise, the lower the probability of the risk scenario, the lower the resulting damages in the event the scenario occurs. Triangular distributions also follow guidance from the EPA in cases for which data is infrequent and professional judgement must be used[26], such as the case with CCS within the US.

Table 3 demonstrates the distributions for each of the risk scenarios identified.

Table 3. Triangle Distributions for Each Risk Scenario.

Risk Event	Event Description	Cost Estimates (Triangular Distribution)		
		Low	Most Likely	High
1	Pipeline Rupture	Sensitive, Confidential, or Privileged Information [redacted]		
2	Pipeline Puncture			
3	Wellhead Equipment Failure			
4	Upward rapid leakage through Installed well			
5	Upward slow leakage through Installed well			
6	Upward rapid leakage through transecting wells			
7	Upward slow leakage through transecting wells			
8	Leaks from undocumented deep wells, high rate			
9	Leaks from undocumented deep wells, low rate			
10	Upward rapid leakage through caprock			
11	Upward slow leakage through caprock			
12	Release through existing faults			
13	Release through induced faults			

For each of the risk scenarios presented in Table 3, the cost distributions estimate the likely range of severity and the associated costs. In the event of a risk scenario occurring, the costs include the consequences of:

- Impacts to human and wildlife health and life within the modeled region of the Decatur project;
- Impacts to plant life and environment within proximity of the Decatur site;
- Impacts to bodies of water within proximity of the Decatur site;
- Impacts to air quality;
- Impacts to soils and sediments within the modeled region of the Decatur project;
- Impacts to groundwater or other aquifers whether actively used or under consideration.

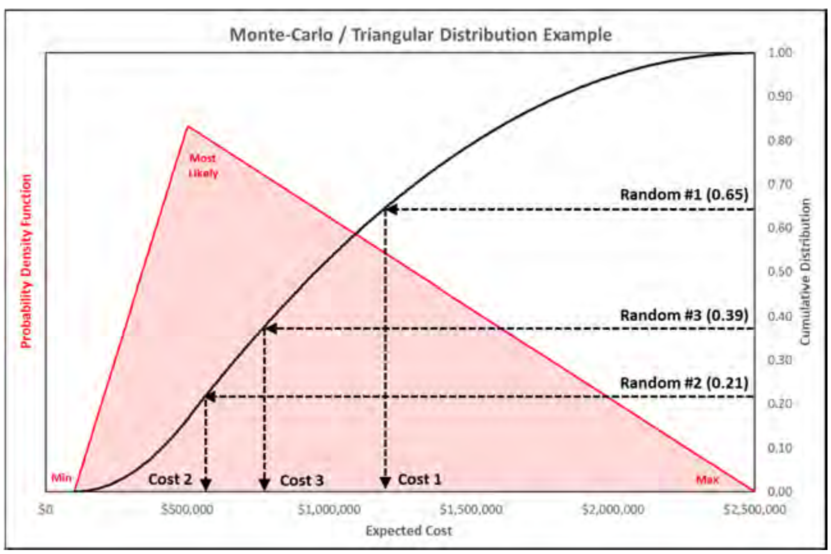
The severity of impacts in the event of a risk scenario occurring are largely estimated from the FutureGen EIS[11] while adjusting the costs for specificity to the Decatur project site. The categories also incorporated the demographics in and around the Decatur area[27].

Costs associated with repair of equipment on surface (risk scenarios 1 - 3) are estimated from the Office of Pipeline Safety[18,19,20,21] and professional judgment. Cost estimates for remediation of leakage (risk scenarios 4 – 13) are estimated from similar studies[11,28] and professional judgment. Due to the lack of particular CCS risk events occurring, and associated cost data, confidence in the costs is assumed by using a 100x multiplier when necessary between the low cost estimate and the high cost estimate. The multiplier, when used, is applied uniformly.

8.4 Monte Carlo Modeling

To demonstrate how the Monte Carlo model generates a scenario, Figure 1 represents the triangular distribution of a hypothetical risk scenario which has minimum estimate of \$100,000, a most-likely estimate of \$500,000 and a maximum estimate of \$2,500,000. The resulting cumulative distribution function (CDF) curve is shown as the solid black line. For each scenario generated in a Monte Carlo simulation, a value between 0 and 1 would be randomly assigned (as seen on the y-axis of the CDF). Using the random value, the representative cost is then determined (as reflected on the x-axis of the CDF). Figure 1 illustrates the results from three random successive cases where this particular event was assumed to take place (65%, 39%, and 21%) and the random probability represented by the CDF curve was then used by the model to assign a cost value for that case.

Figure 1. Monte-Carlo Method Using Random Probabilities



This process is conducted for each risk scenario for the stipulated number of trials. The more trials that are conducted, the smoother the resulting probability distribution function (PDF) becomes. As can be seen in Figure 2, as the number of trials is increased for a hypothetical triangular distribution, the PDF curve of the distribution becomes more defined. However, although the number of trials increases the definition of the distribution, the change in the CDF becomes smaller and smaller, so the efficiency of the Monte Carlo begins to drop, as shown in Table 4. As such, the number of trials best utilized for the Monte Carlo analysis resides in the window of good distribution definition and at the point of minimal decrease in efficiency.

Figure 2. Triangular Distribution Definition vs Number of Trials Conducted

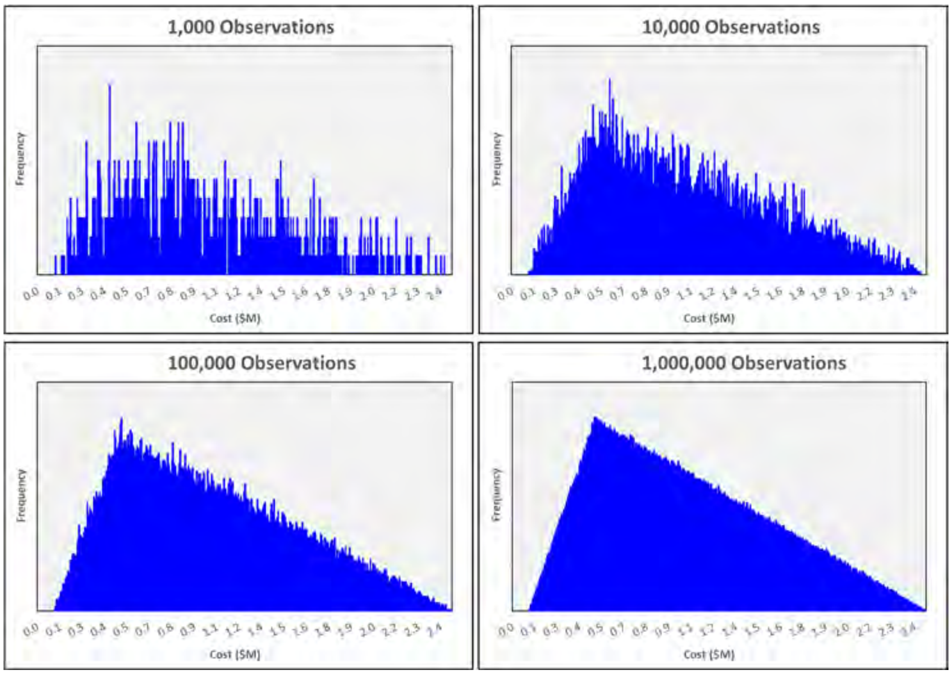


Table 4. Generated Mean from Increasing Trial Counts

Trial Count	Mean
1,000	$0.959 Million
10,000	$0.947 Million
100,000	$0.951 Million
1,000,000	$0.950 Million

For the Decatur project, 100,000 trials were utilized for the Monte Carlo analysis. For each risk scenario, random probabilities were assigned for each year of injection as well as the 10 years of post-injection monitoring and site care. Costs for each year were adjusted upward assuming that future inflation is projected based on an average historical rate of inflation (based on the Consumer Price Index)[29]. The costs for each risk scenario in each year were then totaled to create the total liability cost for that given year; afterward, the cost for that year was adjusted to present value using a long-term bond rate, such as the 10-year or 20-year treasury bond, that best matches the duration of the cashflows from the project[30]. The present values from all 100,000 trials of the Decatur project are shown in Figure 3, and the cumulative distribution of the trials is shown in Figure 4.

Figure 3. Probability Distribution of the Present Values from the Monte Carlo Analysis

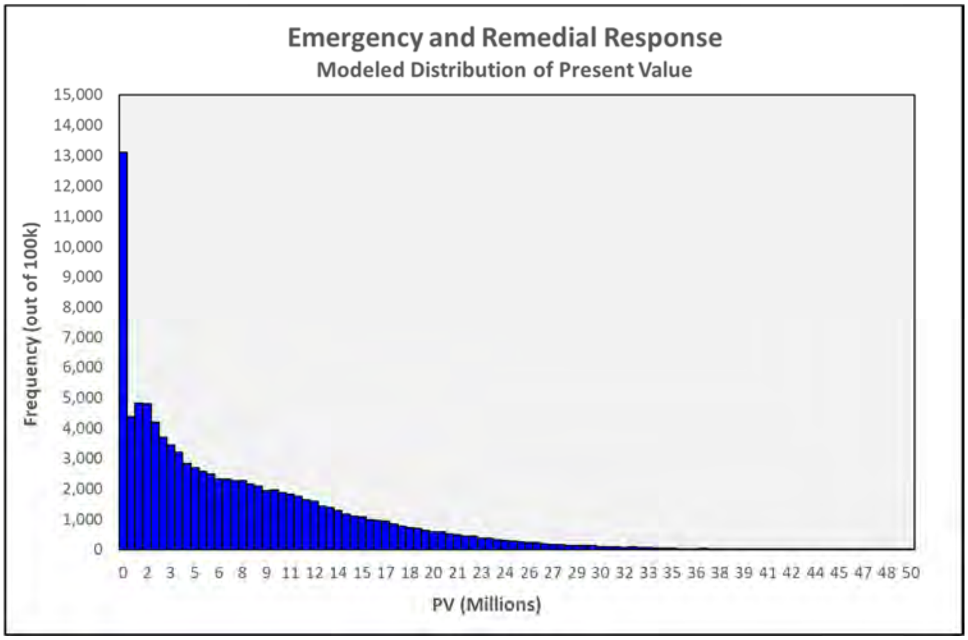
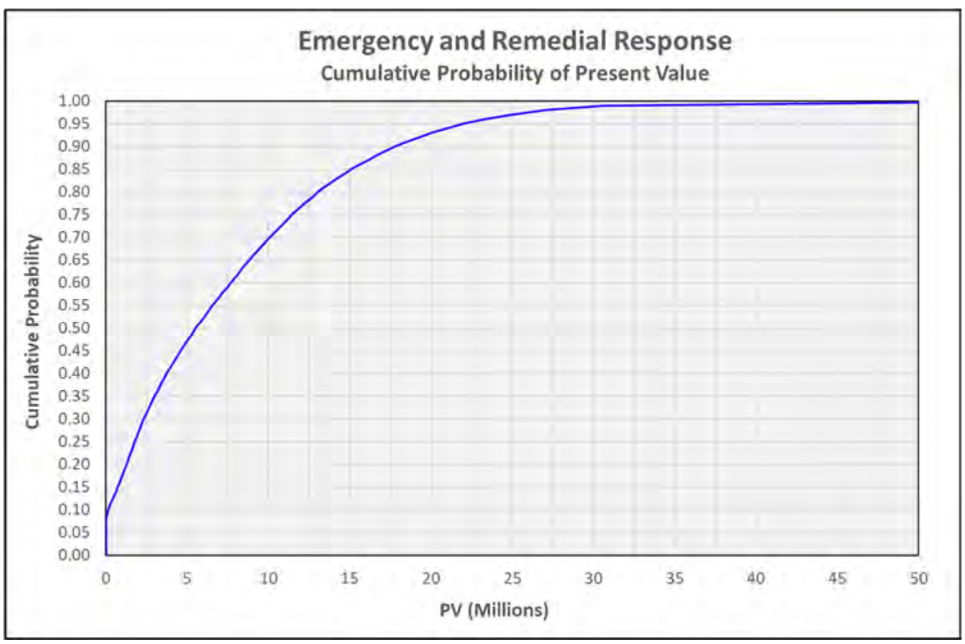


Figure 4. Cumulative Distribution of the Monte Carlo Analysis



To obtain the probable liability cost from the calculated distribution shown in Figure 4, the expected value needs to be determined. The expected value is the weighted average of the liability costs using the probability of occurrence of each cost for weighting[31]. The expected value also corresponds to the mean value of a distribution. The expected value of the Monte Carlo analysis generated for the Decatur project is approximately $5,530,000.

In addition to the expected value, the generated distribution also provides quantitative insight into the statistical “tails” of the distribution. In this case, roughly 10% of the distribution incurs $0 cost, whereas beyond three standard deviations from the mean, the distribution is fairly flat; this long “tail” is associated with those costs which are significant, but that are extremely unlikely to occur. This agrees with the probabilities presented in section 8.2, such that some of the probabilities of an event occurring are so unlikely that the practical cost is $0 almost 100% of the time. For example, risk scenario 10 (rapid leakage through caprock) has a probable occurrence of only 3 in 100,000,000. This also mirrors a similar analysis of Class I Hazardous Injection Wells which found low probabilities for occurrences of such events that ranged from 1 in 1,000,000 and 1 in 10 quadrillion[2].

For these reasons, the expected value of the distribution works well for a practical cost of liability. Beyond that, costs may become larger, but they also have a larger chance of not occurring than actually occurring. The expected value thus strikes a balance of matching the appropriate cost with the actual probable risk of occurrence.

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APPENDIX B: Area of Review Well Database

FIGURES

TABLES

Sensitive, Confidential, or Privileged Information

[redacted]

Sensitive, Confidential, or Privileged Information

[redacted]

Table B.1: Oil and Gas Wells Within the AoR

Map ID	API Number	Permit Number	Longitude	Latitude	Location	Company Name	Well Name	Well Number	Status Code	Elevation (ft)	Elev Ref	Known TD (ft)	TD Formation	Completion Date
1	121150000300		-88.99606600	39.87665000	32-17N-2E	Lincoln Oil&Gas Co	Parish	1	DA	644	Derrick Floor	2,040		12/31/1923
2	121150000400		-88.98442200	39.87683500	33-17N-2E	Meister Henry	Sticker	1	DA	641	Ground level	2,092	Niagaran	
3	121150000500		-88.98216500	39.88415300	33-17N-2E	Wilson Syndicate	Wilson	1	DA	627	Ground level	2,282	Silurian	
4	121150000600		-88.87796200	39.90209100	28-17N-3E	Eureka Oil Corp	Rhodes, Wm.	1	DA	687	Derrick Floor	2,248	Silurian	12/31/1939
5	121150000800		-88.99519400	39.87128100	5-16N-2E	Lincoln Oil Well Serv Co	Powers, Caroline	1	DA	620	Ground level	2,066	Hunton	12/31/1921
6	121150000900		-88.99848900	39.85232000	8-16N-2E	No Company	Powers, Geo. W.	2	UNK	599	Digital Elevation Model	720		
7	121150001600		-88.97751100	39.88607200	33-17N-2E	Arcadia Refining Co.	Wilson	1	DA	620	Ground level	1,862	Fern Glen	
8	121150001700		-88.82305900	39.85775400	11-16N-3E	Jarvis, S. D. etal	Veech, Sarah J.	1	DA	693	Rotary table	2,366	Devonian	2/29/1940
9	121150001800		-88.99850800	39.86317200	5-16N-2E	Atlantic Oil & Gas	Bledsoe	1	DA	614	Ground level	2,062		12/31/1921
10	121150001900		-88.99755800	39.87482700	5-16N-2E	Powers G W	Pfeiffer		DA	667	Ground level	804		
11	121150002000		-88.99749800	39.87124900	5-16N-2E	Lincoln Oil Well Serv Co	Powers, Caroline	2	DA	629	Ground level	2,800	Kimmswick	12/31/1921
12	121150002400		-89.00193300	39.84227900	17-16N-2E	Unknown	Dipper, John	1	DA	618	Derrick Floor	2,125	Silurian	4/6/1939
13	121150002900		-89.01840500	39.88445300	31-17N-2E	Powers, C. G., Etal	Stephenson	1	DA	682	Ground level	2,109	Silurian	11/30/1924
14	121150003600		-88.76819900	39.86617600	5-16N-4E	Paco Petroleum Corp.	Wagner, Lynn	1	DA	730	Derrick Floor	2,445	Silurian	7/31/1955
15	121150003700		-88.82322900	39.86880100	2-16N-3E	Walker Lester	Chapman	1	OILP	694	Digital Elevation Model	2,331	Devonian	7/31/1955
16	121150003800		-88.77290500	39.86618300	5-16N-4E	Carroll, Dell	Shirey, Bryce L.	1	DAP	734	Kelly Bushing	2,422	Silurian	7/31/1955
17	121150003900	2835	-88.76705900	39.85975100	8-16N-4E	Athene Development Company, Inc.	Vulgamott	1	DAP	731	Kelly Bushing	2,444	Silurian	5/31/1955
18	121150004500		-88.84012900	39.86489200	2-16N-3E	Potsch, John P. Sr.	Shambaugh	1	DAP	690	Digital Elevation Model	2,323	Silurian	1/31/1956
19	121150005000		-88.77290000	39.83696400	17-16N-4E	Engle, George S.	Krall, Clarence		DAOP	740	Derrick Floor	2,488	Devonian	8/13/1956
20	121150005100	1968	-88.92851000	39.91287900	24-17N-2E	Mazzarino	Schwarz	1	DAP	664	Derrick Floor	2,215	Silurian	6/22/1956
21	121150005101	1825	-88.92851000	39.91287900	24-17N-2E	Atkins & Hale	Schwarze	1	OILP	664	Derrick Floor	2,209		11/14/1963
22	121150005200	1649	-88.92609900	39.90745800	24-17N-2E	Atkins and Hale	Casey	2	DAP	685	Kelly Bushing	2,184	Silurian	10/10/1964
23	121150005201	17334	-88.92609900	39.90745800	24-17N-2E	Barger Engineering, Inc.	Fold, Baby	3	OIL	665	Kelly Bushing	2,204	Silurian	10/13/1982
24	121150005300		-88.82086800	39.86885400	1-16N-3E	Walker Lester	Hawkins	2	OILP	695	Digital Elevation Model	2,307	Devonian	6/30/1956
25	121150005400	3386	-89.00323200	39.89461800	29-17N-2E	Richardson, M. H.	Troutman	1	DAP	676	Ground level	2,625	St Peter	8/31/1956
26	121150006100	1380	-88.87834400	39.92533300	16-17N-3E	Engle, George S.	Hirsch-Babcock-I.C.R.R. Community	1	DAP	684	Derrick Floor	2,266	Silurian	6/26/1957
27	121150006101	2062	-88.87834400	39.92533300	16-17N-3E	Atkins & Hale	Hirsch Community	1	DAP	684	Derrick Floor	2,270		12/22/1963
28	121150007100		-88.77524300	39.86797700	5-16N-4E	Botts, Elton M. & Assoc.	Davis	1	DAOP	730	Kelly Bushing	2,422	Silurian	9/30/1957
29	121150009800	2060	-88.86758400	39.91999000	21-17N-3E	Atkins & Hale	Pujol - Cundiff	1	DAP	683	Kelly Bushing	2,240	Silurian	11/25/1963
30	121150012900	2322	-88.84756100	39.92765600	15-17N-3E	Atkins and Hale	Rowe		DAOP	690	Kelly Bushing	2,271	Silurian	12/13/1963
31	121150013000		-88.86420500	39.79022700	3-15N-3E	Bridges Basin Oil	Fryman, Leroy	1	DA	636	Digital Elevation Model	1,385		7/31/1949
32	121150021600	2778	-88.99759100	39.87481000	5-16N-2E	Richardson, M. H.	Hood, Paul	1	OILP	620	Ground level	2,037	Silurian	10/8/1954
33	121150021700		-88.99295700	39.87306500	5-16N-2E	Welker Oil Co., Ltd.	Trump	1	OILP	635	Ground level	2,052	Silurian	9/7/1953
34	121150032900		-88.81135000	39.87105300	1-16N-3E	Richey Ancil A	Blickenstaff, Cordia	1	OILP	688	Digital Elevation Model	2,300	Devonian	10/31/1954
35	121150033000		-88.81841400	39.86517400	1-16N-3E	Walker Lester	Harrouff	1	OILP	693	Kelly Bushing	2,281	Devonian	5/31/1954
36	121150033100		-88.81369400	39.86911300	1-16N-3E	Walker Lester	Hawkins	1	OILP	685	Ground level	2,303	Silurian	4/1/1954
37	121150033200		-88.82317600	39.86501100	2-16N-3E	Walker Lester	Veech, Lewis	1	OILP	693	Ground level	2,290	Devonian	5/26/1954
38	121150033300		-88.82336900	39.87835500	2-16N-3E	Walker Lester	Wheeler	1	DAOP	688	Derrick Floor	2,328	Silurian	12/12/1953
39	121150033301		-88.82336900	39.87835500	2-16N-3E	Day R A	Ginder Comm.	1	OILP	688	Derrick Floor	2,286		11/8/1961
40	121150038000		-88.82078200	39.86325000	12-16N-3E	Runyon, Floyd L.	Veech, Otto	1	OILP	697	Kelly Bushing	2,321	Devonian	5/31/1954
41	121150041400		-88.90060000	39.82196200	19-16N-3E	Bernard-Clink	Taylor, L. P.	1	GAS	670	Ground level	65		10/31/1954
42	121150041800		-88.81069600	39.81446400	25-16N-3E	Runyon, Floyd L.	Wilkerson, D. F.	1	DAOP	708	Derrick Floor	2,523	Silurian	2/28/1951
43	121150042000		-88.88379400	39.80814600	29-16N-3E	Robinson, H. F., Inc.	Heckel	1	DAP	650	Derrick Floor	2,417	Devonian	7/31/1951
44	121150043500		-88.80176600	39.86412700	7-16N-4E	Johnson, Sr., Morris H. C.	Sievers, Ray	1	DAP	690	Derrick Floor	2,388	Silurian	6/30/1954
45	121150043600		-88.79204700	39.86425700	7-16N-4E	Stevens C	Wagner, W. H.	1	TAOP	684	Derrick Floor	2,334	Devonian	1/24/1955
46	121150050100		-88.97551800	39.93180800	16-17N-2E	Proctor, Richard H.	Hamman, Esther	1	DAP	654	Ground level	2,103	Silurian	8/31/1954
47	121150050400		-89.00090000	39.90558800	20-17N-2E	Richey Ancil A	Merryman, G. R.	1	DAP	685	Digital Elevation Model	2,023	Silurian	10/31/1954
48	121150050900		-88.99158600	39.89121500	28-17N-2E	Richardson, M. H.	German, Blanche	1	DAP	693	Rotary table	2,080	Silurian	11/30/1954
49	121150051200		-89.00077300	39.88018100	32-17N-2E	Runyon, Floyd L.	Daut, P. J.	2	OILP	638	Derrick Floor	1,981	Silurian	10/31/1954
50	121150051300		-88.99609700	39.88027400	32-17N-2E	Runyon, Floyd L.	Duncan, D.	1	DAP	643	Ground level	2,065	Silurian	8/31/1954
51	121150051400		-88.99605500	39.87665900	32-17N-2E	Runyon, Floyd L.	Lyster Comm	1	OILP	649	Kelly Bushing	2,061	Silurian	8/31/1954
52	121150051500		-88.99852700	39.88564500	32-17N-2E	Richardson, M. H.	Trimby, Benjamin	1	OILP	653	Digital Elevation Model	2,074	Silurian	9/30/1954
53	121150051600		-88.97983500	39.88965400	33-17N-2E	Richardson, M. H.	Duncan, Dora	1	DAOP	282	Derrick Floor	2,106	Silurian	10/31/1954
54	121150051800		-88.98688700	39.88800100	33-17N-2E	Herring, Herman C.	Hays, T. E.	1	DAP	677	Derrick Floor	2,101	Silurian	4/30/1952
55	121150052000		-88.97747000	39.88243700	33-17N-2E	Richardson, M. H.	Keller	1	DAP	639	Digital Elevation Model	2,105	Silurian	9/30/1954
56	121150052100	109	-88.99136600	39.87668300	33-17N-2E	Herring, Herman C.	Parish etal	1	DAP	649	Derrick Floor	2,070	Silurian	1/31/1949
57	121150052101	1971	-88.99136600	39.87668300	33-17N-2E	Runyon, Floyd L.	Parish, Ruth	1	OILP	649	Derrick Floor	2,070		8/7/1954
58	121150053500	1771	-88.81883000	39.92448800	13-17N-3E	Unger, John	Blenz	1	DAP	686	Kelly Bushing	2,315	Silurian	7/7/1954
59	121150053900	1528	-88.88761700	39.90854000	20-17N-3E	Myers, Theodore F.	Kuny	1	DAP	688	Kelly Bushing	2,226	Silurian	7/12/1954
60	121150054000		-88.88289100	39.91049900	20-17N-3E	Robinson, H. F., Inc.	Stout, Bertha	1	DAOP	689	Derrick Floor	2,239	Silurian	1/31/1955
61	121150054300	1560	-88.86877600	39.91815000	21-17N-3E	Breeze, F. E.	Phillips, Roy	1	DAP	670	Derrick Floor	2,233	Devonian	8/5/1949
62	121150054301	2063	-88.86877600	39.91815000	21-17N-3E	Atkins & Hale	Phillips, Roy	1	DAP	670	Derrick Floor	2,275		12/18/1963
63	121150054600	2230	-88.84480100	39.89659600	27-17N-3E	Breeze, F. E. & Bayless	Hiser	1	DAP	695	Kelly Bushing	2,308	Silurian	11/17/1948
64	121150054700		-88.87803700	39.90294700	28-17N-3E	Davis, C. G.	Clements, Belle	1	DAO	678	Derrick Floor	2,344	Devonian	5/5/1947

Table B.1: Oil and Gas Wells Within the AoR

Map ID	API Number	Permit Number	Longitude	Latitude	Location	Company Name	Well Name	Well Number	Status Code	Elevation (ft)	Elev Ref	Known TD (ft)	TD Formation	Completion Date
65	121150054800		-88.88033900	39.89950900	29-17N-3E	Davis, C. G.	Boyd	1	DA	686	Derrick Floor	2,282	Silurian	7/31/1946
66	121150054900		-88.89457800	39.90102100	29-17N-3E	Welker Oil Co., Ltd.	Boyd, A. T.	1	OILP	680	Ground level	2,240	Silurian	3/31/1954
67	121150055000		-88.87986700	39.90595700	29-17N-3E	Costello Leonard J	McKee, John H., Sr.	1	DA	685	Digital Elevation Model	2,251	Devonian	11/30/1946
68	121150055800		-88.86179800	39.87983000	33-17N-3E	Pearcy Ed B	Reas Bridge Park	1	UNK	613	Digital Elevation Model	35		12/31/1936
69	121150055900	225	-88.81133700	39.88590300	36-17N-3E	National Associated Petroleum Co.	Nickey, William H.	1	DAP	678	Kelly Bushing	2,331	Silurian	12/20/1954
70	121150056300		-88.75587600	39.91956700	21-17N-4E	Myers, Theo	McLaughlin	1	DAOP	658	Ground level	2,292	Silurian	11/8/1954
71	121150056600		-88.76309600	39.88815600	33-17N-4E	Richardson, M. H.	Greenberg, Ike	1	DAOP	686	Ground level	2,368	Devonian	11/1/1954
72	121150060900	101	-88.98254100	39.88363000	33-17N-2E	Roth, A. N. & Bartelmay, R.	Pollack, M. D. etal	1	DA	648	Derrick Floor	2,176	Silurian	1/31/1949
73	121150061800		-88.88278700	39.87749400	5-16N-3E	Burt, Luther R.	Rowe		GAS	675	Ground level	88		12/31/1932
74	121150062000		-88.77289700	39.83691700	17-16N-4E	Engle, George S.	Krall, Clarence	1	JAP	740	Digital Elevation Model	2,450	Ste Genevieve	5/31/1956
75	121150065700	2856	-88.79440900	39.86236900	7-16N-4E	Jordan, James	Sensebaugh	1	DA	690	Rotary table	2,342	Devonian	3/31/1961
76	121150066500	1839	-88.82097300	39.89681100	25-17N-3E	Myers, Theo	Bell, Glen	1	DAP	688	Derrick Floor	2,296	Devonian	8/31/1961
77	121150066700	1899	-88.80414900	39.86761600	1-16N-3E	Fawcett, John W.	McClure	1	OILP	689	Derrick Floor	2,326	Devonian	8/31/1961
78	121150067100	2470	-88.81605300	39.86527600	1-16N-3E	Hawkins Wm E	Harrouff, Emma	1	DAP	691	Kelly Bushing	2,320	Silurian	10/31/1961
79	121150068000		-88.75166600	39.84625400	16-16N-4E	National Associated Petroleum Co.	Derr, Charles E.	1	DAP	744	Kelly Bushing	2,496	Devonian	6/30/1962
80	121150071500	628	-88.84275900	39.92405800	15-17N-3E	Atkins & Hale	Rowe	1	TAP	689	Kelly Bushing	2,290	Silurian	5/20/1963
81	121150071501	979	-88.84275900	39.92405800	15-17N-3E	Jarvis, Vernon D.	Rowe	1	DAP	687	Derrick Floor	2,291		7/15/1964
82	121150071800	830	-88.81136800	39.87291100	1-16N-3E	Atkins & Hale	Blickenstaff	1	DAP	687	Kelly Bushing	2,335	Silurian	6/6/1963
83	121150072000	954	-88.84646500	39.91913200	22-17N-3E	Atkins & Hale	Spent Community	1	DAP	681	Kelly Bushing	2,278	Silurian	6/15/1963
84	121150072700	2059	-88.93082700	39.90916200	24-17N-2E	Atkins and Hale	Schwarze	2	OILP	687	Kelly Bushing	2,179	Silurian	11/4/1963
85	121150073200		-88.92498200	39.91480000	24-17N-2E	Atkins and Hale	Stroh Comm.	1	DAP	687	Kelly Bushing	2,220	Silurian	3/21/1964
86	121150073800	1383	-88.92377900	39.91117800	24-17N-2E	Atkins and Hale	Casey	1	DAP	685	Kelly Bushing	2,193	Silurian	9/7/1964
87	121150073900	2061	-88.88999200	39.91035700	20-17N-3E	Atkins and Hale	Roos-Kuny	1	DAP	683	Kelly Bushing	2,229	Silurian	12/3/1963
88	121150074000	1567	-88.99841900	39.87663600	32-17N-2E	Exploration & Development, Inc.	Nonneman	1	DAP	634	Kelly Bushing	2,041	Devonian	9/28/1964
89	121150074001	31785	-88.99841900	39.87663600	32-17N-2E	Barger Engineering, Inc.	Wright, A.	1	JAP	634	Kelly Bushing	1,141	Ste Genevieve	9/19/1984
90	121150080500		-88.96985300	39.80371000	34-16N-2E	Sun Production Co (Sun Oil)			STRUP	687	Ground level	330	Shoal Creek	3/4/1953
91	121150082200	936	-88.93076000	39.90460200	25-17N-2E	Atkins and Hale	Daniel	1	DAP	685	Kelly Bushing	2,191	Silurian	8/1/1965
92	121150082500	1876	-88.77050300	39.86982200	5-16N-4E	Richardson, M. H.	Shirey	2	DAP	626	Ground level	2,383	Silurian	12/14/1965
93	121150083300	1095	-89.00790200	39.88372200	32-17N-2E	Kin-Ark Oil Co	Young, John E.	1	DAP	651	Kelly Bushing	1,999	Silurian	7/29/1966
94	121150083700	1589	-88.85473900	39.93301400	15-17N-3E	Kin-Ark Oil Co	Kingdon, Albert	1	DAP	689	Kelly Bushing	2,252	Silurian	10/22/1966
95	121150083701	336	-88.85473900	39.93301400	15-17N-3E	Collins Assoc. Oil Co.	Kingdon, Albert	1	DAP	689	Kelly Bushing	2,250		5/8/1969
96	121150083800	1989	-88.93088300	39.91463200	24-17N-2E	Barra, Raymond P.	Stroh		OILP	674	Kelly Bushing	2,138	Silurian	2/15/1967
97	121150083801	271	-88.93088300	39.91463200	24-17N-2E	M. & N. Oil Company	Stroh		OILP	670	Ground level	2,139	Silurian	4/19/1972
98	121150084100		-89.00081700	39.88560800	32-17N-2E	Rand, Tim Oil Corp.	Wilder	1	DAP	665	Ground level	2,031	Silurian	5/28/1967
99	121150085300		-88.93466000	39.80438200	35-16N-2E	Phillips Petroleum, Co.		44894	STRU	623	Ground level	410		
100	121150085400		-88.85789800	39.80849300	27-16N-3E	Phillips Petroleum, Co.		44895	STRU	667	Ground level	538		
101	121150088100	813	-88.93090000	39.91646000	24-17N-2E	Mardi Oil Co.	Stroh	2	DAP	681	Kelly Bushing	2,186	Silurian	8/17/1968
102	121150088400	1279	-88.86185400	39.93472000	16-17N-3E	Collins Assoc. Oil Co.	Beadleston	1	DAP	683	Kelly Bushing	2,246	Silurian	10/22/1968
103	121150091700	1469	-88.92852800	39.91469800	24-17N-2E	Mardi Oil Co.	Stroh	3	OILP	675	Kelly Bushing	2,147	Silurian	7/10/1969
104	121150099300	1162	-88.93084500	39.91098900	24-17N-2E	Hale, Richard D.	Schwarze, Vivian		OILP	681	Kelly Bushing	2,155	Silurian	4/25/1971
105	121150101700		-88.93321000	39.91092300	24-17N-2E	Hale Oil Co.	Schwarze	4	JAP	676	Ground level	2,154	Silurian	6/11/1972
106	121150103400		-88.75461500	39.84574500	16-16N-4E	Carter Oil Co., The	Core Hole	197	STRU	742	Ground level	1,626		12/31/1939
107	121150105800		-88.83442000	39.90143100	26-17N-3E	Mashburn, Bruce	Maxey, C. E.		GAS	702	Ground level	100		
108	121152106000		-88.82579100	39.87832700	2-16N-3E	Welker, Emerson	Flack-Brown Comm.	1	OILP	692	Kelly Bushing	2,282	Devonian	6/12/1974
109	121152108200		-88.93086600	39.91281100	24-17N-2E	Triple G Oil Company Ltd.	Schwarze		OILP	679	Kelly Bushing	2,142	Silurian	5/21/1974
110	121152108201	16743	-88.93086600	39.91281100	24-17N-2E	Triple G Oil Company Ltd.	Schwarze		OILP	679	Kelly Bushing	2,142	Silurian	5/21/1974
111	121152108300		-88.83772900	39.87819600	2-16N-3E	Welker, Emerson	King	1	DAOP	688	Kelly Bushing	2,291	Silurian	4/20/1975
112	121152108400	718	-88.83988500	39.88587800	35-17N-3E	Welker, Emerson	Sheffer	1	DAP	674	Kelly Bushing	2,272	Silurian	8/8/1974
113	121152109100		-88.83844500	39.87818900	2-16N-3E	Welker, Emerson	King, Frank		DAP	687	Ground level	2,292	Devonian	10/24/1974
114	121152109300		-88.93322800	39.91274200	24-17N-2E	Triple G Oil Company Ltd.	SCHWARTZ	2	OIL	681	Kelly Bushing	2,147	Silurian	2/2/1975
115	121152109800	125	-88.93794600	39.91260700	23-17N-2E	Triple G Oil Company Ltd.	Phillips	1	OILP	683	Kelly Bushing	2,155	Silurian	3/22/1975
116	121152110000		-88.94024400	39.91162700	23-17N-2E	Triple G Oil Company Ltd.	Phillips	2	OIL	678	Kelly Bushing	2,145	Devonian	10/24/1975
117	121152112000		-88.94261700	39.91246900	23-17N-2E	Triple G Oil Company Ltd.	Phillips	3	OILP	677	Kelly Bushing	2,147	Silurian	7/1/1976
118	121152113400		-88.92702600	39.84930000	12-16N-2E	Staley, A. E. Manfct. Co	Waste Treatment Well	1	WASTE	679	Ground level	504		7/27/1976
119	121152113500	45678	-88.96636300	39.80290800	34-16N-2E	Beasley	Edgecombe, Arthur		INJT	701	Digital Elevation Model	42		5/9/1976
120	121152114300	3056	-88.94263500	39.91428800	23-17N-2E	Triple G Oil Company Ltd.	Hockaday, Nola May	1	OILP	678	Kelly Bushing	2,156	Silurian	5/8/1977
121	121152115200	3865	-88.94259900	39.91064500	23-17N-2E	Triple G Oil Company Ltd.	Phillips	4	OIL	686	Kelly Bushing	2,170	Silurian	2/15/1978
122	121152116500	4175	-88.94264900	39.91611300	23-17N-2E	Triple G Oil Company Ltd.	Hockaday, Nola Mae	2	OILP	681	Kelly Bushing	2,168	Silurian	1/2/1978
123	121152117700	4892	-88.94730300	39.91415300	23-17N-2E	Triple G Oil Company Ltd.	Hockaday Comm.	3	DAOP	674	Kelly Bushing	2,144	Silurian	4/15/1978
124	121152118200	5387	-88.94496500	39.91786800	23-17N-2E	Triple G Oil Company Ltd.	Hockaday	4	OILP	686	Kelly Bushing	2,155	Silurian	6/13/1978
125	121152118400	5515	-88.94266700	39.91793500	23-17N-2E	Triple G Oil Company Ltd.	Hockaday	5	OILP	687	Kelly Bushing	2,160	Silurian	6/11/1980
126	121152118700	5749	-88.93791100	39.90937800	23-17N-2E	Triple G Oil Company Ltd.	Phillips	5	OIL	690	Kelly Bushing	2,174	Silurian	12/2/1978
127	121152118800	5750	-88.94026100	39.90810000	23-17N-2E	Triple G Oil Company Ltd.	Phillips	6	OIL	683	Kelly Bushing	2,167	Silurian	11/17/1978
128	121152119600	6313	-88.93560100	39.91449500	24-17N-2E	Triple G Oil Company Ltd.	Hubble	1	OILP	693	Kelly Bushing	2,153	Silurian	12/26/1978

Table B.1: Oil and Gas Wells Within the AoR

Map ID	API Number	Permit Number	Longitude	Latitude	Location	Company Name	Well Name	Well Number	Status Code	Elevation (ft)	Elev Ref	Known TD (ft)	TD Formation	Completion Date
129	121152120101	8548	-88.94732000	39.91779400	23-17N-2E	Triple G Oil Company Ltd.	Hockaday	6	OILP	682	Kelly Bushing	2,144	Silurian	7/16/1980
130	121152120300	6523	-88.94252300	39.90803400	23-17N-2E	Triple G Oil Company Ltd.	Phillips	9	OIL	678	Kelly Bushing	2,150	Silurian	5/12/1979
131	121152120400	6527	-88.93562600	39.91632500	24-17N-2E	Triple G Oil Company Ltd.	Hubble	2	OILP	693	Kelly Bushing	2,150	Silurian	11/21/1979
132	121152120500	6526	-88.93785700	39.90531800	26-17N-2E	Triple G Oil Company Ltd.	Phillips	7	OIL	677	Kelly Bushing	2,159	Silurian	5/29/1979
133	121152120600	6525	-88.94017700	39.90524900	26-17N-2E	Triple G Oil Company Ltd.	Phillips	8	OIL	671	Kelly Bushing	2,144	Silurian	5/22/1979
134	121152129300	7507	-88.94253900	39.90518000	26-17N-2E	Triple G Oil Company Ltd.	Phillips	10	OIL	673	Kelly Bushing	2,141	Silurian	8/25/1980
135	121152129400	7508	-88.94250300	39.90335300	26-17N-2E	Triple G Oil Company Ltd.	Phillips	11	OIL	680	Kelly Bushing	2,146	Silurian	8/25/1979
136	121152129500	7509	-88.94488900	39.90796500	23-17N-2E	Triple G Oil Company Ltd.	Phillips	12	OIL	678	Kelly Bushing	2,150	Silurian	11/12/1980
137	121152132500	8002	-88.94034000	39.92165000	14-17N-2E	Triple G Oil Company Ltd.	Hubbel	3	OIL	684	Kelly Bushing	2,137	Silurian	5/9/1980
138	121152132600	8050	-88.93835700	39.89253300	26-17N-2E	Triple G Oil Company Ltd.	Snow	1	OILP	663	Kelly Bushing	2,165	Silurian	4/3/1980
139	121152133000	8618	-88.94725500	39.90789600	23-17N-2E	Triple G Oil Company Ltd.	Loeb-Phillips Comm.	1	OIL	678	Kelly Bushing	2,150	Silurian	3/30/1980
140	121152133100	8773	-88.93558000	39.91267600	24-17N-2E	Triple G Oil Company Ltd.	SCHWARZE TRUST	1	OIL	692	Kelly Bushing	2,160	Silurian	2/6/1980
141	121152133200	8922	-88.93564000	39.91814100	24-17N-2E	Triple G Oil Company Ltd.	Hubbel	4	OIL	693	Kelly Bushing	2,141	Silurian	4/20/1980
142	121152133800	9057	-88.89447500	39.86889400	5-16N-3E	Archer Daniels Midland	A.D.M.	1	DAOP	682	Kelly Bushing	2,315	Silurian	2/18/1980
143	121152133900	9156	-88.93095600	39.92193000	13-17N-2E	Triple G Oil Company Ltd.	Oldweiler, Eugenia	1	OILP	684	Kelly Bushing	2,137	Silurian	7/4/1980
144	121152134000	9158	-88.93566100	39.91996600	24-17N-2E	Triple G Oil Company Ltd.	Hubble	5	OIL	685	Kelly Bushing	2,145	Silurian	6/14/1980
145	121152134100	9157	-88.92144400	39.91490100	24-17N-2E	Triple G Oil Company Ltd.	Pense	1	OIL	685	Kelly Bushing	2,170	Silurian	6/6/1980
146	121152134200	9154	-88.94472900	39.89781800	26-17N-2E	Triple G Oil Company Ltd.	Cavender, Oma	1	OILP	670	Ground level	2,150	Silurian	5/25/1980
147	121152134300	9155	-88.94236700	39.89789000	26-17N-2E	Triple G Oil Company Ltd.	Cavender, Oma	2	OILP	674	Kelly Bushing	2,152	Silurian	5/26/1980
148	121152135800	9561	-88.93316700	39.90830100	24-17N-2E	Triple G Oil Company Ltd.	Schwarze Childrens Trust	3	OIL	673	Kelly Bushing	2,177	Silurian	9/25/1980
149	121152135900	9560	-88.93083700	39.90837000	24-17N-2E	Triple G Oil Company Ltd.	Schwarze Childrens Trust	4	OIL	673	Kelly Bushing	2,175	Silurian	9/25/1980
150	121152136000	9559	-88.92846400	39.90846300	24-17N-2E	Triple G Oil Company Ltd.	Schwarze Childrens Trust	5	OIL	673	Kelly Bushing	2,181	Silurian	9/25/1980
151	121152136100	9562	-88.90952000	39.93737200	7-17N-3E	Triple G Oil Company Ltd.	Schwarze, Juanita	1	OILP	684	Kelly Bushing	2,181	Silurian	1/14/1981
152	121152136300	9602	-88.92971100	39.91466500	24-17N-2E	Triple G Oil Company Ltd.	Schwarze, Vivian	1	OIL	682	Kelly Bushing	2,150	Silurian	10/9/1980
153	121152136500	9689	-88.93554500	39.90944700	24-17N-2E	Triple G Oil Company Ltd.	Schwarze Childrens Trust	2	OIL	687	Kelly Bushing	2,179	Silurian	8/31/1980
154	121152137100	10260	-88.92623800	39.93658800	12-17N-2E	Triple G Oil Company Ltd.	McKinley	1	DAP	684	Kelly Bushing	2,136	Silurian	4/29/1981
155	121152137200	10261	-88.93568200	39.92178500	13-17N-2E	Triple G Oil Company Ltd.	Demange	1	DAP	684	Kelly Bushing	2,170	Silurian	8/24/1980
156	121152137300	10263	-88.92972500	39.91649500	24-17N-2E	Triple G Oil Company Ltd.	Schwarze, Vivian	2	OIL	682	Kelly Bushing	2,155	Silurian	10/6/1980
157	121152137400	10290	-88.93093500	39.92011100	24-17N-2E	Triple G Oil Company Ltd.	Schwarze, Vivian	4	OIL	683	Kelly Bushing	2,151	Silurian	10/12/1980
158	121152137500	10291	-88.93091800	39.91828100	24-17N-2E	Triple G Oil Company Ltd.	Schwarze, Vivian	3	OIL	683	Kelly Bushing	2,155	Silurian	10/12/1980
159	121152137600	10264	-88.93523400	39.89326300	25-17N-2E	Triple G Oil Company Ltd.	Henderson	1	OILP	660	Kelly Bushing	2,178	Silurian	11/22/1980
160	121152137700	10262	-88.91675500	39.92271100	18-17N-3E	Triple G Oil Company Ltd.	Fombelle, Hubert	1	OILP	686	Kelly Bushing	2,174	Silurian	5/1/1981
161	121152137800	10332	-88.93825100	39.93627300	11-17N-2E	Triple G Oil Company Ltd.	Chenoweth	1	DAP	686	Ground level	2,143	Silurian	5/5/1981
162	121152138100	10444	-88.88046200	39.90625000	29-17N-3E	Davis, C. G.	French	1	DAP	693	Kelly Bushing	2,294	Devonian	7/14/1980
163	121152138300	10963	-88.99955300	39.86585100	5-16N-2E	Kaufman, E. H.	Shimer	1	DAOP	672	Kelly Bushing	2,090	Silurian	8/29/1980
164	121152139000	11583	-89.00427800	39.86573900	5-16N-2E	Kaufman, E.H.	Wilcox	1	DAP	664	Kelly Bushing	2,061	Silurian	11/12/1980
165	121152139600	11837	-88.94962600	39.91773000	23-17N-2E	Triple G Oil Company Ltd.	Hockaday	7	OILP	680	Kelly Bushing	2,140	Silurian	1/1/1981
166	121152139700	11838	-88.94731700	39.91597700	23-17N-2E	Triple G Oil Company Ltd.	Hockaday	8	OILP	680	Kelly Bushing	2,146	Silurian	1/14/1981
167	121152139800	11813	-88.94728800	39.91233100	23-17N-2E	Triple G Oil Company Ltd.	Loeb Phillips	2	OIL	675	Kelly Bushing	2,155	Silurian	4/7/1981
168	121152139900	11814	-88.94727400	39.91050700	23-17N-2E	Triple G Oil Company Ltd.	Loeb Phillips	3	OILP	671	Ground level	2,155	Silurian	4/9/1981
169	121152140000	11834	-88.92145700	39.91674200	24-17N-2E	Triple G Oil Company Ltd.	Pense	2	OIL	682	Ground level	2,187	Silurian	8/25/1981
170	121152140100	11836	-88.92147100	39.91856100	24-17N-2E	Triple G Oil Company Ltd.	Pense	3	OILP	679	Ground level	2,180	Silurian	8/25/1981
171	121152140200	11833	-88.92617900	39.91660200	24-17N-2E	Triple G Oil Company Ltd.	Schwartz, Vivian	5	OIL	670	Ground level	2,170	Silurian	6/9/1981
172	121152140300	11839	-88.92621000	39.92025700	24-17N-2E	Triple G Oil Company Ltd.	Schwarze, Vivian	6	OIL	673	Kelly Bushing	2,160	Silurian	7/9/1981
173	121152140700	11910	-88.87822100	39.91610300	21-17N-3E	Triple G Oil Company Ltd.	Hirsch, E. & P.	1	OIL	669	Ground level	2,230		5/30/1981
174	121152142400	12321	-88.94961500	39.91590800	23-17N-2E	Triple G Oil Company Ltd.	Hockaday	9	OILP	677	Ground level	2,155	Silurian	4/4/1981
175	121152142500	12199	-88.93797400	39.91533700	23-17N-2E	Barger Engineering, Inc.	Rohrkasse	1	OIL	681	Kelly Bushing	2,175	Silurian	1/1/1981
176	121152142600	12198	-88.94007300	39.89977500	26-17N-2E	Barger Engineering, Inc.	Casey	1	OIL	675	Ground level	2,175	Silurian	4/30/1981
177	121150031900		-88.99454300	39.81145900	29-16N-2E	Pulliam & Reed	Gammon, C. O.		GAS	667	Topographic map	180		12/8/1948
178	121152143700	12452	-89.01827500	39.86257600	6-16N-2E	Bianucci, Ray Management	Gaston	1	DAOP	669	Ground level	2,080	Silurian	4/8/1981
179	121152143800	12417	-88.94965100	39.92137600	14-17N-2E	Robertson, Harold	McKay	1	DAP	682	Kelly Bushing	2,110	Silurian	12/20/1980
180	121152144000	12707	-88.82083900	39.86703500	1-16N-3E	Randall, Russ, Inc.	Bartel	1	OIL	696	Kelly Bushing	2,326	Silurian	4/18/1981
181	121152144100	12573	-88.93331900	39.92185900	13-17N-2E	Triple G Oil Company Ltd.	Demange	2	OILP	679	Kelly Bushing	2,166	Silurian	7/10/1981
182	121152144201	13365	-88.92859700	39.92200400	13-17N-2E	Triple G Oil Company Ltd.	Oldweiler, E.	2	OILP	684	Ground level	2,155	Silurian	9/25/1981
183	121152144300	12572	-88.92382300	39.91667100	24-17N-2E	Triple G Oil Company Ltd.	Schwarze-Pense Comm.	1	OIL	680	Kelly Bushing	2,183	Trenton	7/26/1981
184	121152144400	12571	-88.92384300	39.92033400	24-17N-2E	Triple G Oil Company Ltd.	Schwarze-Pense Community	2	OIL	680	Kelly Bushing	2,892	Silurian	9/27/1981
185	121152144500	12576	-88.94225700	39.89060300	35-17N-2E	Triple G Oil Company Ltd.	Decatur Park District	1	OILP	653	Kelly Bushing	2,175	Silurian	6/11/1981
186	121152144700	12743	-88.94027600	39.91526800	23-17N-2E	Barger Engineering, Inc.	Rohrkasse	2	OIL	673	Ground level	2,163	Silurian	3/25/1981
187	121152144800	12747	-88.93801700	39.91898300	23-17N-2E	Barger Engineering, Inc.	Rohrkasse	3	OILP	678	Ground level	2,160	Silurian	4/7/1981
188	121152144900	12748	-88.94031100	39.91891700	23-17N-2E	Barger Engineering, Inc.	Rohrkasse	4	OILP	677	Ground level	2,160	Silurian	1/20/1981
189	121152145200	12746	-88.93999800	39.89614000	26-17N-2E	Barger Engineering, Inc.	Casey	4	OIL	659	Kelly Bushing	2,160	Silurian	3/1/1981
190	121152146700	13349	-88.94858300	39.89712400	26-17N-2E	North Shore Oil Co.	Walston, Leroy Community	1	DAOP	678	Kelly Bushing	2,153	Silurian	3/21/1981
191	121152146800	13434	-88.94246800	39.89241200	26-17N-2E	Lynch, W.H. Oil Prod.	Hughes-Norfleet	1	OILP	659	Ground level	2,150	Silurian	3/16/1981
192	121152146900	13393	-88.99925600	39.88384600	32-17N-2E	Decatur Petroleum Co.	Kath Comm.	1	DAP	631	Ground level	1,981	Silurian	3/17/1981

Table B.1: Oil and Gas Wells Within the AoR

Map ID	API Number	Permit Number	Longitude	Latitude	Location	Company Name	Well Name	Well Number	Status Code	Elevation (ft)	Elev Ref	Known TD (ft)	TD Formation	Completion Date
193	121152147000	13559	-88.93110500	39.93282700	13-17N-2E	Triple G Oil Company Ltd.	Albert, Keith	1	DAOP	685	Kelly Bushing	2,133	Silurian	5/12/1981
194	121152147100	12451	-88.87822100	39.91651900	21-17N-3E	Bianucci, Ray Management	Hirsch, E & P	1	DAP	669	Ground level	2,230	Silurian	3/31/1981
195	121152147200	13539	-88.97979300	39.88511100	33-17N-2E	Lane, Virgil	Barnett, Vernie J.	1	DAOP	628	Kelly Bushing	2,145	Devonian	3/26/1981
196	121152148200	14030	-88.91673800	39.92089800	19-17N-3E	Triple G Oil Company Ltd.	Jurg-Padrutt	1	OILP	684	Kelly Bushing	2,180	Silurian	9/21/1981
197	121152148700	14414	-89.00313700	39.88016900	32-17N-2E	Watters, Charles	Dalton, John S.	1	DAOP	685	Kelly Bushing	2,024	Silurian	2/11/1982
198	121152148800	14486	-88.98922500	39.89126600	28-17N-2E	Decatur Petroleum Co.	Staley-Butts	1	DAOP	680	Ground level	2,052	Silurian	6/20/1981
199	121152148900	14609	-88.94961700	39.90782700	23-17N-2E	Triple G Oil Company Ltd.	Phillips, Loeb	4	OILP	673	Ground level	2,150	Silurian	6/28/1982
200	121152149000	14610	-88.92148800	39.92040200	24-17N-2E	Triple G Oil Company Ltd.	Pense	4	OIL	678	Ground level	2,170	Silurian	10/9/1981
201	121152149100	14611	-88.91677600	39.92453300	18-17N-3E	Triple G Oil Company Ltd.	Fombelle	2	DAP	682	Ground level	2,141	Silurian	11/18/1981
202	121152149400	15262	-88.91650900	39.90058300	30-17N-3E	Triple G Oil Company Ltd.	Schwarze, R. D.	1	DAP	684	Kelly Bushing	2,187	Silurian	9/8/1981
203	121152151000	15773	-88.92611800	39.90959400	24-17N-2E	Barger Engineering, Inc.	Baby Fold	1	OIL	663	Ground level	2,196	Silurian	10/29/1981
204	121152151200	16104	-88.92623100	39.92207600	13-17N-2E	Triple G Oil Company Ltd.	Oldweiler, Eugenia	3	OILP	689	Kelly Bushing	2,160	Silurian	12/14/1981
205	121152152400	16442	-88.87801100	39.90137400	28-17N-3E	Davis, C. G.	Cundiff	1	DAP	689	Kelly Bushing	2,285	Silurian	11/6/1981
206	121152153000	17235	-88.92849600	39.91104700	24-17N-2E	Triple G Oil Company Ltd.	Schwartz Childrens Trust	6	OIL	674	Kelly Bushing	2,180	Silurian	3/4/1982
207	121152154400	17333	-88.92613500	39.91144400	24-17N-2E	Barger Engineering, Inc.	Baby Fold	2	OIL	669	Kelly Bushing	2,188	Silurian	12/17/1982
208	121152154900	17405	-88.97073800	39.91724700	22-17N-2E	Champaign Valley Res.	Hickory Point	1	DAP	672	Kelly Bushing	2,064	Silurian	2/19/1982
209	121152155200	17839	-88.93529600	39.89627500	25-17N-2E	Barger Engineering, Inc.	Security Savings & Loan	1	OIL	669	Ground level	2,185	Silurian	9/29/1982
210	121152155800	18021	-88.93308500	39.89451400	25-17N-2E	Triple G Oil Company Ltd.	Henderson Community	2	OILP	660	Ground level	2,185	Silurian	5/2/1982
211	121152156100	18130	-88.94490800	39.91057600	23-17N-2E	Triple G Oil Company Ltd.	Phillips	14	OIL	681	Kelly Bushing	2,165	Silurian	4/28/1982
212	121152156900	18693	-88.92386800	39.92215000	13-17N-2E	Triple G Oil Company Ltd.	Oldweiler, Eugenia	4	OILP	681	Kelly Bushing	2,160	Silurian	6/17/1982
213	121152157000	18692	-88.92150500	39.92222100	13-17N-2E	Triple G Oil Company Ltd.	Oldweiler, Eugenia	5	OILP	680	Kelly Bushing	2,177	Silurian	1/7/1983
214	121152159000	20381	-88.93880200	39.89434300	26-17N-2E	Barger Engineering, Inc.	Casey-Hatch-Snow Community	1	OILP	666	Kelly Bushing	2,167	Silurian	10/7/1982
215	121152162100	21851	-88.92590900	39.89836000	25-17N-2E	Triple G Oil Company Ltd.	Klepzig Community	1	OILP	661	Kelly Bushing	2,200	Silurian	5/14/1983
216	121152164300	23770	-89.00573800	39.87657000	32-17N-2E	Watters Oil & Gas Co.	Dalton, John	2	DAOP	669	Kelly Bushing	2,028	Silurian	5/12/1983
217	121152165000	24944	-88.92107600	39.89304000	25-17N-2E	Triple G Oil Company Ltd.	Harrison-Oliver Community	1	DAP	656	Ground level	2,500	Silurian	9/12/1983
218	121152165100	24884	-89.01247800	39.87627800	31-17N-2E	Watters Oil & Gas Co.	Noland, Christina	1	OIL	693	Kelly Bushing	2,169	Silurian	7/26/1983
219	121152165200	24883	-89.00548500	39.87839300	32-17N-2E	Watters Oil & Gas Co.	Dalton, John	3	DAOP	671	Kelly Bushing	2,027	Silurian	7/14/1983
220	121152165900	25726	-89.01597900	39.87459500	6-16N-2E	Watters Oil & Gas Co.	Graves	1	OIL	687	Kelly Bushing	2,070	Silurian	9/14/1983
221	121152166000	25431	-89.01248000	39.87809400	31-17N-2E	Watters Oil & Gas Co.	Nolan, Christina	2	DAOP	681	Ground level	2,075	Silurian	8/14/1983
222	121152166100	25429	-89.01011600	39.87653000	32-17N-2E	Watters Oil & Gas Co.	Dalton, John	4	OIL	681	Kelly Bushing	2,085	Silurian	8/15/1983
223	121152166201	26227	-89.01011800	39.87831900	32-17N-2E	Watters Oil & Gas Co.	Dalton, John	5	OIL	676	Ground level	2,084	Silurian	9/26/1983
224	121152166202	202610	-89.01011800	39.87831900	32-17N-2E	IBEX Geological Consultants, Inc.	Dalton		INJW	679	Kelly Bushing	2,085	Silurian	1/13/2005
225	121152166600	25807	-89.01361500	39.87464600	6-16N-2E	Watters Oil & Gas Co.	Garver		DAOP	676	Ground level	2,074	Silurian	9/4/1983
226	121152166700	25840	-89.01720700	39.87623700	31-17N-2E	Niemeyer, Stephen M.	Friend, Ezra	1	OIL	692	Kelly Bushing	2,102	Silurian	8/30/1983
227	121152166900	25809	-89.00777300	39.87655100	32-17N-2E	Watters Oil & Gas Co.	Dalton, John	6	DAP	674	Kelly Bushing	2,070	Silurian	8/21/1983
228	121152166901	44996	-89.00779100	39.87655100	32-17N-2E	Watters Oil & Gas Co.	Dalton, John		WATRSP	674	Kelly Bushing	2,045		7/16/1991
229	121152167200	26368	-89.00903600	39.87472900	5-16N-2E	Kaufman, E.H.	Reising	1	DAOP	673	Kelly Bushing	2,090	Silurian	9/17/1983
230	121152167400	26565	-89.00894200	39.86927200	5-16N-2E	John Carey Oil Co., Inc.	Shimer	2	OILP	695	Kelly Bushing	2,084	Silurian	12/27/1983
231	121152167900	26226	-89.01484100	39.87653300	31-17N-2E	Watters Oil & Gas Co.	Nolan, Christina	3	OIL	682	Ground level	2,074	Silurian	10/3/1983
232	121152167901	200645	-89.01484100	39.87653300	31-17N-2E	Watters Oil & Gas Co.	Nolan, Christine	3	INJW	682	Ground level	2,075		7/15/1991
233	121152168000	26737	-89.01012300	39.88011000	32-17N-2E	Watters Oil & Gas Co.	Dalton, John	7	DAOP	675	Kelly Bushing	2,031	Silurian	10/19/1983
234	121152168100	26738	-89.00778400	39.88013600	32-17N-2E	Watters Oil & Gas Co.	Dalton, John	8	DAOP	675	Ground level	2,070	Silurian	10/14/1983
235	121152170800	28140	-88.88286400	39.97050200	32-18N-3E	Western Reserves Oil Co.	Parr Trust	1	DAO	690	Kelly Bushing	2,165	Silurian	1/4/1984
236	121152171600	29322	-88.97535500	39.90428400	28-17N-2E	Watters Oil & Gas Co.	Hazen, Velma	1	DAOP	667	Kelly Bushing	2,100	Silurian	5/7/1984
237	121152172100	29999	-88.98004300	39.90420000	28-17N-2E	Watters Oil & Gas Co.	Butt, Howard	1	OILP	663	Kelly Bushing	2,071	Silurian	7/2/1984
238	121152172800		-88.93589000	39.81075600	26-16N-2E	IL State Water Survey	Lake Decatur Sediments		STRAT					6/30/1956
239	121152173600	30868	-88.82807100	39.87072800	2-16N-3E	Baldwin, Don H.	Barnett, Richey	1	OIL	691	Kelly Bushing	2,375	Silurian	11/2/1984
240	121152173700	31134	-88.98236100	39.90233400	28-17N-2E	Watters Oil & Gas Co.	Butt, Howard	2	DAOGP	664	Kelly Bushing	2,082	Silurian	8/14/1984
241	121152174100	31397	-88.78456000	39.87878500	6-16N-4E	Modern Explorations	Berry, Francis	1	DAOP	678	Kelly Bushing	2,360	Silurian	9/16/1984
242	121152174400	31888	-88.99841900	39.87671800	32-17N-2E	Barger Engineering, Inc.	Wright, A.	2	OILP	634	Kelly Bushing	2,123	Silurian	10/17/1984
243	121152174600	32063	-89.01366900	39.88172800	31-17N-2E	Watters Oil & Gas Co.	Nolan, Christina	4	DAOP	684	Kelly Bushing	2,025	Silurian	10/11/1984
244	121152174800	32172	-89.00310500	39.87659500	32-17N-2E	Watters Oil & Gas Co.	Dalton, John	9	OIL	671	Kelly Bushing	2,060	Silurian	11/7/1984
245	121152174900	32173	-89.00312100	39.87839200	32-17N-2E	Watters Oil & Gas Co.	Dalton, John	10	OIL	667	Kelly Bushing	2,051	Silurian	10/30/1984
246	121152184300	33245	-88.79386900	39.93194800	18-17N-4E	Power Explorations	Anderson	1	DAP	660	Kelly Bushing	2,310	Silurian	1/8/1985
247	121152184500	33377	-88.97770300	39.90605900	21-17N-2E	Watters Oil & Gas Co.	Plankenhorn Comm.	1	DAP	666	Kelly Bushing	2,064	Devonian	1/23/1985
248	121152184700	33428	-89.01720900	39.87806100	31-17N-2E	Niemeyer, Stephen M.	Friend	3	DAO	687	Kelly Bushing	2,068	Silurian	3/23/1985
249	121152184800	33512	-88.79424200	39.88607800	31-17N-4E	Carey, John Oil Co., Inc	Eads, R.	1	DAOP	687	Kelly Bushing	2,391	Silurian	2/10/1985
250	121152185200	33859	-88.92119900	39.89849700	25-17N-2E	Triple G Oil Company Ltd.	Batthauer Community	1	OILP	676	Kelly Bushing	2,223	Silurian	2/16/1986
251	121152185900	34804	-88.99858900	39.89107700	29-17N-2E	Petra Oil. Ltd.	Hughes-Robinson Tr.C	1	DAP	674	Kelly Bushing	2,045	Silurian	9/4/1985
252	121152188000	36268	-89.00291000	39.87477200	5-16N-2E	Watters Oil & Gas Co.	Reising, Richard et al Comm	1	DAP	631	Ground level	2,028	Silurian	9/6/1985
253	121152193000	40365	-88.86924200	39.96002700	4-17N-3E	Watters Oil & Gas Co.	Jackson, Nelson et al	1	DAP	686	Kelly Bushing	2,161	Silurian	7/31/1987
254	121152193500	40488	-88.80182600	39.87501100	6-16N-4E	Jasper Oil Company	Garber	1	OILP	692	Kelly Bushing	2,339	Silurian	10/26/1987
255	121152225700		-89.00770400	39.85572600	8-16N-2E	Woollen Brothers	Forster, George		UNK	606	Digital Elevation Model	170		
256	121152226300		-88.99382500	39.88391600	32-17N-2E		Janvrin, Lynn		GAS	670	Digital Elevation Model			

Table B.1: Oil and Gas Wells Within the AoR

Map ID	API Number	Permit Number	Longitude	Latitude	Location	Company Name	Well Name	Well Number	Status Code	Elevation (ft)	Elev Ref	Known TD (ft)	TD Formation	Completion Date
257	121152226400		-88.84512000	39.92034800	22-17N-3E		Rowe		GAS	685	Ground level	93		
258	121152259900		-88.88245700	39.85353700	8-16N-3E	IL State Water Survey	Lake Decatur Sediments		STRAT					
259	121152260000		-88.89181800	39.84975000	8-16N-3E	IL State Water Survey	Lake Decatur Sediments		STRAT					
260	121152260100		-88.86798900	39.83919900	16-16N-3E	Lentz Tony	Decatur Airport	1	UNK	678	Digital Elevation Model			
261	121152260800		-88.85340200	39.91001800	22-17N-3E	IL State Water Survey	Lake Decatur Sediments		STRAT					
262	121152260900		-88.86290000	39.88434900	33-17N-3E	IL State Water Survey	Lake Decatur Sediments		STRAT			45		
263	121152261000		-88.86290000	39.88434900	33-17N-3E	IL State Water Survey	Lake Decatur Sediments		STRAT			2		
264	121152261600		-88.93828000	39.81619400	26-16N-2E	IL State Water Survey	Lake Decatur Sediments		STRAT			1		
265	121152263000		-88.82876500	39.95353900	2-17N-3E	Pure Oil Company	Illinois Prospect		STRU	686	Digital Elevation Model	1,194		
266	121152337800		-88.89219700	39.87726600	5-16N-3E	Illinois State Geological Survey	Archer Daniels Midland		CONF					
267	121152339000		-88.90643800	39.88261000	31-17N-3E	Illinois State Geological Survey	ADM		CONF					
268	121152339200		-88.89710100	39.88387200	32-17N-3E	Illinois State Geological Survey	ADM		CONF					
269	121152339300		-88.89713600	39.88113500	32-17N-3E	Illinois State Geological Survey	ADM		CONF					
270	121152339400		-88.89712000	39.88111800	32-17N-3E	Illinois State Geological Survey	ADM		CONF					
271	121152339500		-88.89709900	39.88109000	32-17N-3E	Illinois State Geological Survey	ADM		CONF					
272	121152339600		-88.89710600	39.88068100	32-17N-3E	Illinois State Geological Survey	ADM		CONF					
273	121152339700		-88.89772400	39.87617000	5-16N-3E	Illinois State Geological Survey	ADM		CONF					
274	121152339800		-88.88917200	39.87963800	5-16N-3E	Illinois State Geological Survey	ADM		CONF					
275	121152339900		-88.88944200	39.87570100	5-16N-3E	Illinois State Geological Survey	ADM		CONF					
276	121152340000		-88.88938400	39.87569000	5-16N-3E	Illinois State Geological Survey	ADM		CONF					
277	121152340100		-88.87725400	39.87150500	4-16N-3E	Illinois State Geological Survey	ADM		CONF					
278	121152341500		-88.89344800	39.87692800	5-16N-3E	Archer Daniels Midland	CCS Well	1	CONF					
279	121152343800		-88.89395500	39.87704100	5-16N-3E	Archer Daniels Midland	Geophysical Monitoring Well	1	CONF					
280	121152346000		-88.89335900	39.87979500	32-17N-3E	Archer Daniels Midland	Verification Well	1	CONF					
281	121152349000		-88.88595000	39.88961200	32-17N-3E	Illinois State Geological Survey	ADM MVA-11LG		CONF					
282	121152349100		-88.88366800	39.88934400	32-17N-3E	Illinois State Geological Survey	MVA-11UG		CONF					
283	121152349300		-88.87988000	39.88345300	32-17N-3E	Illinois State Geological Survey	ADM MVA-13LG		CONF					
284	121152349400		-88.88347100	39.88205700	32-17N-3E	Illinois State Geological Survey	MVA-13-UG		CONF					
285	121152349500		-88.88347100	39.88205700	32-17N-3E	Illinois State Geological Survey	MVA-13B		CONF					
286	121152349600		-88.89650900	39.89265400	32-17N-3E	Illinois State Geological Survey	ADM MVA-10UG		CONF					
287	121152350100		-88.89312100	39.88911300	32-17N-3E	Illinois State Geological Survey	Richland Community College		CONF					
288	121152350200		-88.89312100	39.88911300	32-17N-3E	Illinois State Geological Survey	Richland Community College		CONF					
289	121152350300		-88.88347100	39.88205700	32-17N-3E	Illinois State Geological Survey	ADM		CONF					
290	121152350400		-88.88347100	39.88205700	32-17N-3E	Illinois State Geological Survey	ADM		CONF					
291	121152350500		-88.88347100	39.88205700	32-17N-3E	Illinois State Geological Survey	ADM		CONF					
292	121152355200	11171	-88.89201000	39.89187500	32-17N-3E	Archer Daniels Midland	Verification Well	2	CONF					
293	121152359400		-88.88709200	39.88470200	32-17N-3E	Pioneer Oil Co., Inc.	Geophysical Monitoring	2	CONF					
294	121152360200	62741	-88.90896800	39.90822700	19-17N-3E	Crows Point Exploration, LTD.	Long	1	OIL	683	Kelly Bushing	2,260		7/14/2013
295	121152360300	62740	-88.90424700	39.90643900	30-17N-3E	Crows Point Exploration, LTD.	Long	2	DAP	683	Kelly Bushing	2,260		4/4/2013
296	121152360301	63179	-88.90424700	39.90643900	30-17N-3E	Crows Point Exploration, LTD.	Long		OIL	685	Kelly Bushing	2,289		9/1/2014
297	121152369400	63106	-88.85636900	39.88176300	34-17N-3E	Blackwater Energy, LLC	Bradshaw	1	DA	639	Ground level	2,970		10/5/2013
298	121152369600	63201	-88.84451300	39.88092400	34-17N-3E	MDM Energy, Inc.	Marietta	1	DAP	695	Kelly Bushing	2,370	Silurian	12/20/2013
299	121152371300		-88.88799600	39.88490200	32-17N-3E	Pioneer Oil Co., Inc.	CCS	2	STRAT	707	Kelly Bushing	7,192		
300	121152372800	64568	-88.82554300	39.88207700	35-17N-3E	Performance Plus Consulting	Arends	1	DAP	688	Kelly Bushing	2,525		4/30/2016
301	121152375400	64818	-88.82749000	39.82649300	23-16N-3E	Long Creek Energy LLC	Rutherford	1	OILP	690	Kelly Bushing	2,869		12/16/2015
302	121152375500	64960	-88.82508100	39.82333700	23-16N-3E	Long Creek Energy LLC	Rutherford	3	OILP	682	Kelly Bushing	3,238		6/27/2016
303	121152378100	65068	-88.79888300	39.80929600	30-16N-4E	Gaitros Oil, LLC	Gaitros	1	DAP	714	Kelly Bushing	3,327		9/20/2016
304	121152378200		-88.89646000	39.88082400	32-17N-3E	IL State Geological Survey	ISGS Powerprobe	1	STRAT			34		
305	121152378300		-88.89690400	39.87715100	5-16N-3E	IL State Geological Survey	ISGS Powerprobe	2	STRAT			48		
306	121152378400		-88.89690400	39.87715100	5-16N-3E	IL State Geological Survey	ISGS Powerprobe	3	STRAT			40		
307	121152381600		-88.91658000	39.87365000	6-16N-3E	IL State Geological Survey	ISGS		STRATP					
308	121152381700		-88.91660900	39.87360300	35-17N-2E	IL State Geological Survey	ISGS		STRATP					
309	121152381800		-88.87714500	39.87151000	4-16N-3E	IL State Geological Survey	ISGS		STRATP					
310	121152381900		-88.91681600	39.89129800	31-17N-3E	IL State Geological Survey	ISGS		STRATP					
311	121152387400	65649	-88.93556600	39.91086900	24-17N-2E	Podolsky Oil Co.	Schwarze Community	7	OIL	687	Kelly Bushing	2,215		6/25/2019
312	121470010700		-88.74034200	39.89108300	34-17N-4E	Woollen Brothers	Cerro Gordo #T 1-49		UNK	732	Digital Elevation Model	35		12/31/1948
313	121470010800		-88.74034200	39.89108300	34-17N-4E	Woollen Brothers	Cerro Gordo #T 2-49		UNK	732	Digital Elevation Model	28		12/31/1948
314	121470010900		-88.74034200	39.89108300	34-17N-4E	Woollen Brothers	Cerro Gordo #T 3-49		UNK	732	Digital Elevation Model	26		12/31/1948
315	121150101800		-88.96925200	39.79753000	34-16N-2E	Hyde Park Corp.	Hyde Park Corp.	1	OBSO	686	Kelly Bushing	3,440	St Peter	6/17/1972
316	121152145800	12899	-89.01845800	39.87297400	6-16N-2E	Watters, Charles	Garver, E. Jr., & N. G.	1	DAOP	490	Ground level	2,050	Silurian	2/13/1981
317	121152158600	19912	-88.96614600	39.79563900	34-16N-2E	Watters, Charles	Tallman	1	DAOP	690	Ground level	2,293	Devonian	8/1/1982
318	121152167500	26736	-89.01609400	39.87295300	6-16N-2E	Watters Oil & Gas Co.	Garver		DAOP	682	Ground level	2,089	Silurian	10/8/1983
319	121152169400	27516	-89.02055800	39.87449200	6-16N-2E	Decatur Petroleum Co.	Stein	1	DAOGP	682	Kelly Bushing	2,043	Silurian	12/20/1983
320	121152171700	29477	-89.01836300	39.86750600	6-16N-2E	Watters Oil & Gas Co.	Garver Communitized		DAP	675	Ground level	2,062	Silurian	6/20/1984

Table B.2: Water Wells Within the AoR

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Sensitive, Confidential, or Privileged Information

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APPENDIX C: Quality Assurance and Surveillance Plan

A quality assurance and surveillance plan (QASP) for all testing and monitoring activities pursuant to 40 CFR 146.90(k).

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Carbon Capture and Sequestration (CCS) Project Class VI Injection Wells: Quality Assurance and Surveillance Plan (QASP)

Carbon Sequestration Wells #1, #2, and #3

U.S. EPA ID Number:
IL-115-6A-0001 (CCS#2)
IL-115-6A-0002 (CCS#1)

August 2022

Prepared by:
Archer Daniels Midland Company (ADM)

<u>Class VI Injection Wells: Quality Assurance and Surveillance Plan (QASP)</u>

Carbon Sequestration Wells #1, #2, and #3

Approvals:

______________________________	_______________
Douglas Kirk, Plant Manager, Decatur Corn	Date
______________________________	_______________
Scott McDonald, Director, ADM UIC	Date
______________________________	_______________
Jeff Neisslie, Environmental Manager, Decatur Corn	Date
______________________________	_______________
Laura Evans, Decatur Area Environmental Manager	Date

Table of Contents

A. Project Management

A.1. Project/Task Organization

A.1. a/b. Key Individuals and Responsibilities

The project, led by Archer Daniels Midland Company (ADM), includes participation from several subcontractors. The Testing and Monitoring Activities responsibilities will be shared between ADM and their designated subcontractor and the program will be broken in six subcategories:

I) Shallow Groundwater Sampling

II) Deep Groundwater Sampling

III) Well Logging

IV) Mechanical Integrity Testing (MIT)

V) Pressure/Temperature Monitoring

VI) CO_2 Stream Analysis

VII) Geophysical Monitoring

A.1.c. Independence of Project QA Manager from Data Gathering

The majority of the physical samples collected and data gathered as part of the monitoring, verification, and accounting (MVA) program is analyzed, processed, or witnessed by third parties independent and outside of the project management structure.

A.1.d. QA Project Plan Responsibility

ADM will be responsible for maintaining the QASP. ADM will periodically review this QASP and consult with USEPA if/when changes to the plan are warranted.

A.1.e. Project Organization

The individuals and organizations participating in this project which hold roles and responsibilities for the QASP are as follows:

- UIC Program Director – technical expertise for CCS operations
- Environmental Manager, Decatur Corn Plant – environmental and regulatory expertise for CCS operations
- Plant Manager, Decatur Corn Plant – overall responsibility for running and maintaining CCS operations

- Decatur Area Environmental Manager – environmental and regulatory expertise for CCS operations
- Consultants and Contractors – will be utilized by ADM to fulfil testing, monitoring, reporting, and quality control activities as directed by ADM

A.2. Problem Definition/Background

A.2.a Reasoning

The CCS Project's monitoring, verification, and accounting (MVA) program has operational monitoring, verification, and environmental monitoring components. Operational monitoring is used to ensure safety with all procedures associated with fluid injection, monitor the response of storage unit, and the movement of the CO_2 plume. Key monitoring parameters include the pressure of injection well tubing & annulus, storage unit, above seal strata, and the lowermost USDW reservoir. Other monitoring parameters include injection rate, total mass & volume injected, injection well temperature profile, and geophysical monitoring. The verification component will provide information to evaluate if leakage of CO2 through the caprock is occurring. This includes geophysical logging , pressure, and temperature monitoring. The environmental monitoring components will determine if the injectate is being released into the shallow subsurface or biosphere. This monitoring includes geophysical logging and ground water monitoring.

A robust MVA program has been developed for the CCS project based on the experience gained through the CCS#1 and CCS#2 projects. The knowledge and experience gained provides a high level of confidence that the storage unit (Mt Simon) is capable to accept and permanently retain the injectate. The primary goal of the MVA program is to demonstrate that project activities are protective of human health and the environment. To help achieve this goal, this Quality Assurance Surveillance Plan (QASP) was developed to insure the quality standards of the testing and monitoring program meet the requirements of the U.S. Environmental Protection Agency's (USEPA) Underground Injection Control (UIC) Program for Class VI wells.

A.2.b. Reasons for Initiating the Project

The goal of the injection project is permanent geologic sequestration of industrial-scale volumes of CO_2 in the Mt. Simon Sandstone to reduce atmospheric concentrations of CO_2.

A.2.c. Regulatory Information, Applicable Criteria, Action Limits

The Class VI regulations under 40 CFR 146 Subpart H requires owners or operators of Class VI wells to perform several types of activities during the lifetime of the project in order to ensure that the injection well maintains its mechanical integrity, that fluid migration and the extent of pressure elevation are within the limits described in the permit application, and that underground sources of drinking water (USDWs) are not endangered. These monitoring activities include mechanical integrity tests (MITs), injection well testing during operation, monitoring of ground water quality in several zones, tracking of the CO2 plume and associated pressure front. This document details both the measurements that will be taken as well as the steps to ensure that the quality of all the data is such that the data can be used with confidence in making decisions during the life of the project.

A.3. Project/Task Description

A.3. a/b. Summary of Work to be Performed and Work Schedule

The facility Testing and Monitoring program summarizes the testing and monitoring tasks, reasoning, responsible parties, locations and testing frequency.

Well	Permit #
CCS#1	IL-115-6A-0002 Attachment C
CCS#2	IL-115-6A-0001 Attachment C
CCS#3	*

*Proposed well under application documents under Project Number IL-0007 in GSDT.

Figures 2 shows the geographic locations of CCS wells and associated monitoring wells.

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Figure 2. CCS#1, CCS#2 & CCS#3, Injection, shallow groundwater, geophysical, and deep monitoring well locations.

A.4. Quality Objectives and Criteria

A.4.a. Performance/Measurement Criteria

The overall QA objective for monitoring is to develop and implement procedures for subsurface monitoring, field sampling, laboratory analysis, and reporting which will provide results that will meet the characterization and non-endangerment goals of this project. Groundwater monitoring will be conducted during the pre-injection, injection, and post-injection phases of the project. Shallow and deep groundwater monitoring wells will be used to gather water-quality samples and pressure data. All the groundwater analytical and field monitoring parameters for each interval are listed in the facility Testing and Monitoring Plan. The Testing and Monitoring plan also show analytical parameters for CO2 stream gas monitoring, corrosion coupon assessment, and gauge specifications. Table 11 shows the monitoring outputs. The list of analytes may be reassessed periodically and adjusted to include or exclude analytes based on their effectiveness to the overall monitoring program goals.

Key testing and monitoring areas may include but are not limited to:

I. Shallow Groundwater Sampling
   - Aqueous chemical concentrations

II. Deep Formation Fluid Sampling
   - Aqueous chemical concentrations

III. Well Logging
   - pulse neutron, pressure, temperature, spinner

IV. Mechanical Integrity Testing (MIT)
   - Pulsed neutron, temperature, cement evaluation logging

V. Pressure/Temperature Monitoring
   - Pressure/temperature from in-situ gauges
   - Pressure/temperature from surface gauges

VI. CO_2 Stream Analysis
   - CO_2 Purity (% v/v, [GC])
   - Oxygen (O_2, ppm v/v)
   - Nitrogen (N_2, ppm v/v)
   - Carbon Monoxide (CO, ppm v/v)
   - Oxides of Nitrogen (NOx, ppm v/v)
   - Total Hydrocarbons (THC, ppm v/v as CH_4)
   - Methane (CH_4, ppm v/v)
   - Acetaldehyde (AA, ppm v/v)
   - Sulfur Dioxide (SO_2, ppm v/v)
   - Hydrogen Sulfide (H_2S ppm v/v)
   - Ethanol (ppm v/v)

VII. Geophysical Monitoring
   - Seismic data files (e.g., seg files for triggered events)
   - Processed time-lapse report

Table 4. Summary of analytical and field parameters for groundwater samples.

Parameters	Analytical Methods (1)	Detection limit	Typical Precisions	QC Requirements
Cations: Ca, Fe, K, Mg, Na, and Si	ICP-OES, EPA Method 6010B	0.001 to 0.1 mg/L (analyte, dilution and matrix dependent)	±15%	Daily calibration; blanks, duplicates and matrix spikes at 10% or greater frequency
Anions: Br, Cl, F, NO3, and SO4	Ion Chromatography, EPA Method 300.0	0.005 to 0.5 mg/L (analyte, dilution and matrix dependent)	±15%	Daily calibration; blanks, duplicates and matrix spikes at 10% or greater frequency
Dissolved CO_2	Coulometric titration, ASTM D513-11	0.02 to 0.13 mg/L (analyte, dilution and matrix dependent)	±15%	Duplicate measurement; standards at 10% or greater frequency
Isotopes: $\delta^{13}C$ of DIC	Isotope ratio mass spectrometry	12.2 mg/L HCO3- for δ13C	±0.15‰ for δ13C	10% duplicates; 4 standards/batch
Total Dissolved Solids	Gravimetry; APHA 2540C	12 mg/L	±10%	Balance calibration, duplicate analysis
Water Density (field)	Oscillating body method	0.0000 to 2.0000	±0.0002 g/mL	Duplicate measurements
Alkalinity	APHA 2320B	4 mg/L	±0.2°C	Factory calibration
pH (field)	EPA 150.1	2 to 12 pH units	±0.2 pH unit	User calibration per manufacturer recommendation
Specific conductance (field)	APHA 2510	0 to 200 mS/cm	±1% of reading	User calibration per manufacturer recommendation
Temperature (field)	Thermocouple	-5 to 50°C	±0.2°C	Factory calibration

Note 1: ICP = inductively coupled plasma; MS = mass spectrometry; OES = optical emission spectrometry; GC-P = gas chromatography - pyrolysis. An equivalent method may be employed with the approval of the UIC Program Director.

Table 8. Summary of analytical parameters for CO_2 gas stream. All analysis will be performed by ADM or a designated third-party laboratory.

Parameters	Analytical Methods(1)	Detection Limit/Range	Typical Precisions	QC Requirements
Oxygen	ISBT 4.0 (GC/DID)	1 uL/L to 5,000 uL/L (ppm by volume)	± 10 % of reading	daily standard within 10 % of calibration, secondary standard after calibration
	GC/TCD	0.1 % to 100 %	5 - 10 % relative across the range, RT ± 0.1 min	daily standard, duplicate analysis within 10 % of each other
Nitrogen	ISBT 4.0 GC/DID	1 uL/L to 5,000 uL/L (ppm by volume)	± 10 % of reading	daily standard within 10 % of calibration, secondary standard after calibration
	GC/TCD	0.1 % to 100 %	5 - 10 % relative across the range, RT ± 0.1 min	daily standard, duplicate analysis within 10 % of each other
Carbon Monoxide	ISBT 5.0 Colorimetric	5 uL/L to 100 uL/L (ppm by volume)	± 20 % of reading	duplicate analysis
	ISBT 4.0 (GC/DID)	1 uL/L to 5,000 uL/L (ppm by volume)	± 10 % of reading	daily standard within 10 % of calibration, secondary standard after calibration
Oxides of Nitrogen	ISBT 7.0 Colorimetric	0.2 uL/L to 5 uL/L (ppm by volume)	± 20 % of reading	duplicate analysis
Total Hydrocarbons	ISBT 10.0 THA (FID)	1 uL/L to 10,000 uL/L (ppm by volume)	5 - 10 % of reading relative across the range	daily blank, daily standard within 10 % of calibration, secondary standard after calibration
Methane	ISBT 10.1 GC/FID)	0.1 uL/L to 1,000 uL/L (ppm by volume)- dilution dependent	5 - 10 % of reading relative across the range	daily blank, daily standard within 10 % of calibration, secondary standard after calibration
Acetaldehyde	ISBT 11.0 (GC/FID)	0.1 uL/L to 100 uL/L (ppm by volume)- dilution dependent	5 - 10 % of reading relative across the range	daily blank, daily standard within 10 % of calibration, secondary standard after calibration
Sulfur Dioxide	ISBT 14.0 (GC/SCD)	0.01 uL/L to 50 uL/L (ppm by volume)- dilution dependent	5 - 10 % of reading relative across the range	daily blank, daily standard within 10 % of calibration, secondary standard after calibration
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)	0.01 uL/L to 50 uL/L (ppm by volume)- dilution dependent	5 - 10 % of reading relative across the range	daily blank, daily standard within 10 % of calibration, secondary standard after calibration

Parameters	Analytical Methods[1]	Detection Limit/Range	Typical Precisions	QC Requirements
Ethanol	ISBT 11.0 (GC/FID)	0.1 uL/L to 100 uL/L (ppm by volume)- dilution dependent	5 - 10 % of reading relative across the range	daily blank, daily standard within 10 % of calibration, secondary standard after calibration
CO_2 Purity	ISBT 2.0 Caustic absorption Zahm- Nagel	99.00% to 99.99%	± 10 % of reading	User calibration per manufacturer recommendation
	ALI method SAM 4.1 subtraction method (GC/DID)	1 ppm for each target analyte (analyte dependent) - refer to Oxygen and Nitrogen analysis.	5-10 % relative across the range	duplicate analysis within 10 % of each other
	GC/TCD	0.1 % to 100 %	5-10 % relative across the range, RT ± 0.1 min	standard with every sample, duplicate analysis within 10 % of each other

Note 1: ICP = inductively coupled plasma; MS = mass spectrometry; OES = optical emission spectrometry; GC-P = gas chromatography - pyrolysis. An equivalent method may be employed with the approval of the UIC Program Director.

Table 9. Summary of analytical parameters for corrosion coupons. Instrument calibration conducted by 3rd party lab providing services.

Parameters	Analytical Methods	Detection Limit/Range	Typical Precisions	QC Requirements
Mass	ASTM G1-03	.005mg	+/-2%	Annually - OEM Standard Practice for Calibration of Instrument
Thickness	ASTM G1-03	.001mm	+/-.0005mm	Annually - OEM Standard Practice for Calibration of Instrument

Table 10. Summary of measurement parameters for field gauges.

Parameters	Methods	Detection Limit/Range	Typical Precisions	QC Requirements
Pressure	Factory Calibrated in NIST certified lab.	+/- 0.001 psi / 0-3000 psi	+/- 0.01 psi	Annual Calibration of Instrument (3rd party)
Temperature	Factory Calibrated in NIST certified lab.	+/- 0.001 F / 0-500 F	+/- 0.01 F	Annual Calibration of Instrument (3rd party)
Flowrate	Factory Calibrated in NIST certified lab.	+/- 0.1000% of maximum scale	+/- 0.01 lbs/hr	Annual Calibration of Instrument (3rd party)

Table 11. Actionable testing and monitoring outputs.

	Project Action Limit	Detection Limit	Anticipated Reading
MIT—Pulse neutron logging	Action taken when log indicates CO_2 outside of expected range	+/- 0.5 SIGM or per OEM specification	Brine saturated ~ 60 CO_2 saturated ~ 8
Annual Wellbore MIT testing pressure	<3% pressure loss over 1 hour	+/- 0.001 psi or per OEM specification	>3% pressure loss over 1 hour
Fixed Surface and downhole gauges and logging gauges	Action will be taken when pressures are well outside of modeled/expected range	Refer to Table 10 for surface gauges Refer to Table 12 & 13, or OEM specifications for other gauges	Within injection formation: >80% fracture gradient 0.71 psi/ft
Wellbore integrity—DTS fiber optic temperature	Action will be taken when there is an anomaly in temperature profile	Refer to OEM specifications	DTS provides continuous** temperature profile
Seismic data files	Detected CO_2 outside the AOR	Dependent on fluid saturation, and formation velocities	CO_2 plume migration similar to modeled outcome

** Continuous DTS temperature monitoring will be satisfied with a minimum 10 minute sampling and hourly recording. If the DTS continuous monitoring is unavailable, the well can continue to operate by monitoring the surface tubing pressure and annulus pressure every 4 hours.

A.4.b. Precision

Precision measure of the agreement among set of replicate measurements (e.g., field duplicates); accuracy is the closeness of a measure result to an accepted reference value. For groundwater sampling, data accuracy will be assessed by the collection and analysis of field blanks to test sampling procedures and matrix spikes to test lab procedures. Field blanks will be taken no less than one per sampling event to spot check for sample bottle contamination. Laboratory assessment of analytical precision will be the responsibility of the individual laboratories per their standard operating procedures.

Table 12 summarizes the specifications of each monitoring method. For direct pressure and logging measurements, precision data is presented in Table 13.

A.4.c. Bias

Bias is the systemic distortion of a measurement process that causes error in one direction, and can be introduced during sampling and analysis. Sampling bias is address by using correct sampling methods and tools, analytical bias is assessed by comparing a measured value to a known value (i.e. matrix spike). Pressure or logging bias is address through use of consistent tools, equipment and methodology. Laboratory assessment of analytical bias will be the responsibility of the individual laboratories per their standard operating procedures and analytical methodologies. For direct pressure or logging measurements, there should be no bias.

A.4.d. Representativeness

For groundwater sampling, data representativeness expresses the degree to which data accurately and precisely represents a characteristic of a population, parameter variations at a sampling point, a process condition, or an environmental condition. The sampling network has been designed to provide data representative of site conditions. For analytical results of individual groundwater samples, representativeness will be estimated by ion and mass balances. Ion balances with ±10% error or less will be considered valid. Mass balance assessment will be used in cases where the ion balance is greater than ±10% to help determine the source of error. For a sample and its duplicate, if the relative percent difference is greater than 10%, the sample may be considered non-representative.

A.4.e. Completeness

For groundwater sampling, data completeness is a measure of the amount of valid data obtained from a measurement system compared to the amount that was expected to be obtained under normal conditions. It is anticipated that data completeness of 90% for groundwater sampling will be acceptable to meet monitoring goals. For direct pressure and temperature measurements, it is expected that data will be recorded no less than 90% of the time.

A.4.f. Comparability

Data comparability expresses the confidence with which one data set can be compared to another. The data sets to be generated by this project will be very comparable to future data sets because of the use of standard methods and the level of QA/QC effort. If historical groundwater quality data become available from other sources, their applicability to the project and level of quality will be assessed prior to use with data gathered on this project. Direct pressure, temperature, and logging measurements will be directly comparable to previously obtained data due to consistent measurement techniques.

A.4.g. Method Sensitivity

Table 14 through Table 19 provide additional details on gauge specifications and sensitivities.

Table 12. Pressure and temperature—representative downhole quartz gauge specifications. Actual gauge utilized may have different specifications.

Calibrated working pressure range	Atmospheric to 10,000 psi
Initial pressure accuracy	<+/-2 psi over full scale
Pressure resolution	0.005 psi at 1-s sample rate
Pressure drift stability	<+/-1 psi per year over full scale
Calibrated working temperature range	77–266°F
Initial temperature accuracy	<+/-0.9°F per +/-0.27°F
Temperature resolution	0.009°F at 1-s sample rate
Temperature drift stability	<+/-0.1°F per year at 302
Max temperature	302°F

Table 13. Representative Logging tool specifications. Actual logging tool may have different specifications.

	RST	CBL	USI	Isolation Scanner
Logging speed	1,800 ft/hr	3,600 ft/hr	Standard resolution: 2,700 ft/hr High resolution: 563 ft/hr	Standard resolution: 2,700 ft/hr High resolution: 563 ft/hr
Vertical resolution	15 inches	3 ft	Standard resolution: 0.6 in High speed: 6 in	High resolution: 0.6 in High speed: 6 in
Investigation	Formation	Casing, annulus, and formation	Casing and annulus	Casing and annulus
Temperature rating	302°F	350°F	350°F	350°F
Pressure rating	15,000 psi	20,000 psi	20,000 psi	20,000 psi

A.5. Special Training

A.5.a. Specialized Training

The geophysical survey equipment and wireline logging tools will be operated by trained personnel according to the standards of the service company conducting the work. The subsequent data will be processed and analyzed according to standard industry practice. Trained personnel will be utilized for all groundwater field sampling activities. Upon request, ADM will provide the agency with all laboratory SOPs developed for the specific parameter using the appropriate standard method. Each laboratory technician conducting the analysis on the samples will be trained on the SOP developed for each standard method.

A.5. b/c. Training Provider and Responsibility

Training for personnel will be provided by ADM or by the subcontractor responsible for the data collection activity.

A.6. Documentation and Records

A.6.a. Report Format and Package Information

A semi-annual report from ADM to USEPA will contain all required project data, including testing and monitoring information as specified by the UIC Class VI permit. Data will be provided in electronic or other formats as required by the UIC Program Director.

A.6.b. Other Project Documents, Records, and Electronic Files

Other documents, records, and electronic files such as well logs, test results, or other data will be provided as required by the UIC Program Director.

A.6.c/d. Data Storage and Duration

ADM or a designated contractor will maintain the required project data as provided elsewhere in the permit.

A.6.e. QASP Distribution Responsibility

The QASP copy will be available and distributed through Policy Tech that will be owned by the Environmental Manager, Decatur Corn Plant. Colleagues who have responsibilities for implementing the plan will be marked as a read requirement and will therefore have distribution of the plan.

B. Data Generation and Acquisition

B.1. Sampling Process Design (Experimental Design)

Discussion in this section is focused on groundwater and fluid sampling and does not address monitoring methods that do not gather physical samples (e.g., logging, seismic monitoring, and pressure/temperature monitoring). During the pre-injection and injection phases, groundwater sampling is planned to include an extensive set of chemical parameters to establish aqueous geochemical reference data. Parameters will include selected constituents that: (1) have primary and secondary USEPA drinking water maximum contaminant levels, (2) are the most responsive to interaction with CO2 or brine, (3) are needed for quality control, and (4) may be needed for geochemical modeling. The full set of parameters for each sampling interval is given in the Testing and Monitoring Plan.

After a sufficient baseline is established, monitoring scope may shift to a subset of indicator parameters that are (1) the most responsive to interaction with CO2 or brine and (2) are needed for quality control. Implementation of a reduced set of parameters would be done in consultation with the USEPA. Revised QASP submittals are a form of consultation with USEPA. Isotopic analyses will be performed on baseline samples to the degree that the information helps verify a condition or establish an understanding of non-project related variations. For non-baseline samples, isotopic analyses may be reduced in all monitoring wells if a review of the historical project results or other data determines that further sampling for isotopes is unneeded. During any period where a reduced set of analytes is used, if statistically significant trends are observed that are the result of unintended CO2 or brine migration, the analytical list would be expanded to the full set of monitoring parameters. The Ironton-Galesville groundwater samples will be analyzed by ADM or a third-party laboratory. Dissolved CO2 will be analyzed by methods consistent with Test Method B of ASTM D 513-06, “Standard Test Methods for Total and Dissolved Carbon Dioxide in Water” or equivalent. Isotopic analysis will be conducted using established methods.

B.1.a. Design Strategy

CO_2 Stream Monitoring Strategy

The primary purpose of analyzing the carbon dioxide stream is to evaluate the potential interactions of carbon dioxide and/or other constituents of the injectate with formation solids and fluids. This analysis can also identify (or rule out) potential interactions with well materials. Establishing the chemical composition of the injectate also supports the determination of whether the injectate meets the qualifications of hazardous waste under the Resource Conservation and Recovery Act (RCRA), 42 U.S.C. 6901 et seq. (1976), and/or the Comprehensive Environmental Response, Compensation, and Liability Act, (CERCLA) 42 U.S.C. 9601 et seq. (1980). Additionally, monitoring the chemical and physical characteristics of the carbon dioxide (e.g., isotopic signature, other constituents) may help distinguish the injectate from the native fluids and gases if unintended leakage from the storage reservoir occurred. Injectate monitoring is required at a sufficient frequency to detect changes to any physical and chemical properties that may result in a deviation from the permitted specifications.

Calibration of transmitters used to monitor pressures, temperatures, and flow rates of CO_2 into the subsurface at the injection well and subsequent movement to the verification well shall be conducted annually. Reports shall contain test equipment used to calibrate the transmitters, including test equipment manufacturers, model numbers, serial numbers, calibration dates and expiration dates.

Corrosion Monitoring Strategy

Corrosion coupon analyses will be conducted quarterly to aid in ensuring the mechanical integrity of the equipment in contact with the carbon dioxide. Coupons shall be sent quarterly to a company for analysis and an analysis conducted in accordance with ASTM G01-03 or similar to determine and document corrosion wear rates based on mass loss.

Shallow Groundwater Monitoring Strategy

Eight dedicated monitoring wells have been selected for shallow groundwater monitoring. These wells have already been installed and screened in the Quaternary-age deposits to depths less than 150 ft below ground surface (bgs). The local Quaternary-age deposits are used predominantly as private water well sources in the area. The wells are designated as 10LG, 11LG, 12LG, 13LG, G101, G102,G103, and G104 (Figure 2). The wells were selected to give a spatial distribution around the planned CO_2 injection well locations.

Deep Groundwater Monitoring Strategy

Monitoring of the deeper St. Peter and Ironton-Galesville Sandstones will be used for early leakage detection in formations that are much closer to the Mt. Simon Sandstone injection reservoir. Fluid sampling at wells VW#1, VW#2, VW#3, GM#2 and GM#3 in combination with pressure monitoring, temperature monitoring, and pulse neutron logging will be used to determine if leakage is occurring at or near the injection well. The Ironton-Galesville Sandstone, has sufficient permeability (over 100 mD) such that pressure monitoring at the verification wells would detect a failure of the confining zone should it occur. MIT testing and DTS monitoring at the injection well will also provide data to insure the mechanical integrity of the well is maintained. With the planned sampling and monitoring frequencies, it is expected that baseline conditions can be documented, natural variability in conditions can be characterized, unintended brine or CO_2 leakage could be detected if it occurred, and sufficient data will be collected to demonstrate that the effects of CO_2 injection are limited to the intended storage reservoir. No groundwater fluid sampling is planned for the Mt Simon intervals where free phase CO_2 has broken through.

B.1.b. Type and Number of Samples/Test Runs

Sampling frequencies are detailed in the permit Testing and Monitoring Plan (Permit Attachment C).

B.1.c. Site/Sampling Locations

Shallow groundwater monitoring will use existing wells 10LG, 11LG, 12LG, 13LG, G101, G102,G103, and G104 as noted in Section B.1.a. Deep groundwater monitoring will use existing wells VW#1, VW#2, VW#3, GM#2 and GM#3 (Figure 2) as noted in Section B.1.a.

CO_2 gas stream and corrosion coupon sampling locations will occur in the selected CO2 collection or compression areas for each CO2 source (i.e ethanol fermentation, anthropogenic combustion, and 3rd party sources).

B.1.d. Sampling Site Contingency

The shallow and deep groundwater monitoring wells are located on property of ADM and Richland Community College; access permissions have already been granted. No problems of site inaccessibility are anticipated. If inclement weather makes site access difficult, sampling schedules will be reviewed and alternative dates may be selected that would still meet permit-related conditions.

No problems of site inaccessibility are anticipated for CO_2 gas stream or corrosion coupon sampling. If inclement weather makes site access difficult, sampling schedules will be reviewed and alternative dates may be selected that would still meet permit related conditions.

B.1.e. Activity Schedule

The groundwater sampling activities and frequencies are summarized in the Testing and Monitoring Plan. The CO_2 gas stream and corrosion coupon sampling activities and frequencies are also summarized in the Testing and Monitoring Plan.

B.1.f. Critical/Informational Data

During both groundwater sampling and analytical efforts, detailed field and laboratory documentation will be taken. Documentation will be recorded in field and laboratory forms and notebooks. Critical information will include time and date of activity, person/s performing activity, location of activity (well-field sampling) or instrument (lab analysis), field or laboratory instrument calibration data, field parameter values. For laboratory analyses, much of the critical data are generated during the analysis and provided to end users in digital and printed formats. Noncritical data may include appearance and odor of the sample, problems with well or sampling equipment, and weather conditions.

B.1.g. Sources of Variability

Potential sources of variability related to monitoring activities include:

1. Natural variation in fluid quality, formation pressure and temperature and seismic activity;
2. Variation in fluid quality, formation pressure and temperature, and seismic activity due to project operations;
3. Changes in recharge due to rainfall, drought, and snowfall;
4. Changes in instrument calibration during sampling or analytical activity;
5. Different staff collecting or analyzing samples;
6. Differences in environmental conditions during field sampling or monitoring activities;
7. Changes in analytical data quality during life of project; and
8. Data entry errors related to maintaining project database.

Activities to eliminate, reduce, or reconcile variability related to monitoring activities include:

1. Collecting long-term baseline data to observe and document natural variation in monitoring parameters,
2. Evaluating data in timely manner after collection to observe anomalies in data that can be addressed be resampled or reanalyzed,
3. Conducting statistical analysis of monitoring data to determine whether variability in a data set is the result of project activities or natural variation,

4. Maintaining weather- related data using on-site weather monitoring data or data collected near project site (such as from local airports),
5. Checking instrument calibration before, during and after sampling or sample analysis,
6. Trained staff,
7. Conducting laboratory quality assurance checks using third party reference materials, and/or blind and/or replicate sample checks, and
8. Developing a systematic review process of data that can include sample-specific data quality checks (i.e., cation/anion balance for aqueous samples).

B.2. Sampling Methods

Logging, geophysical monitoring, and pressure/temperature monitoring does not apply to this section, and is omitted.

B.2. a/b. Sampling SOPs

Groundwater samples will be collected primarily using a low-flow sampling method consistent with ASTM D6452-99 (2005) or Puls and Barcelona (1996). If a flow-through cell is not used, field parameters will be measured in grab samples. Groundwater wells will be purged to ensure samples are representative of formation water quality. Static water levels in each well will be determined using an electronic water level indicator before any purging or sampling activities begin. Dedicated pumps (e.g., bladder pumps) will be installed in each monitoring well to minimize potential cross contamination between wells. Groundwater pH, temperature, specific conductance, and dissolved oxygen will be monitored in the field using portable probes and a flow-through cell consistent with standard methods (e.g., APHA, 2005) given sufficient flow rates and volumes. Field chemistry probes will be calibrated at the beginning of each sampling day according to equipment manufacturer procedures using standard reference solutions. When a flow-through cell is used, field parameters will be continuously monitored and will be considered stable when three successive measurements made three minutes apart meet the criteria listed in Table 20.

Table 20. Stabilization criteria of water quality parameters during shallow well purging.

FIELD PARAMETER	STABILIZATION CRITERIA
pH	+/- 0.2 units
Temperature	+/- 1°C
Specific Conductance	+/- 3% of reading in µS/cm
Dissolved Oxygen	+/- 10% of reading or 0.3 mg/L whichever is greater

After field parameters have stabilized, samples will be collected. Samples requiring filtration will be filtered through 0.45 µm flow-through filter cartridges as appropriate and consistent with ASTM D6564-00. Prior to sample collection, filters will be purged with a minimum of 100 mL of well water (or more if required by the filter manufacturer). For alkalinity and total CO_2 samples, efforts will be made to minimize exposure to the atmosphere during filtration, collection in sample containers, and analysis.

Wells GM#2,GM#3, VW#1, VW#2 and VW#3 will use a wireline sampling system with a sampling device (e.g., Kuster sampler or downhole pump) capable of collecting a sample from a discrete interval. The downhole samples will be processed in a manner consistent with ISGS-SOP-WB-V1.14 (dated August 10, 2012).

The existing deep groundwater monitoring wells were developed and purged extensively at the time of completion and similar plans will be used to develop GM#3 and VM#3. Prior to sampling, each zone will be purged to ensure representative samples are collected. Due to the extensive well development, the amount of fluid to be purged at the time of sampling will be relatively small. If a three-foot zone is perforated (similar to VW#1), then the annular space between the 2-7/8-in. tubing and the 5-1/2-in. casing is only 1.92 gal. Thus, relatively small purge volumes will adequately refresh each isolated sampling interval. Similar purging techniques will be used for collecting deep groundwater samples. Additional information about sampling procedures are given in Locke et al. (2013).

For the deep groundwater monitoring wells , gas lifts using a downhole gas lift mandrel will be used to produce fresh reservoir fluid from the formation. Alternatively, a downhole pump or other methods maybe utilized to produce reservoir fluids. During fluid sampling, the sampling device will be positioned at a point at which a representative sample of the reservoir's fluid is collected.

B.2.c. In-situ Monitoring.

In-situ monitoring of groundwater chemistry parameters is not planned.

B.2.d. Continuous Monitoring.

Pressure data will be collected from shallow groundwater wells on a periodic basis (e.g., hourly to daily) using dedicated pressure transducers with data loggers to generally characterize shallow water level trends. These data are not to satisfy any regulatory requirement and are strictly informational.

B.2.e. Sample Homogenization, Composition, Filtration.

Described in section B.2.b.

B.2.f. Sample Containers and Volumes

For CO_2 stream monitoring, samples will be collected in a clean sample container rated for the appropriate collection pressure (i.e. mini cylinders, polybags or equivalent).

For shallow and deep groundwater samples, all sample bottles will be new. Sample bottles and bags for analytes will be used as received (ready for use) from the vendor or contract analytical laboratory for the analyte of interest. A summary of sample containers is presented in Table 22.

B.2.g. Sample Preservation

For groundwater and other aqueous samples, the preservation methods in Table 22 will be used.
No preservation is required or used for CO_2 gas stream, and additional details of sampling requirements are shown in Table 21. Corrosion coupon sampling only requires that the coupons be physically separated (e.g., sleeves, baggies) during transportation to prevent physical abrasion.

Table 21. Summary of sample containers, preservation treatments, and holding times for CO_2 gas stream analysis.

Target Parameters	Volume/Container Material	Preservation Technique	Sample Holding time (max)
CO_2 gas stream	(2) 2L MLB Polybags (1) 75 cc Mini Cylinder	Sample Storage Cabinets	5 Business Days

B.2.h. Cleaning/Decontamination of Sampling Equipment

Dedicated pumps (e.g., bladder pumps) will be installed in each groundwater monitoring well to minimize potential cross contamination between wells. These pumps will remain in each well throughout the project period except for maintenance. Prior to installation, the pumps will be cleaned on the outside with a non-phosphate detergent. Pumps will be rinsed a minimum of three times with deionized water and a minimum of 1 L of deionized water will be pumped through pump and sample tubing. Individual cleaned pumps and tubing will be placed in plastic garbage bags for transport to the field for installation. All field glassware (pipets, beakers, filter holders, etc.) are cleaned with tap water to remove any loose dirt, washed in a dilute nitric acid solution, and rinsed three times with deionized water before use.

CO_2 gas stream sampling containers will be either disposed or decontaminated by the analytical lab. No sampling equipment will be utilized with the corrosion coupons or annual field gauge calibrations.

B.2.i Support Facilities

For sampling of groundwater, the following are required: air compressor, vacuum pump, generator, multi-electrode water quality sonde, analytical meters (pH, specific conductance, etc.). Field activities are usually completed in field vehicles and portable laboratory trailers located on site.

Sampling tubing, connectors and valves required to sample the CO_2 gas stream will be supplied by the analytical lab providing the sampling containers. Sampling will occur within the existing CO_2 compression building.

Similarly, corrosion coupons will be removed from the CO_2 injection line at each CO_2 source.

Field gauges will be removed from the injection well and verification well utilizing existing standard industry tools and equipment. Deployment and retrieval of verification well gauges will be done using procedures and equipment recommended by the vendor, subcontractor, or is standard per industry practice.

B.2.j. Corrective Action, Personnel, and Documentation

Field staff will be responsible for properly testing equipment and performing corrective actions on broken or malfunctioning field equipment. If corrective action cannot be taken in the field, then equipment will be returned to the manufacturer for repair or replaced. Significant corrective actions affecting analytical results will be documented in field notes.

B.3. Sample Handling and Custody

Logging, geophysical monitoring, and pressure/temperature monitoring does not apply to this section, and is omitted.

Sample holding times (Table 22) will be consistent with those described in US EPA (1974), American Public Health Association (APHA, 2005), Wood (1976), and ASTM Method D6517-00 (2005). After collection, samples will be placed in ice chests in the field and maintained thereafter at approximately 4°C until analysis. The samples will be maintained at their preservation temperature and sent to the designated laboratory within 24 hours. Analysis of the samples will be completed within the holding time listed in Table 22. As appropriate, alternative sample containers and preservation techniques approved by the UIC Program Director will be used to meet analytical requirements.

B.3.a Maximum Hold Time/Time Before Retrieval

See Table 22.

B.3.b. Sample Transportation

See description at the beginning of Section B.3.

B.3.c. Sampling Documentation

Field notes will be collected for all groundwater samples collected. These forms will be retained and archived as reference. The sample documentation is the responsibility of groundwater sampling personnel.

An analysis authorization form shall be provided with each CO_2 gas stream sample provided for analysis as shown by the example in Figure 4.

B.3.d. Sample Identification

All sample bottles will have waterproof labels with information denoting project, sampling date, sampling location, sample identification number, sample type (freshwater or brine), analyte, volume, filtration used (if any), and preservative used (if any). See Figure 3 for an example of a label.

Table 22. Summary of anticipated sample containers, preservation treatments, and holding times.

Target Parameters	Volume/Container Material	Preservation Technique	Sample Holding time	Relative Sampling Depth
Cations: Ca, Fe, K, Mg, Na, Si	250 ml/HDPE	Filtered, nitric acid, cool 4°C	60 days	Shallow
Dissolved CO_2	2 × 60 ml/HDPE	Filtered, cool 4°C	14 days	Shallow
Dissolved CO_2	60 ml/HDPE	Filtered, cool 4°C	14 days	Deep
Isotopes: ^{3}H, δD, $\delta^{18}O$, $\delta^{34}S$, and $\delta^{13}C$	2 × 60 ml/HDPE	Filtered, cool 4°C	4 weeks	Shallow
Isotopes: $\delta^{34}S$	250 ml/HDPE	Filtered, cool 4°C	4 weeks	Deep
Isotopes: δD, $\delta^{18}O$, $\delta^{13}C$	60 ml/HDPE	Filtered, cool 4°C	4 weeks	Deep
Alkalinity, anions (Br, Cl, F, NO_3, SO_4**)**	500 ml/HDPE	Filtered, cool 4°C	45 days	Shallow
Field Confirmation: Temperature, dissolved oxygen, specific conductance, pH	200 ml/glass jar	None	< 1 hour	Deep
Field Confirmation: Density	60 ml/HDPE	Filtered	< 1 hour	Deep

IL-ICCS_10LG_20A (fresh water)
01-23-2014
Metals, 60 ml, filtered, HNO_3

Figure 3. Example label for groundwater sample bottles.

B.3.e. Sample Chain-of-Custody

For CO_2 stream analysis, an analysis authorization form (Figure 4) will accompany the sample to the lab at which point a chain-of-custody accompanies the sample through their processes.

For groundwater samples, chain-of-custody will be documented using a standardized form. A typical form is shown in Figure 5, and it or a similar form will be used for all groundwater sampling. Copies of the form will be provided to the person/lab receiving the samples as well as the person/lab transferring the samples. These forms will be retained and archived to allow simplified tracking of sample status. The chain-of -custody form and record keeping is the responsibility of groundwater sampling personnel.

B.4. Analytical Methods

Logging, geophysical monitoring, and pressure/temperature monitoring does not apply to this section, and is omitted.

B.4.a. Analytical SOPs

Analytical SOPs are referenced in the Testing and Monitoring Plan and Table 4. Other laboratory specific SOPs utilized by the laboratory utilized by ADM. Each laboratory technician conducting the analysis on the samples will be trained on the SOP developed for each standard method.

B.4.b. Equipment/Instrumentation Needed

Equipment and instrumentation is specified in the individual analytical methods referenced in Table 4.

B.4.c. Method Performance Criteria

Nonstandard method performance criteria are not anticipated for this project.

B.4.d. Analytical Failure

Each laboratory conducting the analyses in Table 4 will be responsible for appropriately addressing analytical failure according to their individual SOPs.

B.4.e. Sample Disposal

Each laboratory conducting the analyses in in Table 4 will be responsible for appropriate sample disposal according to their individual SOPs.

B.4.f Laboratory Turnaround

Laboratory turnaround will vary by laboratory, but generally turnaround of verified analytical results within one month will be suitable for project needs.

B.4.g. Method Validation for Nonstandard Methods

Nonstandard methods are not anticipated for this project.

Airborne Labs International, Inc.

22C World's Fair Drive, Somerset, NJ 08873 Fax: 732-302-3035 Phone: 732-302-1950
E-mail: airbornelabs@aol.com Website: www.airbornelabs.com

Analysis Authorization

This form MUST be completed & returned with a sample shipment

1.) Report Results to*:

Company: ____________ Sampled On (mm/dd/yy): ________
Address: ____________ P.O. #: ________
Address: ____________ Credit Card: Visa Amex MasterCard Discover
Address: ____________ Card #: ________
Address: ____________ Cardholder: ________
Attention: ____________ Exp. Date: ________
Telephone: (____)____________ Check #: ________
Fax: (____)____________ Other: ________
E-Mail: ____________ Pricing Discussed/Quoted? Y N

*Please attach complete billing address if different from reporting address.

2.) Number of Samples Submitted: ______ Container Type(s): ____________

3.) Sample Description (circle): Liquid CO_2 CO2 (Final) Vapor CO2 Feedgas* CO_2 In-Process Food Grade CO_2 LIN LOX LAR RELOX (Reboiler) ABO

*IF CO_2 Feedgas –Identify source (e.g. Ethanol/Ammonia/Nat. Well/Ethylene/Combustion, Self-Gen, etc.) ____________

Aviator Breathing Oxygen (ABO) Natural Gas Refinery Gas Syn Gas Propane Butane Air Oxygen Nitrogen Argon Hydrogen Helium Neon Xenon Krypton Freon® Refrigerant Gas Mixture Fuel Oil Lubricant

Other (Describe): ____________

4.) Sample Type (Check) : Industrial____ Medical______ MilSpec_____ Other_____
(attach a log for multiple samples)

5.) Sample ID: ____________

6.) Potential Hazards/Safety Issues: ____________

7.) Analytical Test(s) Requested (check program or select individual tests required where applicable):

Std ISBT/Vendor CO_2 Test Program____ Std CO_2 Feedgas Program____ Std CGA Test Program____ Std Medical Gas_____
Std Contract Program____ Std ASTM Test Program____ MIL Spec Test Program____

%Purity THC CH_4 TNMHC Vol Hydrocarbons (C1-C6) BTEX Water Vapor NVR/NVOR Oil/Grease Total Sulfur H_2S SO_2
COS MeSH t-Butyl Mercaptan Vol Sulfur Compnds Odorants Total Nitrogen N_2 NO_x NH_3 NO NO_2 HCN Nitrous Oxide (N_2O)
PH_3 Oxygen Argon Hydrogen Helium CO CO_2 Xenon Neon Krypton Vinyl Chloride Acetaldehyde Vol Oxygenates GC/MS Scan
IR Scan IR Microscope Halogenated Hydrocarbons SF_6 Gas Mixture% Btu (Heat) Content % CHNO Sediment Wt Patch Test
Viscosity Flash/Fire Point Density Specific Gravity Trace Metals TAN TBN XRF SEM-XRF Scan Light Microscope

Other Testing: ____________

8.) Sample Disposition

Retain for ______ Period Perform Clean-up/Maintenance Actions & Return* ____ Report for Instructions ____

Other: ____________

*Supply all return address & shipping instructions

9.) Report Disposition (circle one): E-Mail Fax Mail Telephone Other:____________
(Reports will be sent to the address & contact(s) specified at the top of this form)

10.) Priority Conditions (circle), Note: Additional fees will apply for non-std test scheduling:

Standard 2-Work Day 1-Work Day Same Day Emergency Other:____________

Analytical testing cannot be performed unless this form is completed & returned

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Figure 4. Example of CO_2 gas stream analysis authorization form.

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CHAIN OF CUSTODY RECORD (Page __ of __)

Illinois State Water Survey – Analytical Services Group
Illinois State Geological Survey – Geochemistry Section

For Midwest Geological Sequestration Consortium (MGSC) Projects

	MGSC ID	**ISGS MVA ID**	**Matrix**	**Date Collected**	**Time Collected**	**Sampling Team**	**Circle analyses to be performed**
1							anions, cations, TDS, alk, NH_3, NVOC
2							anions, cations, TDS, alk, NH_3, NVOC
3							anions, cations, TDS, alk, NH_3, NVOC
4							anions, cations, TDS, alk, NH_3, NVOC
5							anions, cations, TDS, alk, NH_3, NVOC
6							anions, cations, TDS, alk, NH_3, NVOC
7							anions, cations, TDS, alk, NH_3, NVOC
8							anions, cations, TDS, alk, NH_3, NVOC
9							anions, cations, TDS, alk, NH_3, NVOC
10							anions, cations, TDS, alk, NH_3, NVOC
11							anions, cations, TDS, alk, NH_3, NVOC
12							anions, cations, TDS, alk, NH_3, NVOC
12							

CHAIN OF CUSTODY		
Relinquished by:	Print Name:	Date and Time:
Received by:	Print Name:	Date and Time:
General Remarks: - Field parameters are to be recorded on separate sheets by sampling teams. - Any special laboratory instructions or remarks should be made below.		
Data Contacts:	Fund:	
Billing Contact:	Billing Address:	
Send Data To:		

Remarks:

Rev. Oct. 2011 (RL)

Figure 5. Example chain-of-custody form.

B.5. Quality Control

Geophysical monitoring and pressure/temperature monitoring does not apply to this section, and is omitted.

B.5.a. QC activities

Blanks

For shallow groundwater sampling, a field blank will be collected and analyzed for the inorganic analytes in Table 4 at a frequency of 10% or greater. Field blanks will be exposed to the same field and transport conditions as the groundwater samples. Blanks will also be utilized for deep groundwater sampling and analyzed for the inorganic analytes in Table 4 at a frequency of 10% or greater. Field blanks will be used to detect contamination resulting from the collection and transportation process.

Duplicates

For each shallow groundwater sampling round, a duplicate groundwater sample is collected from a well from a rotating schedule. Duplicate samples are collected from the same source immediately after the original sample in different sample containers and processed as all other samples. Duplicate samples are used to assess sample heterogeneity and analytical precision.

B.5.b. Exceeding Control Limits

If the sample analytical results exceed control limits (i.e., ion balances > ±10%), further examination of the analytical results will be done by evaluating the ratio of the measured total dissolved solids (TDS) to the calculated TDS (i.e., mass balance) per APHA method. The method indicates which ion analyses should be considered suspect based on the mass balance ratio. Suspect ion analyses are then reviewed in the context of historical data and interlaboratory results, if available. Suspect ion analyses are then brought to the attention of the analytical laboratory for confirmation and/or reanalysis. The ion balance is recalculated, and if the error is still not resolved, suspect data are identified and may be given less importance in data interpretations.

B.5.c. Calculating Applicable QC Statistics

Charge Balance

The analytical results are evaluated to determine correctness of analyses based on anion-cation charge balance calculation. Because all potable waters are electrically neutral, the chemical analyses should yield equally negative and positive ionic activity. The anion-cation charge balance will be calculated using the formula:

$$\% \ difference = 100\frac{\sum cations - \sum anions}{\sum cations + \sum anions}, \qquad \text{(Equation 1)}$$

where the sums of the ions are represented in milliequivalents (meq) per liter and the criteria for acceptable charge balance is ±10%.

Mass Balance

The ratio of the measured TDS to the calculated TDS will be calculated in instances where the charge balance acceptance criteria are exceeded using the formula:

$$1.0 < \frac{measured\ TDS}{calculated\ TDS} < 1.2\,, \qquad \text{(Equation 2)}$$

where the anticipated values are between 1.0 and 1.2.

Outliers

A determination of one or more statistical outliers is essential prior to the statistical evaluation of groundwater. This project will use the USEPA's Unified Guidance (March 2009) as a basis for selection of recommended statistical methods to identify outliers in groundwater chemistry data sets as appropriate. These techniques include Probability Plots, Box Plots, Dixon's test, and Rosner's test. The EPA-1989 outlier test may also be used as another screening tool to identify potential outliers.

B.6. Instrument/Equipment Testing, Inspection, and Maintenance

Logging tool equipment will be maintained as per OEM standard industry practice.

For groundwater sampling, field equipment will be maintained, factory serviced, and factory calibrated per manufacturer's recommendations. Spare parts that may be needed during sampling will be included in supplies on-hand during field sampling.

For all laboratory equipment, testing, inspection and maintenance will be the responsibility of the analytical laboratory per standard practice, method-specific protocol, or NELAP requirement.

B.7. Instrument/Equipment Calibration and Frequency

Geophysical monitoring does not apply to this section, and is omitted.

B.7.a. Calibration and Frequency of Calibration

Pressure/temperature gauge calibration information is located in Table 12-Table 18. Logging tool calibration will be at the discretion of the service company providing the equipment, following standard industry practice. Calibration frequency will be determined by standard industry practices.

For groundwater sampling, portable field meters or muliprobe sondes used to determine field parameters (e.g., pH, temperature, specific conductance, dissolved oxygen) are calibrated according to manufacturer recommendations and equipment manuals (Hach, 2006) each day before sample collection begins. Recalibration is performed if any components yield atypical values or fail to stabilize during sampling.

B.7.b. Calibration Methodology

Logging tool calibration methodology will follow standard industry practice.

For groundwater sampling, standards used for calibration are typically 7 and 10 for pH, a potassium chloride solution yielding a value of 1413 microseimens per centimeter (µS/cm) at 25°C for specific conductance, and a 100% dissolved O_2 solution for dissolved oxygen. Calibration is performed for the pH meters per manufactuer's specifications using a 2-point calibration bounding the range of the sample. For coulometry, sodium carbonate standards (typically yielding a concentration of 4,000 mg CO_2/L) are routinely analyzed to evaluate instrument.

B.7.c. Calibration Resolution and Documentation
Logging tool calibration resolution and documentation will follow standard industry.

For groundwater sampling, calibration values are recorded in daily sampling records and any errors in calibration are noted. For parameters where calibration is not acceptable, redundant equipment may be used so loss of data is minimized.

B.8. Inspection/Acceptance for Supplies and Consumables

B.8. a/b. Supplies, Consumables, and Responsibilities

Supplies and consumables for field and laboratory operations will be procured, inspected, and accepted as required from vendors approved by ADM or the respective subcontractor responsible for the data collection activity. Acquisition of supplies and consumables related to groundwater analyses will be the responsibility of the laboratory per established standard methodology or operating procedures.

B.9. Nondirect Measurements

Seismic Monitoring Methods for CO_2 Plume Tracking

B.9.a Data Sources
For time lapse seismic surveys, repeatability is paramount for accurate differential comparison. Therefore, to ensure survey quality, the locations for the shots and acquisition methodology of sequential surveys will be consistent. Once these surveys are conducted, they will be compared to a baseline survey to track and monitor plume development.

For in-zone pressure monitoring, the in-zone pressure gauges in VW#1, VW#2 and VW#3 will be used to gather pressure data.

B.9.b. Relevance to Project
Time lapse seismic surveys will be used to track changes in the CO_2 plume in the subsurface. Processing and comparing subsequent surveys to a baseline will allow project managers to monitor plume growth, as well as to ensure that the plume does not move outside of the intended storage reservoir. Numerical modeling will be used to predict the CO_2 plume growth and migration over time by combining the processed seismic data with the existing geologic model.

In-zone pressure monitoring data will be used in numerical modeling to predict plume and pressure front behavior and confirm the plume stage within the AOR.

B.9.c. Acceptance Criteria
Following standard industry practices will ensure that the gathered seismic data will be used for accurate modeling and monitoring. Similar ground conditions, shot points located within tolerable limits, functional geophones, and similar seismic input signal will be used from survey to survey to ensure repeatability.

When processing seismic data, several QA checks will be done in accordance with industry standards including reformatting to Omega structured files, geometry application, amplitude compensation, predictive deconvolution, elevation statics correction, RMS amplitude gain, velocity analysis every 2 km, NMO application using picked velocities, CMP stacking, random noise attenuation, and instantaneous gain.

B.9.d. Resources/Facilities Needed

ADM will subcontract all necessary resources and facilities for the seismic monitoring, in-zone pressure monitoring, and groundwater sampling.

B.9.e. Validity Limits and Operating Conditions

For seismic surveys and numerical modeling, intraorganizational checks between trained and experienced personnel will ensure that all surveys and numerical modeling are conducted conforming to standard industry practices.

B.10. Data Management

B.10.a. Data Management Scheme

ADM or a designated contractor will maintain the required project data as provided elsewhere in the permit. Data will be backed up on tape or held on secure servers.

B.10.b. Record-keeping and Tracking Practices

All records of gathered data will be securely held and properly labeled for auditing purposes.

B.10.c. Data Handling Equipment/Procedures

All equipment used to store data will be properly maintained and operated according to proper industry techniques. ADM SCADA system and vendor data acquisition systems will interface with one another and all subsequent data will be held on a secure server.

B.10.d. Responsibility

The primary project managers will be responsible for ensuring proper data management is maintained.

B.10.e. Data Archival and Retrieval

All data will be held by ADM. These data will be maintained and stored for auditing purposes as described in section B.10.a.

B.10.f. Hardware and Software Configurations

All ADM and vendor hardware and software configurations will be appropriately interfaced.

B.10.g. Checklists and Forms

Checklists and forms will be procured and generated as necessary.

C. Assessment and Oversight

C.1. Assessments and Response Actions

C.1.a. Activities to be Conducted

Please refer to Table 1 in section A.3.a/b. (Summary of work to be performed and work schedule); groundwater quality data will be collected at the frequency outlined in that table. After completion of sample analysis, results will be reviewed for QC criteria as noted in section B.5. If the data quality fails to meet criteria set in section B.5., samples will be reanalyzed, if still within holding time criteria. If outside of holding time criteria, additional samples may be collected or sample results may be excluded from data evaluations and interpretations. Evaluation for data consistency will be performed according to procedures described in the USEPA 2009 Unified Guidance (USEPA, 2009).

C.1.b. Responsibility for Conducting Assessments

Organizations gathering data will be responsible for conducting their internal assessments. All stop work orders will be handled internally within individual organizations.

C.1.c. Assessment Reporting

All assessment information should be reported to the individual organizations project manager outlined in A.1.a/b.

C.1.d. Corrective Action

All corrective action affecting only an individual organization's data collection responsibility should be addressed, verified, and documented by the individual project managers and communicated to the other project managers as necessary. Corrective actions affecting multiple organizations should be addressed by all members of the project leadership and communicated to other members on the distribution list for the QASP. Assessments may require integration of information from multiple monitoring sources across organizations (operational, in-zone monitoring, above-zone monitoring) to determine whether correction actions are required and/or the most cost-efficient and effective action to implement. ADM will coordinate multiorganization assessments and corrective actions as warranted.

C.2. Reports to Management

C.2.a/b. QA status Reports

QA status reports should not be needed. If any testing or monitoring techniques are changed, the QASP will be reviewed and updated as appropriate in consultation with USEPA. Revised QASPs will be distributed by ADM to the full distribution list at the beginning of this document.

D. Data Validation and Usability

D.1. Data Review, Verification, and Validation

D.1.a. Criteria for Accepting, Rejecting, or Qualifying Data

Groundwater quality data validation will include the review of the concentration units, sample holding times, and the review of duplicate, blank and other appropriate QA/QC results. All groundwater quality results will be entered into a database or spreadsheet with periodic data review and analysis. ADM will retain copies of the laboratory analytical test results and/or reports. Analytical results will be reported on a frequency based on the approved UIC permit conditions. In the periodic reports, data will be presented in graphical and tabular formats as appropriate to characterize general groundwater quality and identify intrawell variability with time. After sufficient data have been collected, additional methods, such as those described in the USEPA 2009 Unified Guidance (USEPA, 2009), will be used to evaluate intrawell variations for groundwater constituents, to evaluate if significant changes have occurred that could be the result of CO_2 or brine seepage beyond the intended storage reservoir.

D.2. Verification and Validation Methods

D.2.a. Data Verification and Validation Processes

See sections D.1.a. and B.5.

Appropriate statistical software will be used to determine data consistency.

D.2.b. Data Verification and Validation Responsibility

ADM or its designated subcontractor will verify and validate groundwater sampling data.

D.2.c. Issue Resolution Process and Responsibility

ADM or its designated Coordinator will overview the groundwater data handling, management, and assessment process. Staff involved in these processes will consult with the Coordinator to determine actions required to resolve issues.

D.2.d. Checklist, Forms, and Calculations

Checklists and forms will be developed specifically to meet permit requirements. Table 23 provides an example of the type of information used for data verification of groundwater quality data.

Table 23. A representative example table of criteria used to evaluate data quality.

MVA ID	Anion charge	Cation charge	Charge balance	CB rating	Calculated TDS	Measured TDS	TDS ratio	TDS rating
ICCS_10B_01A	14.4	13.60	-2.84	Pass	760.50	785	1.0	pass
ICCS_10B_02A	14.26	15.06	2.73	Pass	783.03	777	1.0	pass
ICCS_10B_03A	14.39	14.96	1.94	Pass	786.86	806	1.0	pass
ICCS_10B_04A	14.39	14.79	1.38	Pass	780.15	777	1.0	pass
ICCS_10B_04B	14.33	14.90	1.96	Pass	780.95	785	1.0	pass

D.3. Reconciliation with User Requirements

D.3.a. Evaluation of Data Uncertainty

Statistical software will be used to determine groundwater data consistency using methods consistent with USEPA 2009 Unified Guidance (USEPA, 2009).

D.3.b. Data Limitations Reporting

The organization-level project managers will be responsible for ensuring that data developed by their respective organizations is presented with the appropriate data-use limitations.

ADM will use the current operating procedure on the use, sharing, and presentation of results and/or data for the IL-ICCS project. This procedure has been developed to ensure quality, internal consistency and facilitate tracking and record keeping of data end users and associated publications.

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APPENDIX D: Existing Site Wells Coring Summary

TABLE 1
LOG SUMMARY: EXISTING SITE WELLS

Well Name	Log Vendor	Log Title	Date Run	Depth Interval (MD ft. KB)
CCS-1	Schlumberger	GR, CAL, SP, Resistivity, RHOB, NPHI	3/9/2009	352 - 3,541
CCS-1		Variable Density CBL		
CCS-1	Schlumberger	GR, CAL, SP, Resistivity, RHOB, NPHI	4/5/2009	352 - 5,317
CCS-1	Schlumberger	Sonic Scanner and FMI	4/5/2009	352 - 5,317
CCS-1	Schlumberger	CMR, ECS, HNGS	4/5/2009	352 - 5,317
CCS-1	Schlumberger	MSCT	4/5/2009	352 - 5,317
CCS-1		Ultrasonic Cement Imaging		
CCS-1	Schlumberger	GR, CAL, SP, Resistivity, RHOB, NPHI	4/26/2009	5,339 - 7,221
CCS-1	Schlumberger	Sonic Scanner and FMI	4/26/2009	5,339 - 7,221
CCS-1	Schlumberger	CMR, ECS, HNGS	4/26/2009	5,339 - 7,221
CCS-1	Schlumberger	MSCT	4/26/2009	5,339 - 7,221
CCS-1	Schlumberger	MDT	4/26/2009	5,339 - 7,221
CCS-1	Schlumberger	VSIT	4/26/2009	5,339 - 7,221
CCS-1		Ultrasonic Cement Imaging		
CCS-1		Variable Density CBL		
CCS-1		Pressure/Temperature Log		
CCS-1		Thermal Neutron Decay (Formation Sigma) Log		
CCS-1		Multi-Finger Caliper Log		
CCS-1		CCL and Perforation Record		
CCS-1		Injection Fullbore Spinner Logs		
CCS-2	Schlumberger	GR, Resistivity, NPHI, SlimPulse	1/12/2015	50 - 349
CCS-2	Schlumberger	CAL, DSLT, GPIT	1/12/2015	50 - 349
CCS-2	Wayne County Well Surveys	CBL	1/16/2015	0 - 351
CCS-2	Schlumberger	GR, CAL, SP, Resistivity, RHOB, NPHI	5/3/2015	344 - 5,252
CCS-2	Schlumberger	Sonic Scanner, FMI, CAL, GPIT	5/3/2015	344 - 5,252
CCS-2	Schlumberger	ECS, HNGS	5/3/2015	344 - 5,252
CCS-2	Schlumberger	Variable Density CBL	5/31/2015	200 - 5,231
CCS-2	Schlumberger	Isolation Scanner Cement Evaluation	5/31/2015	200 - 5,231
CCS-2	Schlumberger	Isolation Scanner Casing Integrity	5/31/2015	200 - 5,231
CCS-2	Schlumberger	GR, CAL, SP, Resistivity, RHOB, NPHI	5/29/2015	5,234 - 7,193
CCS-2	Schlumberger	Sonic Scanner, FMI, CAL, GPIT	5/29/2015	5,234 - 7,193

TABLE 1
LOG SUMMARY: EXISTING SITE WELLS

Well Name	Log Vendor	Log Title	Date Run	Depth Interval (MD ft. KB)
CCS-2	Schlumberger	CMR, Litho Scanner, HNGS	5/29/2015	5,234 - 7,193
CCS-2	Schlumberger	MSCT	5/29/2015	5,234 - 7,193
CCS-2	Schlumberger	Multi-finger Imaging Tool	6/10/2015	30 - 7,048
CCS-2	Schlumberger	Variable Density CBL	6/10/2015	40 - 7,048
CCS-2	Schlumberger	Isolation Scanner Cement Evaluation	6/10/2015	40 - 7,048
CCS-2	Schlumberger	Isolation Scanner Third Interface Echo	6/10/2015	40 - 7,048
VW-1		GR, SP, Resistivity, RHOB, NPHI, Sonic		
VW-1		CBL and/or Cement Imaging		
VW-1	Schlumberger	GR, CAL, Resistivity, RHOB, NPHI		350 - 5,250
VW-1	Schlumberger	Sonic Scanner		350 - 5,250
VW-1	Schlumberger	GR, CAL, Resistivity, RHOB, NPHI		5,250 - 7,228
VW-1	Schlumberger	Sonic Scanner		5,250 - 7,228
VW-1	Schlumberger	MDT	10/25/2010	3,642 - 5,007
VW-1	Schlumberger	XPT (Pressure Express Tool)	11/17/2010	
VW-2	Schlumberger	GR, CAL, Resistivity, RHOB, NPHI	10/8/2012	300 - 5,220
VW-2	Schlumberger	Sonic Scanner	10/8/2012	300 - 5,220
VW-2	Schlumberger	GR, CAL, Resistivity, RHOB, NPHI	10/31/2012	5,320 - 7,150
VW-2	Schlumberger	Sonic Scanner	10/31/2012	5,320 - 7,150
VW-2	Schlumberger	XPT (Pressure Express Tool)	10/31/2012	5,578 - 7,102
VW-2	Schlumberger	RST		203 - 7,110

TABLE 2
CORING SUMMARY: EXISTING SITE WELLS

Sensitive, Confidential, or Privileged Information

[redacted]

TABLE 2

CORING SUMMARY: EXISTING SITE WELLS

Sensitive, Confidential, or Privileged Information

[redacted]

TABLE 2
CORING SUMMARY: EXISTING SITE WELLS

Sensitive, Confidential, or Privileged Information

[redacted]

TABLE 2
CORING SUMMARY: EXISTING SITE WELLS

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[redacted]

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[redacted]

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CORING SUMMARY: EXISTING SITE WELLS

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[redacted]

TABLE 2

CORING SUMMARY: EXISTING SITE WELLS

Sensitive, Confidential, or Privileged Information

[redacted]

APPENDIX E: Stimulation Attachments and Procedures

180.05.CO2.206 CCS#2 Backflow Maintenance Procedure

Enhanced Energetics Publication: “GasGun – Vertical Containment – Sandia Study (undated)

Letter of Determination, Natural Resources Agency of California Department of Conservation, Division of Oil, Gas, & Geothermal Resources, Dated 4/12/2019

Kraken-enhance Perforating Flow Performance Tests, API RP19B Section 4 Test Results, Enhanced Energetics, 2020

Schmidt, Richard A., Warpinski, Norman R., and Paul W. Cooper. "In Situ Evaluation Of Several Tailored-Pulse Well-Shooting Concepts." Paper presented at the SPE Unconventional Gas Recovery Symposium, Pittsburgh, Pennsylvania, May 1980. doi: https://doi.org/10.2118/8934-MS

Approved By: Alcohol Superintendent

1.0 Scope

1.1 The CCS2 well can experience particulate fouling of the perforations leading to higher downhole tubing pressure. The higher downhole pressure reaches the limit of 4,125 PSIA at progressively lower injection rates. A controlled backflow of the well will displace the particulates from the well perforations and allow them to settle to the bottom of the wellbore.

2.0 Definitions

2.1 **CCS2:** Carbon Capture Sequestration Injection Well #2

2.2 **RF8:** Location RF8 is the building associated with CO2 Phase 2 blowers and compression

2.3 **PPE:** Personal Protective Equipment

3.0 Responsibilities

3.1 CCS Project Manager (PM):

3.1.1 Oversees the operation of the CO2 well injection process and backflow operation.

3.1.2 Ensures operability of radio communication and maintains communication with all affected colleagues: at the well, production personnel monitoring the parameters of the well, ADM Security and others as applicable.

3.1.3 Monitors atmospheric conditions to ensure adequacy prior to commencement ofthe backflow operation.

3.1.4 Maintains responsibility for work conducted on the CCS2 equipment.

3.1.5 Ensures all necessary tools and equipment are on site.

3.1.6 Ensures personnel on site are certified on use of proper PPE including supplied breathing air and mask. PPE will be utilized for the duration of the backflow operation. Personnel wearing SCBA will be available to block in the well if the atmospheric conditions at the well head require this level of PPE.

3.1.7 Confirms nitrogen supply at well site. Nitrogen is required to actuate the automatic upper master valve.

3.1.8 Communicates the backflow operation date and time to Richland Community College (RCC).

3.1.9 Coordinates with ADM Security to ensure security personnel are available during times of the backflow operation to limit access to the well site.

3.2 Safety/Environmental (S/E) Manager:

3.2.1 Confirms personal CO2 monitors are available for all personnel at the wellsite during backflow operations.

3.2.2 Confirms all on site CO2 atmospheric monitors are operating properly and in good working order.

3.2.3 Confirms all personnel at the well site have adequate PPE including, but not limited to, hard hat, goggles, long sleeve shirts, gloves with a cut rating of 2 or higher, and double hearing protection (ear plugs and soundproof earmuffs).

3.2.4 Conducts a Job Safety Analysis (JSA) form on the day of the event prior to the back flow operation.

3.2.5 Maintains full authority to stop operations at any time during the backflow operation.

3.3 Engineer in Charge

3.3.1 Strictly focuses on incoming and outgoing communications as needed.

3.4 ADM Security:

3.4.1 Limits access to the road entrance to the well site.

3.4.2 Ensures constant monitoring of backflow operation radio communication.

3.4.3 Maintains constant radio communication with the CCS PM and S/E Manager for the duration of the backflow operation.

4.0 Potential Hazards

4.1 Carbon dioxide (CO2): Carbon Dioxide gas is colorless. At low concentrations, the gas is odorless. At higher concentrations it has a sharp, acidic odor. It will act as an asphyxiant and an irritant. Carbon Dioxide is a powerful cerebral dilator. At concentrations between 2 and 10%, Carbon Dioxide can cause nausea, dizziness, headache, mental confusion, increased blood pressure and respiratory rate. Above 8% nausea and vomiting appear. Above 10%, suffocation and death can occur within minutes. Contact with the cold gas can cause freezing of exposed tissue. Moisture in the air can lead to formation of carbonic acid that can irritate the eyes. All forms of Carbon Dioxide are noncombustible. Carbon Dioxide is heavier than air and should not be allowed to accumulate in low lying areas.

4.2 Noise: The CO2 backflow operation will produce noise levels in excess of 85 decibels. Noise levels above 85 decibels can cause permanent damage to the hair cells in the inner ear, leading to hearing loss. It is required by OSHA to wear double hearing protection consisting of ear plugs and earmuffs when noise levels reach 140 decibels or more.

4.3 Particulate: The backflow operation may produce minor levels of sandy particulate to be suspended in the air. The operation should be stopped at the discretion of the S/E Manager if particulate levels are higher than expected.

4.4 Temperature: A pressure drop in the lower assembly causes it to become cold. If temperatures extend outside the backflow range, particularly below 0°F, operations will begin to close the valve to decrease the flowback operation.

- **Operating Range**: Wellhead valves have an operating range of -20° to 1,300°F.
- **During Backflow**: Typically, 0° to 5°F.

IMPORTANT: ***All activity <u>shall cease</u> if temperature falls below -5°F***.

4.5 Pressure:

- **Operational Rating**: All wellhead valves except the bottom casing flange are rated up to 5,000 PSIG. The bottom casing flange is rated up to 3,000 PSIG.
- **During Backflow**: 135 PSIG or less.

IMPORTANT: ***All activity <u>shall cease</u> if pressure exceeds 3,000 PSIG.***

4.6 **Emergency and Remedial Response**: In the event that the Backflow Emergency and Remedial Response Plan (180.05.CO2.207 CCS Backflow Emergency and Remedial Response Plan) is activated and/or followed, ADM shall implement the verbal and written reporting requirements set forth in Section N(3) of Permit #IL-115-6A-0001.

5.0 Procedure

5.1 CCS PM confirms all site conditions are met before proceeding with backflow operation temperature and wind conditions are conducive to CO_2 mixing in atmosphere. The conditions required to commence this activity are as follows:

5.1.1 Temperature greater than or equal to 40°F and 5-10 mph wind speed, or

5.1.2 Temperature less than 40°F and 10-15 mph wind speed.

5.2 All personnel at well site on day of backflow operation must participate in the review of aJob Safety Analysis (JSA) led by the S/E Manager.

5.2.1 At any time during the backflow operation, the S/E Manager has full authority to stop operation.

5.3 S/E Manager confirms all colleagues at well site have proper PPE and personal CO_2 monitors.

5.4 CCS PM and S/E Manager conduct a test of the automatic (upper) valve to verify closure.

5.5 After verifying valve closure, open the automatic (upper) valve.

5.6 CCS PM verifies radio communication is operational between all affected personnel.

5.7 CCS PM informs ADM Security to limit public access to the road entrance to the well site.

5.8 CCS PM informs ADM Security – GSOC operations will begin.

5.9 CCS PM coordinates stopping well injection at the plant.

5.10 CCS PM communicates their intention to commence the backflow operation.

5.11 S/E Manager assesses the area confirming no colleagues are downwind of the wellinjection valve.

5.12 **S/E Manager provides confirmation backflow operation may begin**.

5.13 CCS PM ensures radio communication with CO_2 Operator and that they are standing by at RF8 Control Room. CCS PM confirms phone communication as a backup method.

5.14 CCS PM continuously monitors operation of surface and downhole sensors (e.g., pressure, temperature) during and after the backflow operations.

5.15 **Close** the Lower Master Valve and record number of turns for closure.

5.16 Disengage the open Automatic (Upper) Master Valve by deactivating the local solenoid or engaging a mechanical locking device. In either case, field personnel will be able to manually activate these devices if the valve is needed for well isolation.

5.17 **Close** the Injection Wing Valve and record number of turns for closure.

5.18 Check the top cap making sure it is secure and tight.

5.19 Check the position of the Crown Valve by opening the valve 5 turns and fully closing the valve. The valve is in the **closed** position.

5.20 Open the Needle Valve located above the Crown Valve. Allow pressure to bleed off the upper section of the wellhead (above the Crown Valve).

5.21 After pressure is bled from the upper section of the wellhead, slowly remove the top cap located above the Crown Valve and (optionally) install 4 ½ choke on top of wellhead.

5.22 Hold another Safety Meeting at this point for all personnel onsite.

5.22.1 Check in with all key personnel off site via Radio or Telephone to inform them backflow operation will begin.

5.22.2 CCS PM ensures all conditions are met and all are personnel are ready.

5.22.3 Engineer in charge is on site and will strictly focus on incoming andoutgoing communications as needed.

5.22.4 S/E Manager confirms all onsite personnel are wearing the proper PPE and prepared for operating and communicating in a loud environment

5.22.5 Remove all unnecessary vehicles proximate or downwind of the wellhead as someliquids or fines may possibly settle.

Backflow Operation Commencement

5.23 **Slowly** open the Crown Valve allowing the pressure above the Lower Master Valve to bleed off. Record the number of turns required to open the valve.

5.24 **Slowly** open Lower Master Valve counting the number of turns to open (matching recorded turns in step 5.15) and observing the developing CO2 plume.

5.25 Monitor atmospheric conditions at the wellhead via CO2 monitors.

5.26 Maintain all personnel (not monitoring environmental conditions) upwind.

5.27 Continue backflowing the well for up to 20 minutes.

5.28 Engineer in charge may elect to suspend venting if environmental or operating conditions deteriorate.

5.29 Monitor DTS temperature profile and wellhead temperature and pressure.

5.30 Maintain communications with the Control Room CO2 Operator.

5.31 Maintain communications with security rover with CO2 monitors that aremonitoring environmental conditions.

5.32 Secure additional areas as needed.

5.33 Upon completion of the venting, partially close the Crown Valve (counting the turns) to bring the wellhead pressure to 300 PSIG and allow the wellhead temperature to increase to approximately 10°F.

5.34 Continue to slowly close the Crown Valve (counting the turns) increasing the well head pressure until the wellhead temperature exceeds 15°F.

5.35 Close the Lower Master Valve counting the turns.

5.36 Close the Crown Valve counting the turns.

5.37 Continue monitoring site conditions for an additional 30 minutes.

5.38 At this point, the backflow operation is complete and the engineer in charge will determine the time and coordinate the starting of injection operations.

6.0 Required Training

6.1 Supplied Air Respirator Fit Testing: Personnel using supplied air respirator equipment are trained on the proper fitting and operation of the supplied air respirator.

7.0 Records

7.1 Carbon Dioxide Venting Calculation: The amount of CO2 emitted to the atmosphere must be calculated to be included on the greenhouse gas report for submittal the following year.

7.2 Particulate Matter Venting Calculation: The amount of particulate matter estimated to be emitted to the atmosphere must be calculated to demonstrate the backflow operation is insignificant and an air construction permit is not required to be issued prior to the operation.

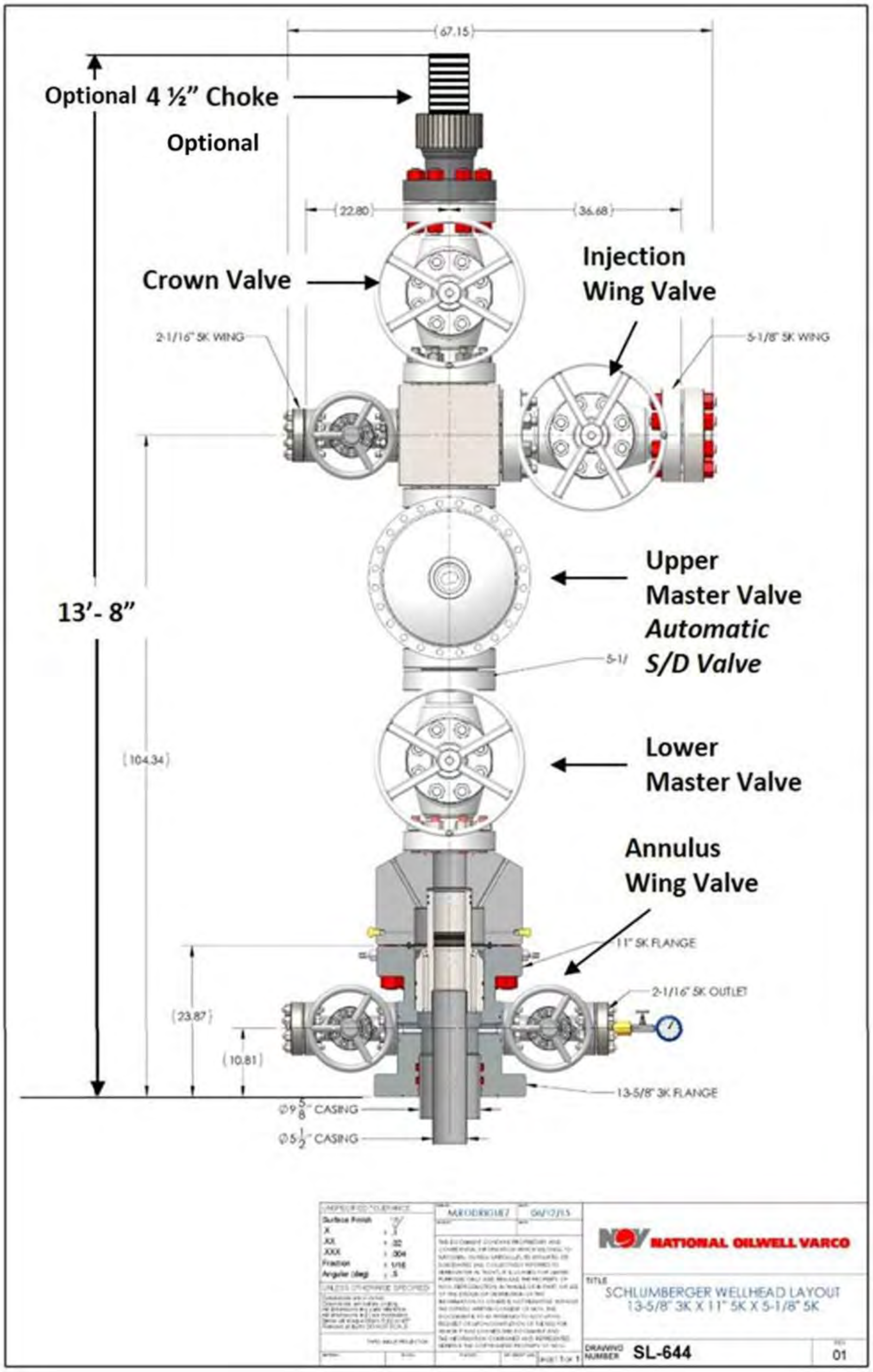
7.3 Job Safety Analysis: A completed JSA form must be reviewed by all affected colleagues prior to the start of the backflow operation.

7.4 Air Supply Respirator Training: Training records will be available upon request for the personnel wearing a supplied air respirator.

8.0 References - None

9.0 Figures

9.1 Figure 1: CCS#2 Well Head Diagram



(67.15)
Optional 4 ½" Choke
Optional
(22.80)
(36.68)
Crown Valve
Injection
Wing Valve
2-1/16" 5K WING
5-1/8" 5K WING
Upper
Master Valve
Automatic
S/D Valve
13'- 8"
(104.34)
Lower
Master Valve
Annulus
Wing Valve
11" 5K FLANGE
2-1/16" 5K OUTLET
(23.87)
(10.81)
13-5/8" 3K FLANGE
Ø9 5/8" CASING
Ø5 1/2" CASING
NATIONAL OILWELL VARCO
SCHLUMBERGER WELLHEAD LAYOUT
13-5/8" 3K X 11" 5K X 5-1/8" 5K
DRAWING NUMBER SL-644
01

10.0 Attachments

10.1 Job Safety Analysis

10.1.1 Front

ADM

JOB SAFETY ANALYSIS (JSA)

Nº

Department/Area/Floor: Date: ____/____/____ Time:____ : ____h

Task/Job name:

Description of the work:

Participants (print names):

POTENTIAL HAZARDS

01	**Slips, trips or falls from same level** (surface condition, slippery floor, lack of housekeeping)	11	**Electricity** (shock, fire, arc flash, blast or stored electrical energy, static)	21	**Manual lifting** (physical effort, weight, position, duration, shape)
02	**Fall from height or into pit or floor opening** (scaffolds, ladder)	12	**Hot or cold material, equipment or environment**	22	**Hoisting, lifting** (use of mechanical equipment)
03	**Hit by projectile or deflected objects** (disintegration, rupture, debries)	13	**Chemical** (irritant, toxic, poison, corrosive)	23	**Ergonomic** (pushing, vibration, pulling, reaching, force, repetitive)
04	**Hit from above** (falling or collapsing object or product)	14	**Atmospheric** (dust, toxic, poison, lack of oxygen)	24	**Access** (difficult to reach, reduced space to work or rescue)
05	**Contacted by** (animals, insects, plants, chemicals, product)	15	**Static energy** (shock, ignition source)	25	**Weather condition** (excessive heat, snow, ice, rain, lightning, flood, wind)
06	**Caught in or between, being drawn in** (movable parts)	16	**Energy release** (gravity, hydraulic, system under pressure, springs, mechanical releases)	26	**Biological** (Pathogens, hygiene, bacteria, pest control, mold)
07	**Sharp edges, stabbing, puncturing** (equipment or tools)	17	**Fire, explosion** (flammable liquid or gas, vapor, dust in suspension, mechanical releases)	27	**Radiation** (lonizing, non-ionizing, laser, electromagnetic)
08	**Pinch, crush**	18	**Excavation** (collapse, egress, underground utilities, trenching)	28	**Environmental** (contamination of air, water or soil)
09	**Struck by** (collision, impact with fixed object or vehicles)	19	**Noise, vibration** (continuous, intermittent, impact)	29	**Product contamination**
10	**Lighting, visibility, reflections, glare**	20	**Engulfment, entrapment** (product, moving equipment or configuration, excavation)	30	

ADM RISK ASSESSMENT TOOL

JSA Work Permit Requirements:
16: Unacceptable level of risk. Task should not be performed at current risk level.
12: Requires review from reporting level above plant manager.
8 - 9: Requires review by management.
4 - 6: Review by management is recommended.
1 - 3: Trained participants can perform task without further approval.
Every effort should be made to reduce the risk to below 8.

		L - LIKELIHOOD (CONSIDERING THE SAFEGUARDS)			
		Control measure non existent or inadequate	Control measure exists, but effectiveness is not guaranteed	Multiple control measures exist, but effectiveness is not guaranteed	Multiple control measures are effective
		Likely	Occasional	Improbable	Very Unlikely
S - Injury Severity		4	3	2	1
Catastrophic: Fatalities or incapacitating cases.	4	16	12	8	4
Very Serious: Permanent disability, but not incapacitating.	3	12	9	6	3
Serious: Lost or restricted work day cases.	2	8	6	4	2
Minor: Medical treatment or first aid cases (recordable and below).	1	4	3	2	1

STEP Nº.	SEQUENCE OF BASIC STEPS	POTENTIAL HAZARDS	S Factor	SAFE PRACTICES / CONTROL MEASURES (see reverse for supporting checklist)	L Factor	RISK (S x L)

10.1.2 Back

REQUIRED PERMITS AND FORMS

- ☐ Confined space/bin entry
- ☐ Hot work
- ☐ Equipment-specific lock out/tag out procedure
- ☐ Line breaking
- ☐ Fire protection impairment
- ☐ Working at height/roof access
- ☐ Energized electrical work
- ☐ Crane/critical lift
- ☐ Rail track encroachment
- ☐ Soil disturbance/excavation
- ☐ Other

PERSONAL PROTECTIVE EQUIPMENT

EYE/FACE
- ☐ Sealed/tightfitting eyewear
- ☐ Welding hood/shaded lens
- ☐ Goggles ☐ Face shield
- ☐ Other:

HAND/ARM
- ☐ Cut resistant ☐ Chemical
- ☐ Thermal ☐ Leather
- ☐ Disposable ☐ Mechanical
- ☐ Arm/sleeve ☐ Other:

FOOT
- ☐ Safety toe boots ☐ Chemical boots
- ☐ Chainsaw footwear ☐ Puncture resistant
- ☐ Meta tarsal guards/boot covers
- ☐ Other:

ELECTRICAL
- ☐ Hard hat - class E ☐ Gloves
- ☐ Leather protectors ☐ Grounding
- ☐ Arc rated suit ☐ Safety glasses
- ☐ Arc rated balaclava ☐ Dielectric mat
- ☐ Arc rated clothing ☐ Voltage rated gloves
- ☐ Arc rated face shield
- ☐ Dielectric blankets/sleeves ☐ Double layered switching hood
- ☐ Hearing protection

RESPIRATORY PROTECTION
- ☐ Filtering face piece ☐ SCBA
- ☐ Supplied air ☐ PAPR
- ☐ Emergency escape ☐ Half face
- ☐ Air purifying respirator ☐ Full face
- ☐ Other: ☐ Cartridge type:

SPECIAL CLOTHING
- ☐ Chemical suit
- ☐ Rain suit
- ☐ Anti-exposure suit
- ☐ Contaminate protection
- ☐ Other:

FALL
- ☐ Harness ☐ Double lanyard
- ☐ Appropriate anchorage point
- ☐ Additional anchorage connector
- ☐ SRL/retractable device
- ☐ Horizontal lifeline system

ADDITIONAL OR TASK-SPECIFIC PPE

SAFE PRACTICES / CONTROL MEASURES SUPPORTING CHECKLIST

01	☐ Mark hazards ☐ Store tools and materials ☐ Keep eyes on path ☐ Review work pace ☐ Create designated walkway ☐ Install barricade ☐ Clear work zone of debris, grain, product	15	☐ Provide and/or verify grounding, bonding ☐ Use static dissipating devices (computer)
02	☐ Use fall protection with proper anchorage ☐ Use fall restraint system ☐ Install barricade, rigid cable, railing, cover ☐ Post signage for pedestrians ☐ Use correct ladder, mobile platform, scaffolding on even, solid surface	16	☐ Provide blocks, wedges ☐ Provide isolation, disconnection ☐ Bleed, relieve pressure or tension ☐ Follow LOTO procedure
03	☐ Use eye and face protection properly ☐ Ensure proper distance between workers ☐ Coordinate work in same area ☐ Install barricade ☐ Inspect hand-held power tools ☐ Ensure nearby machines are properly guarded or shut down	17	☐ Move work to safer location ☐ Obtain Hot Work permit ☐ Ensure safe work distance ☐ Ensure fire extinguisher or hose available ☐ Provide fire retardant clothing ☐ Install fire barriers to prevent access ☐ Remove combustibles ☐ Use approved tools in classified areas
04	☐ Install warning barricade, signage ☐ Ensure proper distance between workers, tools ☐ Coordinate work in area ☐ Prevent tools and materials from falling ☐ Check for, communicate with workers above or below	18	☐ Secure open pits with barricades, signage ☐ Provide proper benching, terracing ☐ Check for underground utilities ☐ Clear, manage water ☐ Install shoring, trench box
05	☐ Inspect and clear area of animals, insects, poisonous plants ☐ Inspect for chemical exposure ☐ Locate eyewash/shower station:	19	☐ Use hearing protection ☐ Keep appropriate distance, separation ☐ Install sound barriers ☐ Take frequent breaks, rotate activity ☐ Wear anti-vibration gloves, other gear; Use anti-vibration mats
06	☐ Use anchorage, secure load ☐ Maintain proper distance ☐ Install guarding ☐ Follow LOTO procedure ☐ Use proper body position, hand placement	20	☐ Obtain Confined Space/Bin Entry permit ☐ Install temporary platform, ladders ☐ Utilize tripod or system to prevent engulfment ☐ Utilize non-entry equipment, tools ☐ Lock out, block movable parts, equipment
07	☐ Wear puncture, cut resistant PPE ☐ Use proper body position, hand placement ☐ Install temporary guarding, covers ☐ Avoid blind reaches ☐ Use extension tools ☐ Inspect immediate area for other sharp edges	21	☐ Utilize NIOSH lifting equation (weight, distance, frequency) ☐ Ask for assistance, use team lift ☐ Use mechanical means or lift assistance devices
08	☐ Secure or cover openings, doors, manways ☐ Use blocks for placing objects on floor ☐ Use tool holder or impact protection device (chisel punch, etc.) ☐ Coordinate manual movement of equipment, material with team ☐ Use proper body position, hand placement (evaluate tool for hand slippage)	22	☐ Inspect rigging and lift devices, equipment ☐ Utilize tag lines, other guide tools ☐ Maintain safe distance from utilities ☐ Ensure adequate anchorage capacity ☐ Install barricades ☐ Use lift calculating checklist ☐ Maintain safe distance from lift ☐ Use lift checklist
09	☐ Review work pace ☐ Use or create designated walkways ☐ Install barricade, signage ☐ Wear reflective vest or clothing ☐ Pad, guard fixed objects to lessen impact or avoid striking	23	☐ Warm up, stretch before work ☐ Utilize NIOSH lifting equation ☐ Use proper body position ☐ Utilize available ergonomically-designed or power tools ☐ Take breaks, rotate workers ☐ Arrange work station to improve positions
10	☐ Use portable lights, flashlights ☐ Use shading ☐ Use proper body position ☐ Block reflection to improve visibility	24	☐ Review, discuss the rescue plan, methods of egress ☐ Use life lines, communication ☐ Obtain Confined Space/Bin Entry permit (if required) ☐ Use proper body position
11	☐ Use voltage tester, multi-meter ☐ Identify interlocks or automation ☐ Install signage, barrier (set at ______ ft) ☐ Use proper clearances, distance ☐ Follow de-energized LOTO procedure ☐ Coordinate with other work in area ☐ Use GFCI ☐ Identify potential stored energy ☐ Define hazard risk category ______ (cal/cm2) and use appropriate tools, PPE ☐ Ensure cords are in good condition, properly secured and protected from pinch points	25	☐ Evaluate weather forecast before task, monitor during task if needed ☐ Define conditions that require work to be stopped ☐ Wear proper PPE, clothing for weather conditions
		26	☐ Evaluate industrial hygiene hazard ☐ Isolate or neutralize the hazard ☐ Utilize body substance isolation, PPE ☐ Ensure proper ventilation, based on hazard
12	☐ Monitor for heat stress ☐ Provide, use ventilation ☐ Take rest breaks, hydrate ☐ Use proper PPE, clothing, tools ☐ Rotate workers ☐ Install warning signage ☐ Install guarding, temporary covers	27	☐ Install barriers, shields ☐ Maintain proper distance ☐ Secure, isolate shutters
13	☐ Review SDS (MSDS), evaluate reactive chemicals ☐ Use less toxic chemical, substitute ☐ Ensure proper containment, labeling/signs, ventilation ☐ Isolate chemicals ☐ Locate and test nearest eye wash, shower ☐ Ensure clean-up kit is available ☐ Use proper PPE (goggles, gloves, face shield, chemical suits, boots, respirator) ☐ Decontaminate, remove chemical residue, hygiene (tools, clothing, equipment, skin, work area)	28	☐ Use methods to prevent spillage. If a leak or spill occurs, immediately control the source and clean up the material. Locate the spill kit and review the control measures prior to starting clean-up. Report any leaks immediately. ☐ Use methods that prevent the release of solids, dust, liquids or gasses. ☐ Ensure that chemicals are in approved containers, properly labeled and stored.
14	☐ Provide, use ventilation/dust collection ☐ Move task to open air environment ☐ Use monitoring equipment (TLV, LEL, ILDH) ☐ Ensure safe work distance ☐ Use proper PPE, respiratory protection ☐ Review emergency response plan	29	☐ Use food grade lubricants and approved tools for food contact ☐ Seal process equipment to avoid external contamination ☐ Ensure post-maintenance inspection performed (HACCP equipment)

JSA WORK PERMIT | Required when risk level is 8 or higher

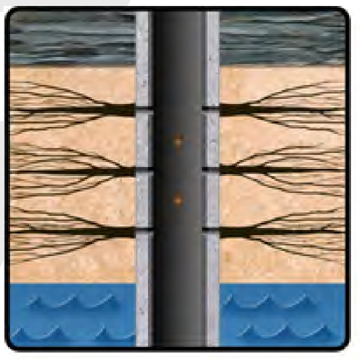
I approve the assigned participants to perform the work described in this Job Safety Analysis, with the additional safe practices/control measures and the amended risk level documented below, in addition to those previously identified.

Step No., Added Control Measures, Amended Risk:

Emergency Contact: (include phone number, radio channel or other information needed)

Appropriate Approval Signature:

"JSA Work Permit Requirements": 16: Unacceptable level of risk. Task should not be performed at current risk level. **12:** Requires review from reporting level above plant manager. **8 - 9:** Requires review by management. **4 - 6:** Review by management is recommended. **1 - 3:** Trained participants can perform task without further approval.



- **Create flow paths in zone**
- **Controlled vertically**
- **Reduce acid job pressure**

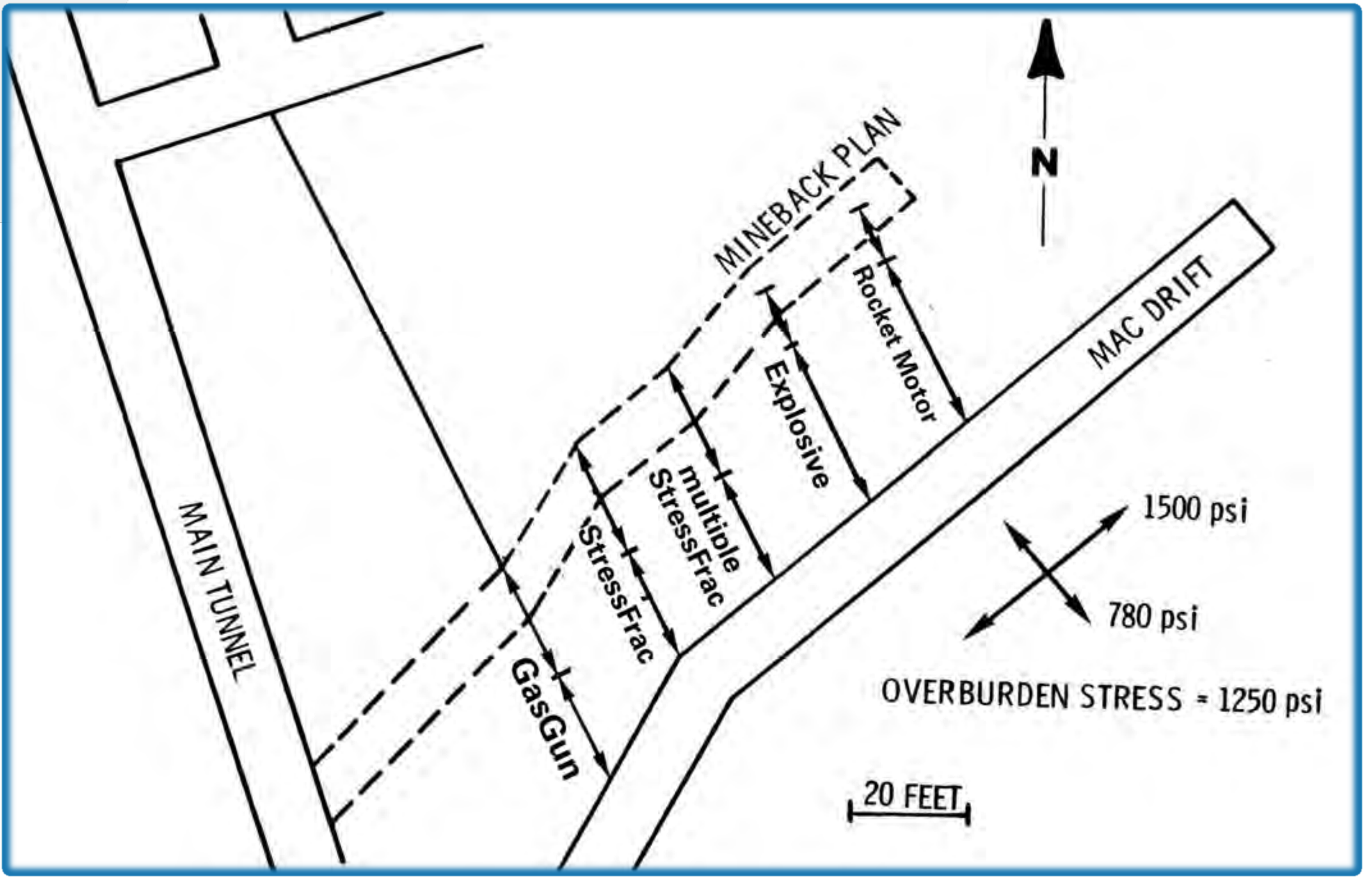
Many oil & gas formations are located in close proximity to water bearing zones. For example the Arbuckle dolomite in Kansas is a natural waterdrive reservoir. Traditional frac & acid stimulation methods pressurize the wellbore and formation slowly (quasi-static) to initiate a single bi-wing fracture, perpendicular to the least principal stress. This slow process allows the intu-stress to dominate fracture growth and can break out of zone.

The GasGun propellant stimulation tool delivers pressure to the rock face in 10-20 milliseconds which creates multiple radial flow paths (like slices in a cake) that penetrate directly out into the formation. Due to the speed of the event, vertical containment of GasGun stimulation is limited to 1'-2' above and below the tool.

Full-scale mine-back experiments conducted by Sandia National Laboratories (SPE8934) provided invaluable information about the exact performance of propellants (GasGun), high explosives, and hydraulic fracturing which led to the development of modern hydraulic fracturing modeling (Warpinski).

O 281-272-6580
11999 FM 529 Rd. Houston, TX 77041
www.enhancedenergetics.com

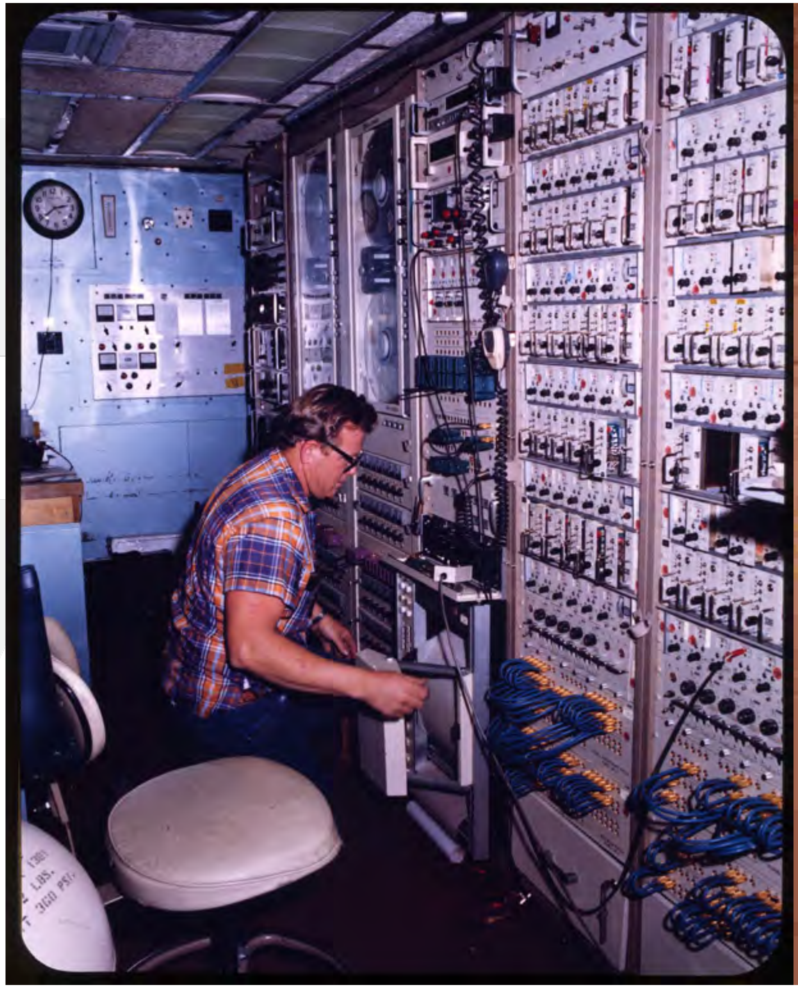
Energetics Testing
Wellbore Mine-back



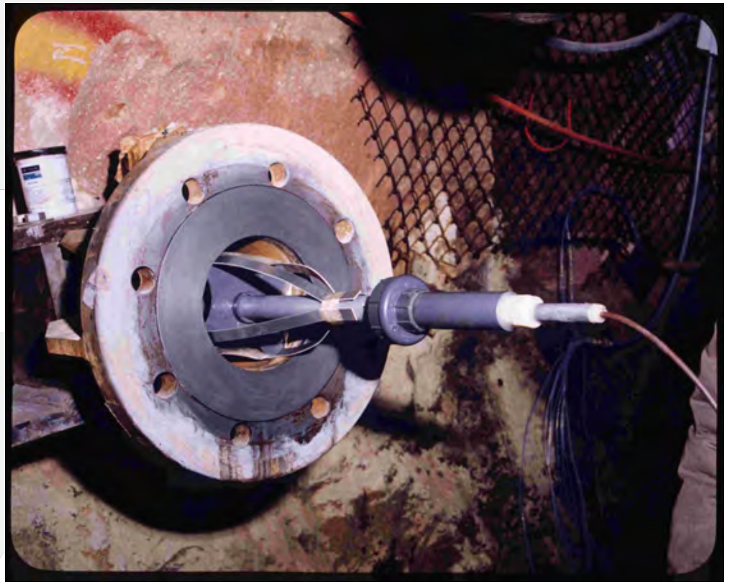
Nevada Test Site – Tunnel Layout

Onsite Team:
Dr. Richard A. Schmidt
Dr. Norm Warpinski
Henry (Hans) Mohaupt

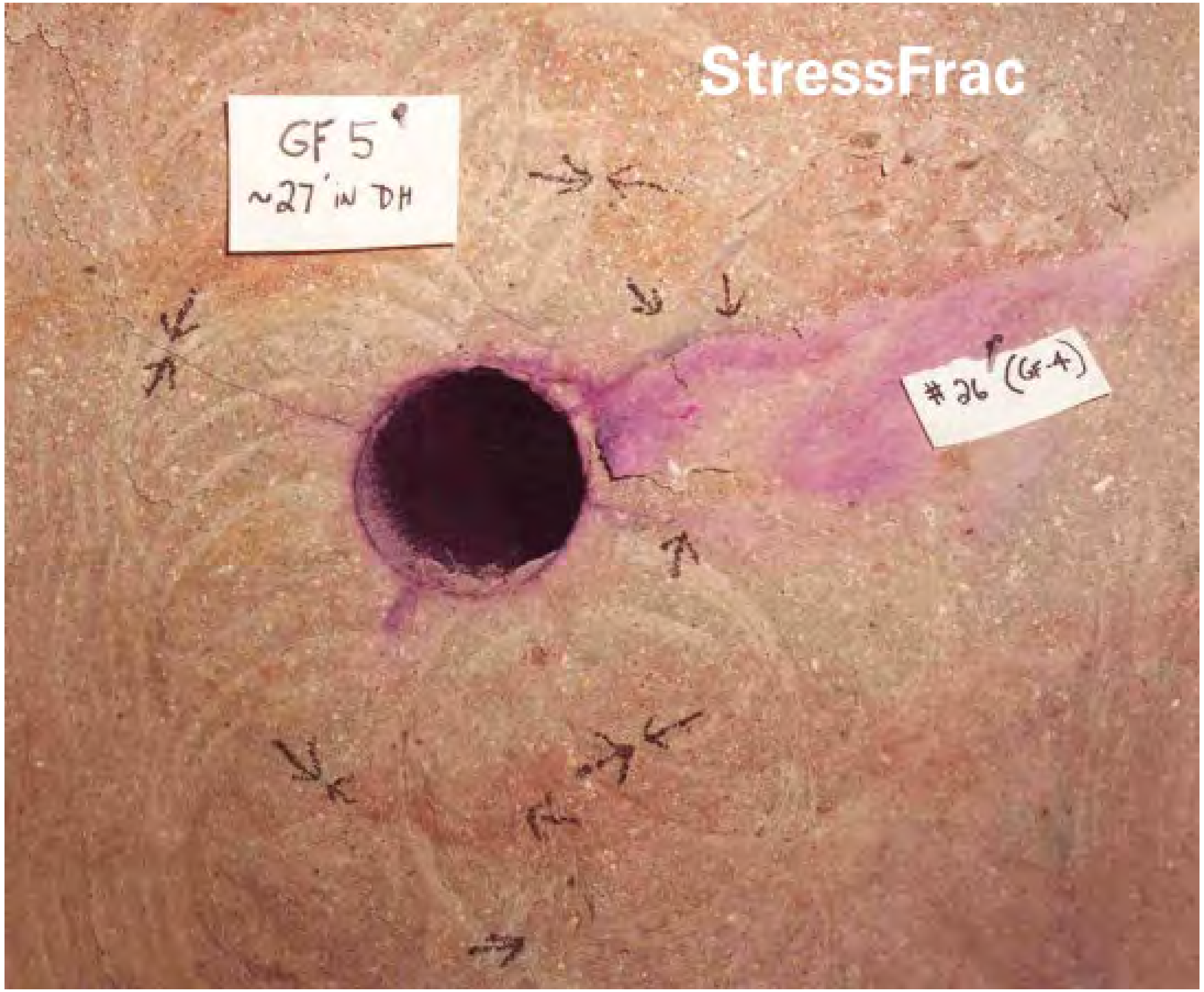
Mine-Back Operation



High Explosive - Crushed Zone and Debris



Regressive Burning Propellant



Progressive Burning Propellant

NATURAL RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION
DIVISION OF OIL, GAS, & GEOTHERMAL RESOURCES

Well Stimulation Determination

Sacramento, California
4/12/2019

Division Engineers have reviewed your request for a Well Stimulation Determination dated, 3/15/2019 and have concluded that the operations described therein do not meet the definition of a well stimulation treatment as defined by § 14 CCR 1761 (a)(1).

This determination applies to the following well:

API:	05902007, 05902008, 05902009, 05901979, 05902011, 05901980, and 05901981
Field:	Huntington Beach
County:	Orange

This determination applies to the following operations:

Using a 3-3/8" gas propellant gun to perforate and may reach more than 36 inches outside of the well bore omni directionally.

The described operations are not a well stimulation treatment because:

The Kraken and GasGun is a propellant perforating gun that designed to overcome near wellbore damage. This has been confirmed in the underground mine-back studies conducted by Sandia National labs. The WST Unit feels that projects utilizing this technique should be documented, and that operators should therefore be required to submit a routine maintenance form for this work (Well Maintenance form OG 179). For more information on well maintenance, please refer to SB4 Regulation section 1777.4. Note that if acid is injected after perforation and penetrate more than 36", it will be consider as well stimulation treatment.

Your determination number for reporting is: DD19-017

May soe

May Soe, Well Stimulation Supervisor

Kraken-enhanced Perforating Flow Performance Tests

ENHANCED ENERGETICS

API RP19B Section 4 Test Results

- Increased perforation flow rate 2.5x
- Decreased breakdown pressure 50%
- Successful field results proven in controlled lab experiment
- Dynamic overbalance created in wellbore

Overview

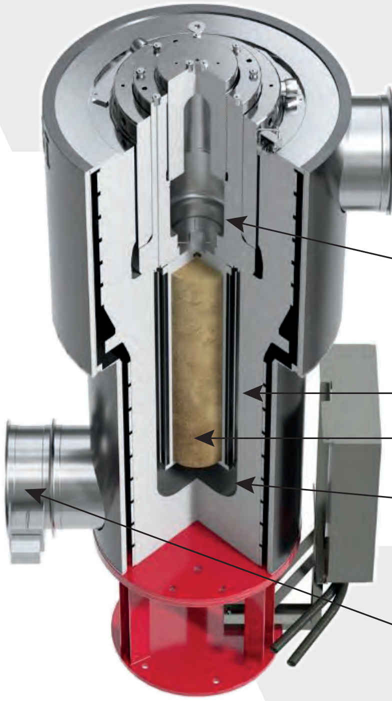
The Kraken® system is field proven to be significantly more effective than standard perforating guns at improving completion and recompletion performance in conventional, unconventional and saltwater disposal wells. Enhanced Energetics set out to further validate the performance of the Kraken system by performing the API Recommended Practices (RP) 19B, Section 4 Test at Halliburton's Jet Research Center (JRC). This test method is the gold standard in evaluating perforation flow performance.

Test Program and Objectives

The purpose of the test was to assess the perforating and injectivity performance of Halliburton's MaxForce®-FRAC charge assisted with Enhanced Energetics' Kraken propellant boosters. The API RP19B Section 4 Test simulates downhole conditions to measure the flow through a perforation into stressed rock. The test setup allows a core rock sample to be perforated with a shaped charge under in-situ stress, temperature and pore pressure conditions. Fluid is then flowed into the perforation to measure the injectivity through the core.

A Nugget sandstone core was used as the perforating rock target because its characteristics closely match that of many North American land reservoirs. A summary of the test parameters is shown in the table on the right. Three Section 4 Tests were performed in separate Nugget cores. The first test was performed with a single shaped charge as the control experiment. The other two tests were performed with a single shaped charge and Kraken propellant boosters. All tests were conducted at identical stress and pressure conditions as described.

Pressure vessel with a Nugget sandstone core used to test the Kraken system.



(Provided courtesy of Halliburton)

Test Parameters

Rock type
Nugget sandstone

Unconfined strength
~16,000 psi

Permeability
~1–5 mD

Porosity
~12%

Wellbore fluid
Odorless mineral spirits (OMS)

Overburden pressure
~3,500 psi

Pore pressure
~2,500 psi

Wellbore pressure
~2,500 psi

Core size
9-in. OD × 30-in. long

Kraken size
25 g

Charge type
23-g MaxForce-FRAC

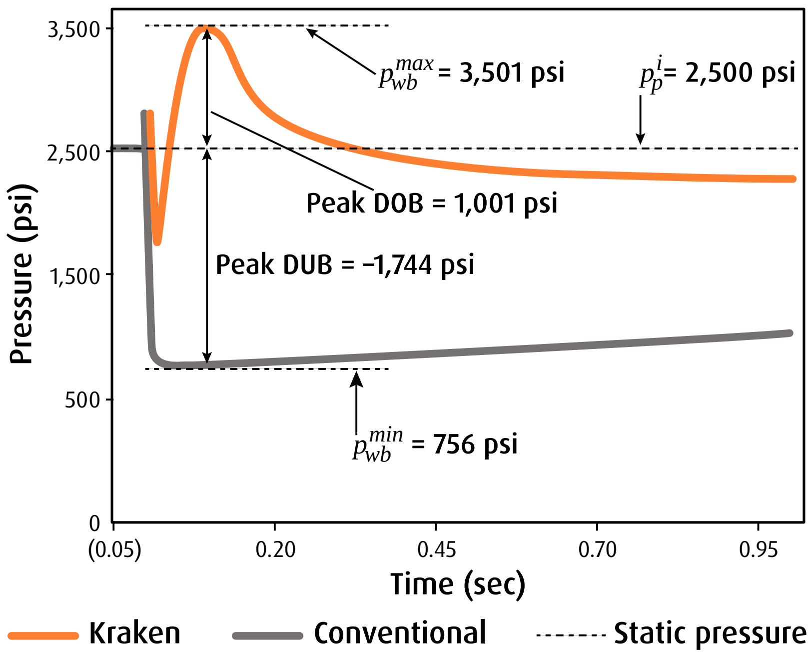
Kraken-enhanced Perforating Flow Performance Tests

API RP19B Section 4 Test Results

Perforating Test Results

The conventional perforating control test, performed with only a shaped charge and no Kraken boosters, resulted in a dynamic-underbalance (DUB) pressure event as seen in the graph below. DUB perforating creates a rapid decrease in pressure (underbalance) in the wellbore because of fluid entering the perforating gun immediately after the explosive event occurs. In the two Kraken perforating tests performed with a shaped charge assisted by Kraken propellant boosters, propellant ignition occurred immediately after the explosion of the shaped charge. The burning of the propellant boosters generated high-pressure gas inside the gun and exited out into the perforation tunnel. This process created a dynamic-overbalance event (DOB) inside the wellbore as seen below. The DOB created by the Kraken system enhances the perforation and creates fractures past the compacted rock (skin) produced by conventional shaped charges, thereby improving access to the formation.

Perforating Pressure Pulse Comparison

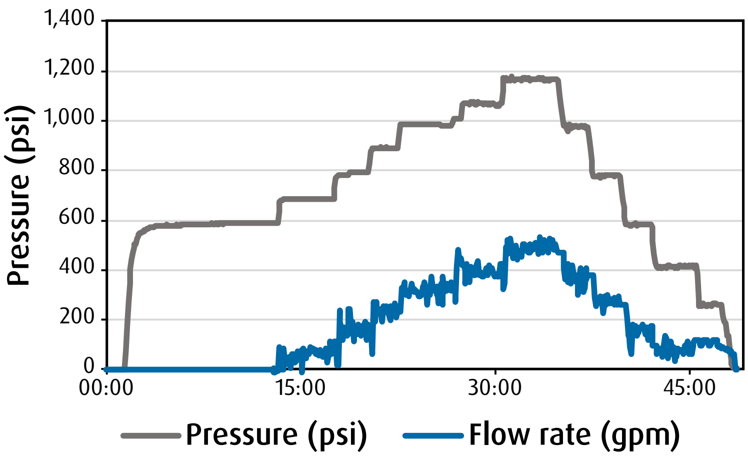


Fracture Created in Core

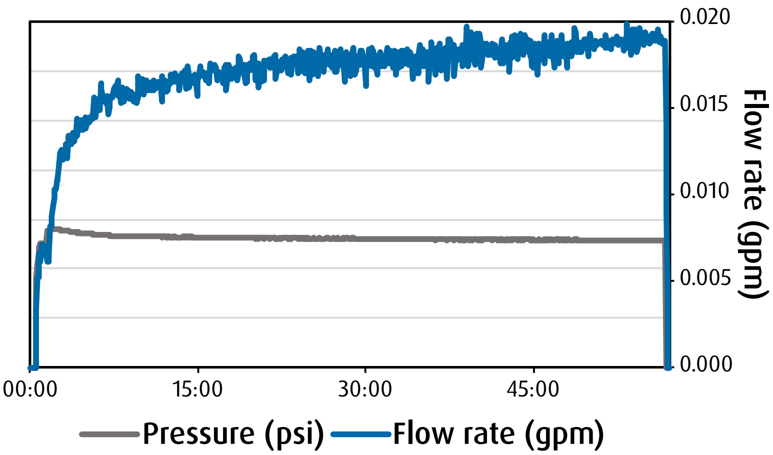
Flow Test Results

The difference in flow performance between a perforation with no Kraken boosters and a perforation with Kraken boosters was dramatic. The injectivity performance is shown in the graphs below. **Kraken achieved over 2.5x the flow rate through the core sample with a ~50% reduction in pressure compared to the shaped charge alone.**

Conventional Perforating Flow Performance



Kraken Perforating Flow Performance



Conclusion

The improved flow performance of the Kraken perforations in the lab closely matches the successful field results reported by customers. Kraken technology has proved to be a step change in completion performance compared with conventional perforating designs.

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Society of Petroleum Engineers

IN SITU EVALUATION OF SEVERAL TAILORED-PULSE WELL-SHOOTING CONCEPTS

by Richard A. Schmidt, Norman R. Warpinski and Paul W. Cooper, Sandia National Laboratories

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ABSTRACT

Dynamic stimulation techniques that produce multiple fracturing in a wellbore are being investigated for enhanced gas recovery. Multiple fracturing appears to be especially promising for stimulating naturally-fractured reservoirs, such as the Devonian shales, since this may be the most effective technique for connecting a wellbore to a pre-existing fracture network. Previous studies have demonstrated that detrimental effects can occur with high-strength explosive techniques and that these effects can be avoided through the use of propellants.[1,2] The use of propellants and other so-called tailored-pulse techniques depend on a controlled pressure-time behavior to minimize wellbore damage and maximize fracture growth by gas penetration.

This paper describes a series of five full-scale tests performed to evaluate various multi-frac concepts. The tests were conducted at the Nevada Test Site in cased, horizontal boreholes drilled in ash-fall tuff from a tunnel under 430 m of overburden. This site provides both realistic in situ conditions for the tests and access to the stimulated regions by mineback which permits direct observation of results. The five tailored-pulse concepts tested involve:

- Case A - a decoupled explosive,[3]
- Case B - a decoupled explosive with propellant booster,[3]
- Case C - a small-diameter propellant charge with pressurized water pad,[4]
- Case D - three successive shots of Case C, and
- Case E - a full-diameter charge of a progressively-burning propellant.[2]

While direct observation by mineback is highly beneficial, evaluation and analysis of these test results also depended heavily on other diagnostics. Thirty-six stressmeters and accelerometers were fielded in the surrounding rock to record the dynamic disturbances, and each borehole contained transducers to measure the actual cavity pressures. Pre-test and post-test evaluations include TV log, caliper log, and permeability measurements. Permeability, which evaluates the effectiveness of the created fracture network to transmit fluids, was determined by analysis of constant-pressure, water-injection tests and the subsequent pressure decline after shut-in.

Results show a large increase in formation permeability for Case E, modest increases for Cases B, C, and D and a decrease for Case A that appears due to the formation of a stress cage. A comparison of Case E results with previous tests suggests a multiple fracture criterion based on pressure rate with little effect of peak pressures.

INTRODUCTION

Oil and gas wells have been stimulated with high-energy explosives since the late 1800's. It appears, however, that the term "well shooting" originated many years before this in days when a water well was sometimes rejuvenated by shooting a rifle down the well. Well shooting as discussed herein refers to any rapid release of energy from a chemical reaction in a wellbore for the purpose of stimulating production, presumably by fracturing the reservoir rock. This includes explosives (solid, liquid, and gas) and propellants that deflagrate rather than explode. In a broad sense, well shooting has been applied in several geotechnical fields; e.g., preparation of oil shale beds for true in situ processing, preparation of underground mineral deposits for solution mining, etc.

Problems of wellbore damage, safety hazards, and upredictable results have

References and illustrations at end of paper.

reduced the relative number of wells stimulated by high-strength explosives. In recent years hydraulic fracturing has been favored, and sophisticated techniques, equipment, fracturing fluids, and proppant have been developed to optimize the hydraulic fracturing process.

Unfortunately, similar efforts toward general understanding and process optimization have been lacking for well shooting. However, recent findings (summarized in Ref. 1) have shed new light on the process of dynamic wellbore fracturing. These findings indicate that vast improvements may be possible using "tailored-pulse" loading techniques.

Tailored-pulse loading involves using propellants, decoupled explosives, or explosive gases to produce a controlled, but rapid, release of energy. This concept is more fully described in a later section, but first the general behavior and limitations of conventional well shooting with high-strength explosives need to be described to understand better the benefits derived from tailored-pulse loading.

GENERAL BEHAVIOR OF A DEEPLY-BURIED CHARGE

One important aspect common to most well shooting configurations is the fact that there is no free surface near enough to the charge to affect the behavior. The phenomena associated with deeply-buried charges, as they are called, differ significantly from those of blasts that occur near a free surface as in excavations, quarries, and road cuts.

Briefly, the high pressures of a detonation in a wellbore are known to be sufficient to cause the nearby rock to yield and compact (plastic flow). When the stress wave passes, the rock unloads elastically leaving an increased borehole diameter and a residual stress field which is compressive near the wellbore. Figure 1 depicts these general steps that take place during such an event.

The creation of this residual stress field is closely analogous to the process of autofrettage or the "gun barrel problem" in which pressure vessels are often overpressurized sufficiently to yield the inside wall and develop residual compressive stresses that help prevent crack growth during service. The zone of highly compacted rock with its associated residual compressive stresses is sometimes referred to as a stress cage, and the phenomena is sometimes called the bladder effect. Fracturing caused by high pressure gas may also be inhibited in this situation since fines are created during the compaction process that can plug newly formed cracks and prevent gas penetration. Some or all of these effects may actually cause decreased permeability near the wellbore and are probably responsible for many well-shooting failures.

The existence of residual stress regions around boreholes that have been subjected to explosive detonations is a well documented phenomenon. Most of these observations have been made with regard to field experiments at the Nevada Test Site[1,5] as well as laboratory experiments[6] and computer code calculations[1,5,7] for the purpose of understanding containment of underground nuclear blasts. This general behavior of a deeply-buried charge, however, is rather universal since it has been demonstrated to occur for detonations ranging from a one pound charge of TNT to a nuclear detonation of several kilotons. Further description of these general phenomena and details of the supporting evidence can be found in Ref. 1.

TAILORED-PULSE LOADING

ADVANTAGES

With the basic knowledge that the bladder effect impedes fracture growth near an explosively loaded cavity, one might wonder how conventional well shooting would ever enhance production. Experience has shown, however, that improved production is sometimes realized. There are several reasons for such results, including the possibility that explosive stimulation may at times be capable of removing skin damage, and that leakage paths may be formed that connect the cavity to the region outside the stress cage. Situations can also occur in which the stress cage will break up and slough into the wellbore. These possibilities are not necessarily predictable or applicable in all formations. It would, of course, be desirable if reliable procedures could be developed to replace conventional well shooting.

Several viable alternatives to explosive well shooting have been considered and tested in recent years that show promise of substantial improvement.[2-4] An approach that has received considerable attention is to tailor the pressure-time behavior of the explosive or a suitable propellant so as to keep the maximum pressure and the loading rate below a level that would cause the rock to crush and undergo plastic flow. The intent here is to avoid entirely the formation of a stress cage while still loading at a sufficiently high rate to produce multiple fractures from the wellbore. Unfortunately, the proper combination of loading parameters that will produce optimal multiple fracturing and avoid the formation of a stress cage are not, as yet, well known.

Tailored-pulse loading of a wellbore has several advantages over hydraulic fracturing that make this technique attractive in certain situations. For example, hydraulic fractures, which are propagated at pressures that are slightly higher than the minimum in situ stress and pumping times that are on the order of hundreds of seconds, typically produce only a single fracture whose orientation is perpendicular to the minimum principal stress.[8,9] Higher wellbore pressures, such as are achieved in tailored-pulse loading, are needed to drive cracks in less favorable directions with respect to the in situ stresses in order to produce multiple fractures.

Multiple fractures may be highly desirable in naturally fractured reservoirs such as Devonian shale for reasons depicted in Figure 2. The production from an unstimulated well, Figure 2a, depends strongly on the number of fractures intersected. Hydraulic fracturing typically produces a single fracture that is likely to run parallel to most of the existing fractures, Figure 2b, since its orientation is governed by in situ stresses that probably also govern the pattern of the natural fractures. Multiple fractures may not extend as far as a hydraulic fracture but may link the well to more, natural fractures, Figure 2c.

In addition, tailored-pulse loading with propellants are likely to produce little formation damage due to the interaction of fluids with the rock. Very little water is produced by these materials, and the products have very little time to react with the rock. Some hydraulic fracturing fluids, on the other hand, are known to cause swelling in shale and other deleterious effects.

Cost is also a factor that may make tailored-pulse techniques very attractive, particularly in marginal wells that probably are not promising enough for expensive hydraulic fracturing treatments. Igniting an explosive or a propellant charge in a well requires very little equipment or time when compared to even a small hydraulic fracture job.

CONCEPTS

Several tailored-pulse concepts rely on the use of propellants which deflagrate rather than detonate. Unlike explosives, the burn front in these materials travels slower than the sound speed, and the burning rate can be varied over a wide range. Pressure-time behavior of propellants differ from explosives in that peak pressures are lower, and burn times are longer. Total energy available, however, is similar in both materials (typically 4kJ/g).

One of the first tailored-pulse concepts investigated was a decoupled explosive such as that used for Case A.[3] A conventional explosive is used, but the charge diameter is some eight times less than the wellbore diameter. The charge is surrounded by water, and the peak pressure reaching the rock after detonation is thus mitigated, presumably to a value below the yield stress. The total explosive energy, however, is limited by the small diameter of the charge.

The concept employed in Case B uses the same decoupled explosive in conjunction with a small propellant charge.[3] The decoupled explosive is designed to initiate multiple cracks and the propellant is then burned to drive water into these cracks to extend them. The propellant is essentially a rocket motor that burns for several seconds. Some field testing has been performed using this device but results are inconclusive.

Case C is a small diameter (4cm) pressure-insensitive propellant charge that is designed both to initiate and propagate multiple cracks.[4] A typical rise time is 3 ms with a burn time of 0.5 s. This device is also designed to push water into the cracks ahead of the gas generated by the propellant reaction products. It has been used in the field as a cleaning tool and as a fracture initiating device to reduce the breakdown pressure for hydraulic fracturing. The number and size of the fractures created by this tool are largely unknown. Case D was three successive shots using the same configuration as Case C.

Case E consists of a gas-producing, progressively-burning propellant with a suitable rise time to initiate and propagate multiple fractures while avoiding the damage of a stress cage.[2,10] This concept differs from the others in three main areas: 1) A full-diameter charge is used that fills the wellbore to maximize the energy released. 2) Lightweight gas products from the propellant itself, rather than water, are pushed into the created fractures. This maximizes the speed in which fractures are penetrated and pressure loaded. 3) The propellant is of the progressively-burning type in that the burning rate increases as material is consumed. This allows energy to be saved and not released until it is most needed, later in time, when fractures are long and system volume is large.

MULTI-FRAC TEST SERIES

FEASIBILITY STUDY

Experiments to investigate tailored-pulse concepts have been conducted in a tunnel complex at the Nevada Test Site. The tunnel facility provides a means of performing realistic tests of deeply-buried charges in rock formations at depth and yet allows for direct observation of resulting fracture behavior by mining back to uncover the test bed itself. The purpose of this test series is two-fold: (1) evaluate and compare several tailored-pulse concepts in a controlled test bed to determine the ability of each to produce multiple fractures and to enhance formation permeability and (2) provide data for testing and verification of various modeling schemes presently being used to describe the complex behavior of tailored-pulse loading.

The feasibility of performing such experiments was demonstrated previously in a test series conducted on Gas Frac.[2] Three canisters, each containing propellant with markedly different burning rates, were ignited in grouted horizontal holes drilled in a water-saturated ash-fall tuff formation. The results of the three tests showed phenomenologically different behavior as depicted in Figure 3. The slowest-burning propellant created a single fracture similar to a hydraulic fracture, the intermediate-rate propellant produced extensive multiple fractures, and the fast-burning propellant produced explosive-type behavior as evidenced by an enlarged borehole and minimal fracturing.

TEST SETUP

The previous Gas Frac tests were not instrumented except for a pressure transducer to measure dynamic cavity pressures. The five tests described below make up the so-called Multi-Frac Test Series and involved thirty-six stressmeters and accelerometers to measure rock formation response as well as pressure transducers to record dynamic cavity pressures. Along with direct observation by mineback, post-test evaluation included a reentry into each test zone for borehole television log, caliper log, and permeability measurements. The caliper log is intended to detect the degree of borehole enlargement (indicating plastic flow) and the permeability test is designed to measure the effectiveness of each test to increase the formation's ability to transmit fluids (i.e., conductivity of fracture network). The rock formation is a water-saturated ash-fall tuff having material properties as listed in Table 1.

The experiments were all conducted in 15 cm diameter, nearly horizontal holes drilled 12.2 m deep from a tunnel drift as depicted in Figure 4. The holes were spaced 6.1 m apart. Experiments A and B were conducted with 3.05 m of open hole and 9.15 m of casing while Experiments C, D, and E had 6.1 m of open hole and 6.1 m of casing. The mineback (not completed as of this writing) is planned so that half of each test zone will be mined out and examined thoroughly, leaving any fracture patterns occurring at the midpoint displayed on the right rib of the tunnel (Figure 4). All test setups were similar and a cross-section of the Case B configuration is seen in Figure 5.

Rock mass instrumentation consisted of an array of stressmeters and accelerometers as depicted in Figure 6. This array of gages was fielded only for Experiments B, D, and E. The stressmeters were special, strain-gaged, borehole-inclusion stressmeters.[11] Two of these transducers were set and preloaded in each instrumentation hole to measure diameteral deformations in the radial and transverse directions. Calibration of these gages was accomplished by static loading of a block of ash-fall tuff that contained a gage mounted in a hole drilled in the sample. Commercially available accelerometers were also set and preloaded in a similar fashion to measure radial and transverse accelerations. (Note that transverse accelerations would not be expected in a symmetric displacement field but could result from motions due to the dynamic propagation of a nearby crack.)

SPECIFIC TEST CONFIGURATIONS

The device fielded in Experiment A was simply a 2 cm diameter by 3 m long PVC tube filled with 2.3 kg of Comp C4 explosive. This was centralized in the hole and the cavity filled with water under atmospheric pressure. The water contained a blue dye to stain the created fractures and to ease identification and mapping during mineback. Dynamic cavity pressure was measured in this experiment using both Kulite* sensors and specially designed ytterbium paddle gages[12] located near the end of the casing section (Figure 5). The Kulite gage model HKM-375, is a piezoresistive integrated sensor. This gage has a 200 MPa pressure range and consists of a miniature silicon member on which a temperature compensated wheatstone bridge is atomically bonded. The miniaturization results in a natural frequency of 400 kHz.

Experiment B involved the same Comp C4 explosive setup but also contained a 2.7 kg charge of propellant. This relatively slow-burning propellant charge consisted of a single, internal-star rocket grain ignited with a black-powder-filled spit tube and housed in a sealed aluminuim canister. The canister was located in the casing section against the bulkhead and was designed to act as a dynamic plunger to push the dyed water down the casing and into fractures initiated by the explosive charge. The fire set was designed to ignite the propellant charge first and then to detonate the explosive 70 msec later by which time the propellant would have reached sufficient pressure. Transducers fielded in this experiment to measure the dynamic cavity pressure event included Kulite and ytterbium gages at the end of the casing section and a fluid-coupled-plate gage[13] located at the bulkhead near the propellant canister. The sensing element used in the fluid-coupled-plate transducer is the same Kulite gage mentioned previously.

The device used for Experiments C and D consisted of a 2 cm diameter by 6.1 m long soft aluminum tube filled with 2.3 kg of propellant which was ignited at one end. The device was centralized in the test hole and the cavity filled with dyed water. The water was pressurized statically to 3.4 MPa using a hydraulic pump just prior to these shots in order to simulate the containment from a 300 m column of water. Dynamic cavity pressure was measured in each of these shots by means of Kulite gages located near the end of the casing section.

The device fielded in Experiment E included a number of design improvements over the previous configuration.[2] The device (Figure 7) consisted of six canisters, each 12.7 cm diameter by 1 m long that screwed together. The canisters were made of perforated plastic tubes with a heat-shrinkable vinyl covering to make the unit watertight. Each canister contained 9.1 kg of M5 multi-perf propellant grains with a 1 mm web thickness. This propellant was ignited by means of a 3.2 cm diameter perforated-steel primer tube that runs through the center of each canister and becomes a continuous igniter when the units are screwed together. The

*Kulite Semiconductor Products, Inc., Ridgefield, NJ.

primer tube contained an explosive and igniter which provided ignition along the entire 6 meter length in less than 1 msec. The primer tube itself was initiated with an exploding bridge wire device as were all other experiments.

Since the propellant burns cleanly, several bags containing carbon black were taped to the outside of the canisters (Figure 7) to act as crack markers so that the created fractures would be more visible during mineback. Also, a number of 1.3 cm diameter ceramic spheres and 0.6 cm diameter cylinders were taped to this device in hopes that they would be propelled into the fractures and thereby act as dynamic crack width indicators when located during mineback. (These spheres and cylinders were used in the other experiments as well.) The assembly was placed in the dry 6.1 meter test section and sealed with a grout plug. The opposite end of the test zone contained a fluid-coupled plate transducer to measure dynamic cavity pressure.

Estimates of the grout-to-casing and grout-to-rock shear strength indicated that sufficient load-carrying capacity was available to contain these shots (refer to Figure 5). However, a strong-back brace was added as a backup measure (Figure 8). The brace was designed to transmit the load from the casing and bulkhead to the opposite tunnel rib if complete containment was not achieved. All shots were fired remotely and were monitored by close-circuit television.

All shots were fired using a capacitive discharge unit which dumps to an exploding bridge wire. Data was recorded in a separate instrumentation trailer using a 50 kHz analog system with voltage-controlled-oscillator and multiplexer. The analog data was recorded on magnetic tape and later digitized, reduced, and plotted.

RESULTS AND DISCUSSION

Note: Reduction and analysis of the test data and mineback evaluation were not complete at the deadline of this paper. Thus, the results and conclusions presented here are preliminary.

All shots were fired successfully except Experiment B. On that test, the propellant charge was ignited as planned. After a 70 msec delay, a signal was sent to the explosive charge, but detonation did not occur. Post-shot evaluation disclosed that the exploding bridge wire was intact, but that the detonation cables had been severed in two places by the propellant charge, preventing the bridge from receiving the impulse required.

Pressure-time and stress-time records from Experiment D are displayed in Figure 9. The stress-time behavior is for radial and transverse stress at a location 1 m from the test section. Note that the presure-time record shows a second pressure peak that occurs 9 msec after the first. This corresponds to the transit time of the stress pulse propagating from the gage to the steel bulkhead and back. This second pulse is also observed in the stress records.

Peak borehole pressure is seen to be 46 MPa. If this pressure were assumed constant and confined to the borehole, a 0.32 MPa stress would be expected at the 1 m stressmeters (with radial stress being compressive and tangential being tension). Peak stresses, however, were much higher: 1.06 MPa tangential tension and 2.16 MPa radial compression. Wave-code analysis indicates that little dynamic effect is present in this rate regime. Note that the tangential and radial stress become nearly equal in magnitude at late times as expected from quasi-static analysis. The discrepancy is likely due, instead, to pressure escaping from the borehole and loading the created fractures, thereby strongly affecting the loading configuration.

Preliminary results of stressmeter data from Experiment E indicate that stresses were more than 10 times larger than calculated from assumptions of a static borehole pressure. This discrepancy must be a result of substantial gas penetration into fractures and is consistent with observations of extensive fracturing detected in this experiment as discussed later.

A pre-test and post-test evaluation of in situ permeability was made for each test to indicate the capability of each device to increase the formation's ability to transmit fluids. Since this water-saturated ash-fall tuff formation has no "reservoir" pressure, per se, measurements were made by pressurizing each zone with water at a constant pressure of 2.8 MPa and recording the decay of flow with time. The flow rate data could then be fit to give the appropriate parameters which characterize the porous media and boundary conditions. However, since flowing time was always greater than a few minutes, the analysis was greatly simplified by an approximate logarithmic equation. The inverse of the flow rate (1/q) is plotted against the logarithm of time, and the permeability is determined from the slope of this line by

$$K = \frac{(185.7)\mu}{H(P_o - P_\infty)m}$$

where

K is permeability in md
μ is viscosity in kPa·s
H is zone length in m,
$P_o - P_\infty$ is injection over-pressure in kPa, and
m is slope in $(cm^3/sec)^{-1}$/cycle

An example of this measurement scheme is displayed in Figure 10. The pressure decay after shut-in was also analyzed in a manner similar to that for a standard pressure buildup record in a gas well.

Results of the pre-test and post-test permeability measurements are presented in Table 2. Each value of permeability is the average of the flow test and the shut-in. A large permeability enhancement is seen for Experiment E which is a clear indication of extensive fracturing. Experiments B, C, and D display a moderate increase in permeability. Experiment A, however, produced a decrease in formation permeability. This is apparently due to the creation of a stress cage (the bladder effect) even though the explosive was "decoupled" from the formation by an 8 to 1 ratio of hole diameter to charge diameter.

These observations are consistent with post-test TV logs. Several, wide radial fractures were seen in the log of Experiment E, and a few narrow fractures were seen in C and D. While no fractures were seen in the log of Experiment B, a single hydraulic-type fracture is expected here due to the very low pressure-loading rate of the propellant used. The presumption of a stress cage in Experiment A was confirmed in the TV log by the observation of an enlarged, distorted borehole with no apparent fractures.

Closed circuit television of Experiment E also showed indications of extensive fracturing. Shortly after ignition, a gas-driven fracture apparently reached an instrumentation hole located 2 m from the test section, which then pressurized the hole and propelled a 3 m long grout plug across the tunnel. Shortly after this another fracture apparently reached the test section of Experiment C (see Figure 4) 6.1 m away and propelled water and debris out of that hole. These observations were confirmed upon reentry in the tunnel when significant levels of combustion gas (carbon monoxide) were monitored coming out of these holes.

An enlightening comparison can also be made among the three previous Gas Frac shots[2] and Experiment E. Pressure-time characteristics and observed fracture behavior are compared in Table 3. Note that a good correlation between pressure rate and resulting behavior exists while no such correlation occurs with peak pressure. This indicates that pressure rate may be the governing parameter in determining whether resulting behavior is hydraulic fracturing, multiple fracturing, or explosive compaction. A preliminary closed-form analysis was performed that indicates the pressure rates in GF2 and Experiment E were low enough such that tangential stress at the borehole wall begins and remains tensile. On the other hand, the pressure rate of GF3 was sufficiently high to cause tangential compression initially. These initial compressions probably delay the tensile failure until after the compaction process has begun causing the bladder effect. This suggests a multiple fracture criterion that is based on a pressure rate being less than a value that would produce tangential compressive stress at the borehole wall. This criterion was previously suggested by Bligh as a means to avoid explosive compaction.[14]

CONCLUSIONS

These experiments have shown that multiple fractures can be created from a borehole while avoiding the formation of a stress cage by using an appropriately designed tailored-pulse technique. In particular, results of TV logs, permeability tests and other indirect data showed that the Case E technique produced a highly stimulated zone around the wellbore; Case B, C, and D resulted in a modest stimulation; and Case A, which apparently induced a stress cage to be formed in this rock even though it was a decoupled charge, actually decreased the formation permeability.

The results of these tests and previous experiments suggest that a multiple fracture criterion be based on borehole pressure-loading rate. Peak pressure conditions may not be important if loading-rate requirements are adequate.

Finally, these tests show the value of carefully designed in situ experiments for evaluating stimulation techniques. Instrumentation such as stressmeters, accelerometers, and pressure transducers can be fielded in critical locations, evaluation techniques such as TV and caliper logs and permeability tests can be conveniently employed, and ultimately, mineback can provide a complete diagnosis of the resultant fracture patterns.

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TABLE 1

ASH-FALL TUFF MATERIAL PROPERTIES

DENSITY	1.8 gm/cm^3
POROSITY (WATER FILLED)	40%
PERMEABILITY	SEE TABLE 2
ELASTIC MODULUS	5 GPa
COMPRESSIONAL WAVE VELOCITY	2.1 mm/μs
SHEAR WAVE VELOCITY	1.2 mm/μs
TENSILE STRENGTH	700 kPa
COMPRESSIVE STRENGTH (UNCONFINED)	30 MPa
FRACTURE TOUGHNESS	400 kPa $\sqrt{m}$

TABLE 2

PERMEABILITY ENHANCEMENT

CASE	TAILORED-PULSE CONCEPT	PRE-TEST PERMEABILITY (md)	POST-TEST PERMEABILITY (md)	FACTOR OF INCREASE	OBSERVATIONS FROM TV LOG
A	DECOUPLED EXPLOSIVE WITH WATER PAD	0.20	0.05	0.25	ENLARGED, DISTORTED BOREHOLE
B	DECOUPLED EXPLOSIVE* WITH PROPELLANT PUSHER (WATER PAD)	0.83	5.6	7	NO FRACTURES APPARENT
C	SMALL DIAMETER PROPELLANT WITH PRESSURIZED WATER PAD	0.0015	0.008**	5**	MULTIPLE FRACTURES (VERY NARROW)
D	THREE SHOTS OF CASE C WITH PRESSURIZED WATER PAD	0.007	0.034	5	MULTIPLE FRACTURES (NARROW)
E	FULL BORE, PROGRESSIVELY-BURNING PROPELLANT WITH AIR PAD	0.014	25.0	1800	MULTIPLE FRACTURES (WIDE)

*EXPLOSIVE DID NOT DETONATE

**SOME PERMEABILITY INCREASE MAY BE DUE TO FRACTURE CAUSED BY EXPERIMENT E

TABLE 3

PRESSURE LOADING CHARACTERISTICS VS. OBSERVED BEHAVIOR

	EXPERIMENT	PEAK PRESSURE (MPa)	PRESSURE RATE (kPa/μs)	RESULTING BEHAVIOR
PREVIOUS GAS FRAC TEST SERIES[2]	GF1	43	0.6	HYDRAULIC FRACTURE
	GF2	95	140	MULTIPLE FRACTURES
	GF3	~200	>10,000	EXPLOSIVE STRESS CAGE
	EXPERIMENT E	250	430	MULTIPLE FRACTURES

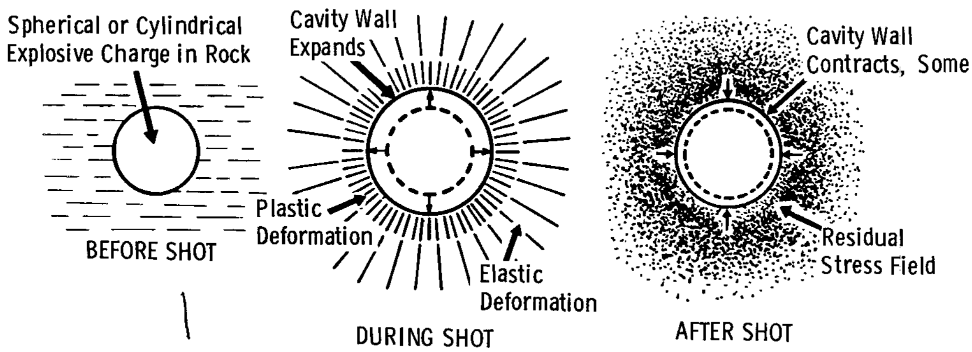


Fig. 1 - General behavior of deeply-buried charge.

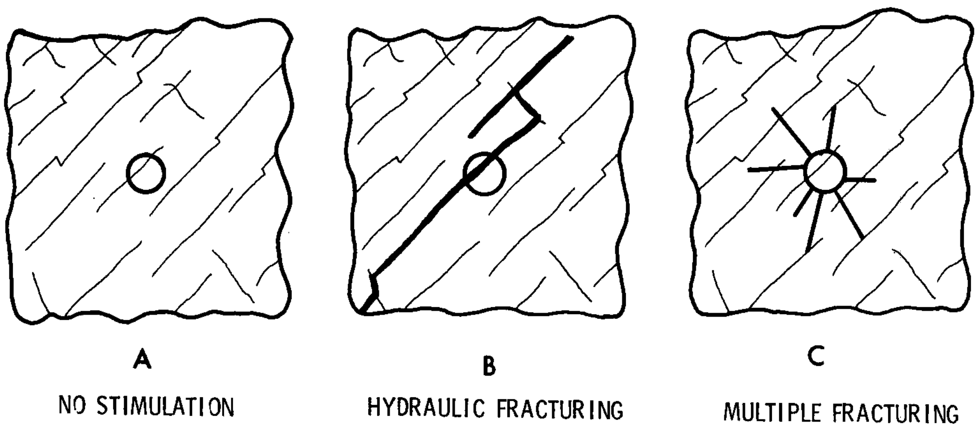


Fig. 2 - Stimulation of naturally fractured reservoir.

	GF1 "SLOW"	GF2 "INTERMEDIATE"	GF3 "FAST"
LOADING RATE (kPa/μs)	0.6	140	>10,000
PEAK PRESSURE (MPa)	43	95	> ~200
PULSE DURATION (msec)	900	9	~1

MINEBACK OBSERVATION

(SCHEMATIC)

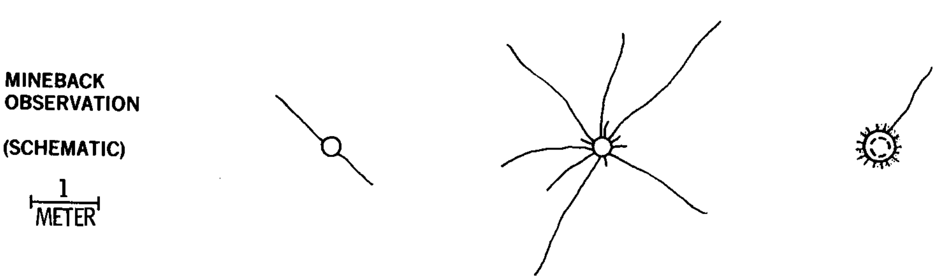


Fig. 3 - Results of gas frac experiments[2].

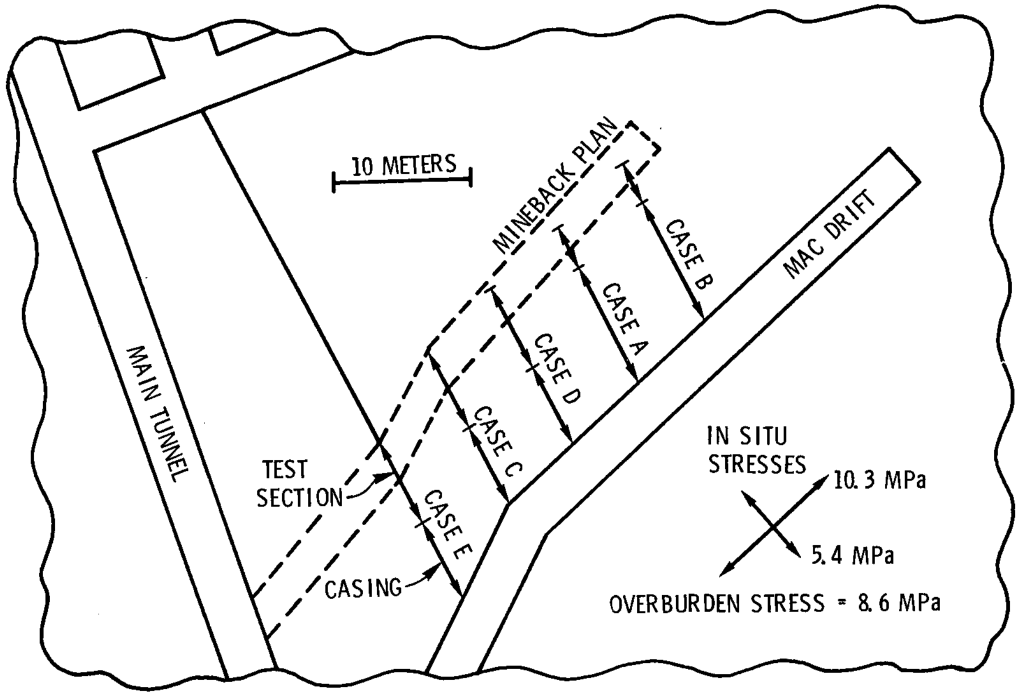


Fig. 4 - Tunnel plan for multi-frac test series.

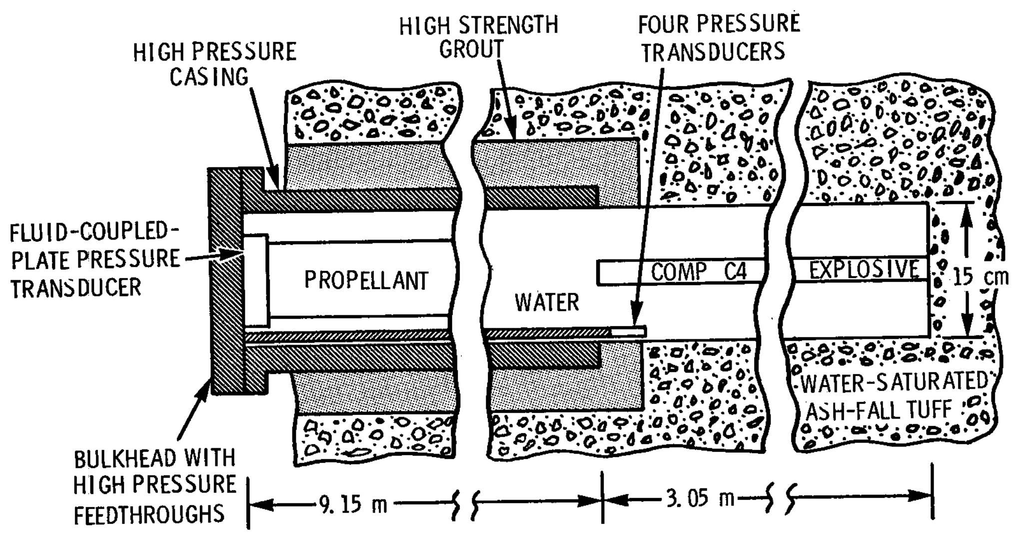


Fig. 5 - Cross section of test setup for experiment B.

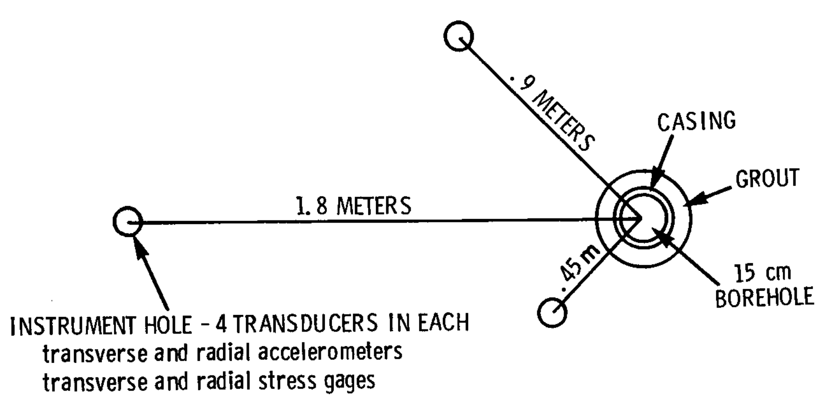


Fig. 6 - Layout of instrumentation holes.

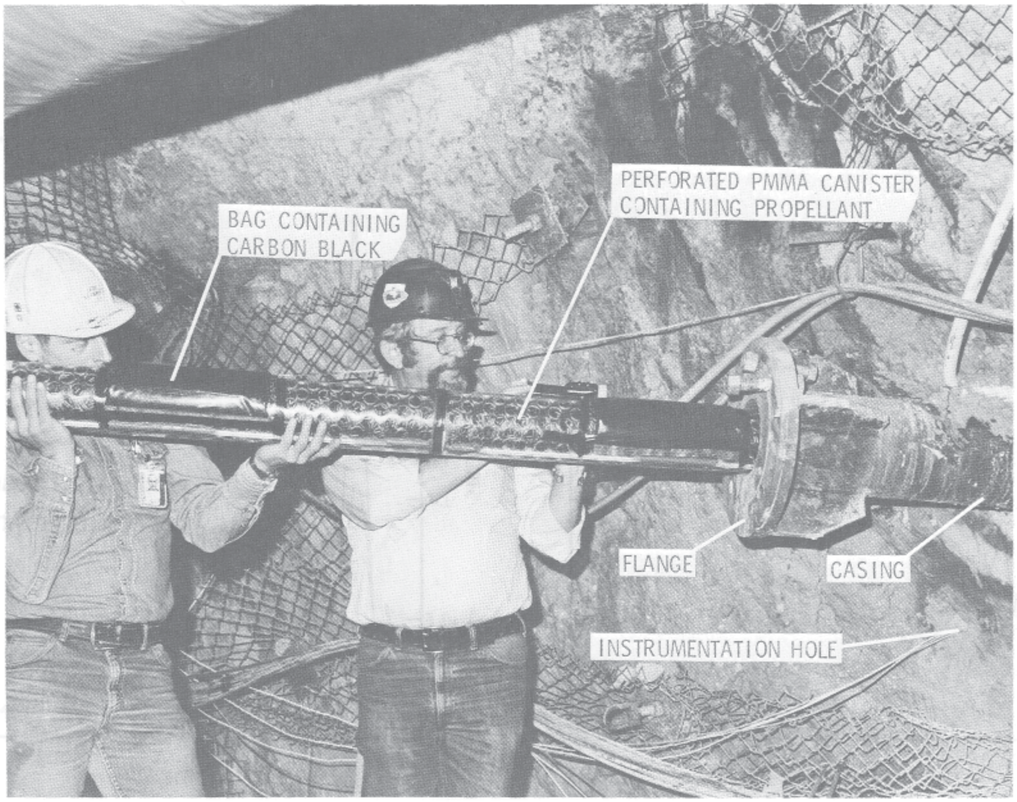


Fig. 7 - Loading of propellant device for experiment E.

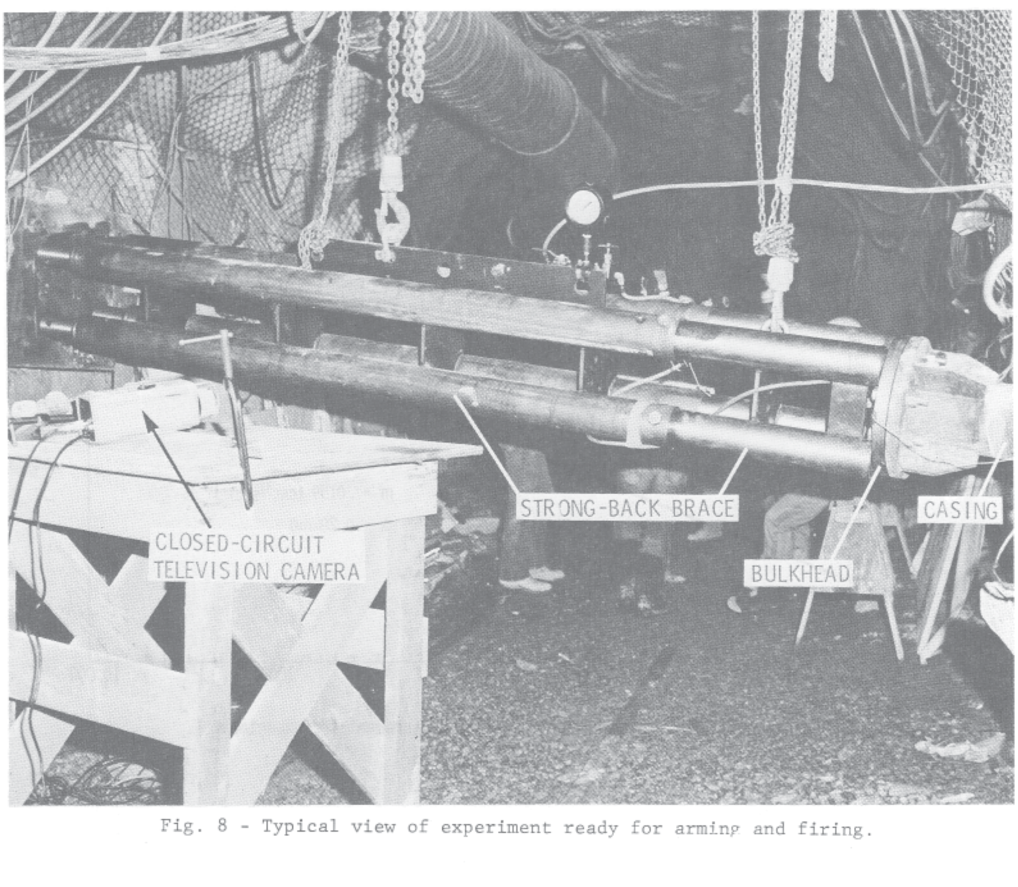
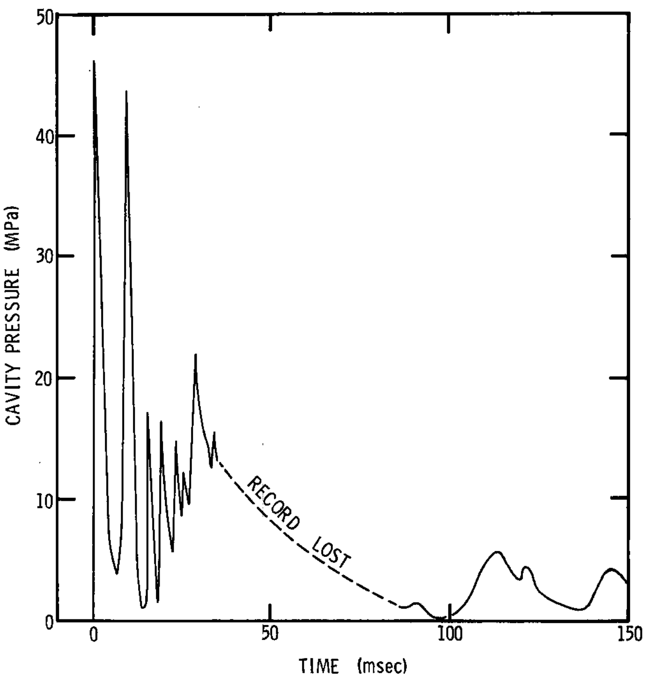


Fig. 8 - Typical view of experiment ready for arming and firing.



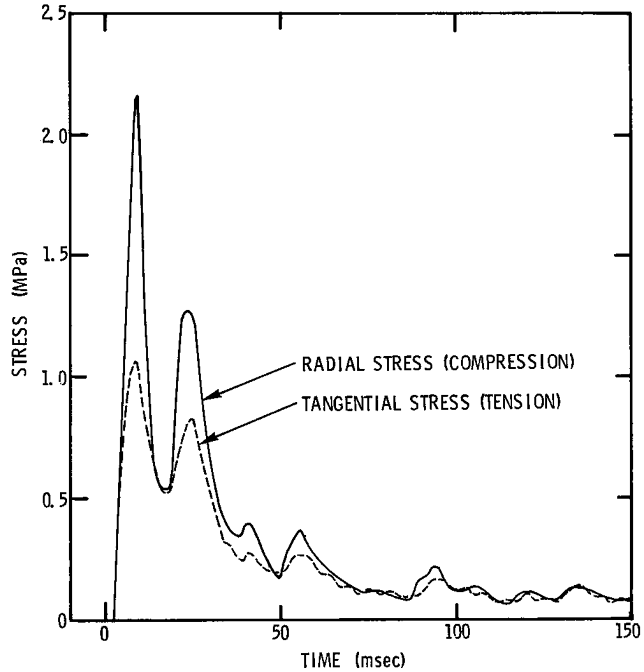


Fig. 9 - Record of cavity pressure and stress at 1 m for experiment D.

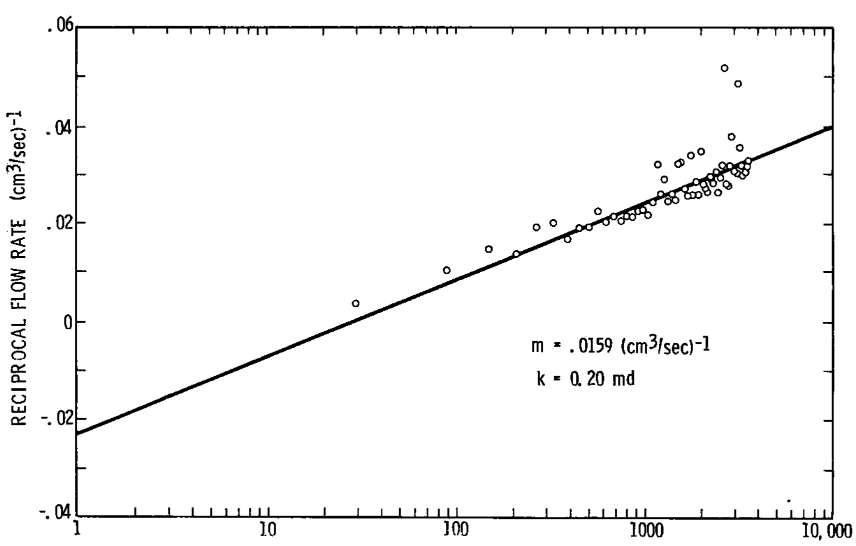


Fig. 10 - Pre-shot permeability measurement for experiment A.

APPENDIX F: Cross-Reference Table of Class VI Injection Well Rules (40 CFR Subpart H)

Class VI Well Regulatory Requirements	Application Section Where Addressed
Sec. 146.82 Required Class VI permit information. (a) Prior to the issuance of a permit for the construction of a new Class VI well or the conversion of an existing Class I, Class II, or Class V well to a Class VI well, the owner or operator shall submit, pursuant to § 146.91(e), and the Director shall consider the following:	
(1) Information required in § 144.31(e)(1) through (6) of this chapter;	Attachment A
(2) A map showing the injection well for which a permit is sought and the applicable area of review consistent with § 146.84. Within the area of review, the map must show the number or name, and location of all injection wells, producing wells, abandoned wells, plugged wells or dry holes, deep stratigraphic boreholes, State- or EPA-approved subsurface cleanup sites, surface bodies of water, springs, mines (surface and subsurface), quarries, water wells, other pertinent surface features including structures intended for human occupancy, State, Tribal, and Territory boundaries, and roads. The map should also show faults, if known or suspected. Only information of public record is required to be included on this map;	Section 4
(3) Information on the geologic structure and hydrogeologic properties of the proposed storage site and overlying formations, including: (i) Maps and cross sections of the area of review;	Section 3
(ii) The location, orientation, and properties of known or suspected faults and fractures that may transect the confining zone(s) in the area of review and a determination that they would not interfere with containment;	Sec. 3.2
(iii) Data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the injection and confining zone(s); including geology/facies changes based on field data which may include geologic cores, outcrop data, seismic surveys, well logs, and names and lithologic descriptions;	Sec. 3.3.2
(iv) Geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone(s);	Sec. 3.6
(v) Information on the seismic history including the presence and depth of seismic sources and a determination that the seismicity would not interfere with containment; and	Sec. 3.8
(vi) Geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the local area.	Sec. 3.4
(4) A tabulation of all wells within the area of review which penetrate the injection or confining zone(s). Such data must include a description of each well’s type, construction, date drilled, location, depth, record of plugging and/ or completion, and any additional information the Director may require;	Appendix B
(5) Maps and stratigraphic cross sections indicating the general vertical and lateral limits of all USDWs, water wells and springs within the area of review, their positions relative to the injection zone(s), and the direction of water movement, where known;	Appendix B
(6) Baseline geochemical data on subsurface formations, including all USDWs in the area of review;	Sec. 3.5, Sec. 4.3
(7) Proposed operating data for the proposed geologic sequestration site: (i) Average and maximum daily rate and volume and/or mass and total anticipated volume and/or mass of the carbon dioxide stream;	Section 4.1.4
(ii) Average and maximum injection pressure;	Section 8.2
(iii) The source(s) of the carbon dioxide stream; and	Sec. 1.1

(iv) An analysis of the chemical and physical characteristics of the carbon dioxide stream.	Sec. 8.6
(8) Proposed pre-operational formation testing program to obtain an analysis of the chemical and physical characteristics of the injection zone(s) and confining zone(s) and that meets the requirements at § 146.87;	Sec. 7.5
Sec. 146.82 Required Class VI permit information. (cont'd) (9) Proposed stimulation program, a description of stimulation fluids to be used and a determination that stimulation will not interfere with containment;	Sec. 8.5.2
(10) Proposed procedure to outline steps necessary to conduct injection operation;	Sec. 8.5
(11) Schematics or other appropriate drawings of the surface and subsurface construction details of the well;	Fig. 6.1.6-1, Fig. 6.1.6-2
(12) Injection well construction procedures that meet the requirements of § 146.86;	Sec. 6
(13) Proposed area of review and corrective action plan that meets the requirements under § 146.84;	Sec. 4.4
(14) A demonstration, satisfactory to the Director, that the applicant has met the financial responsibility requirements under § 146.85;	Sec. 5 and Appendix A
(15) Proposed testing and monitoring plan required by § 146.90;	Sec. 9
(16) Proposed injection well plugging plan required by § 146.92(b);	Sec. 10
(17) Proposed post-injection site care and site closure plan required by § 146.93(a);	Sec. 11
(18) At the Director's discretion, a demonstration of an alternative post-injection site care timeframe required by § 146.93(c);	Sec. 11.3
(19) Proposed emergency and remedial response plan required by § 146.94(a);	Sec. 12
(20) A list of contacts, submitted to the Director, for those States, Tribes, and Territories identified to be within the area of review of the Class VI project based on information provided in paragraph (a)(2) of this section; and	Section 2
(21) Any other information requested by the Director.	Agency action
(b) The Director shall notify, in writing, any States, Tribes, or Territories identified to be within the area of review of the Class VI project based on information provided in paragraphs (a)(2) and (a)(20) of this section of the permit application and pursuant to the requirements at § 145.23(f)(13) of this chapter.	Agency action
(c) Prior to granting approval for the operation of a Class VI well, the Director shall consider the following information: (1) The final area of review based on modeling, using data obtained during logging and testing of the well and the formation as required by paragraphs (c)(2), (3), (4), (6), (7), and (10) of this section; (2) Any relevant updates, based on data obtained during logging and testing of the well and the formation as required by paragraphs (c)(3), (4), (6), (7), and (10) of this section, to the information on the geologic structure and hydrogeologic properties of the proposed storage site and overlying formations, submitted to satisfy the requirements of paragraph (a)(3) of this section; (3) Information on the compatibility of the carbon dioxide stream with fluids in the injection zone(s) and minerals in both the injection and the confining zone(s), based on the results of the formation testing program, and with the materials used to construct the well;	

(4) The results of the formation testing program required at paragraph (a)(8) of this section; (5) Final injection well construction procedures that meet the requirements of § 146.86; (6) The status of corrective action on wells in the area of review; (7) All available logging and testing program data on the well required by § 146.87; (8) A demonstration of mechanical integrity pursuant to § 146.89; (9) Any updates to the proposed area of review and corrective action plan, testing and monitoring plan, injection well plugging plan, post-injection site care and site closure plan, or the emergency and remedial response plan submitted under paragraph (a) of this section, which are necessary to address new information collected during logging and testing of the well and the formation as required by all paragraphs of this section, and any updates to the alternative post-injection site care timeframe demonstration submitted under paragraph (a) of this section, which are necessary to address new information collected during the logging and testing of the well and the formation as required by all paragraphs of this section; and (10) Any other information requested by the Director.	Agency action
(d) Owners or operators seeking a waiver of the requirement to inject below the lowermost USDW must also refer to § 146.95 and submit a supplemental report, as required at § 146.95(a). The supplemental report is not part of the permit application.	Not applicable

§ 146.83 Minimum criteria for siting.	
(a) Owners or operators of Class VI wells must demonstrate to the satisfaction of the Director that the wells will be sited in areas with a suitable geologic system. The owners or operators must demonstrate that the geologic system comprises:	Section 2
(1) An injection zone(s) of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the carbon dioxide stream;	Sec. 3.3.2
(2) Confining zone(s) free of transmissive faults or fractures and of sufficient areal extent and integrity to contain the injected carbon dioxide stream and displaced formation fluids and allow	Sec. 3.3
injection at proposed maximum pressures and volumes without initiating or propagating fractures in the confining zone(s).	Sec. 3.12
(b) The Director may require owners or operators of Class VI wells to identify and characterize additional zones that will impede vertical fluid movement, are free of faults and fractures that may interfere with containment, allow for pressure dissipation, and provide additional opportunities for monitoring, mitigation, and remediation.	Agency action
§ 146.84 Area of review and corrective action.	
(a) The area of review is the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity. The area of review is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and is based on available site characterization, monitoring, and operational data.	Sections 5.1 and Attachment B

(b) The owner or operator of a Class VI well must prepare, maintain, and comply with a plan to delineate the area of review for a proposed geologic sequestration project, periodically reevaluate the delineation, and perform corrective action that meets the requirements of this section and is acceptable to the Director. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. As a part of the permit application for approval by the Director, the owner or operator must submit an area of review and corrective action plan that includes the following information:	Section 5.6
(1) The method for delineating the area of review that meets the requirements of paragraph (c) of this section, including the model to be used, assumptions that will be made, and the site characterization data on which the model will be based;	Sec. 4.2
(2) A description of: (i) The minimum fixed frequency, not to exceed five years, at which the owner or operator proposes to reevaluate the area of review; (ii) The monitoring and operational conditions that would warrant a reevaluation of the area of review prior to the next scheduled reevaluation as determined by the minimum fixed frequency established in paragraph (b)(2)(i) of this section. (iii) How monitoring and operational data (e.g., injection rate and pressure) will be used to inform an area of review reevaluation; and (iv) How corrective action will be conducted to meet the requirements of paragraph (d) of this section, including what corrective action will be performed prior to injection and what, if any, portions of the area of review will have corrective action addressed on a phased basis and how the phasing will be determined; how corrective action will be adjusted if there are changes in the area of review; and how site access will be guaranteed for future corrective action.	Section 4.4
(c) Owners or operators of Class VI wells must perform the following actions to delineate the area of review and identify all wells that require corrective action: (1) Predict, using existing site characterization, monitoring and operational data, and computational modeling, the projected lateral and vertical migration of the carbon dioxide plume and formation fluids in the subsurface from the commencement of injection activities until the plume movement ceases, until pressure differentials sufficient to cause the movement of injected fluids or formation fluids into a USDW are no longer present, or until the end of a fixed time period as determined by the Director. The model must: (i) Be based on detailed geologic data collected to characterize the injection zone(s), confining zone(s) and any additional zones; and anticipated operating data, including injection pressures, rates, and total volumes over the proposed life of the geologic sequestration project; (ii) Take into account any geologic heterogeneities, other discontinuities, data quality, and their possible impact on model predictions; and (iii) Consider potential migration through faults, fractures, and artificial penetrations. (iv)	Sec. 9.5
§ 146.84 Area of review and corrective action.(cont'd) (2) Using methods approved by the Director, identify all penetrations, including active and abandoned wells and underground mines, in the area of review that may penetrate the confining zone(s). Provide a description of each well's type, construction, date drilled, location, depth, record of plugging and/ or completion, and any additional information the Director may require; and	Appendix B

(3) Determine which abandoned wells in the area of review have been plugged in a manner that prevents the movement of carbon dioxide or other fluids that may endanger USDWs, including use of materials compatible with the carbon dioxide stream.	Appendix B
(d) Owners or operators of Class VI wells must perform corrective action on all wells in the area of review that are determined to need corrective action, using methods designed to prevent the movement of fluid into or between USDWs, including use of materials compatible with the carbon dioxide stream, where appropriate.	Sec. 4.4
(e) At the minimum fixed frequency, not to exceed five years, as specified in the area of review and corrective action plan, or when monitoring and operational conditions warrant, owners or operators must: (1) Reevaluate the area of review in the same manner specified in paragraph (c)(1) of this section; (2) Identify all wells in the reevaluated area of review that require corrective action in the same manner specified in paragraph (c) of this section; (3) Perform corrective action on wells requiring corrective action in the reevaluated area of review in the same manner specified in paragraph (d) of this section; and (4) Submit an amended area of review and corrective action plan or demonstrate to the Director through monitoring data and modeling results that no amendment to the area of review and corrective action plan is needed. Any amendments to the area of review and corrective action plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at §§ 144.39 or 144.41 of this chapter, as appropriate.	Sec. 4
(f) The emergency and remedial response plan (as required by § 146.94) and the demonstration of financial responsibility (as described by § 146.85) must account for the area of review delineated as specified in paragraph (c)(1) of this section or the most recently evaluated area of review delineated under paragraph (e) of this section, regardless of whether or not corrective action in the area of review is phased.	Sec. 12 and Sec. 5
(g) All modeling inputs and data used to support area of review reevaluations under paragraph (e) of this section shall be retained for 10 years.	Sec. 9
§ 146.85 Financial responsibility. (a) The owner or operator must demonstrate and maintain financial responsibility as determined by the Director that meets the following conditions: … (b) The requirement to maintain adequate financial responsibility and resources is directly enforceable regardless of whether the requirement is a condition of the permit. … (c) The owner or operator must have a detailed written estimate, in current dollars, of the cost of performing corrective action on wells in the area of review, plugging the injection well(s), post- injection site care and site closure, and emergency and remedial response. … (d) The owner or operator must notify the Director by certified mail of adverse financial conditions such as bankruptcy that may affect the ability to carry out injection well plugging and post-injection site care and site closure. …	Sec. 5, Appendix A

(e) The owner or operator must provide an adjustment of the cost estimate to the Director within 60 days of notification by the Director, as required by § 146.84, if the Director determines during the annual evaluation of the qualifying financial instrument(s) that the most recent demonstration is no longer adequate to cover the cost of corrective action (as required by § 146.84), injection well plugging (as required by § 146.92), post-injection site care and site closure (as required by § 146.93), and emergency and remedial response (as required by § 146.94). (f) The Director must approve the use and length of pay-in-periods for trust funds or escrow accounts.	Agency action
§ 146.86 Injection well construction requirements. (a) *General.* The owner or operator must ensure that all Class VI wells are constructed and completed to: (1) Prevent the movement of fluids into or between USDWs or into any unauthorized zones; (2) Permit the use of appropriate testing devices and workover tools; and (3) Permit continuous monitoring of the annulus space between the injection tbg and long string casing.	Sec. 6
(b) Casing and Cementing of Class VI Wells. (1) Casing and cement or other materials used in the construction of each Class VI well must have sufficient structural strength and be designed for the life of the geologic sequestration project. All well materials must be compatible with fluids with which the materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director. The casing and cementing program must be designed to prevent the movement of fluids into or between USDWs. In order to allow the Director to determine and specify casing and cementing requirements, the owner or operator must provide the following information:	Sec. 6.1, Sec. 6.2
(i) Depth to the injection zone(s);	6.1.1
(ii) Injection pressure, external pressure, internal pressure, and axial loading;	Fig 6.1-3 Fig.6.1-4, Fig. 6.1.7.3
(iii) Hole size;	Sec. 6.2.7.1, Table 6.2.7.1-1
(iv) Size and grade of all casing strings (wall thickness, external diameter, nominal weight, length, joint specification, and construction material);	Sec. 6.1.7.2 Table 6.1.7.2-1
(v) Corrosiveness of the carbon dioxide stream and formation fluids;	Sec. 3.5
(vi) Down-hole temperatures;	Sec. 7.3.7, Table 7.3.7-1
(vii) Lithology of injection and confining zone(s);	Sec. 7.3.1
(viii) Type or grade of cement and cement additives; and	Sec. 6.1.7.2 Table 6.1.7.2-1
(ix) Quantity, chemical composition, and temperature of the carbon dioxide stream.	Sec. 8.6
(2) Surface casing must extend through the base of the lowermost USDW and be cemented to the surface through the use of a single or multiple strings of casing and cement.	Sec. 6.1.7.1, Table 6.1.7.1-1
(3) At least one long string casing, using a sufficient number of centralizers, must extend to the injection zone and must be cemented by circulating cement to the surface in one or more stages.	6.1.7.2, Table 6.1.7.2-1
(4) Circulation of cement may be accomplished by staging. The Director may approve an alternative method of cementing in cases where the cement cannot be recirculated to the surface, provided the owner or operator can demonstrate by using logs that the cement does not allow fluid movement behind wellbore.	Sec. 6.1.7.4

(5) Cement and cement additives must be compatible with the carbon dioxide stream and formation fluids and of sufficient quality and quantity to maintain integrity over the design life of the geologic sequestration project. The integrity and location of the cement shall be verified using technology capable of evaluating cement quality radially and identifying the location of channels to ensure that USDWs are not endangered.	Sec. 6.1.7
(c) Tubing and packer. (1) Tubing and packer materials used in the construction of each Class VI well must be compatible with fluids with which the materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director.	Sec. 6.1.7
(2) All owners or operators of Class VI wells must inject fluids through tubing with a packer set at a depth opposite a cemented interval at the location approved by the Director.	Packer depth TBD.
(3) In order for the Director to determine and specify requirements for tubing and packer, the owner or operator must submit the following information:	
(i) Depth of setting;	Packer depth TBD.
(ii) Characteristics of the carbon dioxide stream (chemical content, corrosiveness, temperature, and density) and formation fluids;	Sec. 8.6
(iii) Maximum proposed injection pressure;	Sec. 8.2, Table 8.2-1
(iv) Maximum proposed annular pressure;	Fig. 6.1-3, 6.1-4, 6.1-5
(v) Proposed injection rate (intermittent or continuous) and volume and/or mass of the carbon dioxide stream;	Sec. 8.1
(vi) Size of tubing and casing; and	Table 6.1.7.3-1
(vii) Tubing tensile, burst, and collapse strengths.	Sec. 6.1.7.3, Table 6.1.7.3-1

§ 146.87 Logging, sampling, and testing prior to injection well operation.	
(a) During the drilling and construction of a Class VI injection well, the owner or operator must run appropriate logs, surveys and tests to determine or verify the depth, thickness, porosity, permeability, and lithology of, and the salinity of any formation fluids in all relevant geologic formations to ensure conformance with the injection well construction requirements under § 146.86 and to establish accurate baseline data against which future measurements may be compared. The owner or operator must submit to the Director a descriptive report prepared by a knowledgeable log analyst that includes an interpretation of the results of such logs and tests. At a minimum, such logs and tests must include:	
(1) Deviation checks during drilling on all holes constructed by drilling a pilot hole which is enlarged by reaming or another method. Such checks must be at sufficiently frequent intervals to determine the location of the borehole and to ensure that vertical avenues for fluid movement in the form of diverging holes are not created during drilling; and	Sec. 7.1
(2) Before and upon installation of the surface casing:	
(i) Resistivity, spontaneous potential, and caliper logs before the casing is installed; and	Sec. 6.1.7.9
(ii) A cement bond and variable density log to evaluate cement quality radially, and a temperature log after the casing is set and cemented.	Sec. 6.1.7.9
(3) Before and upon installation of the long string casing:	
(i) Resistivity, spontaneous potential, porosity, caliper, gamma ray, fracture finder logs, and any other logs the Director requires for the given geology before the casing is installed; and	6.1.7.4

(ii) A cement bond and variable density log, and a temperature log after the casing is set and cemented. (4) A series of tests designed to demonstrate the internal and external mechanical integrity of injection wells, which may include: (i) A pressure test with liquid or gas; (ii) A tracer survey such as oxygen-activation logging; (iii) A temperature or noise log; (iv) A casing inspection log; and (5) Any alternative methods that provide equivalent or better information and that are required by and/or approved of by the Director.	6.1.7.4 Sec. 6.2.9.3 Sec. 7.5.3.2 Sec. 7.5.3.2 Sec. 7.5.3.2 N/a
(b) The owner or operator must take whole cores or sidewall cores of the injection zone and confining system and formation fluid samples from the injection zone(s), and must submit to the Director a detailed report prepared by a log analyst that includes: Well log analyses (including well logs), core analyses, and formation fluid sample information. The Director may accept information on cores from nearby wells if the owner or operator can demonstrate that core retrieval is not possible and that such cores are representative of conditions at the well. The Director may require the owner or operator to core other formations in the borehole.	Sec. 7.3
(c) The owner or operator must record the fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone(s).	Sect. 7.5.3.6
(d) At a minimum, the owner or operator must determine or calculate the following information concerning the injection and confining zone(s): (1) Fracture pressure; (2) Other physical and chemical characteristics of the injection and confining zone(s); and (3) Physical and chemical characteristics of the formation fluids in the injection zone(s).	 Sec. 7.4.2.9 Sec. 7.2 Sec. 7.3.3.1
(e) Upon completion, but prior to operation, the owner or operator must conduct the following tests to verify hydrogeologic characteristics of the injection zone(s): (1) A pressure fall-off test; and, (2) A pump test; or (3) Injectivity tests.	 Sec. 7.5.3.6 Sec. 7.1.2 N/a
(f) The owner or operator must provide the Director with the opportunity to witness all logging and testing by this subpart. The owner or operator must submit a schedule of such activities to the Director 30 days prior to conducting the first test and submit any changes to the schedule 30 days prior to the next scheduled test.	Sec. 6.1.7.9

§ 146.88 Injection well operating requirements. (a) Except during stimulation, the owner or operator must ensure that injection pressure does not exceed 90 percent of the fracture pressure of the injection zone(s) so as to ensure that the injection does not initiate new fractures or propagate existing fractures in the injection zone(s). In no case may injection pressure initiate fractures in the confining zone(s) or cause the movement of injection or formation fluids that endangers a USDW. Pursuant to requirements at § 146.82(a)(9), all stimulation programs must be approved by the Director as part of the permit application and incorporated into the permit.	Sec. 8.2
(b) Injection between the outermost casing protecting USDWs and the well bore is prohibited.	Sec. 8.5

(c) The owner or operator must fill the annulus between the tubing and the long string casing with a non-corrosive fluid approved by the Director. The owner or operator must maintain on the annulus a pressure that exceeds the operating injection pressure, unless the Director determines that such requirement might harm the integrity of the well or endanger USDWs.	Sec. 8.4.2
(d) Other than during periods of well workover (maintenance) approved by the Director in which the sealed tubing-casing annulus is disassembled for maintenance or corrective procedures, the owner or operator must maintain mechanical integrity of the injection well at all times.	Sec. 7.5.3.7
(e) The owner or operator must install and use: (1) Continuous recording devices to monitor: The injection pressure; the rate, volume and/or mass, and temperature of the carbon dioxide stream; and the pressure on the annulus between the tubing and the long string casing and annulus fluid volume; and (2) Alarms and automatic surface shut-off systems or, at the discretion of the Director, down-hole shut- off systems (*e.g.,* automatic shut-off, check valves) for onshore wells or, other mechanical devices that provide equivalent protection; and (3) Alarms and automatic down-hole shut-off systems for wells located offshore but within State territorial waters, designed to alert the operator and shut-in the well when operating parameters such as annulus pressure, injection rate, or other parameters diverge beyond permitted ranges and/or gradients specified in the permit.	Sec. 6.4 Sect. 8.7 N/A
(f) If a shutdown (*i.e.,* down-hole or at the surface) is triggered or a loss of mechanical integrity is discovered, the owner or operator must immediately investigate and identify as expeditiously as possible the cause of the shutoff. If, upon such investigation, the well appears to be lacking mechanical integrity, or if monitoring required under paragraph (e) of this section otherwise indicates that the well may be lacking mechanical integrity, the owner or operator must: (1) Immediately cease injection; (2) Take all steps reasonably necessary to determine whether there may have been a release of the injected carbon dioxide stream or formation fluids into any unauthorized zone; (3) Notify the Director within 24 hours; (4) Restore and demonstrate mechanical integrity to the satisfaction of the Director prior to resuming injection; and (5) Notify the Director when injection can be expected to resume.	Sect. 12 ERRP

§ 146.89 Mechanical integrity. (a) A Class VI well has mechanical integrity if: (1) There is no significant leak in the casing, tubing, or packer; and (2) There is no significant fluid movement into a USDW through channels adjacent to the injection well bore.	Sec. 7.5.3.7, Sec. 9.2
(b) To evaluate the absence of significant leaks under paragraph (a)(1) of this section, owners or operators must, following an initial annulus pressure test, continuously monitor injection pressure, rate, injected volumes; pressure on the annulus between tubing and long-string casing; and annulus fluid volume as specified in § 146.88 (e);	Sec. 9.5.2.1 and Sec. 6.5
(c) At least once per year, the owner or operator must use one of the following methods to determine the absence of significant fluid movement under paragraph (a)(2) of this section: (1) An approved tracer survey such as an oxygen-activation log; or (2) A temperature or noise log.	Sec. 7.5.3.2

(d) If required by the Director, at a frequency specified in the testing and monitoring plan required at § 146.90, the owner or operator must run a casing inspection log to determine the presence or absence of corrosion in the long-string casing.	Agency action
(e) The Director may require any other test to evaluate mechanical integrity under paragraphs (a)(1) or (a)(2) of this section. Also, the Director may allow the use of a test to demonstrate mechanical integrity other than those listed above with the written approval of the Administrator. To obtain approval for a new mechanical integrity test, the Director must submit a written request to the Administrator setting forth the proposed test and all technical data supporting its use. The Administrator may approve the request if he or she determines that it will reliably demonstrate the mechanical integrity of wells for which its use is proposed. Any alternate method approved by the Administrator will be published in the Federal Register and may be used in all States in accordance with applicable State law unless its use is restricted at the time of approval by the Administrator.	Agency action
(f) In conducting and evaluating the tests enumerated in this section or others to be allowed by the Director, the owner or operator and the Director must apply methods and standards generally accepted in the industry. When the owner or operator reports the results of mechanical integrity tests to the Director, he/she shall include a description of the test(s) and the method(s) used. In making his/her evaluation, the Director must review monitoring and other test data submitted since the previous evaluation.	Sec. 7.5.3.7
(g) The Director may require additional or alternative tests if the results presented by the owner or operator under paragraphs (a) through (d) of this section are not satisfactory to the Director to demonstrate that there is no significant leak in the casing, tubing, or packer, or to demonstrate that there is no significant movement of fluid into a USDW resulting from the injection activity as stated in paragraphs (a)(1) and (2) of this section.	Agency action

§ 146.90 Testing and monitoring requirements. The owner or operator of a Class VI well must prepare, maintain, and comply with a testing and monitoring plan to verify that the geologic sequestration project is operating as permitted and is not endangering USDWs. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. The testing and monitoring plan must be submitted with the permit application, for Director approval, and must include a description of how the owner or operator will meet the requirements of this section, including accessing sites for all necessary monitoring and testing during the life of the project. Testing and monitoring associated with geologic sequestration projects must, at a minimum, include:	Sec. 9
(a) Analysis of the carbon dioxide stream with sufficient frequency to yield data representative of its chemical and physical characteristics;	Sec. 9.1
(b) Installation and use, except during well workovers as defined in § 146.88(d), of continuous recording devices to monitor injection pressure, rate, and volume; the pressure on the annulus between the tubing and the long string casing; and the annulus fluid volume added;	Sec. 6.4
(c) Corrosion monitoring of the well materials for loss of mass, thickness, cracking, pitting, and other signs of corrosion, which must be performed on a quarterly basis to ensure that the well components meet the minimum standards for material strength and performance set forth in § 146.86(b), by: (1) Analyzing coupons of the well construction materials placed in contact with the carbon dioxide stream; or	Sec. 9.2

(2) Routing the carbon dioxide stream through a loop constructed with the material used in the well and inspecting the materials in the loop; or (3) Using an alternative method approved by the Director;	
(d) Periodic monitoring of the ground water quality and geochemical changes above the confining zone(s) that may be a result of carbon dioxide movement through the confining zone(s) or additional identified zones including: (1) The location and number of monitoring wells based on specific information about the geologic sequestration project, including injection rate and volume, geology, the presence of artificial penetrations, and other factors; and (2) The monitoring frequency and spatial distribution of monitoring wells based on baseline geochemical data that has been collected under § 146.82(a)(6) and on any modeling results in the area of review evaluation required by § 146.84(c).	Sec. 9.5.2.1, Table 9.5.2-2
(e) A demonstration of external mechanical integrity pursuant to § 146.89(c) at least once per year until the injection well is plugged; and, if required by the Director, a casing inspection log pursuant to requirements at § 146.89(d) at a frequency established in the testing and monitoring plan;	Sec. 7.5.3.7
(f) A pressure fall-off test at least once every five years unless more frequent testing is required by the Director based on site-specific information;	Sec. 9.3
(g) Testing and monitoring to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure (*e.g.,* the pressure front) by using: (1) Direct methods in the injection zone(s); and, (2) Indirect methods (*e.g.,* seismic, electrical, gravity, or electromagnetic surveys and/or down-hole carbon dioxide detection tools), unless the Director determines, based on site-specific geology, that such methods are not appropriate;	Sec. 9.5.2.1 Sec. 9.5.2.2

§ 146.90 Testing and monitoring requirements. (cont'd) (h) The Director may require surface air monitoring and/or soil gas monitoring to detect movement of carbon dioxide that could endanger a USDW. (1) Design of Class VI surface air and/ or soil gas monitoring must be based on potential risks to USDWs within the area of review; (2) The monitoring frequency and spatial distribution of surface air monitoring and/or soil gas monitoring must be decided using baseline data, and the monitoring plan must describe how the proposed monitoring will yield useful information on the area of review delineation and/or compliance with standards under § 144.12 of this chapter; (3) If an owner or operator demonstrates that monitoring employed under §§ 98.440 to 98.449 of this chapter (Clean Air Act, 42 U.S.C. 7401 *et seq.*) accomplishes the goals of paragraphs (h)(1) and (2) of this section, and meets the requirements pursuant to § 146.91(c)(5), a Director that requires surface air/soil gas monitoring must approve the use of monitoring employed under §§ 98.440 to 98.449 of this chapter. Compliance with §§ 98.440 to 98.449 of this chapter pursuant to this provision is considered a condition of the Class VI permit;	Sec. 3.9
(i) Any additional monitoring, as required by the Director, necessary to support, upgrade, and improve computational modeling of the area of review evaluation required under § 146.84(c) and to determine compliance with standards under § 144.12 of this chapter;	Agency action

(j) The owner or operator shall periodically review the testing and monitoring plan to incorporate monitoring data collected under this subpart, operational data collected under § 146.88, and the most recent area of review reevaluation performed under § 146.84(e). In no case shall the owner or operator review the testing and monitoring plan less often than once every five years. Based on this review, the owner or operator shall submit an amended testing and monitoring plan or demonstrate to the Director that no amendment to the testing and monitoring plan is needed. Any amendments to the testing and monitoring plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at §§ 144.39 or 144.41 of this chapter, as appropriate. Amended plans or demonstrations shall be submitted to the Director as follows: (1) Within one year of an area of review reevaluation; (2) Following any significant changes to the facility, such as addition of monitoring wells or newly permitted injection wells within the area of review, on a schedule determined by the Director; or (3) When required by the Director.	Section 9
(k) A quality assurance and surveillance plan for all testing and monitoring requirements.	

§ 146.91 Reporting requirements. The owner or operator must, at a minimum, provide, as specified in paragraph (e) of this section, the following reports to the Director, for each permitted Class VI well: (a) Semi-annual reports containing: (1) Any changes to the physical, chemical, and other relevant characteristics of the carbon dioxide stream from the proposed operating data; (2) Monthly average, maximum, and minimum values for injection pressure, flow rate and volume, and annular pressure; (3) A description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit; (4) A description of any event which triggers a shut-off device required pursuant to § 146.88(e) and the response taken; (5) The monthly volume and/or mass of the carbon dioxide stream injected over the reporting period and the volume injected cumulatively over the life of the project; (6) Monthly annulus fluid volume added; and (7) The results of monitoring prescribed under § 146.90.	
(b) Report, within 30 days, the results of: (1) Periodic tests of mechanical integrity; (2) Any well workover; and, (3) Any other test of the injection well conducted by the permittee if required by the Director.	
(c) Report, within 24 hours: (1) Any evidence that the injected carbon dioxide stream or associated pressure front may cause an endangerment to a USDW; (2) Any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs; (3) Any triggering of a shut-off system (*i.e.,* down-hole or at the surface); (4) Any failure to maintain mechanical integrity; or. (5) Pursuant to compliance with the requirement at § 146.90(h) for surface air/soil gas monitoring or other monitoring technologies, if required by the Director, any release of carbon dioxide to the atmosphere or biosphere.	Sec. 9.7
(d) Owners or operators must notify the Director in writing 30 days in advance of:	

(1) Any planned well workover; (2) Any planned stimulation activities, other than stimulation for formation testing conducted under § 146.82; and (3) Any other planned test of the injection well conducted by the permittee.	
(e) Regardless of whether a State has primary enforcement responsibility, owners or operators must submit all required reports, submittals, and notifications under subpart H of this part to EPA in an electronic format approved by EPA.	
(f) Records shall be retained by the owner or operator as follows: (1) All data collected under § 146.82 for Class VI permit applications shall be retained throughout the life of the geologic sequestration project and for 10 years following site closure. (2) Data on the nature and composition of all injected fluids collected pursuant to § 146.90(a) shall be retained until 10 years after site closure. The Director may require the owner or operator to deliver the records to the Director at the conclusion of the retention period. (3) Monitoring data collected pursuant to § 146.90(b) through (i) shall be retained for 10 years after it is collected. (4) Well plugging reports, post-injection site care data, including, if appropriate, data and information used to develop the demonstration of the alternative post-injection site care timeframe, and the site closure report collected pursuant to requirements at §§ 146.93(f) and (h) shall be retained for 10 years following site closure. (5) The Director has authority to require the owner or operator to retain any records required in this subpart for longer than 10 years after site closure.	

§ 146.92 Injection well plugging. (a) Prior to the well plugging, the owner or operator must flush each Class VI injection well with a buffer fluid, determine bottomhole reservoir pressure, and perform a final external mechanical integrity test.	Sec. 10.2.1
(b) *Well plugging plan.* The owner or operator of a Class VI well must prepare, maintain, and comply with a plan that is acceptable to the Director. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. The well plugging plan must be submitted as part of the permit application and must include the following information: (1) Appropriate tests or measures for determining bottomhole reservoir pressure; (2) Appropriate testing methods to ensure external mechanical integrity as specified in § 146.89; (3) The type and number of plugs to be used; (4) The placement of each plug, including the elevation of the top and bottom of each plug; (5) The type, grade, and quantity of material to be used in plugging. The material must be compatible with the carbon dioxide stream; and (6) The method of placement of the plugs.	Sec. 10.3 and Attachment D
(c) *Notice of intent to plug.* The owner or operator must notify the Director in writing pursuant to § 146.91(e), at least 60 days before plugging of a well. At this time, if any changes have been made to the original well plugging plan, the owner or operator must also provide the revised well plugging plan. The Director may allow for a shorter notice period. Any amendments to the injection well plugging plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at §§ 144.39 or 144.41 of this chapter, as appropriate.	Sec. 10.1

(d) *Plugging report.* Within 60 days after plugging, the owner or operator must submit, pursuant to § 146.91(e), a plugging report to the Director. The report must be certified as accurate by the owner or operator and by the person who performed the plugging operation (if other than the owner or operator.) The owner or operator shall retain the well plugging report for 10 years following site closure.	Sec. 10.3

§ 146.93 Post-injection site care and site closure. (a) The owner or operator of a Class VI well must prepare, maintain, and comply with a plan for post- injection site care and site closure that meets the requirements of paragraph (a)(2) of this section and is acceptable to the Director. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. (1) The owner or operator must submit the post-injection site care and site closure plan as a part of the permit application to be approved by the Director.	Sec. 11
(2) The post-injection site care and site closure plan must include the following information: (i) The pressure differential between pre-injection and predicted post-injection pressures in the injection zone(s); (ii) The predicted position of the carbon dioxide plume and associated pressure front at site closure as demonstrated in the area of review evaluation required under § 146.84(c)(1); (iii) A description of post-injection monitoring location, methods, and proposed frequency; (iv) A proposed schedule for submitting post-injection site care monitoring results to the Director pursuant to § 146.91(e); and, (v) The duration of the post-injection site care timeframe and, if approved by the Director, the demonstration of the alternative post-injection site care timeframe that ensures non- endangerment of USDWs.	Sec. 11.1 Sec. 11.2 Sec. 11.5 Sec. 1.1 and Sec. 11.3
(3) Upon cessation of injection, owners or operators of Class VI wells must either submit an amended post-injection site care and site closure plan or demonstrate to the Director through monitoring data and modeling results that no amendment to the plan is needed. Any amendments to the post-injection site care and site closure plan must be approved by the Director, be incorporated into the permit, and are subject to the permit modification requirements at §§ 144.39 or 144.41 of this chapter, as appropriate.	Sec. 11.4 and 11.5
(4) At any time during the life of the geologic sequestration project, the owner or operator may modify and resubmit the post-injection site care and site closure plan for the Director's approval within 30 days of such change.	As noted
(b) The owner or operator shall monitor the site following the cessation of injection to show the position of the carbon dioxide plume and pressure front and demonstrate that USDWs are not being endangered.	Sec. 11.2 and 11.5

(1) Following the cessation of injection, the owner or operator shall continue to conduct monitoring as specified in the Director-approved post-injection site care and site closure plan for at least 50 years or for the duration of the alternative timeframe approved by the Director pursuant to requirements in paragraph (c) of this section, unless he/she makes a demonstration under (b)(2) of this section. The monitoring must continue until the geologic sequestration project no longer poses an endangerment to USDWs and the demonstration under (b)(2) of this section is submitted and approved by the Director.	Sec. 11.2 and 11.3
(2) If the owner or operator can demonstrate to the satisfaction of the Director before 50 years or prior to the end of the approved alternative timeframe based on monitoring and other site-specific data, that the geologic sequestration project no longer poses an endangerment to USDWs, the Director may approve an amendment to the post-injection site care and site closure plan to reduce the frequency of monitoring or may authorize site closure before the end of the 50-year period or prior to the end of the approved alternative timeframe, where he or she has substantial evidence that the geologic sequestration project no longer poses a risk of endangerment to USDWs.	Sec. 11.3
(3) Prior to authorization for site closure, the owner or operator must submit to the Director for review and approval a demonstration, based on monitoring and other site-specific data, that no additional monitoring is needed to ensure that the geologic sequestration project does not pose an endangerment to USDWs.	Sec. 11.5
(4) If the demonstration in paragraph (b)(3) of this section cannot be made (*i.e.,* additional monitoring is needed to ensure that the geologic sequestration project does not pose an endangerment to USDWs) at the end of the 50-year period or at the end of the approved alternative timeframe, or if the Director does not approve the demonstration, the owner or operator must submit to the Director a plan to continue post-injection site care until a demonstration can be made and approved by the Director.	Sec. 11.3

§ 146.93 Post-injection site care and site closure. (cont'd) (c) *Demonstration of alternative post-injection site care timeframe.* At the Director's discretion, the Director may approve, in consultation with EPA, an alternative post-injection site care timeframe other than the 50 year default, if an owner or operator can demonstrate during the permitting process that an alternative post-injection site care timeframe is appropriate and ensures non-endangerment of USDWs. The demonstration must be based on significant, site-specific data and information including all data and information collected pursuant to §§ 146.82 and 146.83, and must contain substantial evidence that the geologic sequestration project will no longer pose a risk of endangerment to USDWs at the end of the alternative post-injection site care timeframe. (1) A demonstration of an alternative post-injection site care timeframe must include consideration and documentation of: (i) The results of computational modeling performed pursuant to delineation of the area of review under § 146.84; (ii) The predicted timeframe for pressure decline within the injection zone, and any other zones, such that formation fluids may not be forced into any USDWs; and/or the timeframe for pressure decline to pre-injection pressures; (iii) The predicted rate of carbon dioxide plume migration within the injection zone, and the predicted timeframe for the cessation of migration; (iii) A description of the site-specific processes that will result in carbon dioxide trapping including immobilization by capillary trapping, dissolution, and mineralization at the site;	

(iv) The predicted rate of carbon dioxide trapping in the immobile capillary phase, dissolved phase, and/or mineral phase; (v) The results of laboratory analyses, research studies, and/or field or site-specific studies to verify the information required in paragraphs (iv) and (v) of this section; (vi) A characterization of the confining zone(s) including a demonstration that it is free of transmissive faults, fractures, and micro-fractures and of appropriate thickness, permeability, and integrity to impede fluid (e.g., carbon dioxide, formation fluids) movement; (vii) The presence of potential conduits for fluid movement including planned injection wells and project monitoring wells associated with the proposed geologic sequestration project or any other projects in proximity to the predicted/modeled, final extent of the carbon dioxide plume and area of elevated pressure; (viii) A description of the well construction and an assessment of the quality of plugs of all abandoned wells within the area of review; (ix) The distance between the injection zone and the nearest USDWs above and/ or below the injection zone; and (x) Any additional site-specific factors required by the Director. (2) Information submitted to support the demonstration in paragraph (c)(1) of this section must meet the following criteria: (i) All analyses and tests performed to support the demonstration must be accurate, reproducible, and performed in accordance with the established quality assurance standards; (ii) Estimation techniques must be appropriate and EPA-certified test protocols must be used where available; (iii) Predictive models must be appropriate and tailored to the site conditions, composition of the carbon dioxide stream and injection and site conditions over the life of the geologic sequestration project; (iii) Predictive models must be calibrated using existing information (*e.g.,* at Class I, Class II, or Class V experimental technology well sites) where sufficient data are available; (iv) Reasonably conservative values and modeling assumptions must be used and disclosed to the Director whenever values are estimated on the basis of known, historical information instead of site-specific measurements; (v) An analysis must be performed to identify and assess aspects of the alternative post-injection site care timeframe demonstration that contribute significantly to uncertainty. The owner or operator must conduct sensitivity analyses to determine the effect that significant uncertainty may contribute to the modeling demonstration. (vi) An approved quality assurance and quality control plan must address all aspects of the demonstration; and, (vii) Any additional criteria required by the Director. (viii)	Sec. 11.3

§ 146.93 Post-injection site care and site closure. (cont'd) (d) *Notice of intent for site closure.* The owner or operator must notify the Director in writing at least 120 days before site closure. At this time, if any changes have been made to the original post-injection site care and site closure plan, the owner or operator must also provide the revised plan. The Director may allow for a shorter notice period.	Sec. 11.5
(e) After the Director has authorized site closure, the owner or operator must plug all monitoring wells	Sec. 11.5

in a manner which will not allow movement of injection or formation fluids that endangers a USDW.	Sec. 11.5
(f) The owner or operator must submit a site closure report to the Director within 90 days of site closure, which must thereafter be retained at a location designated by the Director for 10 years. The report must include: (1) Documentation of appropriate injection and monitoring well plugging as specified in § 146.92 and paragraph (e) of this section. The owner or operator must provide a copy of a survey plat which has been submitted to the local zoning authority designated by the Director. The plat must indicate the location of the injection well relative to permanently surveyed benchmarks. The owner or operator must also submit a copy of the plat to the Regional Administrator of the appropriate EPA Regional Office; (2) Documentation of appropriate notification and information to such State, local and Tribal authorities that have authority over drilling activities to enable such State, local, and Tribal authorities to impose appropriate conditions on subsequent drilling activities that may penetrate the injection and confining zone(s); and (3) Records reflecting the nature, composition, and volume of the carbon dioxide stream.	Sec. 11.5
(g) Each owner or operator of a Class VI injection well must record a notation on the deed to the facility property or any other document that is normally examined during title search that will in perpetuity provide any potential purchaser of the property the following information: (1) The fact that land has been used to sequester carbon dioxide; (2) The name of the State agency, local authority, and/or Tribe with which the survey plat was filed, as well as the address of the Environmental Protection Agency Regional Office to which it was submitted; and (3) The volume of fluid injected, the injection zone or zones into which it was injected, and the period over which injection occurred.	Sec. 11.5
(h) The owner or operator must retain for 10 years following site closure, records collected during the post-injection site care period. The owner or operator must deliver the records to the Director at the conclusion of the retention period, and the records must thereafter be retained at a location designated by the Director for that purpose.	Sec. 11.5

§ 146.94 Emergency and remedial response.	
(a) As part of the permit application, the owner or operator must provide the Director with an emergency and remedial response plan that describes actions the owner or operator must take to address movement of the injection or formation fluids that may cause an endangerment to a USDW during construction, operation, and post-injection site care periods. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit.	Sec. 12.1 and Attachment F
(b) If the owner or operator obtains evidence that the injected carbon dioxide stream and associated pressure front may cause an endangerment to a USDW, the owner or operator must: (1) Immediately cease injection; (2) Take all steps reasonably necessary to identify and characterize any release; (3) Notify the Director within 24 hours; and (4) Implement the emergency and remedial response plan approved by the Director.	Sec. 12.1 and Attachment F

(c) The Director may allow the operator to resume injection prior to remediation if the owner or operator demonstrates that the injection operation will not endanger USDWs.	Agency action
(d) The owner or operator shall periodically review the emergency and remedial response plan developed under paragraph (a) of this section. In no case shall the owner or operator review the emergency and remedial response plan less often than once every five years. Based on this review, the owner or operator shall submit an amended emergency and remedial response plan or demonstrate to the Director that no amendment to the emergency and remedial response plan is needed. Any amendments to the emergency and remedial response plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at §§ 144.39 or 144.41 of this chapter, as appropriate. Amended plans or demonstrations shall be submitted to the Director as follows: (1) Within one year of an area of review reevaluation; (2) Following any significant changes to the facility, such as addition of injection or monitoring wells, on a schedule determined by the Director; or (3) When required by the Director.	Sec. 12.1 and Attachment F

APPENDIX G: CO_2 Resistant Cement Technical Specification

CO_2 Resistant Cement

Temperature range (BHST): 40 – 110 degC (104 – 230 degF)

Density range: 12.5 – 16.0 lbm/gal [1.5 – 1.92 SG]

System	Initial		6 months
Portland Cement 15.8 lbm/gal			
CRC 15.8 lbm/gal			
CRC 12.5 lbm/gal			

Physical aspect of conventional Portland and CRC before and after six months in carbon dioxide environments at 280 bars – 90 degC

Properties of the CRC slurry as a function of the density and of the BHCT

Design						
BHCT	40 degC [104 degF]			85 degC [185 degF]		
BHST	50 degC [122 degF]			110 degC [230 degF]		
Specific gravity [lbm/gal]	12.5	14.5	15.8	12.5	14.5	15.8
Rheological properties determined with R1B5						
After mixing						
PV (cp)	247	234	208	264	214	175
T_y (lbf/100ft^2)	4.5	8.5	9	16.5	16.8	11.4
After conditioning at BHCT						
PV (cp)	262	292	207	189	216	226
T_y (lbf/100ft^2)	4.4	11.2	15	9.0	2.2	2.7
10" [deg]	5	8	7	4	3	4
10' [deg]	41	40	32	40	32	33
1' [deg]	9	14	14	10	8	8
Stability	Ok	Ok	Ok	Ok	Ok	Ok
API Fluid loss at BHCT	34	40	54	54	56	50
Thickening time at BHCT						
30 Bc	6h 03min	5h 04min	3h 54min	4h 25min	5h 22min	6h 20min
70 Bc	7h 01min	5h 43min	4h 31min	4h 39min	5h 33min	6h 28min
UCA at BHST						
50 psi	9h 52min	9h 04min	6h 16min	10h 08min	9h 56min	6h 16min
500 psi	11h 24min	11h 20min	8h 04min	10h 36min	10h 36min	6h 52min
CS at 24h [psi]	3036	2396	2982	2459	3463	2882

Schlumberger

Client Cement Support Laboratory
16115 Park Row, Suite 190
Houston, Texas 77084

Laboratory Cement Test Report - CO_2 Resistant EverCRETE®

						Signatures
Fluid No : CCS08040004	Client	: ADM Company	Location	: Illinois Basin		Terry Dammel
Date : Jun-6-2008	Well Name	: CO2 Injection	Field	: Mt. Simon		Lab Specialist

Job Type	Casing	Depth	7500 ft	TVD	7500 ft
BHST	130 degF	BHCT	110 degF	BHP	2900 psi
Starting Temp.	80 degF	Time to Temp.	00:29 hr:mn	Heating Rate	1.03 degF/min
Starting Pressure	400 psi	Time to Pressure	00:29 hr:mn	Schedule	9.5-2

Composition

Slurry Density	15.80 lb/gal	Yield	1.09 ft3/sk	Mix Fluid	3.42 gal/sk
Solid Vol. Fraction	58.0 %	Porosity	42.0 %	Slurry type	Other

EverCRETE® Blend 1.9 SG_pilot

Code	Mass Per Sack
D189 CSL Hou	30 lb
S100 CLS Hou	57 lb
D195 CLS Hou	2 lb
D178 CSL Hou	11 lb

Code	Concentration	Sack Reference	Component	Blend Density	Lot Number
1.9 SG_pilot		100 lb of BLEND	Blend	2.54 g/cm3	W2007.0150
Mix water	3.16 gal/sk		Base Fluid		
D175	0.03 gal/sk		Antifoam		W2002-0033
D168	0.17 gal/sk		Fluid loss		W2007.0289
D080	0.05 gal/sk		Dispersant		W2007.0398
D081	0.01 gal/sk		Retarder		W2005.0253

Rheology (Average readings) (R1, B1, F1)

(rpm)	(deg)	(deg)
300	163.0	163.0
200	119.5	122.5
100	71.5	75.0
60	48.5	51.5
30	29.5	32.0
6	11.0	11.0
3	8.0	7.0
10 sec Gel		8
10 min Gel		27
1 min Stirring		15
Temperature	80 degF	110 degF
	k : 1.29E-2 lbf.s^n/ft2 n : 0.781 Ty: 3.38 lbf/100ft2	k : 1.92E-2 lbf.s^n/ft2 n : 0.719 Ty: 1.22 lbf/100ft2

Thickening Time Results

Consistency	Time (Lab DI Water)	Time (Corn Processing Water)	Time (Treated Waste Water)
POD :	3:22 hr:mn	2:45 hr:mn	5:24 hr:mn
30 Bc	4:09 hr:mn	3:32 hr:mn	4:20 hr:mn
70 Bc	5:05 hr:mn	4:27 hr:mn	6:18 hr:mn
100 Bc	5:14 hr:mn	4:39 hr:mn	6:29 hr:mn

NOTE: Testing at a higher pressure of 4550 psi in 39 minutes resulted in a thickening time of 4:07 hr:mn to 70 Bc with DI Water. This compares to the time of 5:05 hr:mn at 2900 psi in 29 minutes.

Free Fluid

0.0 mL/250mL	in 2 hrs
At 110 degF and 0 deg incl.	
Sedimentation	None

Fluid Loss

API Fluid Loss			36	mL
18 mL in	30:00 mn:sc	at 110 degF		and 1000 psi

UCA Compressive Strength @ 130°F

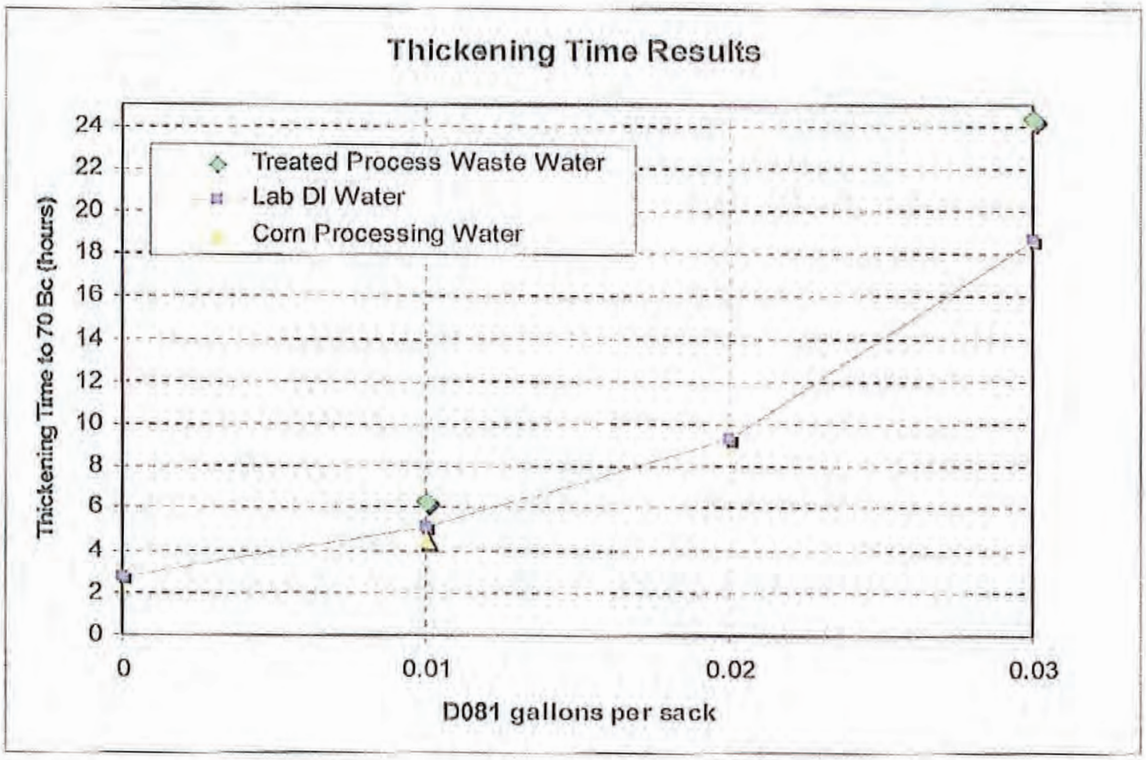
Time	CS
06:04 hr:mn	50 psi
07:25 hr:mn	500 psi
12:00 hr:mn	1604 psi
24:00 hr:mn	3322 psi
72:00 hr:mn	4379 psi

Crush CS (water bath @ 130°F)

Time	CS
24 hours	3230 psi
Time	**Young's Modulus**
24 hours	1,004,400 psi

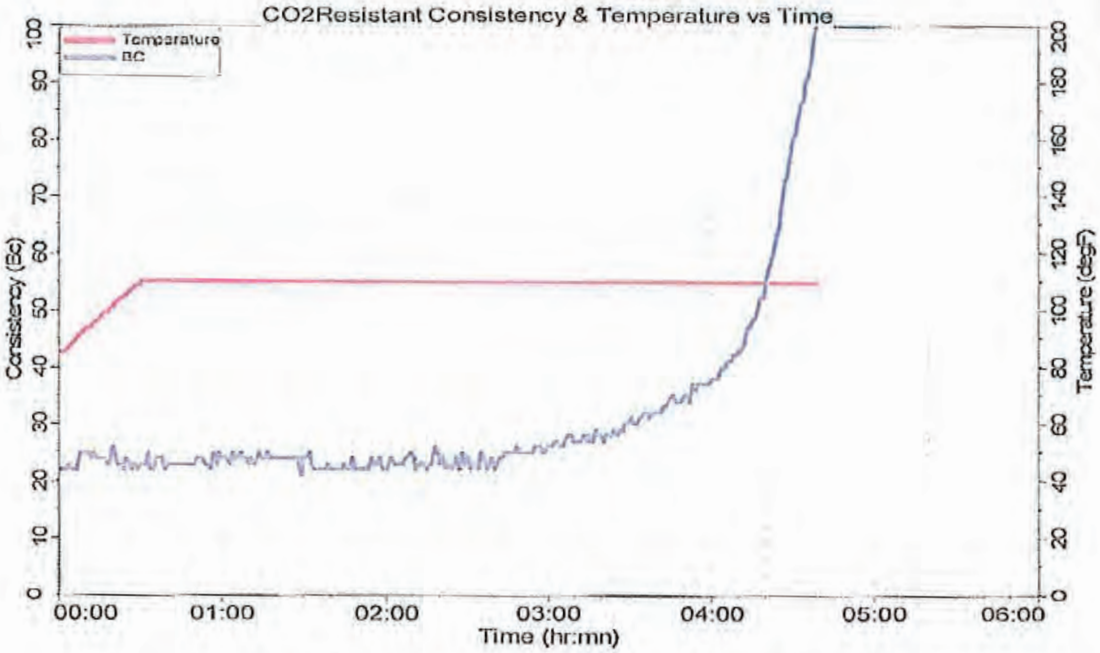
Comments

General Comment: Thickening Time test with new Location Water source from ADM Corn Processing
Fann Reading Comment: R1, B1, F1.
Thickening Time Comment: See attached plot with varying retarder D081 concentrations.
Other test Comment: Fluid Loss tested with filter paper.

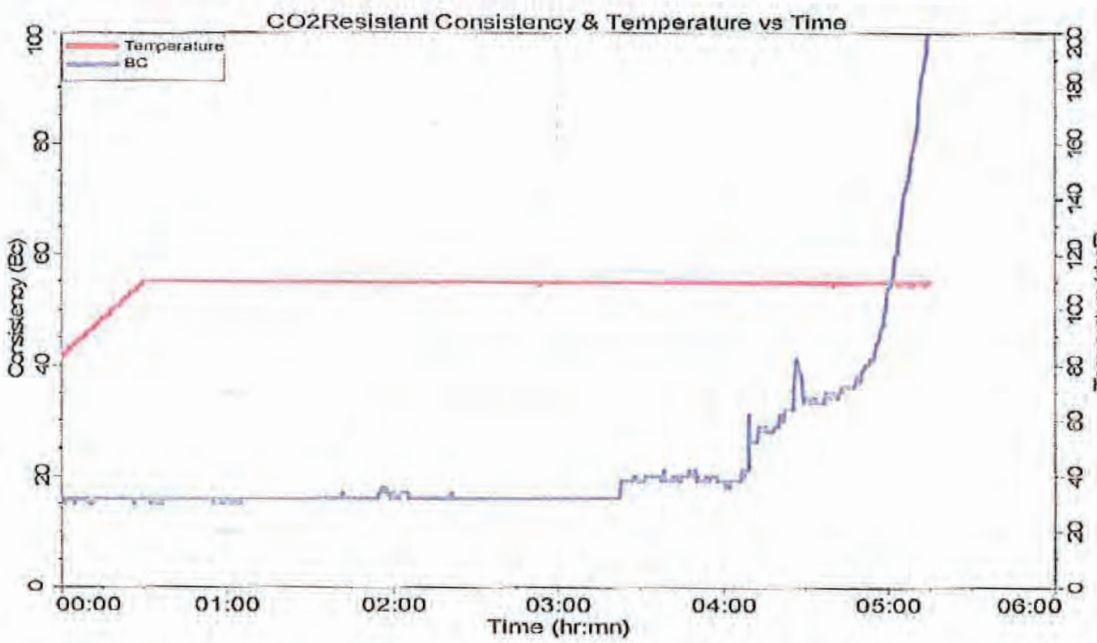


Thickening Time Test with Corn Processing Mix Water

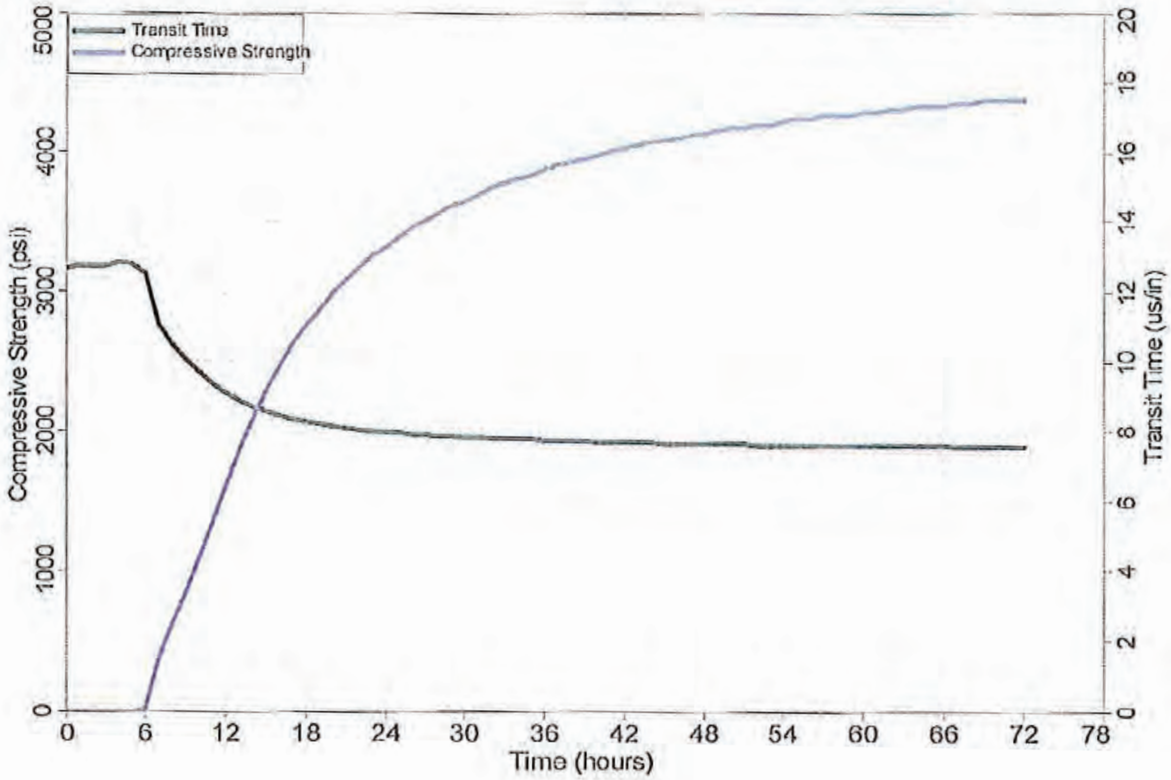
Client : ADM Company	Well : Mt. Simon Sandstone		Schlumberger
String : Casing L/S	District : Illinois Basin		
Country : USA			



Thickening Time Test with Lab DI Mix Water



Ultrasonic Cement Analyzer Strength Test at 130°F


Transit Time
Compressive Strength
Compressive Strength (psi)
Transit Time (us/in)
Time (hours)
0
1000
2000
3000
4000
5000
0
2
4
6
8
10
12
14
16
18
20
0
6
12
18
24
30
36
42
48
54
60
66
72
78

-End-