APPENDIX C: Surficial Aquifer Monitoring Well Locations

Well ID	Well Type	Latitude	Longitude
FG-1	FutureGen Shallow Monitoring Well	39.80675	-90.05283
FGP-1	Private Well	39.79888	-90.0736
FGP-2	Private Well	39.78554	-90.0639
FGP-3	Private Well	39.79497	-90.0746
FGP-4	Private Well	39.79579	-90.0747
FGP-5	Private Well	39.81655	-90.0622
FGP-6	Private Well	39.81086	-90.057560
FGP-7	Private Well	39.81444	-90.065241
FGP-9	Private Well	39.80829	-90.0377
FGP-10	Private Well	39.81398	-90.0427

APPENDIX D: Permanent Gravity Station Locations

Station#	Latitude	Longitude	
0	39.73424	-90.22926	= NGS PID#KC0540, monument at Central Plaza Park, Jacksonville - point tied to 137 on 11/10/11 - this will be the reference used in future surveys.
5	39.79266	-90.07426	Nailed Permanent Stations
21	39.79449	-90.07424	
37	39.79617	-90.07425	
53	39.79814	-90.07427	
65	39.79991	-90.08316	
66	39.79990	-90.08090	
67	39.79989	-90.07886	
68	39.79988	-90.07616	
69	39.79989	-90.07384	
83	39.80164	-90.07889	
86	39.80176	-90.07240	
99	39.80349	-90.07888	
102	39.80352	-90.07239	
107	39.80348	-90.05998	
108	39.80295	-90.05766	
109	39.80332	-90.05519	
110	39.80339	-90.05277	
115	39.80526	-90.07887	
118	39.80529	-90.07237	
126	39.80544	-90.05216	
131	39.80710	-90.07886	
134	39.80721	-90.07154	
135	39.80720	-90.06922	
136	39.80720	-90.06687	
137	39.80727	-90.06485	
147	39.80888	-90.07885	
153	39.80842	-90.06413	
154	39.80894	-90.06224	
163	39.81078	-90.07885	
171	39.81077	-90.06002	
179	39.81248	-90.07884	
187	39.81265	-90.05999	
188	39.81283	-90.05770	
189	39.81286	-90.05538	
193	39.81447	-90.08326	
194	39.81447	-90.08103	
195	39.81451	-90.07870	
196	39.81449	-90.07629	
197	39.81457	-90.07419	
205	39.81443	-90.05513	
206	39.81436	-90.05287	
207	39.81435	-90.05064	
208	39.81437	-90.04825	
213	39.81609	-90.07408	
229	39.81790	-90.07408	

Station#	Latitude	Longitude	
245	39.81971	-90.07407	
246	39.79996722210	-90.08494295	Permanent Stations to be added prior to commencing injection.
247	39.79997642140	-90.08680687	
248	39.79998533330	-90.08861842	
249	39.79999393550	-90.09043265	
250	39.80000198450	-90.09213566	
251	39.80001079270	-90.09400542	
252	39.80001951540	-90.09586339	
253	39.80003000000	-90.09810508	
254	39.81088084490	-90.09544073	
255	39.81088937800	-90.09358759	
256	39.81211009600	-90.0932439	
257	39.81361707930	-90.0931657	
258	39.81450582940	-90.09142522	
259	39.81450590850	-90.08939647	
260	39.81450595100	-90.08745444	
261	39.81450596010	-90.0853458	
262	39.79094794920	-90.07434558	
263	39.78955807990	-90.07434813	
264	39.78808280800	-90.07435083	
265	39.78655838880	-90.07435362	
266	39.78543344990	-90.08777897	
267	39.78542392910	-90.08587085	
268	39.78541218410	-90.0835256	
269	39.78540044900	-90.08119175	
270	39.78540873070	-90.07875712	
271	39.78542609070	-90.07656216	
272	39.78533023230	-90.07434254	
273	39.78541496330	-90.07234073	
274	39.78538771320	-90.07041894	
275	39.78537326690	-90.06835921	
276	39.78537180190	-90.06658679	
277	39.78537006050	-90.06452139	
278	39.78536811720	-90.06226638	
279	39.78533703980	-90.06040206	
280	39.78532614220	-90.05850696	

APPENDIX E: Microseismic Monitoring and Integrated Deformation Station Locations

Well ID/Station ID	Well / Station Type	Latitude (WGS84)	Longitude (WGS84)
MS1	· Microseismic monitoring Station 1(shallow borehole) · Integrated deformation monitoring station	39.8110768	-90.09797015
MS2	· Microseismic monitoring Station 2 (shallow borehole) · Integrated deformation monitoring station	39.78547402	-90.05028403
MS3	· Microseismic monitoring Station 3 (shallow borehole) · Integrated deformation monitoring station	39.81193502	-90.06016279
MS4	· Microseismic monitoring Station 4 (shallow borehole) · Integrated deformation monitoring station	39.78558513	-90.09557015
MS5	· Microseismic monitoring Station 5 (shallow borehole) · Integrated deformation monitoring station	39.80000524	-90.07830287
ACZ1	· Deep microseismic station (deep borehole)	39.80034315	-90.07829648
ACZ2	· Deep microseismic station (deep borehole)	39.80029543	-90.08801028

APPENDIX F: Injection Well Continuous Monitoring Device Locations

Sampling Locations for Continuous Monitoring	
Test Description	**Location**
Annular Pressure Monitoring	Surface
Injection Pressure Monitoring	Surface
Injection Pressure Monitoring - primary	Reservoir - 3,850 feet below ground surface
Injection Rate Monitoring	Surface
Injection Volume Monitoring	Surface
Temperature Monitoring - primary	Surface
Temperature Monitoring	Reservoir - 3,850 feet below ground surface

APPENDIX G: Quality Assurance and Surveillance Plan

FutureGen 2.0 –
CO_2 Pipeline and Storage Project

Quality Assurance and Surveillance Plan

Revision 1

FutureGen Industrial Alliance, Inc.
1101 Pennsylvania Ave., Sixth Floor
Washington, DC 20004

August 2014

A. Project Management

A.1 Title and Approval Sheet

FutureGen 2.0 –
CO_2 Pipeline and Storage Project

Quality Assurance and Surveillance Plan

Revision 1

FutureGen Industrial Alliance, Inc.
1101 Pennsylvania Ave., Sixth Floor
Washington, DC 20004

Approvals:

Project Manager Battelle	Tyler J Gilmore	Date
Monitoring, Verification, and Accounting Task Lead Battelle	Vince R. Vermeul	Date
Project Quality Engineer Battelle	William C. Dey	Date

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Acronyms and Abbreviations

3D	three-dimensional
4D	four-dimensional
ACP	annulus casing packer
ACZ	above confining zone
AMS	accelerator mass spectrometry
AoR	Area of Review
API	American Petroleum Institute
APS	Annulus Pressurization System
ASTM	ASTM International (formerly the American Society for Testing and Materials)
bgs	below ground surface
CCS	carbon capture and storage
CEO	Chief Executive Officer
CFR	Code of Federal Regulations
CMP	Configuration Management Plan
CO_2	carbon dioxide
CVAA	cold vapor atomic absorption
DGPS	Differential Global Positioning System
DIC	dissolved inorganic carbon
DInSAR	Differential Interferometric Synthetic Aperture Radar
DOC	dissolved organic carbon
ECD	electron capture detector
EPA	U.S. Environmental Protection Agency
GC	gas chromatography
GC/FID	gas chromatography with flame ionization detector
GC/HID	gas chromatography with helium ionization detector
GC/MS	gas chromatography-mass spectrometry
GC/SCD	gas chromatograph with sulfur chemiluminescence detector
GPS	Global Positioning System
GS	Geologic Sequestration
HDI	How Do I…? (Pacific Northwest National Laboratory's web-based system for deploying requirements and procedures to staff)
IARF	infinite-acting radial flow
ICP	inductively coupled plasma
ICP-AES	inductively coupled plasma atomic emission mass spectrometry
ICP-MS	inductively coupled plasma mass spectrometry
IRMS	isotope ratio mass spectrometry
ISBT	International Society of Beverage Technologists
LC-MS	liquid chromatography-mass spectrometry
LCS	laboratory control sample

MIT	mechanical integrity testing
MMT	million metric tons
MS	mass spectrometry
MVA	Monitoring, Verification, and Accounting
NA	not applicable
OD	outside diameter
OES	optical emission spectrometry
P	pressure
P/T	pressure-and-temperature
P/T/SpC	pressure, temperature, and specific conductance
PDMP	Project Data Management Plan
PFT	perfluorocarbon tracer
PLC	programmable logic controller
PM	Project Manager
PNC	pulsed-neutron capture
PNWD	Battelle Pacific Northwest Division
QA	quality assurance
QASP	Quality Assurance and Surveillance Plan
QC	quality control
QE	Quality Engineer
RAT	reservoir access tube
RTD	resistance temperature detector
RTK	Real-Time Kinematic
RTU	remote terminal unit
SAR	Synthetic Aperture Radar
SCADA	Supervisory Control and Data Acquisition
$scCO_2$	supercritical carbon dioxide
SLR	single-level in-reservoir
SME	subject matter expert
SNR	signal-to-noise ratio
SpC	specific conductance
T	temperature
TC	thermocouple
TCD	thermal conductivity detector
TDMP	Technical Data Management Plan
TIC	total inorganic carbon
TOC	total organic carbon
UIC	Underground Injection Control
USDW	underground source of drinking water
VOA	Volatile Organic Analysis
WS-CRDS	wavelength scanned cavity ring-down spectroscopy

Definitions

Injection interval: The open (e.g., perforated) section of the injection well, through which the carbon dioxide (CO_2) is injected.

Injection zone: A geologic formation, group of formations, or part of a formation that is of sufficient areal extent, thickness, porosity, and permeability to receive CO_2 through a well or wells associated with a geologic sequestration project.

Prover: A device that verifies the accuracy of a gas meter.

Reservoir: A subsurface body of rock having sufficient porosity and permeability to store and transmit fluids (Schlumberger Oilfield Glossary). Used interchangeably with injection zone.

Sigma: A measure of the decay rate of thermal neutrons as they are captured.

A.3 Distribution List

Table A.1 lists the individuals that should receive a copy of the approved Quality Assurance and Surveillance Plan (QASP) and any subsequent revisions.

Table A.1. Distribution List

Name	Organization	Project Role(s)	Contact Information (telephone / email)
K. Humphreys	FutureGen Industrial Alliance, Inc.	Chief Executive Officer	202-756-2492 Khumphreys@futgen.org
T. J. Gilmore	Battelle PNWD	Project Manager	509-371-7171 Tyler.Gilmore@pnnl.gov
W. C. Dey	Battelle PNWD	Quality Engineer	509-371-7515 William.Dey@pnnl.gov
V. R. Vermeul	Battelle PNWD	Task Lead – Monitoring, Verification, and Accounting; Groundwater Quality Monitoring; CO_2 Plume and Pressure-Front Tracking	509-371-7170 Vince.Vermeul@pnnl.gov
M. E. Kelley	Battelle Columbus	Task Lead − CO_2 Injection Stream Monitoring; Corrosion Monitoring; External Well Integrity Testing	614-424-3704 kelleym@battelle.org
A. Bonneville	Battelle PNWD	Task Lead – Indirect Geophysical Monitoring	509-371-7263 Alain.Bonneville@pnnl.gov
R. D. Mackley	Battelle PNWD	Task Lead – USDW Groundwater Geochemical Monitoring, and Indicator Parameter Monitoring	509-371-7178 rdm@pnnl.gov
F. A. Spane	Battelle PNWD	Task Lead – Hydrologic Testing; Pressure Fall-Off Testing	509-371-7087 Frank.Spane@pnnl.gov

A.4 Project/Task Organization

The high-level project organizational structure for the FutureGen 2.0 CO_2 Pipeline and Storage Project is shown in Figure A.1 (Alliance 2013a).

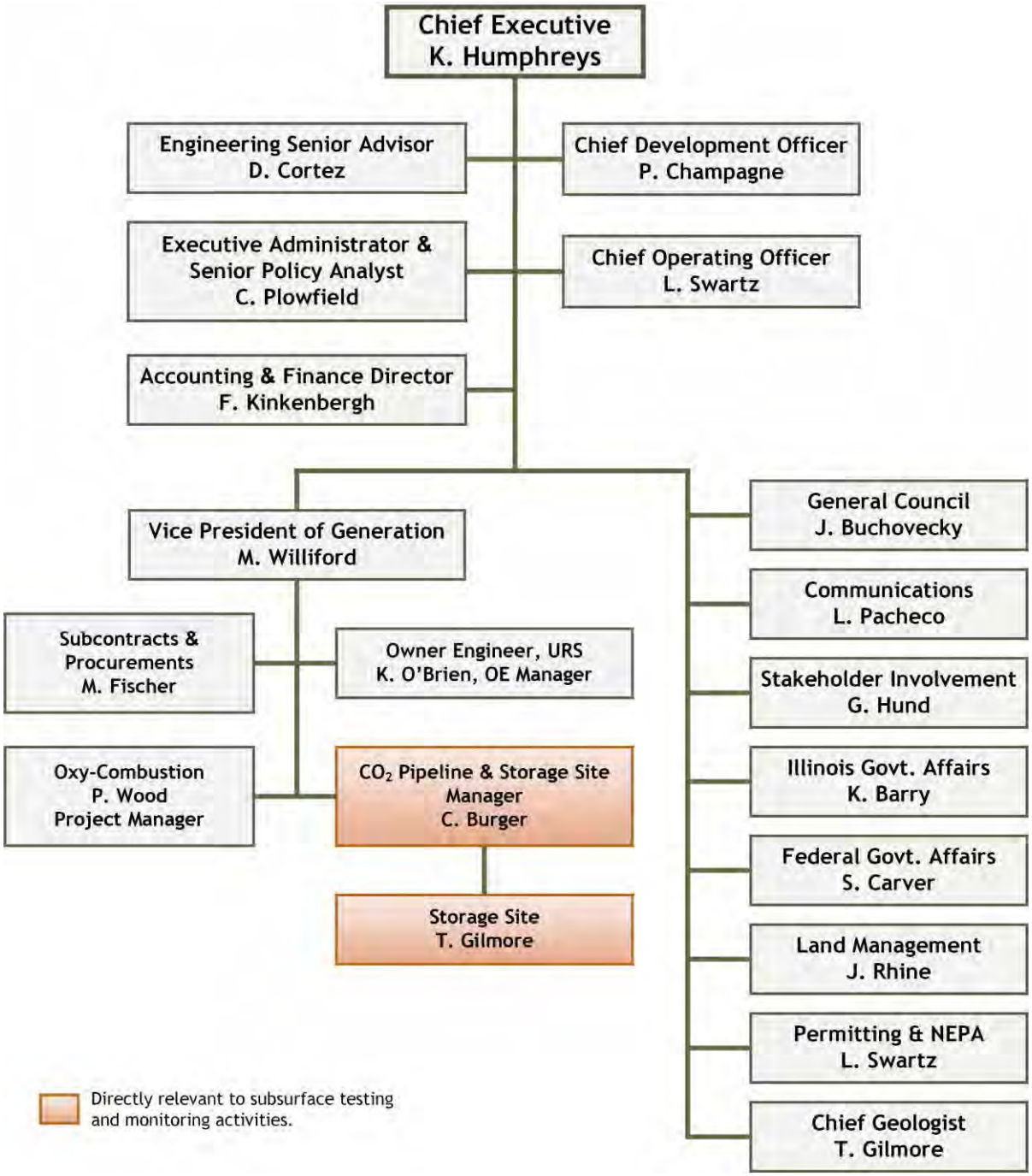

Figure A.1. CO_2 Pipeline and Storage Project Structure (after Alliance 2013a)

The organizational structure specific to well testing and monitoring is shown in Figure A.2.

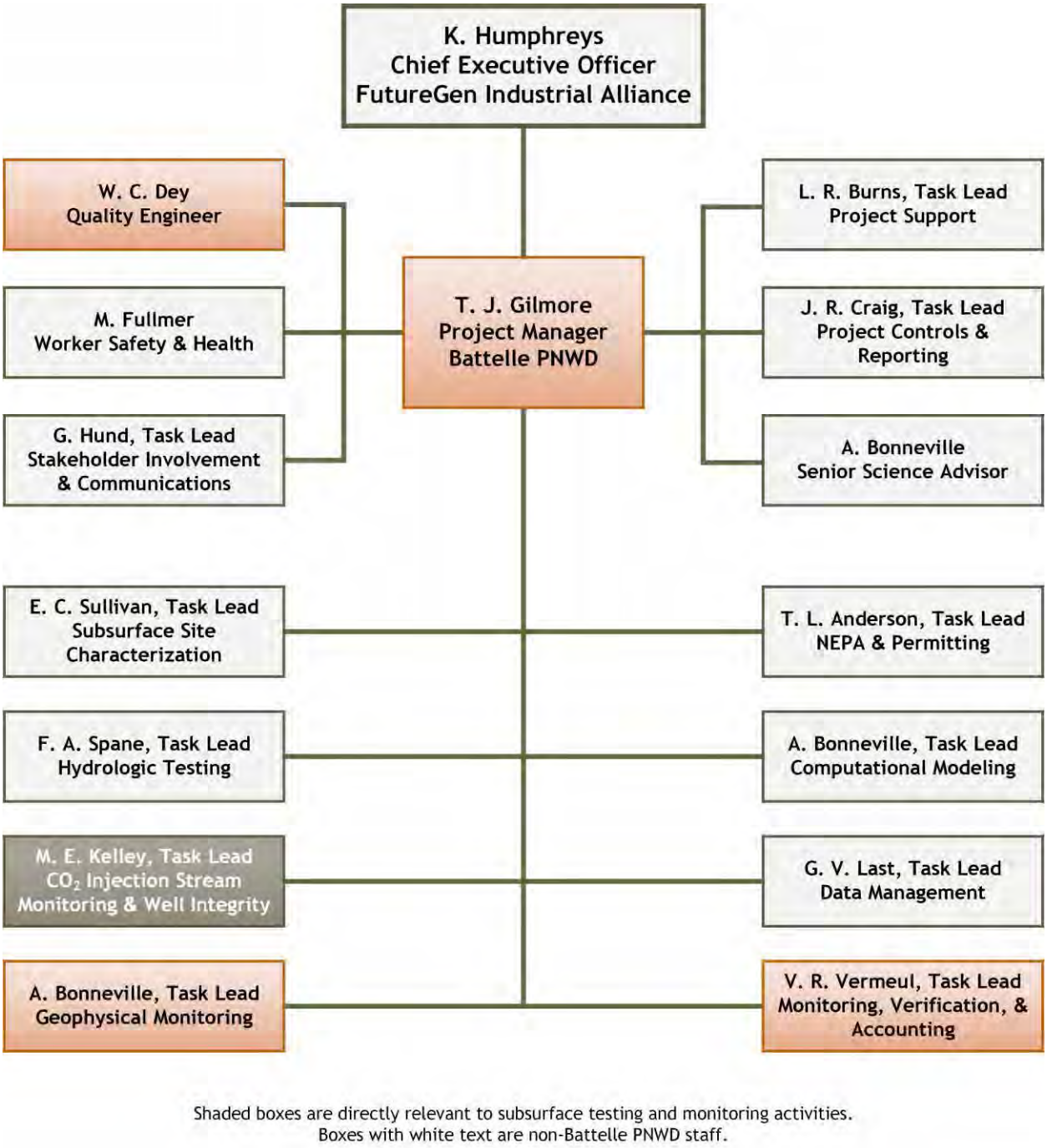

Figure A.2. Task Level Project Organization Relevant to Well Testing and Monitoring

A.4.1 Alliance Chief Executive Officer

The FutureGen 2.0 CO_2 Pipeline and Storage Project is led by the Chief Executive Officer (CEO) of the FutureGen Industrial Alliance, Inc. (Alliance), who is responsible on a day-to-day basis for the project. The Alliance CEO reports to a board of directors composed of industry executives (one executive for each company contributing funds on an equal basis to the Alliance).

A.4.2 Project Manager

The Project Manager (PM) plays a central role in the implementation of all data gathering and analysis for the CO_2 Pipeline and Storage Project and provides overall coordination and responsibility for all organizational and administrative aspects. The PM is responsible for the planning, funding, schedules, and controls needed to implement project plans and ensure that project participants adhere to the plan.

A.4.3 Quality Engineer

The role of the Quality Engineer (QE) is to identify quality-affecting processes and to monitor compliance with project requirements. The QE is responsible for establishing and maintaining the project quality assurance plans and monitoring project staff compliance with them. The QE is responsible for ensuring that this Quality Assurance and Surveillance Plan (QASP) meets the project's quality assurance requirements.

A.4.4 Monitoring, Verification, and Accounting Task Lead

Well testing and monitoring activities are the responsibility of the Monitoring, Verification, and Accounting (MVA) Task Lead. The MVA Task Lead is responsible for developing, maintaining, and updating all well testing and monitoring plans, including this QASP.

A.4.5 Subject Matter Experts/Subtask Task Leads

Well Testing and Monitoring Subject Matter Experts (SMEs) and Task Leads comprise both internal (Battelle Pacific Northwest Division [PNWD]) and external (Battelle Columbus and other subcontractors) geologists, hydrologists, chemists, atmospheric scientists, ecologists, etc. The role of these SMEs is to develop testing and monitoring plans, to collect environmental data specified in those plans using best practices, and to maintain and update those plans as needed.

The SMEs, assisted by the MVA Task Lead, are responsible for planning, collecting, and ensuring the quality of testing and monitoring data and managing all necessary metadata and provenance for these data. The SMEs are also often responsible for data analysis and data products (e.g., publications), and acquisition of independent data quality/peer reviews.

A.5 Problem Definition/Background

A.5.1 Purpose and Objectives

The FutureGen CO_2 Pipeline and Storage Project is part of the larger FutureGen 2.0 Project aimed at demonstrating the technical feasibility of oxy-combustion technology as an approach to implementing carbon capture and storage (CCS) from new and existing coal-fueled energy facilities. The advancement of CCS technology is critically important to addressing CO_2 emissions and global climate change concerns associated with coal-fueled energy. The objective of this project is to design, build, and operate

a commercial-scale CCS system capable of capturing, treating, and storing the CO_2 off-gas from a oxy-combustion coal-fueled power plant located in Meredosia, Morgan County, Illinois. Using safe and proven pipeline technology, the CO_2 will be transported to a nearby storage site, located near Jacksonville, Illinois, where it will be injected into the Mount Simon and Eau Claire formations at a rate of 1.1 million metric tons (MMT) of CO_2 each year, for a planned duration of at least 20 years.

The objective of the CO_2 Pipeline and Storage project is to demonstrate utility-scale integration of transport and permanent storage of captured CO_2 in a deep geologic formation (a.k.a. geologic sequestration) and to demonstrate that this can be done safely and ensure that the injected CO_2 is retained within the intended storage reservoir.

A.5.2 Background

The U.S. Environmental Protection Agency (EPA) established requirements for CO_2 geologic sequestration under the Underground Injection Control (UIC) Program for Geologic Sequestration (GS) Class VI Wells. These federal requirements (codified in the U.S. Code of Federal Regulations [40 CFR 146.81 et seq.], known as the Class VI Rule) set minimum technical criteria for CO_2 injection wells for the purposes of protecting underground sources of drinking water (USDWs). Testing and Monitoring Requirements (40 CFR 146.90) under the Class VI Rule require owners or operators of Class VI wells to develop and implement a comprehensive testing and monitoring plan that includes injectate monitoring; corrosion monitoring of the well's tubular, mechanical, and cement components; pressure fall-off testing; groundwater quality monitoring; and CO_2 plume and pressure-front tracking. These requirements (40 CFR 146.90[k]) also require owners and operators to submit a QASP for all testing and monitoring requirements.

This QASP details all aspects of the testing and monitoring activities that will be conducted, and ensures that they are verifiable, including the technologies, methodologies, frequencies, and procedures involved. As the project evolves, this QASP will be updated in concert with the Testing and Monitoring Plan.

A.6 Project/Task Description

The FutureGen CO_2 Pipeline and Storage Project will undertake testing and monitoring as part of its MVA program to verify that the Morgan County CO_2 storage site is operating as permitted and is not endangering any USDWs. The MVA program includes operational CO_2 injection stream monitoring, well corrosion and mechanical integrity testing, geochemical and indicator parameter monitoring of both the reservoir and shallow USDWs, and indirect geophysical monitoring, for characterizing the complex fate and transport processes associated with CO_2 injection. Table A.2 summarizes the general Testing and Monitoring tasks, methods, and frequencies.

Table A.2. Monitoring Tasks, Methods, and Frequencies by Project Phase

Monitoring Category	Monitoring Method	Baseline 3 yr	Injection (startup) ~3 yr	Injection ~2 yr	Injection ~15 yr	Post-Injection 50 yr
CO_2 Stream Analysis	Grab sampling and analysis	3 events, during commissioning	Quarterly	Quarterly	Quarterly	NA
Continuous Recording of Injection Pressure, Rate, and Annulus Pressure	Continuous monitoring of injection process (injection rate, pressure, and temperature; annulus pressure and volume)	NA	Continuous	Continuous	Continuous	NA
Corrosion Monitoring	Corrosion coupon monitoring of Injection Well Materials	NA	Quarterly	Quarterly	Quarterly	NA
Groundwater Quality Monitoring	Fluid sample collection and analysis in all ACZ and USDW monitoring wells	3 events	Quarterly	Semi-Annual	Annual	Every 5 yr
	Electronic P/T/SpC probes installed in ACZ and USDW wells	1 yr min	Continuous	Continuous	Continuous	Continuous
External Well Mechanical Integrity Testing	PNC and Temperature logging	Once after well completion	Annual	Annual	Annual	Annual until wells plugged
	Cement-evaluation and casing inspection logging	Once after well completion	During well workovers	During well workovers	During well workovers	NA
Pressure Fall-Off Testing	Injection well pressure fall-off testing	NA	Every 5 yr	Every 5 yr	Every 5 yr	NA
Direct CO_2 Plume and Pressure-Front Monitoring	Fluid sample collection and analysis in SLR monitoring wells	3 events	Quarterly	Semi-Annual	Annual	Every 5 yr
	Electronic P/T/SpC probes installed in SLR wells	1 yr min	Continuous	Continuous	Continuous	Continuous
Indirect CO_2 Plume and Pressure-Front Monitoring	Passive seismic monitoring (microseismicity)	1 yr min	Continuous	Continuous	Continuous	Continuous
	Integrated deformation monitoring	1 yr min	Continuous	Continuous	Continuous	Continuous
	Time-lapse gravity	3 events	Annual	Annual	Annual	NA
	PNC logging of RAT wells	3 events	Quarterly	Quarterly	Annual	Annual

ACZ = above confining zone; NA = not applicable; PNC = pulsed-neutron capture; P/T/SpC = pressure, temperature, and specific conductance; RAT = reservoir access tube; SLR = single-level in-reservoir; USDW = underground source of drinking water.

A.6.1 CO_2 Injection Stream and Corrosion/Well Integrity Monitoring

The CO_2 injection stream will be continuously monitored at the surface for pressure, temperature, and flow, as part of the instrumentation and control systems for the FutureGen 2.0 CO_2 Pipeline and Storage Project. Periodic grab samples will also be collected and analyzed to track CO_2 composition and purity.

The pressure and temperature will be monitoring within each injection well at a position located immediately above the injection zone at the end of the injection tubing. The downhole sensor will be the point of compliance for maintaining injection pressure below 90 percent of formation fracture pressure.

CO_2 Stream Analysis

The composition and purity of the CO_2 injection stream will be monitored through the periodic collection and analysis of grab samples.

Continuous Recording of Injection Pressure, Rate, and Volume; Annulus Pressure

Pressure monitoring of the CO_2 stream at elevated pressure will be done using local analog gauges, pressure transmitters, or pressure transmitters with local digital readouts. Flow monitoring will be conducted using Coriolis mass type meters. Normal temperature measurements will be made using thermocouples (TCs) or resistance temperature detectors (RTDs). A Supervisory Control and Data Acquisition (SCADA) system will be used to transmit operational power plant, pipeline, and injection well data long distances (~30 mi) for the pipeline and storage project.

Corrosion Monitoring

Samples of injection well materials (coupons) will be periodically monitored for signs of corrosion to verify that the well components meet the minimum standards for material strength and performance and to identify well maintenance needs.

External Well Mechanical Integrity Testing

Wireline logging, including pulsed-neutron capture (PNC) logs (both in the gas-view and oxygen-activation modes) and temperature logs, and cement-evaluation and casing inspection logging, will be conducted to verify the absence of significant fluid movement through potential channels adjacent to the injection well bore and/or to determine the need for well repairs.

A.6.2 Storage Site Monitoring

The objective of the storage site monitoring program is to select and implement a suite of monitoring technologies that are both technically robust and cost-effective and provide an effective means of 1) evaluating CO_2 mass balance (i.e., verify that the site is operating as permitted) and 2) detecting any unforeseen containment loss (i.e., verify that the site is not endangering any USDWs). Both direct and indirect measurements will be used collaboratively with numerical models of the injection process to verify that the storage site is operating as predicted and that CO_2 is effectively sequestered within the targeted deep geologic formation and is fully accounted for. The approach is based in part on reservoir-monitoring wells, pressure fall-off testing, and indirect (e.g., geophysical) methods. Early-detection monitoring wells will target regions of increased leakage potential (e.g., proximal to wells that penetrate the caprock). During baseline monitoring, a comprehensive suite of geochemical and isotopic analyses will be performed on fluid samples collected from the reservoir and overlying monitoring intervals.

These analytical results will be used to characterize baseline geochemistry and provide a metric for comparison during operational phases. Selection of this initial analyte list was based on relevance for detecting the presence of fugitive brine and CO_2. The results for this comprehensive set of analytes will be evaluated and a determination made regarding which analytes to carry forward through the operational phases of the project. This selection process will consider the uniqueness and signature strength of each potential analyte and whether its characteristics provide for a high-value leak-detection capability. Indicator parameters will be used to inform the monitoring program. Once baseline conditions and early CO_2 arrival responses have been established, observed relationships between analytical measurements and indicator parameters will be used to guide less-frequent aqueous sample collection and reduced analytical parameters in later years.

Monitoring Well Network (Geochemical and Indicator Parameter Monitoring)

The monitoring well network will address transport uncertainties by using an "adaptive" or "observational" approach to monitoring (i.e., the monitoring approach will be adjusted as needed based on observed monitoring results).

Two aquifers above the primary confining zone will be monitored for any unforeseen leakage of CO_2 and/or brine out of the injection zone. These include the aquifer immediately above the confining zone (Ironton Sandstone, monitored with above confining zone [ACZ] wells) and the St. Peter Sandstone, which is separated from the Ironton by several carbonate and sandstone formations and is considered to be the lowermost USDW. In addition to directly monitoring for CO_2, wells will initially be monitored for changes in geochemical and isotopic signatures that may provide indication of CO_2 leakage. Wells will also be instrumented to detect changes in the stress regime (via pressure in all wells and microseismicity in selected wells) to avoid over-pressurization within the injection or confining zones that could compromise sequestration performance (e.g., caprock fracturing). Table A.3 describes the planned monitoring well network for geochemical and indicator parameter monitoring. Figure A.3 illustrates the nominal monitoring well layout.

Table A.3. Planned Monitoring Wells in the Network

	Single-Level In-Reservoir (SLR)	Above Confining Zone (ACZ)	USDW
Number of Wells	2	2	1
Total Depth (ft)	4,150	3,470	2,000
Monitored Zone	Mount Simon SS	Ironton SS	St. Peter SS
Monitoring Instrumentation	P/T/SpC probe in monitored interval[(a)]	Fiber-optic (microseismic) cable cemented in annulus; P/T/SpC probe in monitored interval[(a)]	P/T/SpC probe in monitored interval[(a)]

(a) The P/T/SpC probe is an electronic downhole multi-parameter probe incorporating sensors for measuring fluid pressure (P), temperature (T), and specific conductance (SpC) within the monitored interval. The probe will be installed inside a tubing string, which is perforated (slotted) over the monitoring interval. Measurements will be recorded with a data logger at each well location and also transmitted to the MVA data center in the control building.

SS = sandstone.

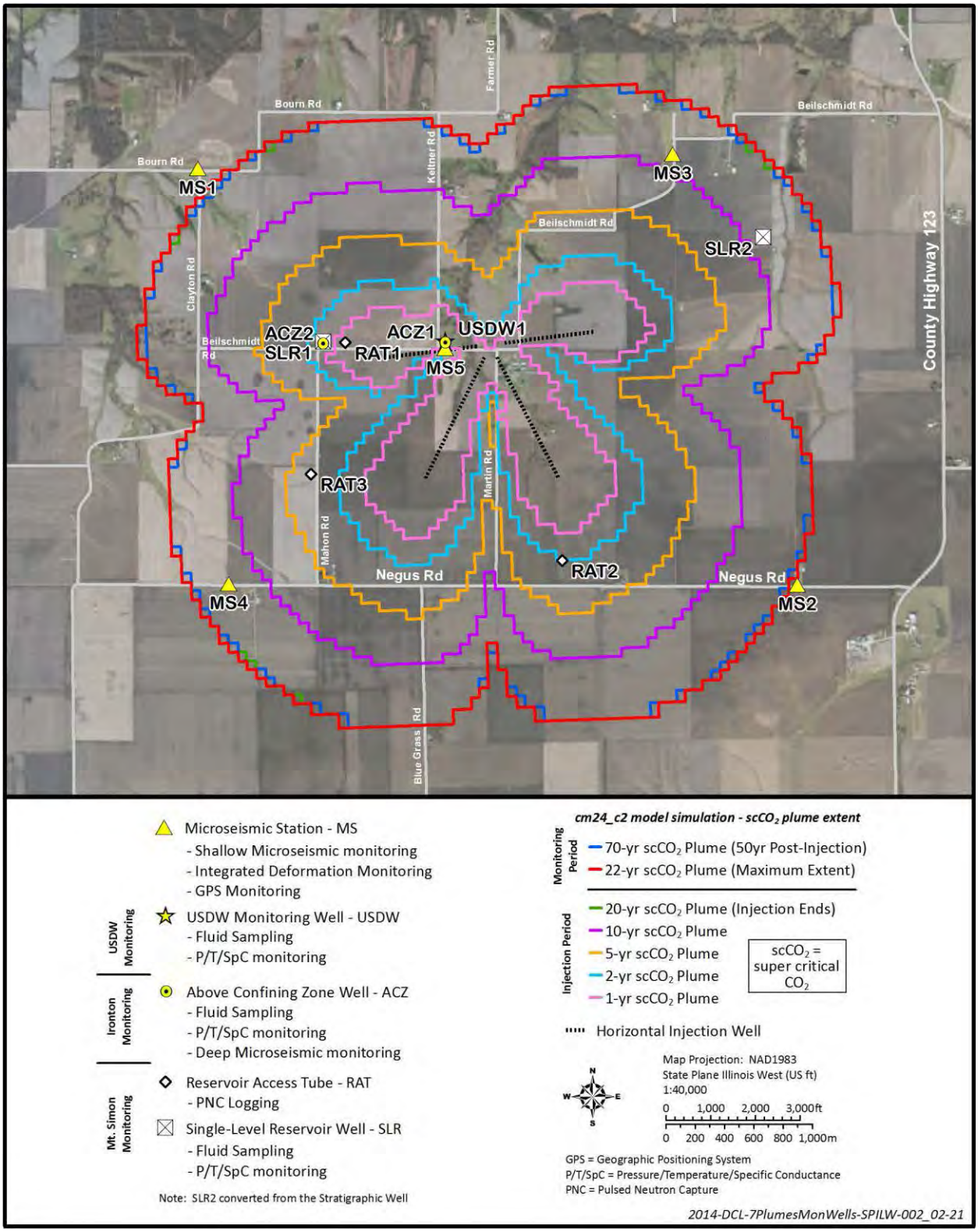

Figure A.3. Nominal Monitoring Well Layout and Modeled Supercritical CO_2 ($scCO_2$) Plume at different times. Note that the monitoring well locations are approximate and subject to landowner approval.

Groundwater Quality Monitoring

Fluid sampling (and subsequent geochemical analyses) and continuous monitoring of indicator parameters will be conducted at each ACZ and USDW monitoring well.

Indicator Parameter Monitoring – Fluid pressure, temperature, and specific conductance (P/T/SpC) will be monitored continuously. These are the most important parameters to be measured in real time within the monitoring interval of each well. These are the primary parameters that will indicate the presence of CO_2 or CO_2-induced brine migration into the monitored interval. A data-acquisition system will be located at the surface to store the data from all sensors at the well site and will periodically transmit the stored data to the MVA data center in the control building.

In addition, in the two ACZ wells, a fiber-optic cable with integral geophones (fiber Bragg grating optical accelerometer) will extend from ground surface to the monitoring interval (i.e., to the annulus casing packer [ACP] just above the monitoring interval); this cable will be strapped to the outside of the casing and permanently cemented in place to support the microseismic monitoring program. Data from the fiber-optic sensors will be transmitted back to the MVA data center via a local-area fiber-optic network where the data-acquisition system will be located.

Geochemical Monitoring – Aqueous samples will be collected from each ACZ and USDW well, initially on a quarterly basis and decreasing in frequency as the system stabilizes over time, to determine the hydrochemistry in the monitoring interval fluids.

CO_2 Plume and Pressure-Front Tracking

Fluid sampling (and subsequent geochemical analyses) and continuous monitoring of indicator parameters will be conducted at each single-level in-reservoir (SLR) monitoring well.

Indicator Parameter Monitoring – Fluid P/T/SpC will be monitored continuously. They are the most important parameters to be measured in real time within the monitoring interval of each well. They are the primary parameters that will indicate the presence of CO_2 or CO_2-induced brine migration into the monitored interval. A data-acquisition system will be located at the surface to store the data from all sensors at the well site and will periodically transmit the stored data to the MVA data center in the control building.

Geochemical Monitoring – Aqueous samples will be collected from each SLR well, initially on a quarterly basis and decreasing in frequency as the system stabilizes over time, to determine the hydrochemistry in the monitoring interval fluids. Aqueous sampling will not be used to assess CO_2 saturation levels. Once supercritical carbon dioxide ($scCO_2$) arrives, these wells can no longer provide representative fluid samples because of the two-phase fluid characteristics and buoyancy of $scCO_2$.

Indirect CO_2 Plume and Pressure-Front Tracking

The primary objectives of indirect (e.g., geophysical) monitoring are 1) tracking CO_2 plume evolution and CO_2 saturation levels; 2) tracking development of the pressure front; and 3) identifying or mapping areas of induced microseismicity, including evaluating the potential for slip along any faults or fractures identified by microseismic monitoring. Table A.4 summarizes potential geophysical monitoring technologies and identifies those included in the Testing and Monitoring Plan.

Pulsed-Neutron Capture Logging – The monitoring network will also include three reservoir access tube (RAT) installations designed for the collection of PNC logs to indirectly quantify CO_2 saturations within the Mount Simon injection zone or reservoir (Muller et al. 2007). PNC logging will serve as the primary measure for CO_2 saturation changes that occur within the injection zone. These monitoring points will be located within the predicted lateral extent of the 1- to 3-year CO_2 plume based on numerical simulations of injected CO_2 movement. The RAT locations were selected to provide information about CO_2 arrival at different distances from the injection wells and at multiple lobes of the CO_2 plume.

Geophysical Monitoring

Table A.4. Monitoring Technologies and Decision to Include in Monitoring Plans

Technology	Purpose	Analysis & Limitations
Pulsed-Neutron Capture Logging	Monitors CO_2 saturation changes along boreholes. Used for reservoir model calibration and leak detection.	Will provide quantitative CO_2 saturations. Sensitive only to region around the borehole.
Integrated Surface Deformation Monitoring	Monitors subtle changes in the Earth's surface due to geomechanical response to injection.	Will be able to measure expected deformation. Monitor for anomalies in pressure-front development. DInSAR can be difficult in vegetated areas.
Passive Microseismic	For locating fracture opening and slip along fractures or faults; may indicate location of the pressure front.	Can accurately detect seismic events. Not likely to detect limit of CO_2 plume.
Time-Lapse Gravity	Monitors changes in density distribution in the subsurface, caused by the migration of fluids. Relatively inexpensive.	Non-unique solution, must be used in conjunction with integrated surface deformation monitoring.

Passive Microseismic Monitoring – The objective of the microseismic monitoring network is to accurately determine the locations, magnitudes, and focal mechanisms of injection-induced seismic events with the primary goals of 1) addressing public and stakeholder concerns related to induced seismicity; 2) estimating the spatial extent of the pressure front from the distribution of seismic events; and 3) identifying features that may indicate areas of caprock failure and possible containment loss. The proposed seismic monitoring network consists of five shallow borehole stations, surface stations, and two deep borehole stations. The shallow borehole stations will be drilled to at least the uppermost competent bedrock (~100 m). Actual noise levels and sensor magnitude detection limits at the stations will not be determined until after the sensors have been emplaced and monitored for a period of time. The results of this preliminary evaluation will guide the location of a small number (fewer than five) of additional surface stations.

Deep borehole sensors will be clamped to the outside of the casing of the two ACZ monitoring wells and cemented in place. A 24-level three-component borehole array will be installed in each well. The use of 24-level arrays results in a slight improvement in event location, but more importantly offers redundant sensors in case of failure. Optical three-component accelerometers are technically optimal due to their designed long-term performance characteristics.

Time-Lapse Gravity – The objective of this technique is to estimate the areal extent of the CO_2 plume, based on observed changes in density distribution in the subsurface, caused by the migration of fluids. Gravity changes at the surface are expected to be small but averaging many measurements and/or analysis of long-term trends may allow for tracking of the CO_2 plume. The solution is non-unique and is most useful when combined with Differential Global Positioning System (DGPS) surveys and other integrated surface deformation methods and/or seismic surveys. The locations of permanent and proposed permanent station monuments are shown in Figure A.4.

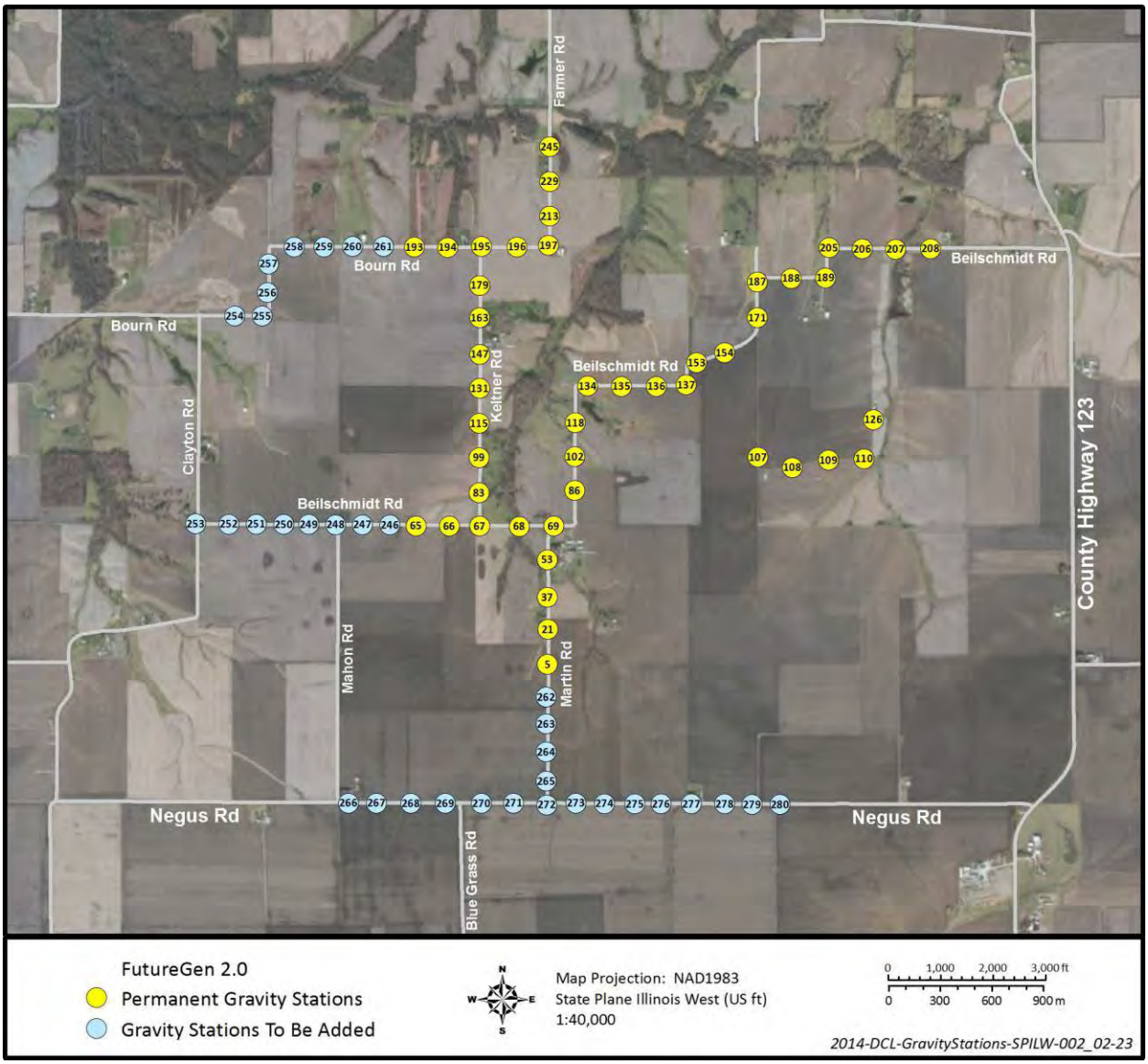

Figure A.4. Locations of Permanent and Proposed Permanent Gravity and Supplemental DGPS Stations

Integrated Deformation Monitoring – Integrated deformation monitoring integrates ground-surface data from permanent Global Positioning System (GPS) stations and tiltmeters, supplemented with annual DGPS surveys and larger-scale Differential Interferometric Synthetic Aperture Radar (DInSAR) surveys to detect and map temporal ground-surface deformation. The DInSAR and proposed GPS network are

expected to resolve sub-centimeter surface changes and accurately measure the anticipated injection-induced surface deformation. Permanent GPS and tiltmeter stations will be co-located with the shallow microseismic locations and are expected to have the spatial coverage needed to characterize the overall shape and evolution of the geomechanical changes that occur as a result of CO_2 injection.

A.7 Quality Objectives and Criteria for Measurement Data

The primary goal of testing and monitoring activities is to verify that the Morgan County CO_2 storage site is operating as permitted and is not endangering any USDWs. The Class VI Rule requires that the owner or operator submit the results of testing and monitoring as part of the required semi-annual reports (40 CFR 146.91(a)(7)).

A.7.1 Quality Objectives

The overall Quality Assurance (QA) objective for testing and monitoring is to provide results, interpretation, and reporting that provide reasonable assurance that decision errors regarding compliance with permitting and protection of USDWs are unlikely. The EPA (2013 EPA 816-R-13-001 – Testing and Monitoring Guidance) provides a number of recommendations that can be used as qualitative measures/criteria against which the testing and monitoring results can be compared to evaluate compliance.

Mechanical Integrity Testing

Demonstrating and maintaining the mechanical integrity of a well is a key aspect of protecting USDWs from possible endangerment and a specific requirement for Class VI wells in the UIC Program. The Class VI Rule requires mechanical integrity testing (MIT) to be conducted prior to injection (40 CFR 146.87(a)(4)), during the injection phase (40 CFR 146.89), and prior to well plugging after injection has ceased (40 CFR 146.92(a)). The EPA further identified a number of acceptable MIT methods.

A Class VI well can be demonstrated to have mechanical integrity if there is no significant leak (i.e., fluid movement) in the injection tubing, packer, or casing (40 CFR 146.89(a)(1)), and if there is no significant fluid movement through channels adjacent to the injection well bore (40 CFR 146.89(a)(2)). Note that the UIC Program Director will evaluate the results and interpretations of MIT to independently assess the integrity of the injection wells.

Operational Testing and Monitoring During Injection

The Class VI Rule requires owners or operators to monitor injectate properties, injection rate, pressure, volume, corrosion of well materials, and perform pressure fall-off testing (40 CFR 146.90(a), (b), (c), and (f)), to indicate possible deviation from planned project operations, verify compliance with permit conditions, and to inform Area of Review (AoR) reevaluations. The results are expected to be interpreted with respect to regulatory requirements and past results. Note the UIC Program Director will evaluate the results to ensure that the composition of the injected stream is consistent with permit conditions and that it does not result in the injectate being classified as a hazardous waste.

Plume and Pressure-Front Tracking

The EPA (2013 EPA 816-R-13-001 – Testing and Monitoring Guidance) indicates that identification of the position of the injected CO_2 plume and the presence or absence of elevated pressure (i.e., the pressure

front) are integral for verifying the storage reservoir is behaving as predicted, informing the reevaluation of the AoR, and protecting the USDWs. The temporal changes will be analyzed by comparing the new data to previously collected data, and time-series graphs will be developed and interpreted for each well, taking into consideration the injection rate and well location. Spatial patterns will also be analyzed by constructing maps that present contours of pressure and/or hydraulic head. Increases in pressure in wells above the confining zone may be indicative of fluid leakage. Increases in pressure within the injection zone will be compared to modeling predictions to determine whether the AoR is consistent with monitoring results. Pressure increases at a monitoring well location greater than predicted by the current site AoR model, or increases at a greater rate, may indicate that the model needs to be revised.

Geochemical Monitoring

The results of groundwater monitoring will be compared to baseline geochemical data collected during site characterization (40 CFR 146.82(a)(6)) to obtain evidence of fluid movement that may affect USDWs. The EPA (2013 EPA 816-R-13-001 – Testing and Monitoring Guidance) suggests that trends in groundwater concentrations may be indicative of fluid leakage—such as changes in total dissolved solids, major cations and anions, increasing CO_2 concentrations, decreasing pH, increasing concentration of injectate impurities, increasing concentration of leached constituents, and/or increased reservoir pressure and/or static water levels. The EPA also suggests that geochemical data be compared to results from rock-water-CO_2 experiments or geochemical modeling.

Note that the UIC Program Director will evaluate the groundwater monitoring data to independently assess data quality, constituent concentrations (including potential contaminants), and the resulting interpretation to determine if there are any indications of fluid leakage and/or plume migration and whether any action is necessary to protect USDWs (EPA 2013 EPA 816-R-13-001 – Testing and Monitoring Guidance).

A.7.2 Measurement Performance/Acceptance Criteria

The qualitative and quantitative design objective of the FutureGen CO_2 Pipeline and Storage Project's testing and monitoring activities is to monitor the performance of the storage reservoir relative to permit and USDW protection requirements. The design of these activities is intended to provide reasonable assurance that decision errors regarding compliance with the permit and/or protection of the USDW are unlikely. In accordance with EPA 2013 EPA 816-R-13-001 – Testing and Monitoring Guidance, the well testing and monitoring program includes operational CO_2 injection stream monitoring, well MIT, geochemical and indicator parameter monitoring of both the reservoir and lowermost USDWs, and indirect geophysical monitoring. Table A.5 lists the field and laboratory analytical parameters, methods, and performance criteria for CO_2 injection stream monitoring. Table A.6 shows the MIT parameters, methods, and performance criteria. Table A.7 lists the groundwater geochemical and indicator parameters, methods, and performance criteria. Table A.8 lists the performance criteria for continuously recorded parameter measurements. Table A.9 lists the indirect geophysical parameters, methods, and performance criteria.

Table A.5. CO_2 Injectate Monitoring Requirements

Analytical Parameter	Analytical Method #	Detection Limit or (Range)	Typical Precision/Accuracy	QC Requirements
Pressure	Analog gauges, pressure transmitters	0-2500 psi	Accuracy: ±0.065% of span	CO_2 Pressure Transmitter, Mfg: Rosemount Part No: 3051TG4A2B21AS5M5Q4
Temperature	Thermocouples, or resistance temperature detectors	0-150 °F	Accuracy: ±0.03% of span	CO_2 Temperature Transmitter Mfg: Rosemount Part No: 644HANAXAJ6M5F6Q4
Flow	Coriolis mass meter	Range spanning maximum anticipated injection rate per well	±0.5 %	A single flow prover will be installed to calibrate the flow meters, and piping and valving will be configured to permit the calibration of each flow meter.
CO_2	GC/TCD	0.1-100%	± 10%	Replicate analyses within 10% of each other
O_2	GC/TCD	0.1-100%	± 10%	Replicate analyses within 10% of each other
Total sulfur	ISBT 14.0 (GC/SCD)	0.01 µL/L to 50 µL/L (ppmv) dilution dependent	± 10%	Daily blank, daily standard within 10% of calibration, secondary standard after calibration
Arsenic	ICP-MS, EPA Method 6020	1 ng/m^3 (filtered volume)	±10%	Daily calibration
Selenium	ICP-MS, EPA Method 6020	5 ng/m^3 (filtered volume)	±10%	Daily calibration
Mercury (Hg)	Cold vapor atomic absorption (CVAA)	0.25 µg/m^3	± 10%	Daily calibration
H_2S	ISBT 14.0 (GC/SCD)	0.01 µL/L to 50 µL/L (ppmv) dilution dependent	± 10%	Daily blank, daily standard within 10% of calibration, secondary standard after calibration
Ar	GC/TCD	0.1-100%	± 10%	Replicate analyses within 10% of each other
Water vapor (moisture)	GC/HID*	< 100 ppm	± 10%	Replicate analyses within 10% of each other

GC/TCD – gas chromatography with a thermal conductivity detector
ISBT – International Society of Beverage Technologists
GC/SCD – gas chromatography with a sulfur chemiluminescence detector
GC/HID - gas chromatography with helium Ionization detector
* Andrawes (1983) or equivalent. Method subject to change in subsequent revisions.

Table A.6. Mechanical Integrity Testing and Corrosion Requirements

Analytical Parameter	Analytical Method #	QC Requirements
Corrosion of Well Tubulars		
Corrosion of well casing and tubing	Corrosion coupon monitoring (visual, weight, and size); U.S. EPA SW846 Method 1110A – "Corrosivity Toward Steel" (or a similar standard method).	Proper preparation of coupons per ASTM G1-03, Standard Practice for Preparing, Cleaning, and Evaluating Corrosion Test Specimens. Refer to SW846 Method 1110A for measurement QC requirements.
Corrosion of well casing (internal radius, wall thickness; general corrosion, pitting, and perforations)	Wireline logging (mechanical, ultrasonic, electromagnetic); casing evaluation would only be done during well workovers that require removal of tubing string.	Vendor calibration of well logging tool(s) per manufacturer recommendations.
Well cement corrosion (quality of cement bond to pipe, and channels in cement)	Wireline logging (acoustic, ultrasonic); casing evaluation would only be done during well workovers that require removal of tubing string.	Baseline cement evaluation logs prior to start of injection. Vendor calibration of well logging tool(s) per manufacturer recommendations
External Mechanical Integrity		
Temperature adjacent to the well	Temperature logging to identify fluid movement adjacent to well bore	Baseline temperature log prior to start of injection. Vendor calibration of well logging tool(s) per manufacturer recommendations
Fluid composition adjacent to the well; fluid movement	Pulsed-neutron logging in oxygen activation mode and thermal capture cross-section (sigma) mode	Baseline log prior to start of injection. Tool calibration per manufacturer recommendations
Internal Mechanical Integrity		
Continuous measurement of fluid pressure and fluid volume in annulus between tubing and long casing string during injection	Pressure and fluid volumes will be measured and logged automatically using electronic pressure sensors and fluid level indicators that are incorporated into the annulus pressurization system (APS).	Initial and ongoing calibration of pressure and fluid level sensors will be done as part of the Annulus Pressurization System Operations and Maintenance program.
Initial annulus pressure test prior to start of injection and following workovers that involve removing tubing and/or packer.	Annular pressure test per EPA UIC requirements	
Pressure Fall-Off Testing		
Well pressure; CO_2 injection rate-history.	Pressure transient analysis methods will be used to analyze pressure fall-off test data to assess well condition (skin) that could indicate need for well rehabilitation.	Initial and ongoing calibration of in-well pressure sensors. Initial and ongoing calibration (proving) of CO_2 flow-rate meters.

Table A.7. Groundwater Geochemical and Indicator Parameter Requirements

Parameter	Analysis Method	Detection Limit or Range	Typical Precision/ Accuracy	QC Requirements
Major Cations: Al, Ba, Ca, Fe, K, Mg, Mn, Na, Si,	ICP-AES, EPA Method 6010B or similar	1 to 80 µg/L (analyte dependent)	±10%	Daily calibration; blanks, LCS, and duplicates and matrix spikes at 10% level per batch of 20
Trace Metals: Sb, As, Cd, Cr, Cu, Pb, Se, Tl	ICP-MS, EPA Method 6020 or similar	0.1 to 2 µg/L (analyte dependent)	±10%	Daily calibration; blanks, LCS, and duplicates and matrix spikes at 10% level per batch of 20
Cyanide (CN-)	SW846 9012A/B	5 µg/L	±10%	Daily calibration; blanks, LCS, and duplicates at 10% level per batch of 20
Mercury	CVAA SW846 7470A	0.2 µg/L	±20%	Daily calibration; blanks, LCS, and duplicates and matrix spikes at 10% level per batch of 20
Anions: Cl^-, Br^-, F^-, SO_4^{2-}, NO_3^-	Ion Chromatography, EPA Method 300.0A or similar	33 to 133 µg/L (analyte dependent)	±10%	Daily calibration; blanks, LCS, and duplicates at 10% level per batch of 20
Total and Bicarbonate Alkalinity (as $CaCO_3^{2-}$)	Titration, Standard Methods 2320B	1 mg/L	±10%	Daily calibration; blanks, LCS, and duplicates at 10% level per batch of 20
Gravimetric Total Dissolved Solids (TDS)	Gravimetric Method Standard Methods 2540C	10 mg/L	±10%	Balance calibration, duplicate samples
Water Density	ASTM D5057	0.01 g/mL	±10%	Balance calibration, duplicate samples
Total Inorganic Carbon (TIC)	SW846 9060A or equivalent Carbon analyzer, phosphoric acid digestion of TIC	0.2 mg/L	±20%	Quadruplicate analyses, daily calibration
Dissolved Inorganic Carbon (DIC)	SW846 9060A or equivalent Carbon analyzer, phosphoric acid digestion of DIC	0.2 mg/L	±20%	Quadruplicate analyses, daily calibration
Total Organic Carbon (TOC)	SW846 9060A or equivalent Total organic carbon is converted to carbon dioxide by chemical oxidation of the organic carbon in the sample. The carbon dioxide is measured using a non-dispersive infrared detector.	0.2 mg/L	±20%	Quadruplicate analyses, daily calibration
Dissolved Organic Carbon (DOC)	SW846 9060A or equivalent Total organic carbon is converted to carbon dioxide by chemical oxidation of the organic carbon in the sample. The carbon dioxide is measured using a non-dispersive infrared detector.	0.2 mg/L	±20%	Quadruplicate analyses, daily calibration
Volatile Organic Analysis (VOA)	SW846 8260B or equivalent Purge and Trap GC/MS	0.3 to 15 µg/L	±20%	Blanks, LCS, spike, spike 1 duplicate per batch of 20
Methane	RSK 175 Mod Headspace GC/FID	10 µg/L	±20%	Blanks, LCS, spike, spike 1 duplicate per batch of 20
Stable Carbon Isotopes $^{13/12}C$ ($1^{13}C$) of DIC in Water	Gas Bench for $^{13/12}C$	50 ppm of DIC	±0.2p	Duplicates and working standards at 10%

Table A.7. (contd)

Parameter	Analysis Method	Detection Limit or Range	Typical Precision/ Accuracy	QC Requirements
Radiocarbon ^{14}C of DIC in Water	AMS for ^{14}C	Range: 0 to 200 pMC	±0.5 pMC	Duplicates and working standards at 10%
Hydrogen and Oxygen Isotopes $^{2/1}H$ (δ) and $^{18/16}O$ ($1^{18}O$) of Water	CRDS H_2O Laser	Range: -500‰ to 200‰ vs. VSMOW	$^{2/1}H$: ±2.0‰ $^{18/16}O$: ±0.3‰	Duplicates and working standards at 10%
Carbon and Hydrogen Isotopes (^{14}C, $^{13/12}C$, $^{2/1}H$) of Dissolved Methane in Water	Offline Prep & Dual Inlet IRMS for ^{13}C; AMS for ^{14}C	^{14}C Range: 0 & DupMC	^{14}C: ±0.5pMC ^{13}C: ±0.2‰ $^{2/1}H$: ±4.0‰	Duplicates and working standards at 10%
Compositional Analysis of Dissolved Gas in Water (including N_2, CO_2, O_2, Ar, H_2, He, CH_4, C_2H_6, C_3H_8, iC_4H_{10}, nC_4H_{10}, iC_5H_{12}, nC_5H_{12}, and C_6+)	Modified ASTM 1945D	1 to 100 ppm (analyte dependent)	Varies by component	Duplicates and working standards at 10%
Radon (^{222}Rn)	Liquid scintillation after pre-concentration	5 mBq/L	±10%	Triplicate analyses
pH	pH electrode	2 to 12 pH units	±0.2 pH unit *For indication only*	User calibrate, follow manufacturer recommendations
Specific Conductance	Electrode	0 to 100 mS/cm	±1% of reading *For indication only*	User calibrate, follow manufacturer recommendations

ICP-AES = inductively coupled plasma atomic emission spectrometry; ICP-MS = inductively coupled plasma mass spectrometry; LCS = laboratory control sample; GC/MS = gas chromatography–mass spectrometry; GC/FID = gas chromatography with flame ionization detector; AMS = accelerator mass spectrometry; CRDS = cavity ring down spectrometry; IRMS = isotope ratio mass spectrometry; LC-MS = liquid chromatography-mass spectrometry; ECD = electron capture detector

Table A.8. Required Minimum Specifications for Real-Time Parameter Measurements

Parameter	Range	Resolution	Accuracy	Additional Requirements
Pressure	0 – 2000 psi	0.05 psi	±2 psi	Calibration per manufacturer recommendations
Temperature	50 – 120 °F	0.1 °F	±2 °F	Calibration per manufacturer recommendations
Specific Conductance	0 – 85 mS/cm	0.002 mS/cm	±0.01 mS/cm	Calibration during sampling events

Table A.9. Indirect Geophysical Monitoring Requirements

Analytical Parameter	Analytical Method #	Detection Limit or (Range)	Typical Precision/Accuracy	QC Requirements
Sigma neutron capture cross section	PNC	Dependent on formation and well completion. Salinity >40 Kppm; porosity >0.10	0.5 c.u.	Manufacturer calibration and periodic recalibration
Carbon/Oxygen inelastic	PNC	Dependent on formation and well completion. Porosity >0.15;	Dependent on log time. Requires slow (5−8 ft/min) logging speed	Manufacturer calibration and periodic recalibration
Temperature	Temperature logging	0-350 °F	0.2 °F	Manufacturer calibration and periodic recalibration
Gamma	Gamma-ray logging	NA	1 count/API	Manufacturer calibration and periodic recalibration
Velocity	Passive seismic: geophone	145 dB; 1−350 Hz	10^{-7} m/s	Manufacturer calibration and periodic recalibration
Velocity	Passive seismic: seismometer	165dB ; 0.01−150 Hz	10^{-9} m/s	Manufacturer calibration and periodic recalibration
Acceleration	Passive seismic: force balance accelerometer	155 dB; DC-200 Hz	10^{-6} m/s^2	Manufacturer calibration and periodic recalibration
Acceleration	Passive seismic: fiber-optic accelerometer	0.01−2000 Hz	< 5. 10^{-7} m/s^2 / √Hz	Manufacturer calibration
Position	Integrated deformation: GPS	NA	5 mm+1 ppm horiz.; 10 mm +1 ppm vert.	Manufacturer calibration and periodic recalibration
Deformation	Integrated deformation: DInSAR	NA	<10 mm	Space Agency calibration
Acceleration	Time-lapse gravity	NA	10^{-8} m/s^2 (10^{-6} Gal)	Manufacturer calibration and periodic recalibration

A.8 Special Training/Certifications

Wireline logging, indirect geophysical methods, and some non-routine sampling will be performed by trained, qualified, and certified personnel, according to the service company's requirements. The subsequent data will be processed and analyzed according to industry standards (Appendix A).

Routine injectate and groundwater sampling will be performed by trained personnel; no specialized certifications are required. Some special training will be required for project personal, particularly in the areas of PNC logging, certain geophysical methods, certain data-acquisition/transmission systems, and certain sampling technologies.

Training of project staff will be conducted by existing project personnel knowledgeable in project-specific sampling procedures. Training documentation will be maintained as project QA records.

A.9 Documentation and Records

The Class VI Rule requires that the owner or operator submit the results of testing and monitoring as part of the required semi-annual reports (40 CFR 146.91(a)(7)). These reports will follow the format and content requirement specified in the final permit, including required electronic data formats.

All data are managed according to the Project Data Management Plan (Bryce et al. 2013). All project records are managed according to the project records management requirements. All data and project records will be stored electronically on secure servers and routinely backed-up.

The FutureGen CO_2 Pipeline and Storage Facility PM (assisted by the QEngineer) will be responsible for ensuring that all affected project staff (as identified in the distribution list) have access to the current version of the approved QASP.

B. Data Generation and Acquisition

The primary goal of testing and monitoring activities is to verify that the Morgan County carbon dioxide (CO_2) storage site is operating as permitted and is not endangering any underground sources of drinking water (USDWs). To this end, the primary objectives of the testing and monitoring program are to track the lateral extent of supercritical carbon dioxide ($scCO_2$) within the target reservoir; characterize any geochemical or geomechanical changes that occur within the reservoir, caprock, and overlying aquifers; monitor any change in land-surface elevation associated with CO_2 injection; determine whether the injected CO_2 is effectively contained within the reservoir; and detect any adverse impact on USDWs.

This element of the Quality Assurance and Surveillance Plan (QASP) addresses data-generation and data-management activities, including experimental design, sampling methods, sample handling and custody, analytical methods, quality controls, and instrumentation/equipment specific to each testing and monitoring method. It should be noted that not all of these QASP aspects are applicable to all testing and monitoring methods. Other QASP aspects, such as inspection/acceptance of supplies and consumables (Section B.12), non-direct measurements (e.g., existing data) (Section B.13), and data management (Section B.14), are applicable to all techniques and are discussed separately.

Well testing and monitoring activities are broken into eight main categories/subtasks, as listed below.

1. CO_2 Injection Stream Analysis – includes CO_2 injection stream gas sampling and chemical analyses. See Section B.1.
2. Continuous Recording of Injection Pressure, Rate, and Volume, and Annulus Pressure. See Section B.2.
3. Corrosion Monitoring – includes sampling and analysis of corrosion coupons. See Section B.3.
4. Groundwater Quality Monitoring – includes formation fluid sampling within the Ironton Sandstone (Above Confining Zone) and St. Peter Sandstone (lowermost USDW) and subsequent geochemical analyses, as well as continuous monitoring of indicator parameters. See Section B.4.
5. External Mechanical Integrity Testing – includes temperature logging and pulsed-neutron capture (PNC) logging (both gas-view and oxygen-activation mode), as well as cement-evaluation and casing inspection logging. See Section B.5.
6. Pressure Fall-Off Testing. See Section B.6.
7. Direct CO_2 Plume and Pressure-Front Tracking − includes all formation fluid sampling within the Mount Simon Sandstone, as well as continuous monitoring of pressure, temperature, and fluid specific conductance. See Section B.7.
8. Indirect CO_2 Plume and Pressure-Front Tracking – includes PNC logging, passive seismic monitoring, integrated deformation monitoring, and time-lapse gravity. Optional supplementary methods may include three-dimensional (3D) multicomponent surface seismic, and multicomponent vertical seismic profiling. See Sections B.8 through B.11.

B.1 Carbon Dioxide Stream Analysis

The Alliance will conduct injection stream analysis to meet the requirements of 40 CFR 146.90(a). This section describes the experimental design, sampling methods, sample handling and custody, analytical methods, quality controls, and instrumentation/equipment specific to CO_2 stream analysis monitoring

activities. Refer to Sections B.12 through B.14 for general descriptions of material inspection/acceptance methods, non-direct measurements (e.g., existing data), and data management.

B.1.1 Sampling Process Design (Experimental Design)

Based on the anticipated composition of the CO_2 stream, a list of parameters has been identified for analysis. Samples of the CO_2 stream will be collected regularly (e.g., quarterly) for chemical analysis.

Table B.1. Parameters and Frequency for CO_2 Stream Analysis

Parameter/Analyte	Frequency
Pressure	Continuous
Temperature	Continuous
CO_2 (%)	quarterly
Water (lb/mmscf)	quarterly
Oxygen (ppm)	quarterly
Sulfur (ppm)	quarterly
Arsenic (ppm)	quarterly
Selenium (ppm)	quarterly
Mercury (ppm)	quarterly
Argon (%)	quarterly
Hydrogen Sulfide (ppm)	quarterly

B.1.2 Sampling Methods

Grab samples of the CO_2 stream will be obtained for analysis of gases, including CO_2, O_2, H_2S, Ar, and water moisture. Samples of the CO_2 stream will be collected from the CO_2 pipeline at a location where the material is representative of injection conditions. A sampling station will be installed in the ground or on a structure close to the pipeline and connected to the pipeline via small-diameter stainless steel tubing to accommodate sampling cylinders that will be used to collect the samples. A pressure regulator will be used to reduce the pressure of the CO_2 to approximately 250 psi so that the CO_2 is collected in the gas state rather than as a supercritical liquid. Cylinders will be purged with sample gas (i.e., CO_2) prior to sample collection to remove laboratory-added helium gas and ensure a representative sample.

B.1.3 Sample Handling and Custody

Samples will be transported to the Monitoring, Verification, and Accounting (MVA) laboratory space in the control building for processing, packaging, and shipment to the contracted laboratory, following standard sample handling and chain-of-custody guidance (EPA 540-R-09-03, or equivalent).

B.1.4 Analytical Methods

Analytical methods are listed in Table A.5

B.1.5 Quality Control

A wide variety of monitoring data will be collected specifically for this project, under appropriate quality assurance (QA) protocols. Data QA and surveillance protocols will be designed to facilitate compliance with requirements specified in 40 CFR 146.90(k).

B.1.6 Instrument/Equipment Testing, Inspection, and Maintenance

For sampling, field equipment will be maintained, serviced, and calibrated per manufacturers' 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 method-specific protocols and the laboratory's QA program, which will be reviewed by the Alliance prior to contract award.

B.1.7 Instrument/Equipment Calibration and Frequency

Calibration of all laboratory instrumentation/equipment will be the responsibility of the analytical laboratory per method-specific protocols and the laboratory's QA program, which will be reviewed by the Alliance prior to contract award.

B.2 Continuous Recording of Injection Pressure, Rate, Volume, and Annulus Pressure

This section describes the experimental design, sampling methods, sample handling and custody, analytical methods, quality controls, and instrumentation/equipment specific to continuous monitoring of injection parameters. Refer to Sections B.12 through B.14 for general descriptions of material inspection/acceptance methods, non-direct measurements (e.g., existing data), and data management.

B.2.1 Sampling Process Design (Experimental Design)

The Alliance will conduct continuous monitoring of injection parameters to meet the requirements of 40 CFR 146.90(b). These activities include continuous recording of injection pressure, temperature, flow rate, and volume, as well as the annulus pressure.

B.2.2 Sampling Methods

Continuous Recording of Injection Pressure and Temperature

An electronic P/T gauge will be installed on the outside of the tubing string, approximately 30 ft above the packer, and ported into the tubing to continuously measure CO_2 injection P/T inside the tubing at this depth. Mechanical strain gauges and thermocouples will be the primary monitoring devices for pressure and temperature.

Injection P/T will also be continuously measured at the surface via real-time P/T instruments installed in the CO_2 pipeline near the pipeline interface with the wellhead. The P/T of the injected CO_2 will be continuously measured for each well. The pressure will be measured by electronic pressure transmitter with analog output mounted on the CO_2 line associated with each injection well. The temperature will be measured by an electronic temperature transmitter mounted in the CO_2 line at a location near the pressure transmitter, and both transmitters will be located near the wellhead. The transmitters will be connected to the Annulus Pressurization System (APS) programmable logic controller (PLC) located in the Control Building adjacent to the injection well pad.

Continuous Recording of Injection Mass Flow Rate

The mass flow rate of CO_2 injected into the well field will be measured by a flow meter skid with a Coriolis mass flow transmitter for each well. Each meter will have analog output (Micro Motion Coriolis Flow and Density Meter Elite Series or similar). A total of six flow meters will be supplied, providing for two spare flow meters to allow for flow meter servicing and calibration. Valving will be installed to select flow meters for measurement and for calibration. A single flow prover will be installed to calibrate the flow meters, and piping and valving will be configured to permit the calibration of each flow meter. The flow transmitters will each be connected to a remote terminal unit (RTU) on the flow meter skid.

The flow meters will be connected to the main CO_2 storage site SCADA system for continuous monitoring and control of the CO_2 injection rate into each well. The flow rate into each well will be controlled using a flow-control valve located in the CO_2 pipeline associated with each well. The control system will be programmed to provide the desired flow rate into three of the four injection wells, with the fourth well receiving the balance of the total flow rate.

B.2.3 Sample Handling and Custody

No specialized sample/data handling procedures are required. Electronic sensor data (e.g., pressure data) will be networked through the local-area fiber-optic network using Ethernet network interfaces back to data-acquisition systems located in the MVA data center.

Electronic data and field records will be transferred to laptop and/or desktop computers and/or backed-up on secured servers at least quarterly, as well as scanned copies of all pertinent hardcopy field records/notes.

B.2.4 Analytical Methods

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

B.2.5 Quality Control

Continuous monitoring equipment will be calibrated according to the manufacturers' recommendations. If trends or other unexplained variability in the data are observed that might indicate a suspect response, instruments will be evaluated and, if required, recalibrated or replaced.

B.2.6 Instrument/Equipment Testing, Inspection, and Maintenance

The surface instruments will be maintained according to manufacturers' recommendations; however, if data trends indicate a suspect response, instruments will be evaluated and, if required, recalibrated or replaced.

B.2.7 Instrument/Equipment Calibration and Frequency

Because the bottom-hole P/T gauge will be attached to the tubing string, the gauge will be recalibrated or replaced only when the injection well tubing string is pulled, which would occur only if warranted by a

downhole issue that can only be addressed by performing a well workover. The surface P/T instruments will be calibrated according to manufacturers' recommendations.

B.3 Corrosion Monitoring

This section describes the experimental design, sampling methods, sample handling and custody, analytical methods, quality controls, and instrumentation/equipment specific to corrosion-monitoring activities. Refer to Sections B.12 through B.14 for general description of material inspection/acceptance methods, non-direct measurements (e.g., existing data), and data management.

B.3.1 Sampling Process Design (Experimental Design)

The Alliance will conduct corrosion monitoring of well materials to meet the requirements of 40 CFR 146.90(c). Corrosion-monitoring activities are designed to monitor the integrity of the injection wells throughout the operational period. This includes using corrosion coupons as well as periodic cement-evaluation and casing inspection logs when tubing is removed from the well (i.e., during well workovers). Corrosion coupons will be made of the same materials as the long string of casing and the injection tubing, and will be placed in the CO_2 pipeline for ease of access.

B.3.2 Sampling Methods

Corrosion monitoring will include corrosion coupons as well as periodic cement-evaluation and casing inspection logs.

Corrosion Coupon Monitoring

Corrosion coupons will be made of the same material as the long string of casing and the injection tubing and placed in the CO_2 injection pipeline. The coupons will be removed quarterly and assessed for corrosion using the ASTM International (ASTM) G1-03, Standard Practice for Preparing, Cleaning, and Evaluating Corrosion Test Specimens (ASTM 2011). Upon removal, coupons will be inspected visually for evidence of corrosion (e.g., pitting). The weight and size (thickness, width, length) of the coupons will also be measured and recorded each time they are removed. The corrosion rate will be calculated as the weight loss during the exposure period divided by the duration (i.e., weight loss method).

Cement-evaluation and Casing Inspection Logging

Cement-evaluation and casing inspection logs will be run periodically, on an opportunistic basis, whenever tubing is removed from the well (i.e., during well workovers). See Section B.5 on external mechanical integrity testing.

B.3.3 Sample Handling and Custody

Corrosion monitoring will include corrosion coupons as well as periodic cement-evaluation and casing inspection logs. No specialized sample handling or chain-of-custody procedures are needed. The coupons will be removed from the pipeline, then taken to the nearby mobile lab (field trailer) where they will be cleaned, inspected, weighed, and measured. They will be immediately returned to the pipeline. Cement-evaluation and casing inspection log data will be handled using best management practices. See Section B.5 on external mechanical integrity testing.

B.3.4 Analytical Methods

The corrosion coupons will be cleaned, inspected visually for evidence of corrosion (e.g., pitting), weighed, and measured each time they are removed (ASTM G1-03, Standard Practice for Preparing, Cleaning, and Evaluating Corrosion Test Specimens). The corrosion rate will be calculated as the weight loss during the exposure period divided by the duration (i.e., weight loss method).

See Section B.5 on external mechanical integrity testing for cement-evaluation and casing inspection logging analytical methods.

B.3.5 Quality Control

Two groups of four replicate corrosion coupons of each material type will be placed in proximity to each other within two different locations within the CO_2 injection pipeline. A third group of four replicate samples of each material type will placed in proximity to each other within a simulated injection pipeline as a control (not exposed to CO_2). All samples will be removed quarterly and subjected to the same visual and measurement methodologies. This approach will allow an evaluation of the potential spatial variability in corrosion rates within the injection tubing, as well as the natural variability between coupon samples. Corrosion rates (calculated as the weight loss during the exposure period divided by the duration, i.e., weight loss method) and statistical analyses (e.g., t-test) will be independently reviewed and documented.

See Section B.5 on external mechanical integrity testing for cement-evaluation and casing inspection logging quality control methods.

B.3.6 Instrument/Equipment Testing, Inspection, and Maintenance

Equipment and instrumentation for visual inspection and measurement of the corrosion coupons will consist of materials to clean corrosion products off the coupons as well as equipment and instrumentation for visual inspection and measurement in accordance with ASTM G1-03. Key inspection and measurement equipment may include calipers, an analytical balance (e.g., electronic scale), and a low-power microscope or hand lens (e.g., 7X to 30X). The analytical balance should be able to measure to with + or -0.2 to 0.02 mg. Calipers should be able to measure to about 1% of the area measured (ASTM G1-03).

Maintenance (e.g., charging, batteries, etc.) and instrument checks will be performed quarterly, prior to each sampling event. All equipment and materials will be visually inspected for damage, calibration dates, battery life, etc. prior to use. Fresh batteries and backup equipment/instrumentation will be stored in the mobile lab/field trailer.

See Section B.5 on external mechanical integrity testing for instrumentation and equipment testing, inspection, and maintenance relative to cement-evaluation and casing inspection logging.

B.3.7 Instrument/Equipment Calibration and Frequency

Calipers, analytical balances, and other measuring and testing instrumentation will be calibrated by the manufacturer, according to its recommended procedures and frequencies. See Section B.5 on external mechanical integrity testing for instrumentation and equipment calibration relative to cement-evaluation and casing inspection logging.

B.4 Groundwater Quality Monitoring (ACZ and USDW wells)

This section describes the experimental design, sampling methods, sample handling and custody, analytical methods, quality controls, and instrumentation/equipment specific to groundwater quality monitoring activities. Refer to Sections B.12 through B.14 for general description of material inspection/acceptance methods, non-direct measurements (e.g., existing data), and data management.

B.4.1 Sampling Process Design (Experimental Design)

The Alliance will conduct ground-water-quality/geochemical monitoring above the confining zone to meet the requirements of 40 CFR 146.90(d).

The planned groundwater quality monitoring well network layout, number of wells, well design, and sampling regimen are based upon site-specific characterization data, and consider structural dip, the locations of existing wells, expected ambient flow conditions, and the potential for heterogeneities or horizontal/vertical anisotropy within the overburden materials (see also Section A.6.2). The planned monitoring network consists of two wells within the first permeable interval immediately above the primary confining zone (Ironton Sandstone), and one well within the lowermost USDW (St. Peter Sandstone) (Figure A.3). The above confining zone (ACZ) wells will be completed in the Ironton Sandstone and monitor for changes in pressure, groundwater chemistry, indicator parameters, and microseismicity. The ACZ monitoring interval is located immediately above the primary confining zone. One of these wells will be located ~1,000 ft west of the injection site adjacent to the western injection lateral; the other will be located ~1,500 ft west of the western injection lateral terminus. The USDW well (USDW1) will be installed at the base of the St. Peter Sandstone to monitor the groundwater quality of the lowermost USDW.

The Alliance plans to conduct periodic fluid sampling as well as continuous pressure, temperature, and specific conductance (P/T/SpC) monitoring throughout the injection phase in the two ACZ monitoring wells and the USDW well. (Table A.3 lists the parameters and instrumentation that will be used at each of the ACZ and USDW monitoring wells. Minimum specifications for the planned continuous measurements are listed in Table A.8.)

The Alliance will also conduct baseline surficial aquifer sampling in the shallow, semi-consolidated glacial sediments, using approximately nine local landowner wells and one well drilled for the project. Because near-surface environmental impacts are not expected, surficial aquifer (<100 ft bgs) monitoring will only be conducted for a sufficient duration to establish baseline conditions (minimum of three sampling events). Surficial aquifer monitoring is not planned during the injection phase; however, the need for additional surficial aquifer monitoring will be continually evaluated throughout the operational phases of the project, and may be reinstituted if conditions warrant.

B.4.2 Sampling Methods

Fluid samples will be collected at monitored formation depths and maintained at formation pressures within a closed pressurized sample container to prevent the escape of dissolved gases. Access to the monitored intervals at the ACZ and USDW monitoring wells will be through the 5-1/2-in. casing that is cemented into the borehole.

Aqueous samples will be collected from each monitoring well, initially on a quarterly basis and later less frequently, to determine the concentration of CO_2 and other constituents in the monitoring interval fluids. The fluid samples will be collected within the open interval of each monitoring well using a flow-through

sampler with a 950-cc (or larger) sample chamber. The samples will be maintained at formation pressure within a closed sample container to prevent the escape of dissolved gases. Prior to sampling, the P/T/SpC probe will be monitored as the well is purged (up to three times the volume of the well-screen section will be discharged from the well before collecting the sample). The probe will then be removed from the well and the sampler will be run into the borehole on the same wireline cable to collect the pressurized fluid sample. Additional purging may be conducted just prior to collection of the pressurized fluid sample if mixing between the fluid column and sampling interval during insertion of the sampler is a concern.

B.4.3 Sample Handling and Custody

After removing the sampler from the well, the closed and pressurized sample container(s) will be transported to the MVA laboratory space in the control building for processing following standard chain-of-custody procedures.

B.4.4 Analytical Methods

The analytical methods for groundwater quality monitoring in the ACZ and USDW wells are summarized in Table A.7.. Where possible, methods are based on standard protocols from EPA or Standard Methods for the Examination of Water and Wastewater (American Public Health Association, American Water Works Association, Water Environment Federation, 19th edition or later, Washington, D.C.). Laboratories shall have standard operating procedures for the analytical methods performed.

B.4.5 Quality Control

The quality control (QC) elements in this section are used to help evaluate whether groundwater samples are free of contamination and whether the laboratories performed the analyses within acceptable accuracy and precision requirements. Several types of field and laboratory QC samples are used to assess and enhance data quality (Table B.2)

Table B.2. Quality Control Samples

Field QC		
Sample Type	Primary Characteristic Evaluated	Frequency
Trip Blank	Contamination from containers or transportation	1 per sampling event
Field Duplicates	Reproducibility	1 per sampling event
Laboratory QC		
Sample Type	Primary Characteristic Evaluated	Frequency
Method Blank	Laboratory contamination	1 per batch
Lab Duplicate	Laboratory reproducibility	(a)
Matrix Spike	Matrix effects and laboratory accuracy	(a)
Matrix Spike Duplicate	Laboratory reproducibility/accuracy	(a)
Laboratory Control Sample	Method accuracy	1 per batch

(a) As defined in the laboratory contract and analysis procedures (typically 1 per 10 samples).

Field QC samples consist of trip blanks and duplicate samples. Trip blanks are preserved sample bottles that are filled with deionized water and transported unopened to the field in the same storage container that will be used for samples collected that day. Trip blanks evaluate bottle cleanliness, preservative purity, equipment decontamination, and proper storage and transport of samples. The frequency of collection for trip blanks is one per sampling event. Field duplicates are replicate samples that are collected at the same well. After each type of bottle is filled, a second, identical bottle is filled for each type of analysis. Both sets of samples are stored and transported together. Field duplicates provide

information about sampling and analysis reproducibility. The collection frequency for field duplicates is one per sampling event.

Laboratory QC samples include method blanks, laboratory duplicates, matrix spikes, matrix spike duplicates, and laboratory control samples (defined below). These samples are generally required by EPA method protocols. Frequencies of analysis are specified in Table B.2 and in the laboratories' standard operating procedures.

- **Method blank** – an analyte-free matrix to which all reagents are added in the same volumes or proportions as used in sample processing. The method blank is carried through the complete preparation and analysis process. Method blanks are used to quantify contamination from the analytical process.
- **Laboratory duplicate** – an intra-laboratory split sample that is used to evaluate the precision of a method in a given sample matrix.
- **Matrix spike** – an aliquot of a sample that is spiked with a known concentration of target analytes(s). The matrix spike is used to assess the bias of a method in a given sample matrix. Spiking occurs prior to sample preparation and analysis.
- **Matrix spike duplicate** – a replicate spiked aliquot of a sample that is subjected to the entire sample preparation and analytical process. Matrix spike duplicate results are used to determine the bias and precision of a method in a given sample matrix.
- **Laboratory control sample** – a control matrix (typically deionized water) spiked with analytes representative of the target analytes or a certified reference material that is used to evaluate laboratory accuracy.

Besides these measures, the laboratories maintain internal QA programs and are subject to internal and external audits.

B.4.6 Instrument/Equipment Testing, Inspection, and Maintenance

For groundwater sampling, field equipment will be maintained, serviced, and calibrated according to the manufacturers' 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 according to method-specific protocols and the laboratory's QA program, which will be reviewed by the Alliance prior to contract award.

B.4.7 Instrument/Equipment Calibration and Frequency

Calibration of all laboratory instrumentation/equipment will be the responsibility of the analytical laboratory according to method-specific protocols and the laboratory's QA program, which will be reviewed by the Alliance prior to contract award.

B.5 External Mechanical Integrity Testing

This section describes the experimental design, sampling methods, sample handling and custody, analytical methods, quality controls, and instrumentation/equipment specific to external mechanical

integrity testing (MIT) activities. Refer to Sections B.12 through B.14 for general descriptions of material inspection/acceptance methods, non-direct measurements (e.g., existing data), and data management.

B.5.1 Sampling Process Design (Experimental Design)

The Alliance will conduct external MIT to meet the requirements of 40 CFR 146.90(e). These tests are designed to include temperature logging, PNC logging, and cement-evaluation logging. An initial (baseline) temperature and PNC logs will be run on the well after well construction but prior to commencing CO_2 injection. These baseline log(s) will serve as a reference for comparing future temperature and PNC logs for evaluating external mechanical integrity.

Temperature Logging

Temperature logs can be used to identify fluid movement along channels adjacent to the well bore. In addition to identifying injection-related flows behind casing, temperature logs can often locate small casing leaks. Injection of CO_2 will have a cooling or heating effect on the natural temperature in the storage reservoirs, depending on the temperature of the injected CO_2 and other factors. Once injection starts, the flowing temperature will stabilize quickly (assuming conditions remain steady).

When an injection well is shut-in for temperature logging, the well bore fluid begins to revert toward ambient conditions. Zones that have taken injectate, either by design or not, will exhibit a "storage" signature on shut-in temperature surveys (storage signatures are normally cold anomalies in deeper wells, but may be cool or hot depending on the temperature contrast between the injectate and the reservoir). Losses behind pipe from the injection zone can be detected on both flowing and shut-in temperature surveys and exhibit a "loss" signature.

For temperature logging to be effective for detecting fluid leaks, there should be a contrast in the temperature of the injected CO_2 and the reservoir temperature. The greater the contrast in the CO_2 when it reaches the injection zone and the ambient reservoir temperature, the easier it will be to detect temperature anomalies due to leakage behind casing. Based on data from the stratigraphic well, ambient bottom-hole temperatures in the Mount Simon Sandstone are expected to be approximately 100°F; the temperature of the injected CO_2 is anticipated to be on the order of 72°F to 90°at the surface (depending on time of year) but will undergo some additional heating as it travels down the well. After the baseline (i.e., prior to injection) temperature log has been run to determine ambient reservoir temperature in each well, it will be possible to determine whether there will be sufficient temperature contrast to make the temperature log an effective method for evaluating external mechanical integrity.

The Alliance will consult the EPA Region 5 guidance for conducting temperature logging (EPA 2008) when performing this test.

Oxygen-Activation Logging

Oxygen activation is a geophysical logging technique that uses a PNC tool to quantify the flow of water in or around a borehole. For purposes of demonstrating external mechanical integrity, a baseline oxygen activation will be run prior to the start of CO_2 injection and compared to later runs to determine changing fluid flow conditions adjacent to the well bore (i.e., formation of channels or other fluid isolation concerns related to the well).

The PNC tool emits high-energy neutrons that interact with water molecules present in the casing-formation annular space, among others. This temporarily activates oxygen (^{16}O) to produce an isotope of nitrogen (^{16}N) that decays back to oxygen with a half-life of 7.1 seconds and emits an easily detected gamma ray. Typical PNC tools have two or three gamma-ray detectors (above and below the neutron source) to detect the movement of the activated molecules, from which water velocity can then be calculated. The depth of investigation for oxygen-activation logging is typically less than 1 ft; therefore, this log type provides information immediately adjacent to the well bore.

Repeat runs will be made under conditions that mimic baseline conditions (e.g., similar logging speeds and tool coefficients) as closely as possible to ensure comparability between baseline and repeat data.

The Alliance will consult the EPA Region 5 guidance for conducting the oxygen-activation logging (EPA 2008) when performing this test.

In addition to oxygen activation logging, the PNC tool will also be run in thermal capture cross-section (sigma) mode to detect the presence of CO_2 outside the casing.

PNC logging will be the primary method used to evaluate the external mechanical integrity of the injection wells.

Cement-Evaluation Logging

Cement evaluation beyond the preliminary cement-bond log is not required for Class VI wells under MIT or corrosion monitoring (40 CFR 146.89 and 146.90). However, it is recognized that cement integrity over time can influence the mechanical integrity of an injection well. Therefore, cement-evaluation logs will be run when tubing is removed from the well (i.e., during well workovers that involve removing the tubing string). Some cement-evaluation logs are also capable of providing information about the condition of the casing string, such as wall thickness and inside diameter (e.g., Schlumberger isolation scanner tool).

B.5.2 Sampling Methods

PNC logging will be the primary method used to evaluate the external mechanical integrity of the injection wells (EPA requires annual MIT demonstrations). PNC and temperature logging will be conducted on an opportunistic basis, for example, when each well is taken out of service. Temperature and PNC logging will be performed through the tubing and therefore will not require removal of the tubing and packer from the well. However, the cement-evaluation and casing-evaluation logging will be conducted only when tubing is removed from the well as this cannot be performed through tubing.

B.5.3 Sample Handling and Custody

No specialized sample/data handling procedures are required. Logging data will be recorded on a computer located in the wireline logging truck. All electronic data and field records will be transferred to laptop and/or desktop computers and backed-up on secure servers at the conclusion of each logging event, as will scanned copies of all pertinent hardcopy field records/notes.

B.5.4 Analytical Methods

Wireline log data will be processed following industry best practices and coordinated with the borehole-logging operator to optimize data-collection parameters. Modeling can be done to simulate near-borehole

interferences and remove their effects from the signal. Modeling is a recommended procedure and requires knowledge of the target formations and fluids that must be obtained from cores and additional logging data. Each logging result will be compared for each well to the baseline or previous survey, as applicable, to determine changes.

B.5.5 Quality Control

Verification of vendor processing software and results will ensure that the acquired data are acceptable and are reproducible. Third-party logging and processing for a subset of boreholes and logging events can be used as part of the validation procedure. Failure of tool performance in the field or unreproducible "repeat sections" will result in non-acceptance of the data, and may trigger a return of the wireline tool to the manufacturer for recalibration or replacement. Off-normal results/comparisons to baseline will trigger additional evaluation and possible new logging runs.

B.5.6 Instrument/Equipment Testing, Inspection, and Maintenance

Examples of industry-published guidelines for calibration and field operation of the pulsed-neutron capture (PNC) wireline log hardware and data-collection software are provided in Appendix A.

B.5.7 Instrument/Equipment Calibration and Frequency

To ensure data acquisition quality, each logging tool will be calibrated for accuracy, checked to be in good working order, and verified by the manufacturer. All tools and field operation software will be provided by the manufacturer with an auditable verification record to ensure traceability. In addition to the initial manufacturer calibration, tool recalibration will be performed monthly and both prior to and after each logging event following the manufacturer's guidelines. Examples of industry-published guidelines for calibration and field operation of wireline log hardware and data-collection software are provided in Appendix B.

B.6 Pressure Fall-Off Testing

This section describes the experimental design, sampling methods, sample handling and custody, analytical methods, quality controls, and instrumentation/equipment specific to pressure fall-off testing activities. Refer to Sections B.12 through B.14 for general descriptions of material inspection/acceptance methods, non-direct measurements (e.g., existing data), and data management.

B.6.1 Sampling Process Design (Experimental Design)

Pressure fall-off testing will be conducted upon completion of the injection wells to characterize reservoir hydrogeologic properties and aquifer response model characteristics (e.g., nonleaky vs. leaky reservoir; homogeneous vs. fractured media) as well as changes in near-well/reservoir conditions that may affect operational CO_2 injection behavior in accordance with 40 CFR 146.87(e)(1). Pressure fall-off testing will also be conducted at least once every five (5) years after injection operations begin, or more frequently if required by the UIC Program Director (40 CFR 146.90 (f)). Specifically, the objective of the periodic pressure fall-off testing is to determine whether any significant changes in the near-wellbore conditions have occurred that may adversely affect well/reservoir performance (e.g., well injectivity, anomalous reservoir pressure behavior). Detailed descriptions for conducting and analyzing pressure fall-off tests are provided by the EPA (2002, 2003, and 2012). These guidelines will be followed when conducting pressure fall-off tests for the FutureGen 2.0 CO_2 Pipeline and Storage Project.

B.6.2 Sampling Methods

Controlled pressure fall-off tests are conducted by terminating injection for a designed period/duration of time. The pressure fall-off test is initiated by terminating injection, shutting-in the well by closing the surface wellhead valve(s), and maintaining continuous monitoring the surface and downhole pressure recovery within the well/test interval system during the fall-off/recovery period. The designed duration of the pressure fall-off recovery test is a function of a number of factors, including the exhibited pre-operational injection reservoir test response characteristics, the injection well history prior to termination (i.e., injection duration, rate history), and potential pressure interference effects imposed by any surrounding injection wells completed within the same reservoir. Because of the potential impact of injection-rate variability on early-time pressure fall-off recovery behavior, the EPA (2012) recommends that injection rates and pressures be uniform and held relatively constant prior to initiating a pressure fall-off test.

Upon shutting-in the well, in-well pressure measurements are monitored continuously in real time, both downhole (within or in proximity to the injection reservoir) and at the surface wellhead location. The EPA (2012) recommends the use of two pressure probes at each location, with one serving as a verification source and the other as a backup/replacement sensor if the primary pressure transducer becomes unreliable or inoperative. The duration of the shut-in period used in conducting the pressure fall-off test should be extended sufficiently beyond wellbore storage effects and when the pressure recovery is indicative of infinite-acting radial flow (IARF) conditions. The establishment of IARF conditions is best determined by using pressure derivative diagnostic analysis plots (Bourdet et al. 1989; Spane 1993; Spane and Wurstner 1993), and is indicated when the log-log pressure derivative/recovery time plot, plots as a horizontal line. When IARF pressure fall-off conditions are indicated, the pressure response vs. log of fall-off/recovery time plots as a straight line on a standard semi-log plot. The EPA (2012) recommends a general rule-of-thumb of extending pressure fall-off tests a factor of three to five beyond the time required to reach radial flow conditions, while Earlougher (1977) suggests extending recovery periods between 1 to 1.5 log cycles beyond when the pressure response starts to deviate from purely wellbore storage response characteristics (i.e., a unit slope, 1:1 on a standard log-log pressure fall-off recovery plot).

For projects like FutureGen 2.0 that will use multiple injection wells completed within the same reservoir zone, the EPA (2012) recommends special considerations to be used for pressure fall-off testing to minimize the pressure response impacts from neighboring injection wells on the pressure fall-off test well recovery response. For the neighboring injection wells (i.e., those not being tested), the EPA (2012) recommends that injection at these wells either should be terminated prior to initiating the pressure fall-off test for a duration exceeding the planned shut-in period, or that injection rates at the neighboring injection wells be held constant and continuously recorded prior to and during the fall-off recovery test. After completion of the fall-off test, additional large-scale areal reservoir hydraulic/storativity characterization information may be derived for the injection reservoir by implementing a stepped-pulse pressure interference signal (by significantly increasing and/or decreasing injection rates) initiated from the neighboring injection wells. The arrival of the observed pulsed pressure signal at the fall-off test well provides information (i.e., due to arrival time and attenuation of the pressure pulse signal) about inter-well reservoir conditions (e.g., hydraulic diffusivity, directional lateral extent of injected CO_2), particularly if compared to pre-injection interference test response characteristics.

B.6.3 Sample Handling and Custody

No specialized sample/data handling procedures are required. Electronic sensor data (e.g., pressure data) will be recorded on data loggers. All electronic data and field records will be transferred to laptop and/or desktop computers and backed-up on secure servers at the conclusion of each test, as well as scanned copies of all pertinent hardcopy field records/notes.

B.6.4 Analytical Methods

Quantitative analysis of the pressure fall-off test response recorded following termination of injection for the test well provides the basis for assessing near well and larger-scale reservoir behavior. Comparison of diagnostic pressure fall-off plots established prior to operational injection of CO_2 and periodic fall-off tests conducted during operational injection phases can be used to determine whether significant changes in well or injection reservoir conditions have occurred. Diagnostic derivative plot analysis (Bourdet et al. 1989; Spane 1993; Spane and Wurstner 1993) of the pressure fall-off recovery response is particularly useful for assessing potential changes in well and reservoir behavior.

The EPA (2002, 2003) provides a detailed discussion on the use of standard semi-log and log-log diagnostic and analysis procedures for pressure fall-off test interpretation. The plotting of downhole temperature concurrent with the observed fall-off test pressure is also useful diagnostically for assessing any observed anomalous pressure fall-off recovery response. Commercially available pressure gauges typically are self-compensating for environmental temperature effects within the probe sensor (i.e., within the pressure sensor housing). However, as noted by the EPA (2012), if temperature anomalies are not accounted for correctly (e.g., well/reservoir temperatures responding differently than registered within the probe sensor), erroneous fall-off pressure response results maybe be derived. As previously discussed, concurrent plotting of downhole temperature and pressure fall-off responses is commonly useful for assessing when temperature anomalies may be affecting pressure fall-off/recovery behavior. In addition, diagnostic pressure fall-off plots should be evaluated relative to the sensitivity of the pressure gauges used to confirm adequate gauge resolution (i.e., excessive instrument noise).

Standard diagnostic log-log and semi-log plots of observed pressure change and/or pressure derivative plots versus recovery time are commonly used as the primary means for analyzing pressure fall-off tests. In addition to determining specific well performance conditions (e.g., well skin) and aquifer hydraulic property and boundary conditions, the presence of prevailing flow regimes can be identified (e.g., wellbore storage, linear, radial, spherical, double-porosity, etc.) based on characteristic diagnostic fall-off pressure derivative patterns. A more extensive list of diagnostic derivative plots for various formation and boundary conditions is presented by Horne (1990) and Renard et al. (2009).

As discussed by the EPA (2002), early pressure fall-off recovery response corresponds to flow conditions within and in proximity to the well bore, while later fall-off recovery response is reflective of progressively more distant reservoir conditions from the injection well location. Significant divergence in pressure fall-off response patterns from previous pressure fall-off tests (e.g., accelerated pressure fall-off recovery rates) may be indicative of a change in well and/or reservoir conditions (e.g., reservoir leakage). A more detailed discussion of using diagnostic plot analysis of pressure fall-off tests for discerning possible changes to well and reservoir conditions is presented by the EPA (2002, 2003).

As indicated by the EPA (2012), quantitative analysis of the pressure fall-off test data can be used to determine formation hydraulic property characteristics (e.g., permeability, transmissivity), and well skin factor (additional pressure change effects due to altering the permeability/storativity conditions of the

reservoir/well injection interval boundary). Determination of well skin is a standard result for pressure fall-off test analysis and is described in standard well-test analysis texts such as that by Earlougher (1977). Software programs are also commercially available (e.g., Duffield 2007, 2009) for analyzing pressure fall-off tests. Significant changes in well and reservoir property characteristics (as determined from pressure fall-off analysis), compared to those used in site computational modeling and AoR delineation, may signify a reevaluation of the AoR, as may be required by the UIC Program Director, as noted by the EPA (2012).

B.6.5 Quality Control

Periodic QC checks will be routinely made in the field, and on occasion, where permanent pressure gauges are used, a second pressure gauge with current certified calibration will be lowered into the well to the same depth as the permanent downhole gauge.

B.6.6 Instrument/Equipment Testing, Inspection, and Maintenance

All field equipment will be visually inspected and tested prior to use. Spare instruments, batteries, etc. will be stored in the field support trailer.

B.6.7 Instrument/Equipment Calibration and Frequency

Pressure gauges that are used to conduct fall-off tests will be calibrated in accordance with manufacturers' recommendations, and current calibration certificates will be provided with test results to the EPA. In lieu of removing the injection tubing to regularly recalibrate the downhole pressure gauges, their accuracy will be demonstrated by comparison to a second pressure gauge, with current certified calibration, that will be lowered into the well to the same depth as the permanent downhole gauge. Calibration curves, based on annual calibration checks (using the second calibrated pressure gauge) developed for the downhole gauge, can be used for the purpose of the fall-off test. If used, these calibration curves (showing all historic pressure deviations) will accompany the fall-off test data submitted to the EPA.

B.7 Carbon Dioxide Plume and Pressure-Front Tracking

This section describes the experimental design, sampling methods, sample handling and custody, analytical methods, quality controls, and instrumentation/equipment specific to CO_2 plume and pressure-front tracking activities. Refer to Sections B.12 through B.14 for general descriptions of material inspection/acceptance methods, non-direct measurements (e.g., existing data), and data management.

B.7.1 Sampling Process Design (Experimental Design)

The Alliance will conduct direct and indirect CO_2 plume and pressure-front monitoring to meet the requirements of 40 CFR 146.90(g). The planned reservoir-monitoring well network design is based on the Alliance's current conceptual understanding of the site and predictive simulations of injected CO_2 fate and transport. The number, layout, design, and sampling regimen of the monitoring wells are based upon site-specific characterization data collected from the stratigraphic well, as well as structural dip, expected ambient flow conditions, and potential for heterogeneities or horizontal/vertical anisotropy within the injection zone and model predictions.

The planned monitoring well network for direct plume and pressure-front monitoring consists of two sets of monitoring wells: single-level in-reservoir (SLR) wells and reservoir access tube (RAT) wells (Figure