KANSAS GEOLOGICAL SURVEY
The University of Kansas

File L - Other Information Required by UIC Program Director

Note: This document contains the original KGS permit that was prepared prior to the new EPA submission format introduced to KGS on June 3rd 2014. All references to figures, tables, and sub-sections that were not included in other permit documents can be found in the original KGS permit, which also contains an Executive Summary, cover letter, application forms, complete table of contents, list of tables and figures, appendices, and a cross reference table which lists sub-sections that address all Class VI 40 CFR sections 146.82 – 146.93 requirements. Therefore, to facilitate the review process, the entire original permit application has been submitted in this document titled "L - Other Information Required by the UIC Program Director."

The items contained in the original KGS permit that were not previously submitted are presented in the following sections:

A Research and Service Division of the University of Kansas
1930 Constant Avenue | Lawrence, KS 66047-3724 | (785) 864-3965 | Fax 785-864-5317 | www.kgs.ku.edu

File L: Other Information Required by the UIC Program Director

Items not Included in Previous Application Documents:

BEREXCO LLC

May 23, 2014

Mr. Ken Hildebrandt
Drinking Water Management Branch
US-EPA Region 7
11201 Renner Boulevard
Lenexa, KS 66219

Re: Berexco, LLC UIC Class 6 Permit Application
Wellington Oil Field Small Scale Carbon Capture and Storage Project, Wellington, KS

Dear Mr. Hildebrandt:

Enclosed please find a hard copy and an electronic version of our Underground Injection Control permit application for the Wellington Oil Field Small Scale Carbon Capture and Storage Demonstration Project. The project is funded by the US Department of Energy with the goal of demonstrating that CO2 can be safely stored in the subsurface and its movement monitored and simulated with computer models.

As documented in the attached application, a maximum of 40,000 metric tons is to be injected in the Arbuckle Group within a nine month period. Based on the computer simulation results, the subsurface foot print of the injected CO_2 is relatively small with a maximum lateral spread of approximately 1,750 feet. Additionally, the induced pore pressures are well below the estimated fracture gradient in the Arbuckle Group.

As Lynn Watney at KGS has communicated to you, we are prepared to meet with you and your team to personally present our project finding and the salient features of our Class VI compliance plans. If you have any questions regarding the application, please feel free to contact me at (316)-265-3311, or Lynn Watney at (785)-864-2184.

Sincerely,

Dana Wreath

Dana Wreath
Vice President
Berexco, LLC

OMB No. 2040-0042 Approval Expires 11/30/2014

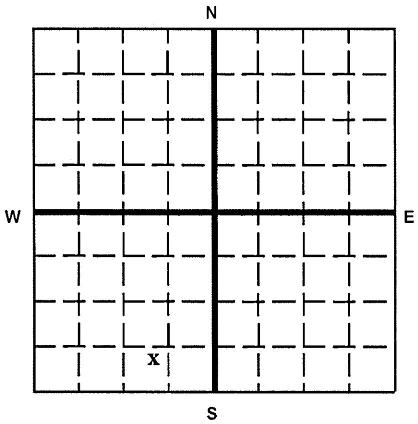
EPA

United States Environmental Protection Agency
Washington, DC 20460

PLUGGING AND ABANDONMENT PLAN

Name and Address of Facility	Name and Address of Owner/Operator
Berexco LLC North Bramblewood Dr., Wichita KS 67206	Berexco LLC North Bramblewood Dr., Wichita KS 67206

Locate Well and Outline Unit on Section Plat - 640 Acres



State	County	Permit Number
Kansas	Sumner	

Surface Location Description

NE 1/4 of sw 1/4 of SE 1/4 of sw 1/4 of Section 28 Township 31S Range 1W

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface Location 560 ft. frm (N/S) S Line of quarter section
and 1700 ft. from (E/W) W Line of quarter section.

TYPE OF AUTHORIZATION

- [x] Individual Permit
- [ ] Area Permit
- [ ] Rule

Number of Wells 1

WELL ACTIVITY

- [ ] CLASS I
- [ ] CLASS II
  - [ ] Brine Disposal
  - [ ] Enhanced Recovery
  - [ ] Hydrocarbon Storage
- [ ] CLASS III

Lease Name Wellington KGS

Well Number Class VI (GS)/ #1-28

CASING AND TUBING RECORD AFTER PLUGGING

SIZE(in)	WT (LB/FT)	TO BE PUT IN WELL (FT)	TO BE LEFT IN WELL (FT)	HOLE SIZE
13-3/8	54.5	125	125	17.5"
8-5/8	24	647	647	12.25"
5-1/2	15.5	5,241	5,241	7.875"

METHOD OF EMPLACEMENT OF CEMENT PLUGS

- [x] The Balance Method
- [ ] The Dump Bailer Method
- [ ] The Two-Plug Method
- [ ] Other

CEMENTING TO PLUG AND ABANDON DATA:	PLUG #1	PLUG #2	PLUG #3	PLUG #4	PLUG #5	PLUG #6	PLUG #7
Size of Hole or Pipe in which Plug Will Be Placed (inches)	4.95	4.95					
Depth to Bottom of Tubing or Drill Pipe (ft.	5155	4910					
Sacks of Cement To Be Used (each plug)	30	100					
Slurry Volume To Be Pumped (cu. ft.)	33	132					
Calculated Top of Plug (ft.)	4910	3930					
Measured Top of Plug (if tagged ft.)	n/a	n/a					
Slurry Wt. (Lb./Gal.)	15	15					
Type Cement or Other Material (Class III)	AA-2	AA-2					

LIST ALL OPEN HOLE AND/OR PERFORATED INTERVALS AND INTERVALS WHERE CASING WILL BE VARIED (if any)

From	To	From	To

Estimated Cost to Plug Wells

Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possiblity of fine and imprisonment. (Ref. 40 CFR 144.32)

Name and Official Title *(Please type or print)*	Signature	Date Signed
DANA WREATH, Vice President	Dana Wreath	May 23, 2014

OMB No. 2040-0042   Approval Expires 11/30/2014

EPA

United States Environmental Protection Agency

Underground Injection Control
Permit Application

(Collected under the authority of the Safe Drinking Water Act. Sections 1421, 1422, 40 CFR 144)

I. EPA ID Number

	T/A	C
U		

Read Attached Instructions Before Starting

For Official Use Only

Application approved (mo day year)	Date received (mo day year)	Permit Number	Well ID	FINDS Number

II. Owner Name and Address

Owner Name		
Berexco LLC		
Street Address		Phone Number
2020 North Bramblewood Dr.		(316) 265-3311
City	State	ZIP CODE
Wichita	KS	67206

III. Operator Name and Address

Owner Name		
Berexco LLC		
Street Address		Phone Number
2020 North Bramblewood Dr.		(316) 265-3311
City	State	ZIP CODE
Wichita	KS	67206

IV. Commercial Facility	V. Ownership	VI. Legal Contact	VII. SIC Codes
[x] Yes [ ] No	[x] Private [ ] Federal [ ] Other	[x] Owner [ ] Operator	1311, 1321, 1381, 1382

VIII. Well Status *(Mark "x")*

[ ] A. Operating	Date Started (mo day year)	[ ] B. Modification/Conversion	[x] C. Proposed

IX. Type of Permit Requested *(Mark "x" and specify if required)*

[x] A. Individual	[ ] B. Area	Number of Existing Wells	Number of Proposed Wells	Name(s) of field(s) or project(s)
		0	1	Wellington Field

X. Class and Type of Well *(see reverse)*

A. Class(es) (enter code(s))	B. Type(s) (enter code(s))	C. If class is "other" or type is code 'x,' explain	D. Number of wells per type (if area permit)
Other (Class VI)	X	Geologic Sequestration	

XI. Location of Well(s) or Approximate Center of Field or Project

Latitude			Longitude			Township and Range							
Deg	Min	Sec	Deg	Min	Sec	Sec	Twp	Range	1/4 Sec	Feet From	Line	Feet From	Line
37	19	10.1	97	26	.451	28	31S	1W	SW	560	S	1700	W

XII. Indian Lands (Mark 'x')

[ ] Yes
[x] No

XIII. Attachments

(Complete the following questions on a separate sheet(s) and number accordingly; see instructions)

For Classes I, II, III, (and other classes) complete and submit on a separate sheet(s) Attachments A--U (pp 2-6) as appropriate. Attach maps where required. List attachments by letter which are applicable and are included with your application.

XIV. Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possiblity of fine and imprisonment. (Ref. 40 CFR 144.32)

A. Name and Title *(Type or Print)*	B. Phone No. *(Area Code and No.)*
Dana Wreath, Vice President Berexco LLC	(316) 337-8331
C. Signature Dana Wreath	D. Date Signed May 23, 2014

EPA Form 7520-6 (Rev. 12-11)

Table of Contents

List of Figures and Tables

Executive Summary

A small-scale pilot carbon capture and storage (CCS) project is proposed by Berexco, LLC, and Kansas Geological Survey at the Wellington oilfield approximately 4 mi northwest of the City of Wellington in Sumner County, Kansas (Figure ES-1). The project is part of a U.S. Department of Energy (DOE) funded pilot-scale study to demonstrate the ability of the 5,000 ft deep Cambrian-Ordovician age Arbuckle saline aquifer to accept and retain carbon dioxide (CO_2) for permanent geologic sequestration. Up to 40,000 tons of CO_2 may be injected in the Arbuckle aquifer over a period of 9 months. The details of the project and EPA Underground Injection Control (UIC) Class VI requirements pertaining to construction, operations, monitoring, well plugging, Area of Review (AoR), post-injection site care and site closure, emergency remedial/response, and financial responsibility are summarized below.

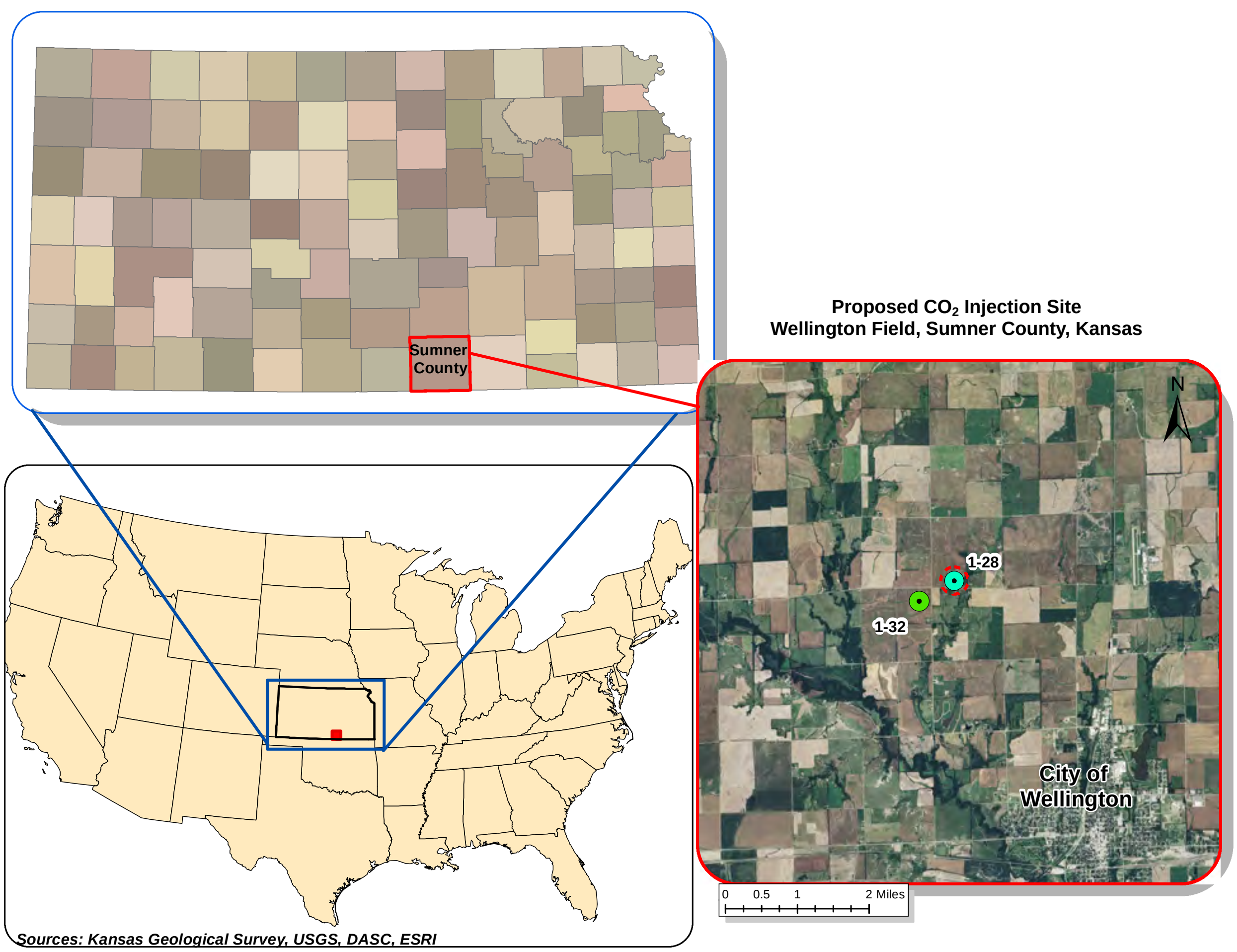


Figure ES-1—Location of small-scale CO_2 storage site at Wellington, Kansas.

Site Setting

The Wellington sequestration site is located in a rural area where land is used primarily for non-irrigated crop cultivation (Figure ES-2). CO_2 injection is to occur at the recently completed well (KGS 1-28), which was constructed per EPA UIC Class VI specifications. There are no potable water wells in the vicinity of the injection well. The EPA AoR based on the maximum extent of plume migration is only 1,700 feet from the well as shown in Figure ES-2.

Geology

Arbuckle Group (Injection Zone)

Figure ES-3 presents the geologic column at the injection well site. The injection is to occur in the 1,000 ft thick regionally extensive Arbuckle Group of Cambrian-Ordovician period, the top of which is located approximately 4,160 ft below ground at the Wellington site. The injection is to occur near the base of the Arbuckle Group, which has higher permeability compared to the rest of the formation.

Simpson Group/Chattanooga Shale/Pierson Formation (Upper Confining Zone)

The Ordovician and Devonian shales within the Simpson Group and Chattanooga Shale, along with the argillaceous siltstone in the Pierson formation of the Mississippian subsystem, have the characteristics of caprock and will therefore function as the top confining zone and effectively prevent upward migration of CO_2. The 240 ft thick confining zone has no known communicative fractures between the Arbuckle injection zone and Mississippian oil and gas reservoir overlying the confining zone. Additionally, there are several thick layers of shale above the upper confining zone as shown in Figure ES-3, which can potentially provide additional impedance to flow but which are not relied on in this application to demonstrate confinement potential.

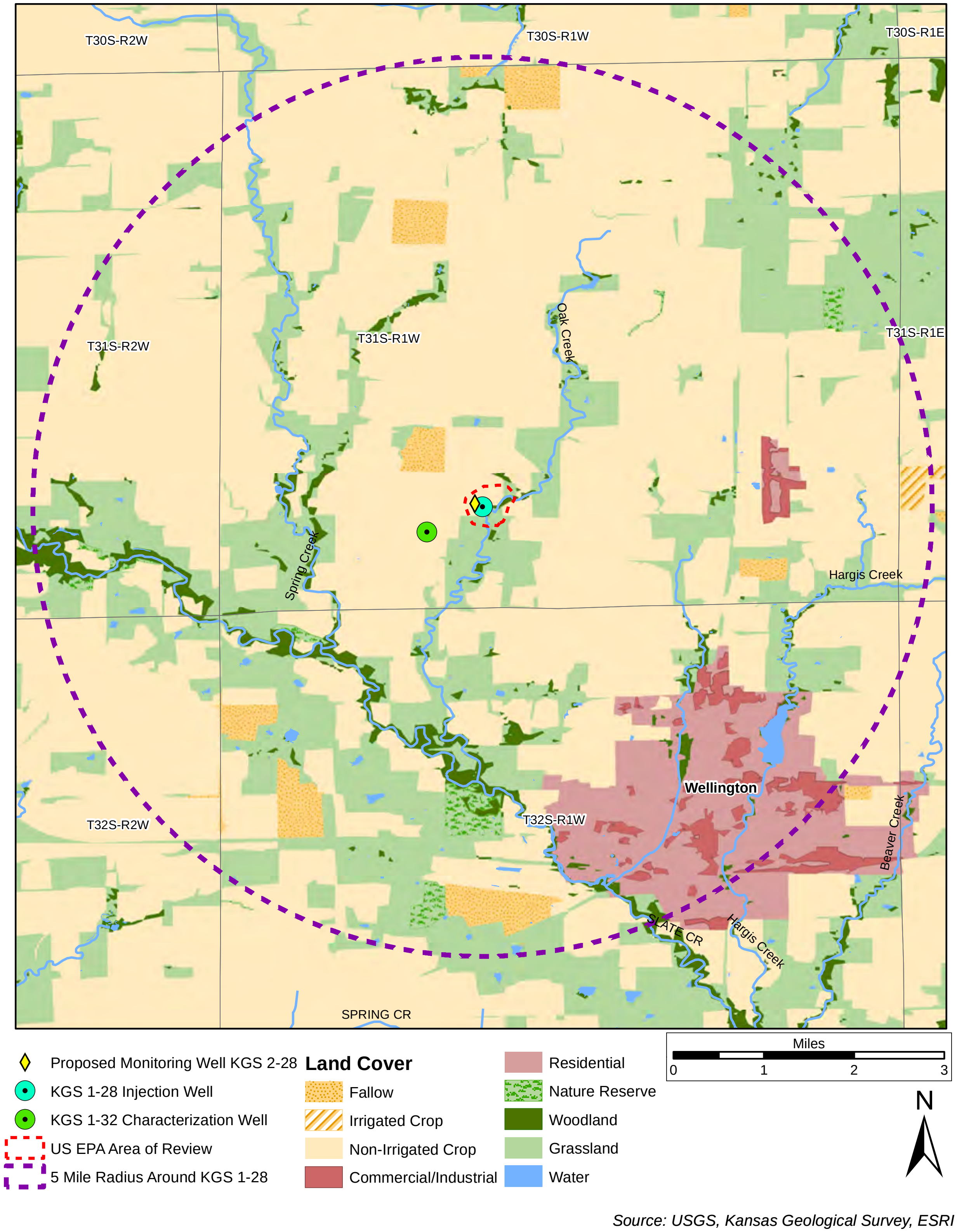


Figure ES-2—Land use in the vicinity of the Wellington small-scale CO_2 storage site.

Precambrian Granitic Basement (Lower Confining Zone)

Precambrian-age basement granites underlie the Arbuckle Group throughout Kansas and are expected to provide hydraulic confinement at the base of the injection zone.

Upper Wellington Formation (USDW)

The lowermost and only Underground Sources of Drinking Water (USDW) extends from land surface to 250 ft below ground and comprises Permian shales in the Upper Wellington Formation as shown in Figure ES-3. Below the Upper Wellington are the Hutchinson Salt Beds, which overlie bedrock shale in the Lower Wellington Formation. The USDW (Upper Wellington formation) lies approximately 4,700 ft above the top of the injection interval (in the lower Arbuckle aquifer). There are no groundwater withdrawals in the vicinity of the Wellington CO_2 storage site.

Estimated Sequestration Capacity of Arbuckle Group

The total amount of CO_2 that could be stored in the Arbuckle Group within Kansas is estimated by the U.S. DOE to be as high 89.5 billion metric tons, the equivalent of several years of annual CO_2 emissions (approximately 6 billion metric tons/year) for the entire United States. Approximately 300,000–360,000 metric tons of CO_2 per square mile can be stored in the Arbuckle aquifer at the Wellington site as shown in Figure ES-4. Only 40,000 metric tons of CO_2 will be injected into the Arbuckle during a period of 9 months. This amount of CO_2, according to DOE estimates, should be stored in an area of 1/10th of a square mile. This estimate, based on analytical methods, was confirmed by the numerical modeling conducted in this study.

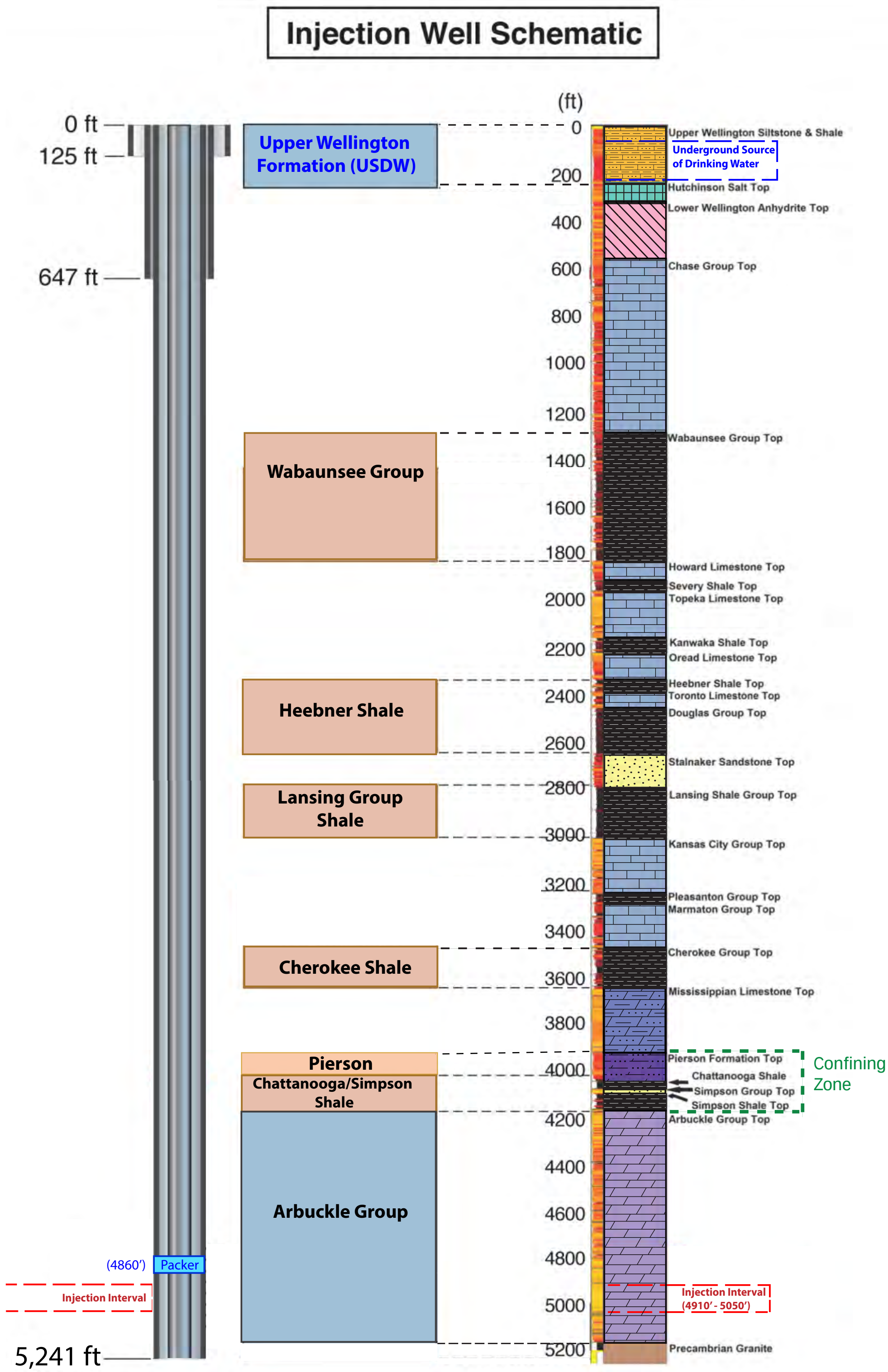


Figure ES-3—Schematic of injection well showing geologic formations at Wellington sequestration site.

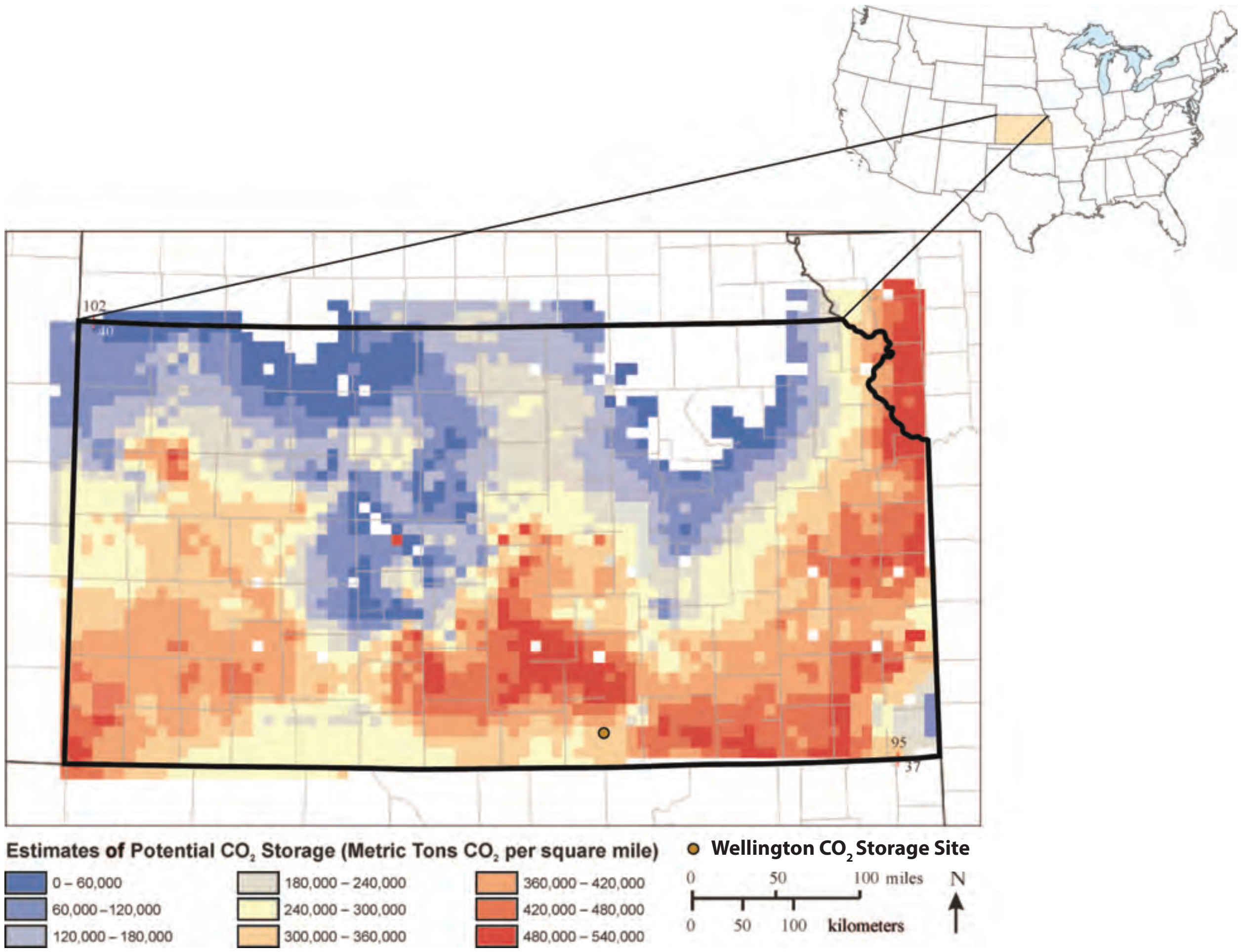


Figure ES-4—Map showing the estimated sequestration potential in the Arbuckle saline aquifer in metric tons CO_2 per square mile.

Modeling

During construction of the injection well (KGS 1-28) and the geologic characterization well (KGS 1-32) shown in Figure ES-1, an extensive suite of geophysical logs were obtained to understand the geology and hydrogeology and to derive petrophysical properties. These include the Array Compensated True Resistivity, Temperature, Compensated Spectral Natural Gamma Ray, Microlog, Spectral Density Dual Spaced Neutron, Annular Hole Volume Plot, Extended Range Micro Imager Correlation Plot, Radial Cement Bond, Composite Plot, and Magnetic Resonance Imaging logs. The data were used to develop a reservoir simulation model of the Arbuckle Group. An extensive set of computer simulations were conducted using the base-case model and eight alternative models to account for parametric uncertainty and to bracket the impacts of CO_2 injection on subsurface fluid pressures and extent of CO_2 plume migration. The underlying motivation was to determine whether the injected CO_2 could negatively impact the USDW or potentially escape into the atmosphere through existing wells or faults/fractures that may either be present, reactivated, or created by the injected fluid.

Simulation results indicate that the maximum pressure induced in the Arbuckle aquifer is insufficient to cause vertical migration of brines into the USDW due to under-pressurization of the Arbuckle aquifer. The pre-injection heads in the Arbuckle injection zone are approximately 600 ft lower than heads in the USDW. Simulation results also indicate that the pressures induced due to injection will dissipate within three months of cessation of injection. Also, the maximum pressures induced at the top of the Arbuckle are insufficient to cause Arbuckle fluids to migrate upward due to the high entry pressure constraints in the confining zone.

Simulation results indicate that the CO_2 will largely remain confined in the lower Arbuckle injection zone and not migrate even into the mid-Arbuckle (Figure ES-5a). The induced pore pressures drop to levels below that necessary to cause vertical migration of the brine at a distance of a few tens of feet from the injection well. Laterally, the maximum extent of the plume (as defined by the 1% CO_2 saturation isoline) is expected to be approximately 1,700 ft from the injection well as shown in Figure ES-5b, and the plume growth is expected to cease in less than a year after cessation of injection. Therefore, a post-injection monitoring period of one year is proposed for the project as indicated below.

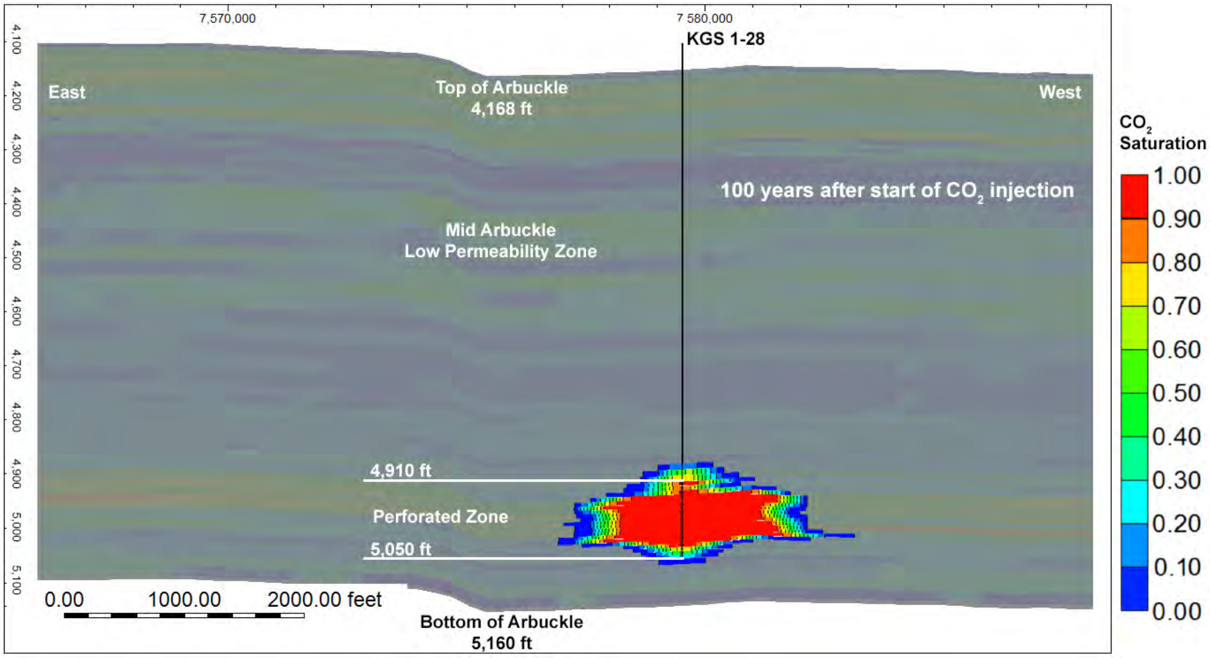


Figure ES-5a—Vertical extent of CO_2 plume migration along an east-west cross-section through the injection well (KGS 1-28) at 100 years after the start of injection

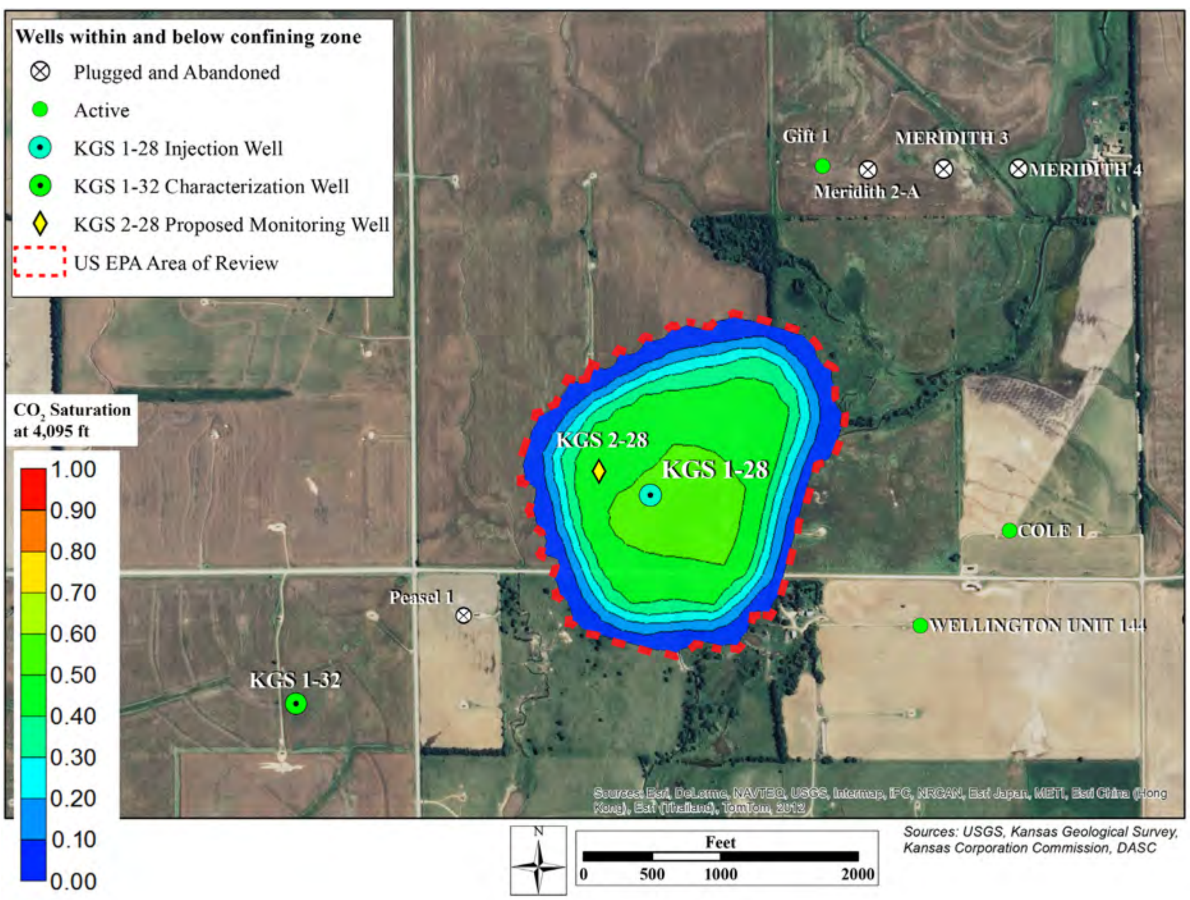


Figure ES-5b—Maximum lateral extent of free-phase CO_2 plume migration.

AoR and Corrective Action

The EPA AoR derived for the Wellington project is based on EPA's *Maximum Extent of the Separate-phase Plume or Pressure-front (MESPOP)* methodology. It was determined that the pressures induced due to injection of CO_2 at Wellington are of insufficient magnitude to cause brines from the Arbuckle Group to migrate vertically into the USDW through any natural or artificial penetration. Therefore, the AoR is based on the maximum extent of plume migration, which as shown in Figure ES-5b extends approximately 1,700 ft from the injection well. There are no existing or abandoned wells (other than the proposed injection well) either in the Arbuckle Group or the overlying confining zone within the AoR. Therefore, no well corrective action is required.

After injection begins, if significant deviations in the projected formation pressures and plume migration patterns are observed, then the reservoir model may be recalibrated, which will trigger an automatic re-evaluation of the AoR and Corrective Action Plan. This iterative process may continue until field-based observations and model projections are in agreement.

CO_2 Compatibility in Injection Zone and Well

Geochemical analyses suggests that the injection of anthropogenic CO_2 should not cause any compatibility problems with formation waters and minerals in the Arbuckle Group, which could result in reduced pore space, excessive formation/well pressures, or any hindrance to injection operations or geologic storage.

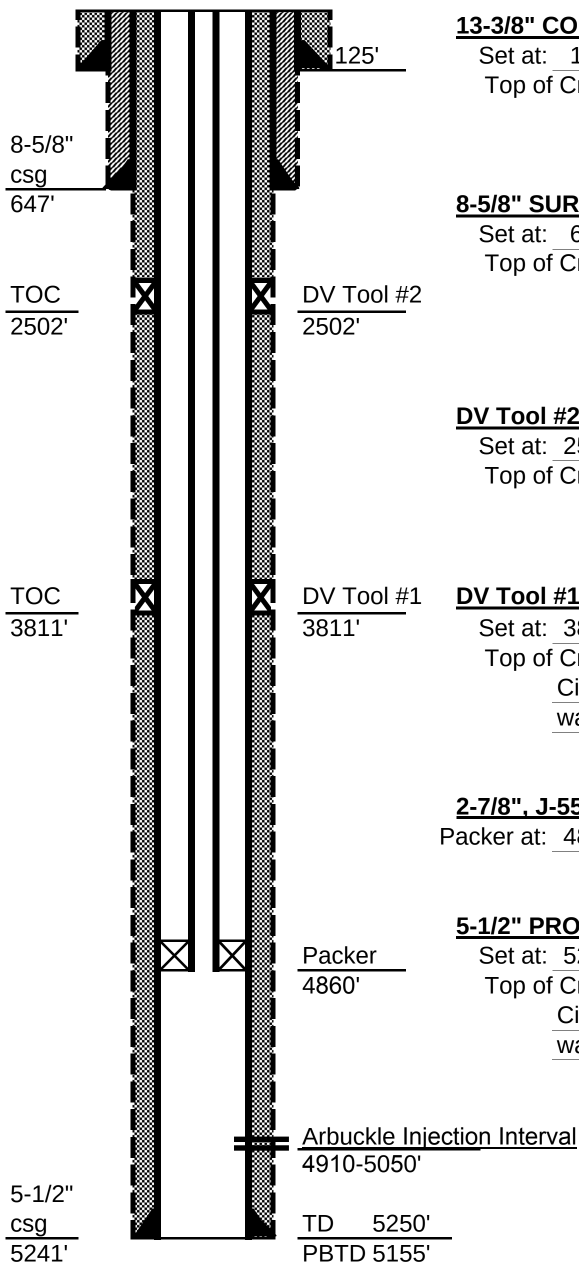
The tubing, casing, packer, and cement of the injection well are also designed for CO_2 injection operations (Figure ES-6). The chemical composition of the injectate should not cause any adverse reactions or degradation of the well components for the short nine-month duration of injection. The low water content of the injected CO_2 and the low temperatures will result in only a mildly corrosive environment. Quarterly monitoring for corrosion using coupons, however, is to be conducted to provide early warning of a deteriorating environment.

Wellbore Diagram

LEASE Wellington KGS #1-28 **API 15-191- 22590**

NE SW SE SW Sec 28 31s - 1w Sumner COUNTY KANSAS

Perforate Arbuckle for CO2 Injection 4910' to 5050'



13-3/8" CONDUCTOR, 48#/FT
Set at: 125' 135 sx cement
Top of Cmt @ Circulated to Surface

8-5/8" SURFACE CASING 24 #/FT
Set at: 647' 325 sx cement
Top of Cmt @ Circulated to Surface

DV Tool #2
Set at: 2502' 610 sx cement
Top of Cmt @ Circulated to Surface

DV Tool #1
Set at: 3811' 260 sx cement
Top of Cmt @ 2502'
Circ cement to surface when DV Tool #2 was opened

2-7/8", J-55 Lined Injection Tubing
Packer at: 4860'

5-1/2" PRODUCTION CASING 15.5#/FT, J55
Set at: 5241' 250 sx cement
Top of Cmt @ 3811'
Circ cement to surface when DV Tool #1 was opened

Wellington KGS #1-28==WellBore Diagram.xls
-bl- Date Printed: 12/8/2011

Figure ES-6—Well construction details of injection well KGS 1-28.

Testing and Monitoring Plan

A total of five monitoring wells will be used for tracking the CO_2 plume and pressure front. The locations of these monitoring wells and the formations they will monitor are shown in Figure ES-7. One monitoring well is located in the Arbuckle aquifer. Two existing Mississippian wells will be used to check whether CO_2 has escaped upward from the primary confining zone (base of Simpson Group to top of Pierson formation) at the site. Two shallow wells in the Upper Wellington Formation (USDW) will be monitored to protect potable water supply in the area. Both direct and indirect measurement methods will be used to monitor the movement of the pressure and plume fronts, identify potential risks to USDWs, and to verify model predictions of plume movement.

Injection Well Monitoring

The surface and bottomhole pressures and temperatures will be monitored continuously at the injection well. The chemical composition of the injectate will be tested quarterly to ensure the CO_2 meets the required specifications. Due to the short nine-month period of injection, corrosion is not expected to occur in the Wellington injection or observation wells. However, corrosion coupons will be used for monitoring loss of material in the Arbuckle injection and monitoring well on a quarterly basis.

Internal and external Mechanical Integrity Tests (MITs) will be conducted before, during, and after injection. Temperature logs will be used to demonstrate external MIT. Before injection begins, an Annulus Pressure Test will also be conducted at the injection well to demonstrate internal mechanical integrity. The test will provide information necessary to determine whether there is a failure of the casing-cement bond, injection tubing, and packers.

A pre-injection pressure fall-off test will be conducted to estimate formation properties in the vicinity of the injection well. This information will serve as a baseline in the event of any changes in the near-wellbore environment that may impact injectivity and result in pressure increases.

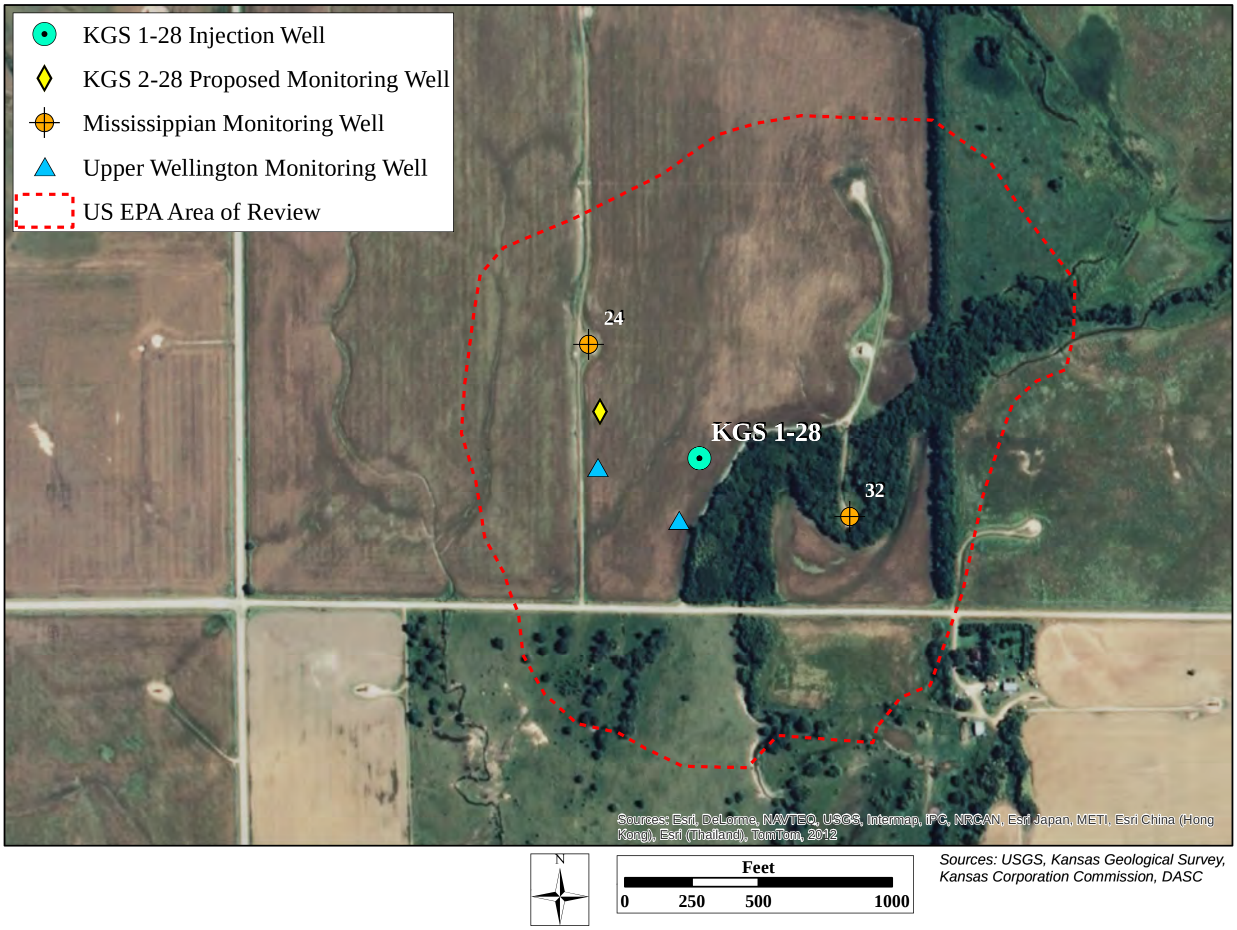


Figure ES-7—Location of monitoring wells in the Arbuckle, Mississippian, and Wellington formations.

Pressure-Front Monitoring

Pressure transducers will be installed in the Arbuckle injection and monitoring wells (KGS 1-28 and KGS 2-28). The acquired pressure data will be compared with model-based prediction of the pressure front, and if necessary, the simulation model will be recalibrated to conform to field data. In addition to direct monitoring, the pressure front will also be tracked areally by monitoring surface deformation using InSAR (Interferometric Synthetic Aperture Radar) remote sensing technique.

Monitoring the Plume Front

Various direct and indirect MVA tools and techniques shall be used to monitor the plume front. The crosswell tomography, U-tube, and continuous active source seismic monitoring (CASSM) technology shall be used to monitor and visualize the movement of the CO_2 plume. Sampling and analysis of water and casing head gas from existing Mississippian wells/boreholes around the Arbuckle injector shall be used to determine whether injected CO_2 has breached the confining zone and escaped into the overlying Mississippian reservoir. Shallow groundwater sampling and analysis will help confirm whether any injected CO_2 has reached the USDW. The newly acquired data will be compared with the existing baseline seismic data to track the plume movement. The monitored data will also be used revise the simulation model, update site characterization, and potentially revise the monitoring plan if deemed necessary.

A 3-D seismic survey will also be undertaken before closure to validate the absence of CO_2 outside the containment strata and confirm that future leakage risks are minimal to non-existent.

Geomechanical Failure and Seismic Risk

Simulation results indicate that the pressures induced due to CO_2 injection at KGS 1-28 are insufficient to initiate new fractures, propagate existing fractures, or cause slippage along any existing fault planes. There are no documented faults in the vicinity of the injection well, with the closest fault approximately 12.5 miles southeast of the site where negligible pressures will be induced due to injection. The Wellington storage site (and all of Kansas) is in a low seismic hazard area as determined by the U.S. Geological Survey. Historical record indicates that most earthquakes in Kansas are small, with the largest measured at 4.0 on the Richter scale, which is not of sufficient strength to cause any infrastructure damage.

CO_2 Trapping Potential of the Mississippian Oil Field

The Mississippian oil reservoir lies immediately above the primary upper confining zone (Figure ES-3). It is a highly under-pressurized system, which is likely a consequence of oil and gas production that has occurred in this formation since the early 1900s. Due to this under-pressurization, any CO_2 that may escape from the primary confining zone is likely to be trapped in the Mississippian formation. This under-pressurization could not have existed in the absence of a competent low permeability confining zone between the Arbuckle and the Mississippian systems, which essentially provides a hydraulic seal between the two formations.

Injection Well Construction

The 5,241 ft deep injection well (KGS 1-28) penetrates the top of the Precambrian basement rock at a depth of approximately 5,160 ft. The well will be perforated between 4,910 and 5,050 ft for injection into the highly permeable lower Arbuckle zone as shown in Figures ES-3 and ES-6. The injection well was constructed in accordance with UIC Class VI construction guidelines using CO_2-resistant cement and corrosion-resistant material in the production casing and injection tubing. The tubing and the casing are designed to withstand axial, burst, and collapse stresses. Cement bond and variable density logs were acquired after setting and cementing the surface casing and long-string casing. These logs do not indicate any loss of mechanical integrity.

Injection Well Plugging Plan

The injection well and potentially the Arbuckle monitoring well (KGS 2-28) will be plugged as per UIC Class VI specifications to the top of the Pierson formation, which corresponds to the top of the confining zone. Both wells may be used in the future for CO_2 Enhanced Oil Recovery (EOR) injection or other oilfield operations in the locally producing Mississippian formation, so plugging will only occur to the base of the intended oil recovery zone (top of Pierson formation). The Arbuckle monitoring well KGS 2-28 will be plugged as a Class VI well in the event that the CO_2 plume reaches this well or is expected to reach this well at any time in the future.

Surface Facilities and Operations

The planned volume of CO_2 injection is 150 metric tons (MT) per day for a total of 40,000 MT over the nine-month injection period. The CO_2 will be transported to the site in trucks in liquid state at a pressure of approximately 250 pounds per square inch (psi) and temperature of

-10° F. The surface facilities at the Wellington injection site will consist of a storage tank, a pump, a programmable logic controller (PLC), and wellhead. The bottomhole and wellhead pressures and temperatures as well as the flow rate will be monitored continuously, and the data will be fed continuously to the PLC. The PLC will manipulate the control valve to not exceed the maximum specified flow rate and to ensure that the bottomhole pressure in the injection well does not exceed the maximum allowable pressure, which corresponds to 90% of the fracture pressure. The PLC will be programmed to initiate shutdown if the operating ranges are exceeded.

Post-Injection Site Care and Site Closure Plan (PISC)

Due to the expected stabilization of the pressure and plume fronts in less than a year after cessation of injection, it is proposed that the site be closed one year after cessation of injection. Upon cessation of injection, the most recently acquired field data will be used to refine the reservoir model, if necessary, and to update simulation results and the projected pressure and fronts. The revised projections will be used to determine whether the monitoring, AoR, and PISC plans are adequate to ensure accurate tracking of the plume/pressure front and support closure of the site. If necessary, this process of data acquisition and model refinement/projections may continue to determine whether or not the injected CO_2 could migrate out of the storage formation into the USDW. Once a determination of no negative impacts to the USDW is made, an application for site closure will be filed with the EPA Director.

Emergency Remedial Response Plan

An Emergency Remedial Response Plan has been prepared and will be implemented if Berexco obtains evidence that the injected CO_2 stream and/or associated pressure front may endanger the USDW. Specific plans are outlined for a variety of emergency conditions related to testing, monitoring, and mechanical failure. The plans involve immediate cessation of injection, identification and characterization of the failure, notification of the EPA UIC Program Director within 24 hours, and implementation of the appropriate response and remedial action. In addition to executing an automatic shutdown, the PLC will also notify Berexco of a shutdown over cellular network.

Financial Responsibility Plan

Due to its extensive experience in subsurface oil and gas operations and strong financial position, Berexco is opting for the self-insurance option to demonstrate financial responsibility to carry out CO_2 storage activities related to performing well corrective action, injection well plugging, post-injection site care, site closure, and implementing an emergency/remedial plan. Berexco meets or exceeds all minimum financial coverage criteria to demonstrate financial strength and ability to complete sequestration activities. In addition, the Wellington project is part of a cooperative agreement with the U.S. DOE in which the U.S. DOE has accepted KGS's proposal to provide financial assistance of approximately $11 million for this project. Therefore, financial risks to Berexco are minimal.

Conclusions and Risks to USDW

Detailed AoR, Construction and Operations, Testing and Monitoring, Injection Well Plugging, Post-Injection Site Care and Site Closure, Emergency and Remedial Response, and Financial Responsibility plans have been prepared and documented in this application to fulfill all EPA requirements for developing and operating a Class VI CO_2 geologic sequestration project.

The modeling-based projections for the small-scale pilot project indicate that the subsurface pressures induced due to CO_2 injection will be insufficient to cause vertical migration of brines from the injection zone into the USDW. Additionally, the injected CO_2 is expected to be contained within the injection zone in the lower portions of the Arbuckle, and the plume is expected to stabilize within one year of cessation of injection. Therefore, risk of contamination of the USDW from injection operations at Wellington is minimal.

Cross Reference Table between Class VI Rule Requirements and Corresponding Documentation in this Permit Application

Class VI Well Regulatory Requirements	Section Where Requirements Addressed
Sec. 146.82 Required Class VI permit information. (a) Prior to the issuance of a permit for the construction of a new Class VI well or the conversion of an existing Class I, Class II, or Class V well to a Class VI well, the owner or operator shall submit, pursuant to § 146.91(e), and the Director shall consider the following:	Secs. 1-14
(1) Information required in § 144.31(e)(1) through (6) of this chapter;	Sec. 1.5, Table ES.1
(2) A map showing the injection well for which a permit is sought and the applicable area of review consistent with § 146.84. Within the area of review, the map must show the number or name, and location of all injection wells, producing wells, abandoned wells, plugged wells or dry holes, deep stratigraphic boreholes, State- or EPA-approved subsurface cleanup sites, surface bodies of water, springs, mines (surface and subsurface), quarries, water wells, other pertinent surface features including structures intended for human occupancy, State, Tribal, and Territory boundaries, and roads. The map should also show faults, if known or suspected. Only information of public record is required to be included on this map;	Fig. 1.12, Table 1.2
(3) Information on the geologic structure and hydrogeologic properties of the proposed storage site and overlying formations, including: (i) Maps and cross sections of the area of review; (ii) The location, orientation, and properties of known or suspected faults and fractures that may transect the confining zone(s) in the area of review and a determination that they would not interfere with containment; (iii) Data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the injection and confining zone(s); including geology/facies changes based on field data which may include geologic cores, outcrop data, seismic surveys, well logs, and names and lithologic descriptions; (iv) Geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone(s); (v) Information on the seismic history including the presence and depth of seismic sources and a determination that the seismicity would not interfere with containment; and (vi) Geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the local area.	(i) Figs. 4.2a-d, 4.9, 4.10, 4.11, 4.12, 4.22, 4.23, and 4.24 (ii) Secs. 4.7.5, 6.4, 6.5, and 6.6 (iii) Secs. 4.3, 4.6, & 4.8 (iv) Secs. 4.7 & 6.3 (v) Sec. 6.6 (vi) Figs. 1.5, 4.2a-d, Secs. 4.3, 4.5, 4.6, & 4.7

(4) A tabulation of all wells within the area of review which penetrate the injection or confining zone(s). Such data must include a description of each well's type, construction, date drilled, location, depth, record of plugging and/ or completion, and any additional information the Director may require;	Fig. 1.12, Table 1.2
(5) Maps and stratigraphic cross sections indicating the general vertical and lateral limits of all USDWs, water wells and springs within the area of review, their positions relative to the injection zone(s), and the direction of water movement, where known;	Sec. 4.5
(6) Baseline geochemical data on subsurface formations, including all USDWs in the area of review;	Sec. 4.5, & 4.6.7
(7) Proposed operating data for the proposed geologic sequestration site: (i) Average and maximum daily rate and volume and/or mass and total anticipated volume and/or mass of the carbon dioxide stream; (ii) Average and maximum injection pressure; (iii) The source(s) of the carbon dioxide stream; and (iv) An analysis of the chemical and physical characteristics of the carbon dioxide stream.	(i) Sec. 8.4 (ii) Sec. 8.4 (iii) Sec. 10.3.1 (iv) Sec. 10.3.1
(8) Proposed pre-operational formation testing program to obtain an analysis of the chemical and physical characteristics of the injection zone(s) and confining zone(s) and that meets the requirements at § 146.87;	Sec. 10.3.5 and 10.3.4.
(9) Proposed stimulation program, a description of stimulation fluids to be used and a determination that stimulation will not interfere with containment;	Sec. 8.14
(10) Proposed procedure to outline steps necessary to conduct injection operation;	Sec. 8
(11) Schematics or other appropriate drawings of the surface and subsurface construction details of the well;	Fig. 8.1 & 8.2
(12) Injection well construction procedures that meet the requirements of § 146.86;	Sec. 8
(13) Proposed area of review and corrective action plan that meets the requirements under § 146.84;	Sec. 9
(14) A demonstration, satisfactory to the Director, that the applicant has met the financial responsibility requirements under § 146.85;	Sec. 14
(15) Proposed testing and monitoring plan required by § 146.90;	Sec. 10
(16) Proposed injection well plugging plan required by § 146.92(b);	Sec. 11
(17) Proposed post-injection site care and site closure plan required by § 146.93(a);	Sec. 12
(18) At the Director's discretion, a demonstration of an alternative post-injection site care timeframe required by § 146.93(c);	Sec. 12.3 & 12.5
(19) Proposed emergency and remedial response plan required by § 146.94(a);	Sec. 13
(20) A list of contacts, submitted to the Director, for those States, Tribes, and Territories identified to be within the area of review of the Class VI project based on information provided in paragraph (a)(2) of this section; and	Sec. 1.7
(21) Any other information requested by the Director.	EPA Discretion

(b) The Director shall notify, in writing, any States, Tribes, or Territories identified to be within the area of review of the Class VI project based on information provided in paragraphs (a)(2) and (a)(20) of this section of the permit application and pursuant to the requirements at § 145.23(f)(13) of this chapter.	EPA Discretion
(c) Prior to granting approval for the operation of a Class VI well, the Director shall consider the following information: (1) The final area of review based on modeling, using data obtained during logging and testing of the well and the formation as required by paragraphs (c)(2), (3), (4), (6), (7), and (10) of this section; (2) Any relevant updates, based on data obtained during logging and testing of the well and the formation as required by paragraphs (c)(3), (4), (6), (7), and (10) of this section, to the information on the geologic structure and hydrogeologic properties of the proposed storage site and overlying formations, submitted to satisfy the requirements of paragraph (a)(3) of this section; (3) Information on the compatibility of the carbon dioxide stream with fluids in the injection zone(s) and minerals in both the injection and the confining zone(s), based on the results of the formation testing program, and with the materials used to construct the well; (4) The results of the formation testing program required at paragraph (a)(8) of this section; (5) Final injection well construction procedures that meet the requirements of § 146.86; (6) The status of corrective action on wells in the area of review; (7) All available logging and testing program data on the well required by § 146.87; (8) A demonstration of mechanical integrity pursuant to § 146.89; (9) Any updates to the proposed area of review and corrective action plan, testing and monitoring plan, injection well plugging plan, post-injection site care and site closure plan, or the emergency and remedial response plan submitted under paragraph (a) of this section, which are necessary to address new information collected during logging and testing of the well and the formation as required by all paragraphs of this section, and any updates to the alternative post-injection site care timeframe demonstration submitted under paragraph (a) of this section, which are necessary to address new information collected during the logging and testing of the well and the formation as required by all paragraphs of this section; and (10) Any other information requested by the Director.	EPA Activity
(d) Owners or operators seeking a waiver of the requirement to inject below the lowermost USDW must also refer to § 146.95 and submit a supplemental report, as required at § 146.95(a). The supplemental report is not part of the permit application.	Not applicable

§ 146.83 Minimum criteria for siting. (a) Owners or operators of Class VI wells must demonstrate to the satisfaction of the Director that the wells will be sited in areas with a suitable geologic system. The owners or operators must demonstrate that the geologic system comprises: (1) An injection zone(s) of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the carbon dioxide stream; (2) Confining zone(s) free of transmissive faults or fractures and of sufficient areal extent and integrity to contain the injected carbon dioxide stream and displaced formation fluids and allow injection at proposed maximum pressures and volumes without initiating or propagating fractures in the confining zone(s).	(1) Sec. 4.6 (2) Sec. 4.7.5
(b) The Director may require owners or operators of Class VI wells to identify and characterize additional zones that will impede vertical fluid movement, are free of faults and fractures that may interfere with containment, allow for pressure dissipation, and provide additional opportunities for monitoring, mitigation, and remediation.	Sec. 7
§ 146.84 Area of review and corrective action. (a) The area of review is the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity. The area of review is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and is based on available site characterization, monitoring, and operational data.	Sec. 9.2
(b) The owner or operator of a Class VI well must prepare, maintain, and comply with a plan to delineate the area of review for a proposed geologic sequestration project, periodically reevaluate the delineation, and perform corrective action that meets the requirements of this section and is acceptable to the Director. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. As a part of the permit application for approval by the Director, the owner or operator must submit an area of review and corrective action plan that includes the following information:	Sec. 9.3
(1) The method for delineating the area of review that meets the requirements of paragraph (c) of this section, including the model to be used, assumptions that will be made, and the site characterization data on which the model will be based;	Sec 4.6-4.8 (characterization), Sec. 5 (modeling), & Sec. 9.1 (AoR)

(2) A description of: (i) The minimum fixed frequency, not to exceed five years, at which the owner or operator proposes to reevaluate the area of review; (ii) The monitoring and operational conditions that would warrant a reevaluation of the area of review prior to the next scheduled reevaluation as determined by the minimum fixed frequency established in paragraph (b)(2)(i) of this section. (iii) How monitoring and operational data (e.g., injection rate and pressure) will be used to inform an area of review reevaluation; and (iv) How corrective action will be conducted to meet the requirements of paragraph (d) of this section, including what corrective action will be performed prior to injection and what, if any, portions of the area of review will have corrective action addressed on a phased basis and how the phasing will be determined; how corrective action will be adjusted if there are changes in the area of review; and how site access will be guaranteed for future corrective action.	Sec. 9.3
(c) Owners or operators of Class VI wells must perform the following actions to delineate the area of review and identify all wells that require corrective action: (1) Predict, using existing site characterization, monitoring and operational data, and computational modeling, the projected lateral and vertical migration of the carbon dioxide plume and formation fluids in the subsurface from the commencement of injection activities until the plume movement ceases, until pressure differentials sufficient to cause the movement of injected fluids or formation fluids into a USDW are no longer present, or until the end of a fixed time period as determined by the Director. The model must: (i) Be based on detailed geologic data collected to characterize the injection zone(s), confining zone(s) and any additional zones; and anticipated operating data, including injection pressures, rates, and total volumes over the proposed life of the geologic sequestration project; (ii) Take into account any geologic heterogeneities, other discontinuities, data quality, and their possible impact on model predictions; and (iii) Consider potential migration through faults, fractures, and artificial penetrations. (iv)	Sec. 4.7 (fractures), Sec. 5 (modeling), Sec. 6 (faults), and Sec. 9.1 (AoR)
(2) Using methods approved by the Director, identify all penetrations, including active and abandoned wells and underground mines, in the area of review that may penetrate the confining zone(s). Provide a description of each well's type, construction, date drilled, location, depth, record of plugging and/ or completion, and any additional information the Director may require; and	Fig. 1.10-1.12. Table 1.1 Sec. 8 (Injection well construction)
(3) Determine which abandoned wells in the area of review have been plugged in a manner that prevents the movement of carbon dioxide or other fluids that may endanger USDWs, including use of materials compatible with the carbon dioxide stream.	Fig. 1.10-1.12.

(d) Owners or operators of Class VI wells must perform corrective action on all wells in the area of review that are determined to need corrective action, using methods designed to prevent the movement of fluid into or between USDWs, including use of materials compatible with the carbon dioxide stream, where appropriate.	Sec. 9.3
(e) At the minimum fixed frequency, not to exceed five years, as specified in the area of review and corrective action plan, or when monitoring and operational conditions warrant, owners or operators must: (1) Reevaluate the area of review in the same manner specified in paragraph (c)(1) of this section; (2) Identify all wells in the reevaluated area of review that require corrective action in the same manner specified in paragraph (c) of this section; (3) Perform corrective action on wells requiring corrective action in the reevaluated area of review in the same manner specified in paragraph (d) of this section; and (4) Submit an amended area of review and corrective action plan or demonstrate to the Director through monitoring data and modeling results that no amendment to the area of review and corrective action plan is needed. Any amendments to the area of review and corrective action plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at §§ 144.39 or 144.41 of this chapter, as appropriate.	Sec. 9.3.
(f) The emergency and remedial response plan (as required by § 146.94) and the demonstration of financial responsibility (as described by § 146.85) must account for the area of review delineated as specified in paragraph (c)(1) of this section or the most recently evaluated area of review delineated under paragraph (e) of this section, regardless of whether or not corrective action in the area of review is phased.	Sec. 13.
(g) All modeling inputs and data used to support area of review reevaluations under paragraph (e) of this section shall be retained for 10 years.	Section 9.5

§ 146.85 Financial responsibility. (a) The owner or operator must demonstrate and maintain financial responsibility as determined by the Director that meets the following conditions: … (b) The requirement to maintain adequate financial responsibility and resources is directly enforceable regardless of whether the requirement is a condition of the permit. … (c) The owner or operator must have a detailed written estimate, in current dollars, of the cost of performing corrective action on wells in the area of review, plugging the injection well(s), postinjection site care and site closure, and emergency and remedial response. … (d) The owner or operator must notify the Director by certified mail of adverse financial conditions such as bankruptcy that may affect the ability to carry out injection well plugging and post-injection site care and site closure. … (e) The owner or operator must provide an adjustment of the cost estimate to the Director within 60 days of notification by the Director, as required by § 146.84, if the Director determines during the annual evaluation of the qualifying financial instrument(s) that the most recent demonstration is no longer adequate to cover the cost of corrective action (as required by § 146.84), injection well plugging (as required by § 146.92), post-injection site care and site closure (as required by § 146.93), and emergency and remedial response (as required by § 146.94). (f) The Director must approve the use and length of pay-in-periods for trust funds or escrow accounts.	(a) Sec. 14 (b) Sec.14 (c) Table 14.2 (d) Sec. 14.5. (e) Sec. 14.4 (f) N/A
§ 146.86 Injection well construction requirements. (a) *General.* The owner or operator must ensure that all Class VI wells are constructed and completed to: (1) Prevent the movement of fluids into or between USDWs or into any unauthorized zones; (2) Permit the use of appropriate testing devices and workover tools; and (3) Permit continuous monitoring of the annulus space between the injection tbg and long string casing.	(1) Sec. 8 (2) Sec. 8.7 (3) Sec. 8.10

(b) *Casing and Cementing of Class VI Wells.* (1) Casing and cement or other materials used in the construction of each Class VI well must have sufficient structural strength and be designed for the life of the geologic sequestration project. All well materials must be compatible with fluids with which the materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director. The casing and cementing program must be designed to prevent the movement of fluids into or between USDWs. In order to allow the Director to determine and specify casing and cementing requirements, the owner or operator must provide the following information: (i) Depth to the injection zone(s); (ii) Injection pressure, external pressure, internal pressure, and axial loading; (iii) Hole size; (iv) Size and grade of all casing strings (wall thickness, external diameter, nominal weight, length, joint specification, and construction material); (v) Corrosiveness of the carbon dioxide stream and formation fluids; (vi) Down-hole temperatures; (vii) Lithology of injection and confining zone(s); (viii) Type or grade of cement and cement additives; and (ix) Quantity, chemical composition, and temperature of the carbon dioxide stream.	(i) Table 4.2, Fig. 4.2 (ii) Table 8.1, Secs. 8.4, 8.5, and 8.9 (iii) Fig. 8.1 (iv) Sec 8.5 (v) Sec 8.11 (vi) Sec. 4.6.5 (vii) Sec. 4.6.2 (viii) Sec. 8.6 (ix) Sec. 8.16.2, Table 8.1
(2) Surface casing must extend through the base of the lowermost USDW and be cemented to the surface through the use of a single or multiple strings of casing and cement.	Sec. 8.5
(3) At least one long string casing, using a sufficient number of centralizers, must extend to the injection zone and must be cemented by circulating cement to the surface in one or more stages.	Sec. 8.5
(4) Circulation of cement may be accomplished by staging. The Director may approve an alternative method of cementing in cases where the cement cannot be recirculated to the surface, provided the owner or operator can demonstrate by using logs that the cement does not allow fluid movement behind wellbore.	Sec. 8.6
(5) Cement and cement additives must be compatible with the carbon dioxide stream and formation fluids and of sufficient quality and quantity to maintain integrity over the design life of the geologic sequestration project. The integrity and location of the cement shall be verified using technology capable of evaluating cement quality radially and identifying the location of channels to ensure that USDWs are not endangered.	Sec. 8.6, Appendix B (Cement Bond Log), Appendix H (Log Analyst Report)

(c) *Tubing and packer.* (1) Tubing and packer materials used in the construction of each Class VI well must be compatible with fluids with which the materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director.	Sec. 8.7
(2) All owners or operators of Class VI wells must inject fluids through tubing with a packer set at a depth opposite a cemented interval at the location approved by the Director.	Sec. 8.7 & 8.8.
(3) In order for the Director to determine and specify requirements for tubing and packer, the owner or operator must submit the following information: (i) Depth of setting; (ii) Characteristics of the carbon dioxide stream (chemical content, corrosiveness, temperature, and density) and formation fluids; (iii) Maximum proposed injection pressure; (iv) Maximum proposed annular pressure; (v) Proposed injection rate (intermittent or continuous) and volume and/or mass of the carbon dioxide stream; (vi) Size of tubing and casing; and (vii) Tubing tensile, burst, and collapse strengths.	(i) Fig. 8.1. (ii) Sec 8.16.2.1. (iii) Table 8.1. (iv) Sec. 8.10 & Fig. 8.4. (v) Sec. 8.4.3 & Table 8.1. (vi) Tables 8.2 and 8.4. (vii) Sec. 8.9.

§ 146.87 Logging, sampling, and testing prior to injection well operation.	
(a) During the drilling and construction of a Class VI injection well, the owner or operator must run appropriate logs, surveys and tests to determine or verify the depth, thickness, porosity, permeability, and lithology of, and the salinity of any formation fluids in all relevant geologic formations to ensure conformance with the injection well construction requirements under § 146.86 and to establish accurate baseline data against which future measurements may be compared. The owner or operator must submit to the Director a descriptive report prepared by a knowledgeable log analyst that includes an interpretation of the results of such logs and tests. At a minimum, such logs and tests must include:	Table 8.5, Appendix H (Log Analyst Report)
(1) Deviation checks during drilling on all holes constructed by drilling a pilot hole which is enlarged by reaming or another method. Such checks must be at sufficiently frequent intervals to determine the location of the borehole and to ensure that vertical avenues for fluid movement in the form of diverging holes are not created during drilling; and	(1) Appendix H
(2) Before and upon installation of the surface casing: (i) Resistivity, spontaneous potential, and caliper logs before the casing is installed; and (ii) A cement bond and variable density log to evaluate cement quality radially, and a temperature log after the casing is set and cemented.	(2) Appendices B, C, and H
(3) Before and upon installation of the long string casing: (i) Resistivity, spontaneous potential, porosity, caliper, gamma ray, fracture finder logs, and any other logs the Director requires for the given geology before the casing is installed; and (ii) A cement bond and variable density log, and a temperature log after the casing is set and cemented.	(3) Appendices B, C, and H
(4) A series of tests designed to demonstrate the internal and external mechanical integrity of injection wells, which may include: (i) A pressure test with liquid or gas; (ii) A tracer survey such as oxygen-activation logging; (iii) A temperature or noise log; (iv) A casing inspection log; and	(4) Appendix H (temperature log)
(5) Any alternative methods that provide equivalent or better information and that are required by and/or approved of by the Director.	(5) EPA Discretion

(b) The owner or operator must take whole cores or sidewall cores of the injection zone and confining system and formation fluid samples from the injection zone(s), and must submit to the Director a detailed report prepared by a log analyst that includes: Well log analyses (including well logs), core analyses, and formation fluid sample information. The Director may accept information on cores from nearby wells if the owner or operator can demonstrate that core retrieval is not possible and that such cores are representative of conditions at the well. The Director may require the owner or operator to core other formations in the borehole.	Appendix H (Core Samples). Sec. 4.6.1 and Figure 4.20 (for similarity of sub-surface conditions at KGS #1-32 and KGS #1-28).
(c) The owner or operator must record the fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone(s).	Secs. 4.6.3, 4.6.5, 4.6.7, 4.6.8.2.
(d) At a minimum, the owner or operator must determine or calculate the following information concerning the injection and confining zone(s): (1) Fracture pressure; (2) Other physical and chemical characteristics of the injection and confining zone(s); and (3) Physical and chemical characteristics of the formation fluids in the injection zone(s).	(1) Sec. 4.6.9 (2) Secs. 4.6 & 4.7 (3) 4.6.7
(e) Upon completion, but prior to operation, the owner or operator must conduct the following tests to verify hydrogeologic characteristics of the injection zone(s): (1) A pressure fall-off test; and, (2) A pump test; or (3) Injectivity tests.	(1) 10.3.5 (3) 4.6.4
(f) The owner or operator must provide the Director with the opportunity to witness all logging and testing by this subpart. The owner or operator must submit a schedule of such activities to the Director 30 days prior to conducting the first test and submit any changes to the schedule 30 days prior to the next scheduled test.	8.15.7
§ 146.88 Injection well operating requirements. (a) Except during stimulation, the owner or operator must ensure that injection pressure does not exceed 90 percent of the fracture pressure of the injection zone(s) so as to ensure that the injection does not initiate new fractures or propagate existing fractures in the injection zone(s). In no case may injection pressure initiate fractures in the confining zone(s) or cause the movement of injection or formation fluids that endangers a USDW. Pursuant to requirements at § 146.82(a)(9), all stimulation programs must be approved by the Director as part of the permit application and incorporated into the permit.	Sec. 8.4.2 (pressure limit) Sec. 8.14 (stimulation plan)
(b) Injection between the outermost casing protecting USDWs and the well bore is prohibited.	Injection through tubing (Sec. 8.7)
(c) The owner or operator must fill the annulus between the tubing and the long string casing with a non-corrosive fluid approved by the Director. The owner or operator must maintain on the annulus a pressure that exceeds the operating injection pressure, unless the Director determines that such requirement might harm the integrity of the well or endanger USDWs.	Sec. 8.10

(d) Other than during periods of well workover (maintenance) approved by the Director in which the sealed tubing-casing annulus is disassembled for maintenance or corrective procedures, the owner or operator must maintain mechanical integrity of the injection well at all times.	Sec. 10.3.2 (monitoring) Sec. 10.3.4 (MIT)
(e) The owner or operator must install and use: (1) Continuous recording devices to monitor: The injection pressure; the rate, volume and/or mass, and temperature of the carbon dioxide stream; and the pressure on the annulus between the tubing and the long string casing and annulus fluid volume; and (2) Alarms and automatic surface shut-off systems or, at the discretion of the Director, down-hole shutoff systems (*e.g.,* automatic shut-off, check valves) for onshore wells or, other mechanical devices that provide equivalent protection; and (3) Alarms and automatic down-hole shut-off systems for wells located offshore but within State territorial waters, designed to alert the operator and shut-in the well when operating parameters such as annulus pressure, injection rate, or other parameters diverge beyond permitted ranges and/or gradients specified in the permit.	(1) Sec. 10.3.2 (2) Sec. 13.4 (3) Sec. 13.4
(f) If a shutdown (*i.e.,* down-hole or at the surface) is triggered or a loss of mechanical integrity is discovered, the owner or operator must immediately investigate and identify as expeditiously as possible the cause of the shutoff. If, upon such investigation, the well appears to be lacking mechanical integrity, or if monitoring required under paragraph (e) of this section otherwise indicates that the well may be lacking mechanical integrity, the owner or operator must: (1) Immediately cease injection; (2) Take all steps reasonably necessary to determine whether there may have been a release of the injected carbon dioxide stream or formation fluids into any unauthorized zone; (3) Notify the Director within 24 hours; (4) Restore and demonstrate mechanical integrity to the satisfaction of the Director prior to resuming injection; and (5) Notify the Director when injection can be expected to resume.	Sec. 13 (Emergency and Remedial Response Plan)
§ 146.89 Mechanical Integrity. (a) A Class VI well has mechanical integrity if: (1) There is no significant leak in the casing, tubing, or packer; and (2) There is no significant fluid movement into a USDW through channels adjacent to the injection well bore.	
(b) To evaluate the absence of significant leaks under paragraph (a)(1) of this section, owners or operators must, following an initial annulus pressure test, continuously monitor injection pressure, rate, injected volumes; pressure on the annulus between tubing and long-string casing; and annulus fluid volume as specified in § 146.88 (e);	Sec. 10.3.2 Sec. 10.3.4

(c) At least once per year, the owner or operator must use one of the following methods to determine the absence of significant fluid movement under paragraph (a)(2) of this section: (1) An approved tracer survey such as an oxygen-activation log; or (2) A temperature or noise log.	Sec. 10.3.4
(d) If required by the Director, at a frequency specified in the testing and monitoring plan required at § 146.90, the owner or operator must run a casing inspection log to determine the presence or absence of corrosion in the long-string casing.	EPA Discretion
(e) The Director may require any other test to evaluate mechanical integrity under paragraphs (a)(1) or (a)(2) of this section. Also, the Director may allow the use of a test to demonstrate mechanical integrity other than those listed above with the written approval of the Administrator. To obtain approval for a new mechanical integrity test, the Director must submit a written request to the Administrator setting forth the proposed test and all technical data supporting its use. The Administrator may approve the request if he or she determines that it will reliably demonstrate the mechanical integrity of wells for which its use is proposed. Any alternate method approved by the Administrator will be published in the Federal Register and may be used in all States in accordance with applicable State law unless its use is restricted at the time of approval by the Administrator.	EPA Discretion
(f) In conducting and evaluating the tests enumerated in this section or others to be allowed by the Director, the owner or operator and the Director must apply methods and standards generally accepted in the industry. When the owner or operator reports the results of mechanical integrity tests to the Director, he/she shall include a description of the test(s) and the method(s) used. In making his/her evaluation, the Director must review monitoring and other test data submitted since the previous evaluation.	Section 10.3.4
(g) The Director may require additional or alternative tests if the results presented by the owner or operator under paragraphs (a) through (d) of this section are not satisfactory to the Director to demonstrate that there is no significant leak in the casing, tubing, or packer, or to demonstrate that there is no significant movement of fluid into a USDW resulting from the injection activity as stated in paragraphs (a)(1) and (2) of this section.	EPA Discretion
§ 146.90 Testing and monitoring requirements. The owner or operator of a Class VI well must prepare, maintain, and comply with a testing and monitoring plan to verify that the geologic sequestration project is operating as permitted and is not endangering USDWs. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. The testing and monitoring plan must be submitted with the permit application, for Director approval, and must include a description of how the owner or operator will meet the requirements of this section, including accessing sites for all necessary monitoring and testing during the life of the project. Testing and monitoring associated with geologic sequestration projects must, at a minimum, include:	Sec. 10 (Testing and Monitoring Plan)
(a) Analysis of the carbon dioxide stream with sufficient frequency to yield data representative of its chemical and physical characteristics;	Sec. 10.3.1
(b) Installation and use, except during well workovers as defined in § 146.88(d), of continuous recording devices to monitor injection pressure, rate, and volume; the pressure on the annulus between the tubing and the long string casing; and the annulus fluid volume added;	Sec. 10.3.2

(c) Corrosion monitoring of the well materials for loss of mass, thickness, cracking, pitting, and other signs of corrosion, which must be performed on a quarterly basis to ensure that the well components meet the minimum standards for material strength and performance set forth in § 146.86(b), by: (1) Analyzing coupons of the well construction materials placed in contact with the carbon dioxide stream; or (2) Routing the carbon dioxide stream through a loop constructed with the material used in the well and inspecting the materials in the loop; or (3) Using an alternative method approved by the Director;	Sec. 10.3.3
(d) Periodic monitoring of the ground water quality and geochemical changes above the confining zone(s) that may be a result of carbon dioxide movement through the confining zone(s) or additional identified zones including: (1) The location and number of monitoring wells based on specific information about the geologic sequestration project, including injection rate and volume, geology, the presence of artificial penetrations, and other factors; and (2) The monitoring frequency and spatial distribution of monitoring wells based on baseline geochemical data that has been collected under § 146.82(a)(6) and on any modeling results in the area of review evaluation required by § 146.84(c).	Sec.10.2 (monitoring wells) Sec. 10.4 (monitoring plan)
(e) A demonstration of external mechanical integrity pursuant to § 146.89(c) at least once per year until the injection well is plugged; and, if required by the Director, a casing inspection log pursuant to requirements at § 146.89(d) at a frequency established in the testing and monitoring plan;	Sec. 10.3.4
(f) A pressure fall-off test at least once every five years unless more frequent testing is required by the Director based on site-specific information;	Sec. 10.3.5
(g) Testing and monitoring to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure (*e.g.,* the pressure front) by using: (1) Direct methods in the injection zone(s); and, (2) Indirect methods (*e.g.,* seismic, electrical, gravity, or electromagnetic surveys and/or down-hole carbon dioxide detection tools), unless the Director determines, based on site-specific geology, that such methods are not appropriate;	Sec. 10.5

(h) The Director may require surface air monitoring and/or soil gas monitoring to detect movement of carbon dioxide that could endanger a USDW. (1) Design of Class VI surface air and/ or soil gas monitoring must be based on potential risks to USDWs within the area of review; (2) The monitoring frequency and spatial distribution of surface air monitoring and/or soil gas monitoring must be decided using baseline data, and the monitoring plan must describe how the proposed monitoring will yield useful information on the area of review delineation and/or compliance with standards under § 144.12 of this chapter; (3) If an owner or operator demonstrates that monitoring employed under §§ 98.440 to 98.449 of this chapter (Clean Air Act, 42 U.S.C. 7401 *et seq.*) accomplishes the goals of paragraphs (h)(1) and (2) of this section, and meets the requirements pursuant to § 146.91(c)(5), a Director that requires surface air/soil gas monitoring must approve the use of monitoring employed under §§ 98.440 to 98.449 of this chapter. Compliance with §§ 98.440 to 98.449 of this chapter pursuant to this provision is considered a condition of the Class VI permit;	EPA Discretion
(i) Any additional monitoring, as required by the Director, necessary to support, upgrade, and improve computational modeling of the area of review evaluation required under § 146.84(c) and to determine compliance with standards under § 144.12 of this chapter;	EPA Discretion
(j) The owner or operator shall periodically review the testing and monitoring plan to incorporate monitoring data collected under this subpart, operational data collected under § 146.88, and the most recent area of review reevaluation performed under § 146.84(e). In no case shall the owner or operator review the testing and monitoring plan less often than once every five years. Based on this review, the owner or operator shall submit an amended testing and monitoring plan or demonstrate to the Director that no amendment to the testing and monitoring plan is needed. Any amendments to the testing and monitoring plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at §§ 144.39 or 144.41 of this chapter, as appropriate. Amended plans or demonstrations shall be submitted to the Director as follows: (1) Within one year of an area of review reevaluation; (2) Following any significant changes to the facility, such as addition of monitoring wells or newly permitted injection wells within the area of review, on a schedule determined by the Director; or (3) When required by the Director.	Sec. 10.7
(k) A quality assurance and surveillance plan for all testing and monitoring requirements.	Sec. 10.9

§ 146.91 Reporting requirements. The owner or operator must, at a minimum, provide, as specified in paragraph (e) of this section, the following reports to the Director, for each permitted Class VI well: (a) Semi-annual reports containing: (1) Any changes to the physical, chemical, and other relevant characteristics of the carbon dioxide stream from the proposed operating data; (2) Monthly average, maximum, and minimum values for injection pressure, flow rate and volume, and annular pressure; (3) A description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit; (4) A description of any event which triggers a shut-off device required pursuant to § 146.88(e) and the response taken; (5) The monthly volume and/or mass of the carbon dioxide stream injected over the reporting period and the volume injected cumulatively over the life of the project; (6) Monthly annulus fluid volume added; and (7) The results of monitoring prescribed under § 146.90.	Sec. 10.6
(b) Report, within 30 days, the results of: (1) Periodic tests of mechanical integrity; (2) Any well workover; and, (3) Any other test of the injection well conducted by the permittee if required by the Director.	Sec. 10.6
(c) Report, within 24 hours: (1) Any evidence that the injected carbon dioxide stream or associated pressure front may cause an endangerment to a USDW; (2) Any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs; (3) Any triggering of a shut-off system (*i.e.,* down-hole or at the surface); (4) Any failure to maintain mechanical integrity; or. (5) Pursuant to compliance with the requirement at § 146.90(h) for surface air/soil gas monitoring or other monitoring technologies, if required by the Director, any release of carbon dioxide to the atmosphere or biosphere.	Sec. 10.6

(d) Owners or operators must notify the Director in writing 30 days in advance of: (1) Any planned well workover; (2) Any planned stimulation activities, other than stimulation for formation testing conducted under § 146.82; and (3) Any other planned test of the injection well conducted by the permittee.	Sec. 10.6
(e) Regardless of whether a State has primary enforcement responsibility, owners or operators must submit all required reports, submittals, and notifications under subpart H of this part to EPA in an electronic format approved by EPA.	Sec. 10.6
(f) Records shall be retained by the owner or operator as follows: (1) All data collected under § 146.82 for Class VI permit applications shall be retained throughout the life of the geologic sequestration project and for 10 years following site closure. (2) Data on the nature and composition of all injected fluids collected pursuant to § 146.90(a) shall be retained until 10 years after site closure. The Director may require the owner or operator to deliver the records to the Director at the conclusion of the retention period. (3) Monitoring data collected pursuant to § 146.90(b) through (i) shall be retained for 10 years after it is collected. (4) Well plugging reports, post-injection site care data, including, if appropriate, data and information used to develop the demonstration of the alternative post-injection site care timeframe, and the site closure report collected pursuant to requirements at §§ 146.93(f) and (h) shall be retained for 10 years following site closure. (5) The Director has authority to require the owner or operator to retain any records required in this subpart for longer than 10 years after site closure.	Sec. 10.8
§ 146.92 Injection well plugging. (a) Prior to the well plugging, the owner or operator must flush each Class VI injection well with a buffer fluid, determine bottomhole reservoir pressure, and perform a final external mechanical integrity test.	Section 11 (Injection Well Plugging Plan)

(b) *Well plugging plan.* The owner or operator of a Class VI well must prepare, maintain, and comply with a plan that is acceptable to the Director. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. The well plugging plan must be submitted as part of the permit application and must include the following information: (1) Appropriate tests or measures for determining bottomhole reservoir pressure; (2) Appropriate testing methods to ensure external mechanical integrity as specified in § 146.89; (3) The type and number of plugs to be used; (4) The placement of each plug, including the elevation of the top and bottom of each plug; (5) The type, grade, and quantity of material to be used in plugging. The material must be compatible with the carbon dioxide stream; and (6) The method of placement of the plugs.	(1) Sec. 11.3. (2) Sec. 11.4. (3) Sec. 11.5. (4) Sec. 11.5 (5) Sec. 11.5 (6) Sec. 11.5
(c) *Notice of intent to plug.* The owner or operator must notify the Director in writing pursuant to § 146.91(e), at least 60 days before plugging of a well. At this time, if any changes have been made to the original well plugging plan, the owner or operator must also provide the revised well plugging plan. The Director may allow for a shorter notice period. Any amendments to the injection well plugging plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at §§ 144.39 or 144.41 of this chapter, as appropriate.	Sec. 11.6.
(d) *Plugging report.* Within 60 days after plugging, the owner or operator must submit, pursuant to § 146.91(e), a plugging report to the Director. The report must be certified as accurate by the owner or operator and by the person who performed the plugging operation (if other than the owner or operator.) The owner or operator shall retain the well plugging report for 10 years following site closure.	Sec. 11.7.
§ 146.93 Post-injection site care and site closure. (a) The owner or operator of a Class VI well must prepare, maintain, and comply with a plan for postinjection site care and site closure that meets the requirements of paragraph (a)(2) of this section and is acceptable to the Director. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. (1) The owner or operator must submit the post-injection site care and site closure plan as a part of the permit application to be approved by the Director.	Sec. 12 (Post Injection Site Care and Site Closure Plan)

(2) The post-injection site care and site closure plan must include the following information: (i) The pressure differential between pre-injection and predicted post-injection pressures in the injection zone(s); (ii) The predicted position of the carbon dioxide plume and associated pressure front at site closure as demonstrated in the area of review evaluation required under § 146.84(c)(1); (iii) A description of post-injection monitoring location, methods, and proposed frequency; (iv) A proposed schedule for submitting post-injection site care monitoring results to the Director pursuant to § 146.91(e); and, (v) The duration of the post-injection site care timeframe and, if approved by the Director, the demonstration of the alternative post-injection site care timeframe that ensures nonendangerment of USDWs.	(i) Sec. 12.3 (ii) Sec. 12.4 (iii) Sec. 12.2 (iv) Sec. 12.2 (v) Sec. 12.3
(3) Upon cessation of injection, owners or operators of Class VI wells must either submit an amended post-injection site care and site closure plan or demonstrate to the Director through monitoring data and modeling results that no amendment to the plan is needed. Any amendments to the post-injection site care and site closure plan must be approved by the Director, be incorporated into the permit, and are subject to the permit modification requirements at §§ 144.39 or 144.41 of this chapter, as appropriate.	Sec. 12.1
(4) At any time during the life of the geologic sequestration project, the owner or operator may modify and resubmit the post-injection site care and site closure plan for the Director's approval within 30 days of such change.	Noted in Sec. 12.2

(b) The owner or operator shall monitor the site following the cessation of injection to show the position of the carbon dioxide plume and pressure front and demonstrate that USDWs are not being endangered. (1) Following the cessation of injection, the owner or operator shall continue to conduct monitoring as specified in the Director-approved post-injection site care and site closure plan for at least 50 years or for the duration of the alternative timeframe approved by the Director pursuant to requirements In paragraph (c) of this section, unless he/she makes a demonstration under (b)(2) of this section. The monitoring must continue until the geologic sequestration project no longer poses an endangerment to USDWs and the demonstration under (b)(2) of this section is submitted and approved by the Director. (2) If the owner or operator can demonstrate to the satisfaction of the Director before 50 years or prior to the end of the approved alternative timeframe based on monitoring and other site-specific data, that the geologic sequestration project no longer poses an endangerment to USDWs, the Director may approve an amendment to the post-injection site care and site closure plan to reduce the frequency of monitoring or may authorize site closure before the end of the 50-year period or prior to the end of the approved alternative timeframe, where he or she has substantial evidence that the geologic sequestration project no longer poses a risk of endangerment to USDWs. (3) Prior to authorization for site closure, the owner or operator must submit to the Director for review and approval a demonstration, based on monitoring and other site-specific data, that no additional monitoring is needed to ensure that the geologic sequestration project does not pose an endangerment to USDWs. (4) If the demonstration in paragraph (b)(3) of this section cannot be made (*i.e.,* additional monitoring is needed to ensure that the geologic sequestration project does not pose an endangerment to USDWs) at the end of the 50-year period or at the end of the approved alternative timeframe, or if the Director does not approve the demonstration, the owner or operator must submit to the Director a plan to continue post-injection site care until a demonstration can be made and approved by the Director.	(1) Sec. 12.2 & 12.6 (2) Sec. 12.6 (3) Sec. 12.6 (4) Sec. 12.6

(c) *Demonstration of alternative post-injection site care timeframe.* At the Director's discretion, the Director may approve, in consultation with EPA, an alternative post-injection site care timeframe other than the 50 year default, if an owner or operator can demonstrate during the permitting process that an alternative post-injection site care timeframe is appropriate and ensures non-endangerment of USDWs The demonstration must be based on significant, site-specific data and information including all data and information collected pursuant to §§ 146.82 and 146.83, and must contain substantial evidence that the geologic sequestration project will no longer pose a risk of endangerment to USDWs at the end of the alternative post-injection site care timeframe. (1) A demonstration of an alternative post-injection site care timeframe must include consideration and documentation of: (i) The results of computational modeling performed pursuant to delineation of the area of review under § 146.84; (ii) The predicted timeframe for pressure decline within the injection zone, and any other zones, such that formation fluids may not be forced into any USDWs; and/or the timeframe for pressure decline to pre-injection pressures. The predicted rate of carbon dioxide plume migration within the injection zone, and the predicted timeframe for the cessation of migration; (iii) A description of the site-specific processes that will result in carbon dioxide trapping including immobilization by capillary trapping, dissolution, and mineralization at the site; (iv) The predicted rate of carbon dioxide trapping in the immobile capillary phase, dissolved phase, and/or mineral phase; (v) The results of laboratory analyses, research studies, and/or field or site-specific studies to verify the information required in paragraphs (iii) and (iv) of this section; (vi) A characterization of the confining zone(s) including a demonstration that it is free of transmissive faults, fractures, and micro-fractures and of appropriate thickness, permeability, and integrity to impede fluid (e.g., carbon dioxide, formation fluids) movement; (vii) The presence of potential conduits for fluid movement including planned injection wells and project monitoring wells associated with the proposed geologic sequestration project or any other projects in proximity to the predicted/modeled, final extent of the carbon dioxide plume and area of elevated pressure; (viii) A description of the well construction and an assessment of the quality of plugs of all abandoned wells within the area of review; (ix) The distance between the injection zone and the nearest USDWs above and/ or below the injection zone; and	Justification for Alternative PISC and Site Closure Timeframe is presented in sections 12.3 and 12.5. The data utilized in support of the early closure request is referenced below. (i) Sec. 5.4 (ii) Sec. 5.4.6.1 and Sec. 5.4.6.2. (iii) Secs. 5.4.1 and 5.4.3. (iv) Sec. 5.4.6.1 (v) Sec. 4.6 (vi) Sec. 4.7 & 6.6. (viii) Sec. 9.2.2 & 9.2.3. (ix) Table 4.2, Fig. 4.1.

(d) *Notice of intent for site closure.* The owner or operator must notify the Director in writing at least 120 days before site closure. At this time, if any changes have been made to the original post-injection site care and site closure plan, the owner or operator must also provide the revised plan. The Director may allow for a shorter notice period.	Sec. 12.6
(e) After the Director has authorized site closure, the owner or operator must plug all monitoring wells in a manner which will not allow movement of injection or formation fluids that endangers a USDW.	Sec. 12.6
(f) The owner or operator must submit a site closure report to the Director within 90 days of site closure, which must thereafter be retained at a location designated by the Director for 10 years. The report must include: (1) Documentation of appropriate injection and monitoring well plugging as specified in § 146.92 and paragraph (e) of this section. The owner or operator must provide a copy of a survey plat which has been submitted to the local zoning authority designated by the Director. The plat must indicate the location of the injection well relative to permanently surveyed benchmarks. The owner or operator must also submit a copy of the plat to the Regional Administrator of the appropriate EPA Regional Office; (2) Documentation of appropriate notification and information to such State, local and Tribal authorities that have authority over drilling activities to enable such State, local, and Tribal authorities to impose appropriate conditions on subsequent drilling activities that may penetrate the injection and confining zone(s); and (3) Records reflecting the nature, composition, and volume of the carbon dioxide stream.	Sec. 12.6
(g) Each owner or operator of a Class VI injection well must record a notation on the deed to the facility property or any other document that is normally examined during title search that will in perpetuity provide any potential purchaser of the property the following information: (1) The fact that land has been used to sequester carbon dioxide; (2) The name of the State agency, local authority, and/or Tribe with which the survey plat was filed, as well as the address of the Environmental Protection Agency Regional Office to which it was submitted; and (3) The volume of fluid injected, the injection zone or zones into which it was injected, and the period over which injection occurred.	Sec. 12.6
(h) The owner or operator must retain for 10 years following site closure, records collected during the post-injection site care period. The owner or operator must deliver the records to the Director at the conclusion of the retention period, and the records must thereafter be retained at a location designated by the Director for that purpose.	Sec. 12.6

Section 1
Project Background

1.1 Introduction

Approximately 750 gigatons (GT) of carbon dioxide (CO_2) is cycled through the atmosphere annually from natural terrestrial and oceanic sources (Figure 1.1). CO_2 output from anthropogenic sources has steadily increased since the beginning of the industrial era and currently stands at approximately 29 GT annually (Pachauri and Reisinger, 2007). Geologic strata are natural storage media for hydrocarbons such as methane as well as naturally occurring CO_2, so in principle the storage of CO_2 in deep, brine-filled formations could be a very effective means of atmospheric carbon containment.

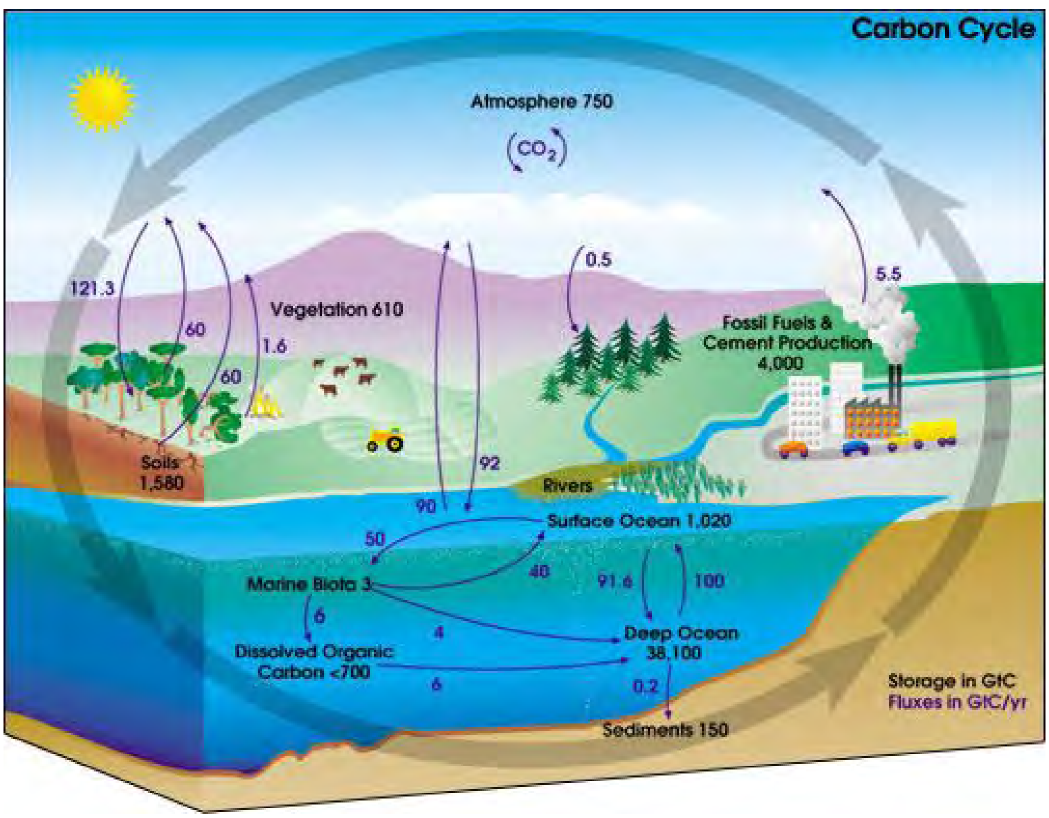


Figure 1.1—Illustration of global carbon cycle major sources and sinks (source: www.visionlearning.com/en/library/earth-science/6/The-Carbon-Cycle/95).

The high storage capacity of saline aquifers is largely due to the high pressure and temperature in deep aquifers that cause CO_2 to exist in a supercritical state. As shown in Figure 1.2, CO_2 can exist in a solid, liquid, gaseous, or supercritical state depending on the subsurface pressure and temperature. At temperatures and pressures greater than 88° F and 1,070 psi (which commonly exist in aquifers at 2,400 ft [730 m] or deeper), CO_2 exists in supercritical state (Figure 1.3). This is the expected state within the Arbuckle aquifer (proposed injection zone) at a depth of approximately 5,000 ft below land as indicated in Figure 1.2. Supercritical CO_2 has qualities and attributes of both liquid and gas but is highly dense as shown in Figure 1.3. This makes it a suitable phase for geological storage as less pore space is required.

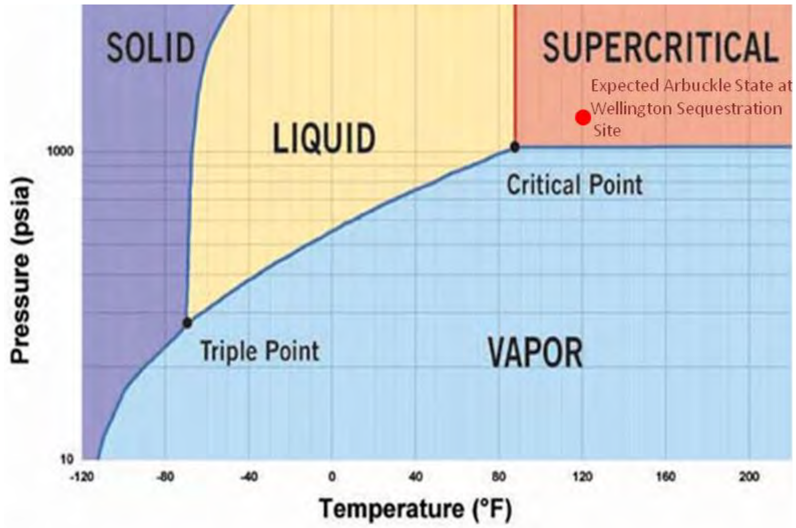


Figure 1.2—CO_2 phase diagram as a function of pressure and temperature, showing the expected CO_2 state in the Arbuckle at the proposed injection depth (red dot) (source: http://www.achrnews.com/articles/print/co2-in-refrigeration-applications).

The Arbuckle Group aquifer system located in the central plains states of Kansas, Missouri, and Oklahoma is one of the largest regional-scale aquifer systems in North America. The Arbuckle Group is not an underground source of drinking water (USDW) in south-central Kansas because it is saline, with chloride levels increasing almost linearly from 33,000 ppm to 110,000 ppm between depths of approximately 4,300 and 5,100 ft at the Wellington project location. Therefore, this formation is suitable for CO_2 storage. The Arbuckle Group is Cambrian-Ordovician in age and is composed predominantly of dolomites. It is more than 4,000 feet below ground surface in south-central Kansas, where it may produce oil in select locations but is also widely used for disposal of oil field brines (Carr et al., 2005). In fact, the Arbuckle has been used to successfully dispose of oil field brine and hazardous wastes throughout the state of Kansas for many decades, indicating that the Arbuckle may safely retain CO_2 as well. The presence of Devonian-age shales and other younger shale intervals indicates the presence of confining zones (seals) above the Arbuckle. Therefore, the Arbuckle Group offers an opportunity for large-scale geologic storage of CO_2 with hydrodynamic trapping, long-term isolation from the atmosphere, and protection of USDW supplies.

A small-scale pilot Carbon Capture and Storage (CCS) project at Wellington, Kansas, (Figure 1.4) is proposed. The goal of the study is to inject a maximum of 40,000 tons of CO_2 into the saline Arbuckle aquifer and to demonstrate the ability of advanced computer simulation and field-based techniques to monitor, verify, and account (MVA) for the CO_2 plume in near real time.

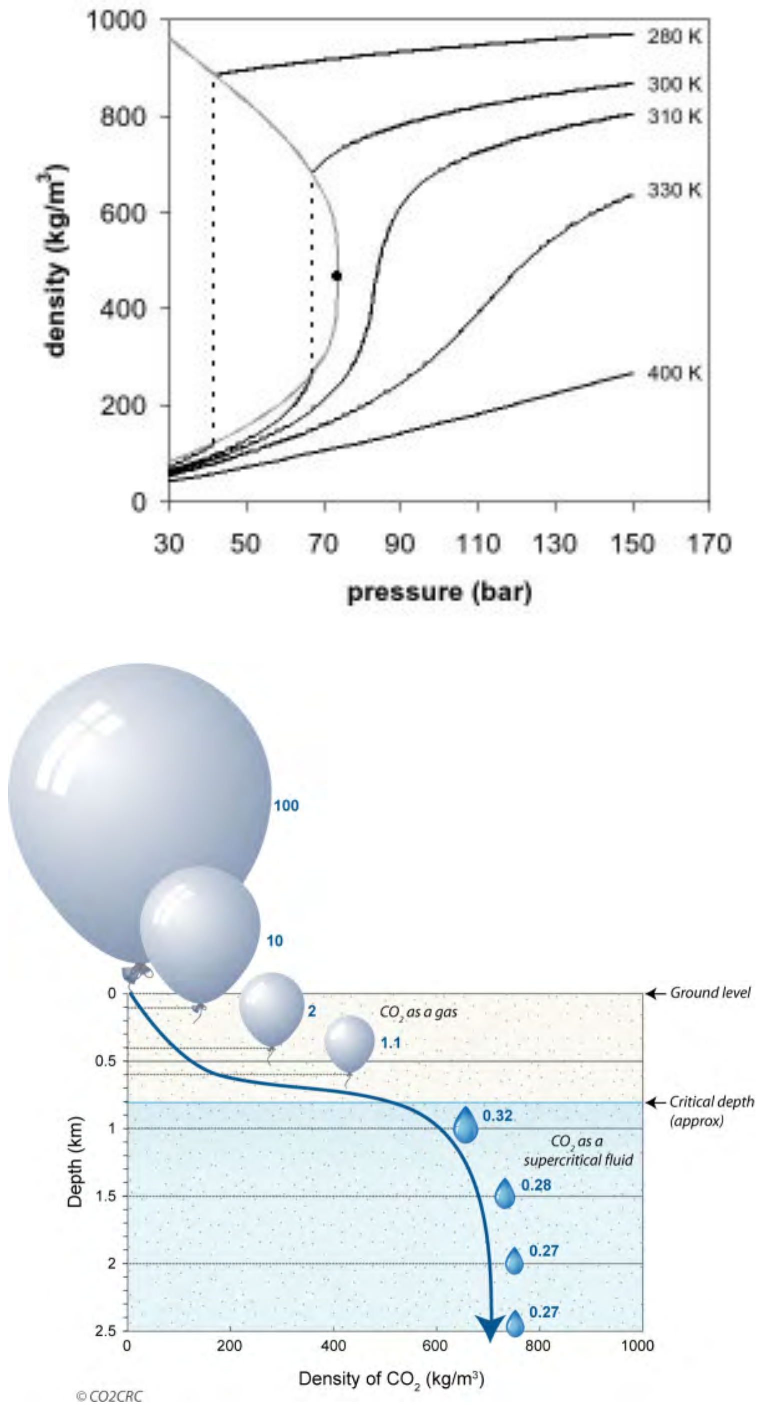


Figure 1.3—CO_2 density as a function of pressure and temperature (top) and as a function of depth in the subsurface (bottom). Source: http://en.wikipedia.org/wiki/Supercritical_fluid (top image), http://www.cgenpower.com/images/other/pop-up/densiteit.jpg (bottom image).

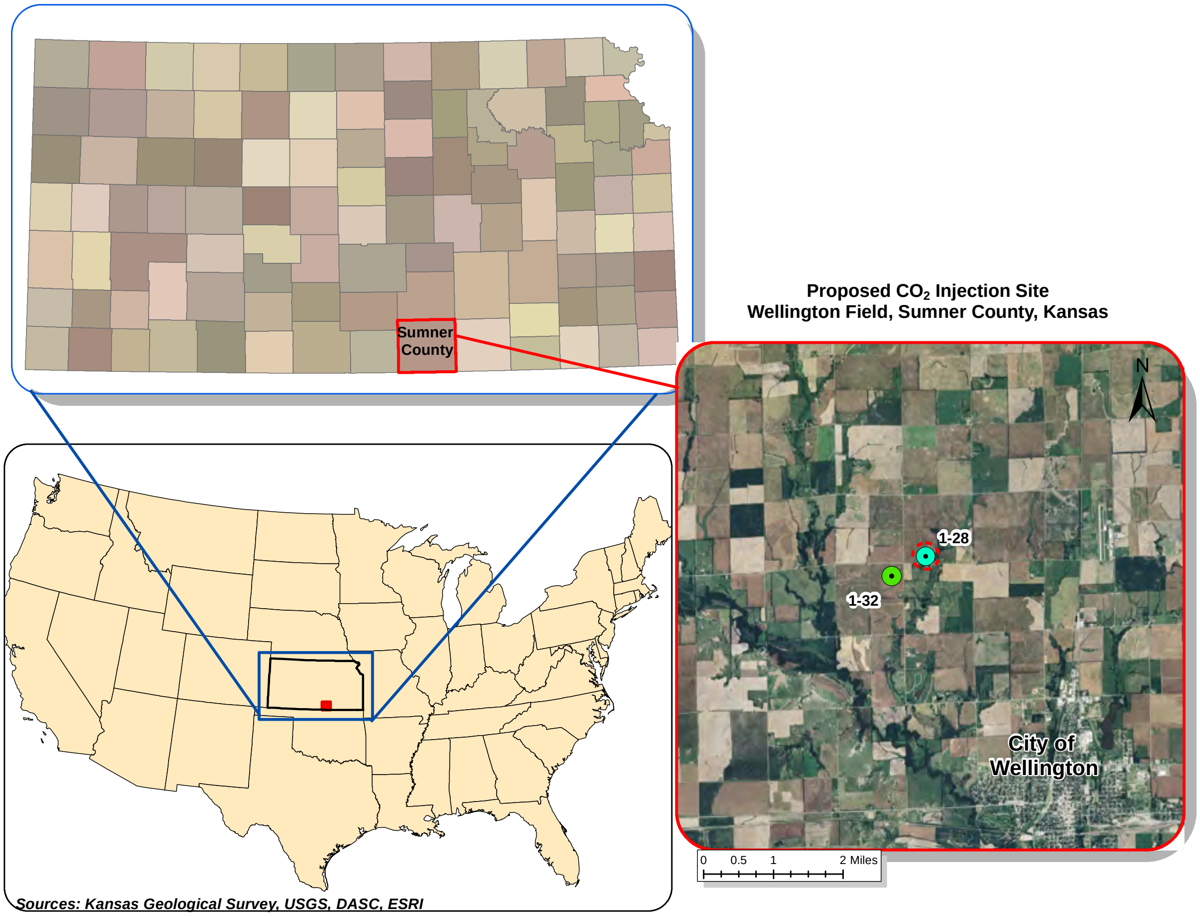


Figure 1.4—Location of small-scale CO_2 storage site at Wellington, Kansas.

This document presents the information required by the U.S. Environmental Protection Agency in support of a Class VI CO_2 injection well permit. The relevant information is provided in the following sections of this document:

Section 2: CO_2 Storage Potential of Arbuckle Group—This section addresses the storage potential of the Arbuckle Group.

Section 3: Regional Geology and Hydrogeology—This section addresses regional geologic and hydrologic characteristics of the injection zone, upper confining zone, and lower confining zone.

Section 4: Local Geology and Hydrogeology—This section presents site scale information pertaining to the USDW, upper confining zone, and injection zone, including information necessary for constructing a reservoir simulation model.

Section 5: Reservoir Modeling—This section describes base case and uncertainty simulations to bound the extent of CO_2 migration and the delineation of the EPA Area of Review (AoR).

Section 6: Geomechanical and Caprock Integrity Analyses—This section documents fault and fracture stability investigations to demonstrate that the pressures resulting from the small-scale injection will not cause slippage along any structural features or initiate new fractures in the Arbuckle aquifer or in the overlying confining zone.

Section 7: CO_2 Trapping Potential of Mississippian Formations—This section addresses the trapping capabilities of the overlying Mississippian formations in the unlikely event of CO_2 escape from the Arbuckle Group.

Section 8: System Design, Construction, and Operations—This section details surface facilities and the injection well construction to demonstrate conformance to EPA guidelines. It also addresses required well testing activities.

Section 9: Area of Review and Corrective Action Plan—This section addresses the EPA AoR as well as how the AoR will be revisited as required by EPA regulation. Also included is the associated well Corrective Action Plan, which addresses how wells within the AoR will undergo corrective action, as and if necessary.

Section 10: Testing, Verification, and Monitoring Plan—This section addresses monitoring, verification, and accounting activities (MVA) that will be deployed in the Testing and Monitoring Plan to monitor and track the CO_2 plume and reservoir pressures.

Section 11: Well Plugging Plan—This section presents the proposed Arbuckle injection and monitoring well plugging details.

Section 12: Post-Injection Site Care and Site Closure Plans—This section presents and discusses monitoring, mechanical integrity testing, and reporting activities planned for the period after injection and before site closure. This section specifies final project status reporting and field testing plans associated with site closure.

Section 13: Emergency Remedial Response Plan—This section identifies risk scenarios and discusses potential emergency plans to be deployed in the event of detection of a CO_2 leak. It also discusses communication plans and other emergency response information.

Section 14: Financial Assurances—This section documents the financial strength of the site operator, Berexco, to satisfy the EPA's financial requirements for injecting CO_2 in the subsurface.

1.2 Project Objectives

The following are the objectives of the Wellington small-scale pilot CCS project:

1. To inject under super-critical conditions a maximum of 40,000 metric tons of CO_2 into the Arbuckle saline aquifer;

2. To demonstrate the application of state-of-the-art tools and techniques to monitor and visualize the injected CO_2 plume and pressure front;
3. To develop a robust Arbuckle geomodel by integrating data collected from the proposed study area and a multi-component 3-D seismic survey;
4. To conduct reservoir simulation studies to map CO_2 plume dispersal and estimate tonnage of CO_2 stored in solution and gaseous phases;
5. To integrate monitoring data and analysis with reservoir modeling studies to detect potential CO_2 leakage and to validate the simulation model;
6. To develop a rapid-response mitigation plan to minimize any potential CO_2 leakage and develop a comprehensive risk management strategy; and
7. To establish best-practice methodologies for plume/pressure monitoring and closure.

1.3 Project Goals

The principal goal of this project is to gain a better scientific understanding of the carbon storage process by incorporating advanced characterization and modeling techniques; evaluating best practices for CO_2 monitoring tailored to the geologic setting; optimizing methods for remediation and risk management; and providing technical information and training to enable additional projects and to facilitate discussions about issues of liability and risk management for operators, regulators, and those making policy decisions.

As discussed in Section 10, a suite of MVA technologies will be applied during the project. These technologies will enable accurate mapping of the CO_2 plume with the goal of improved understanding of the storage mechanisms, the reservoir storage capability, methods for ensuring well integrity, and the economics of CO_2 geologic storage.

1.4 Project Description and Summary (§ 146.82 [a][2])

The injection site is northwest of Wellington, a town in south-central Kansas with a population of 7,500 (Figure 1.4). Figure 1.4 shows two recently completed Arbuckle wells, KGS 1-28 (proposed injection well) and KGS 1-32 (geologic characterization well). As shown on topographic, aerial, and land-use maps (Figures 1.5–1.7), the site is rural and land use is primarily agricultural. Several small intermittent streams flow into Slate Creek south of the site (Figure 1.6a), which discharges into the Arkansas River along the eastern boundary of Sumner County.

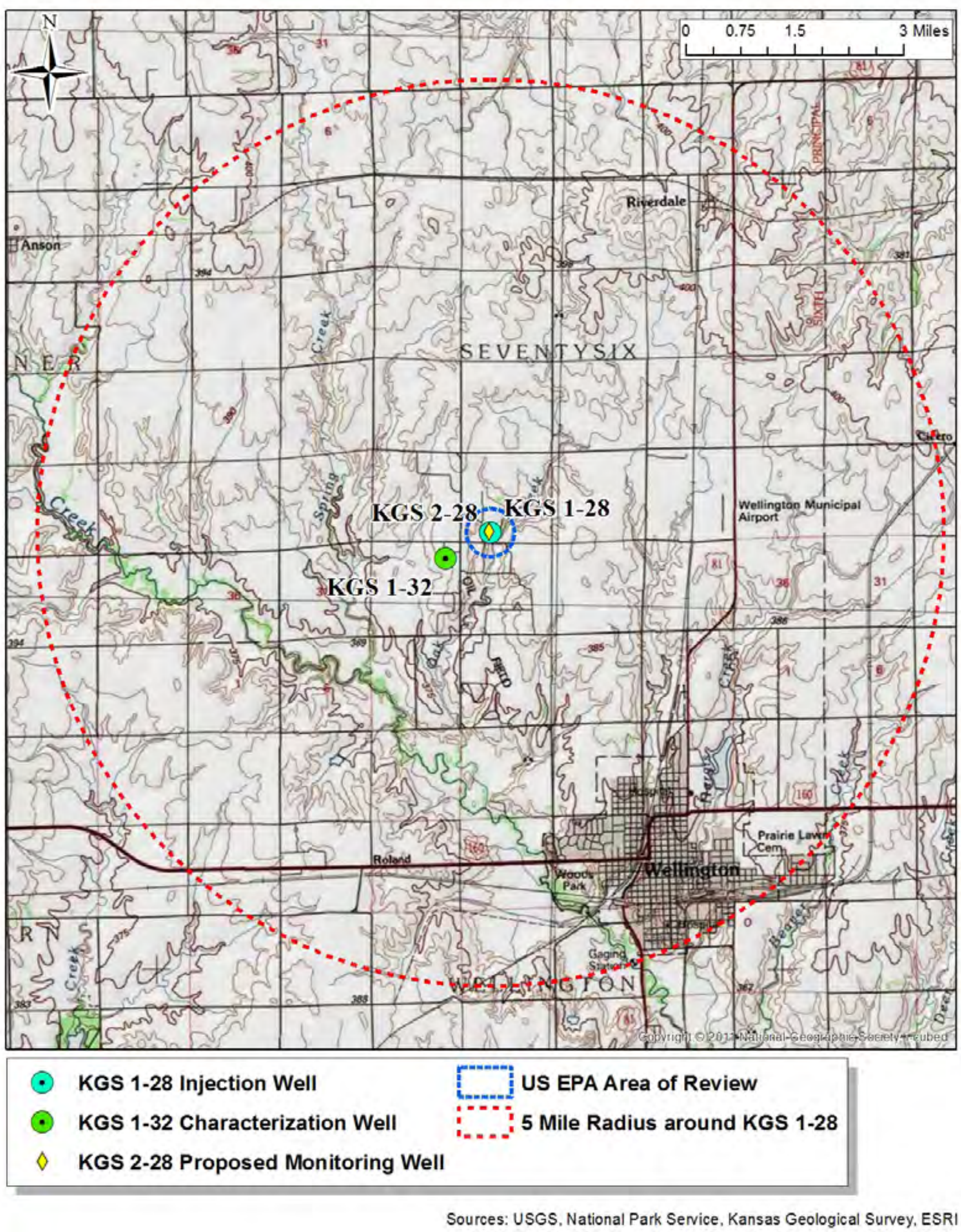


Figure 1.5—Topographic map of Wellington storage site.

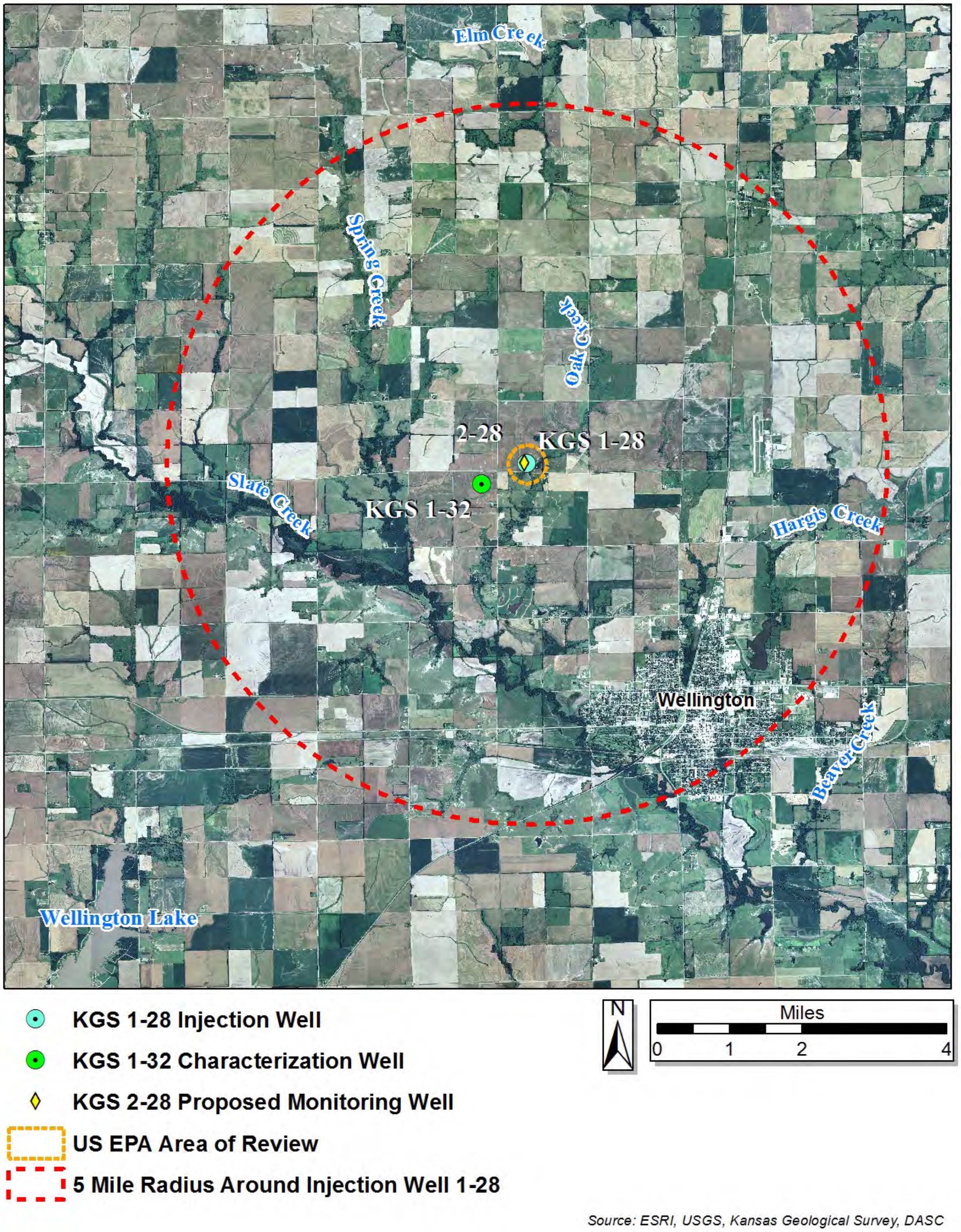


Figure 1.6a—Aerial map of Wellington storage site and vicinity, Sumner County, Kansas.

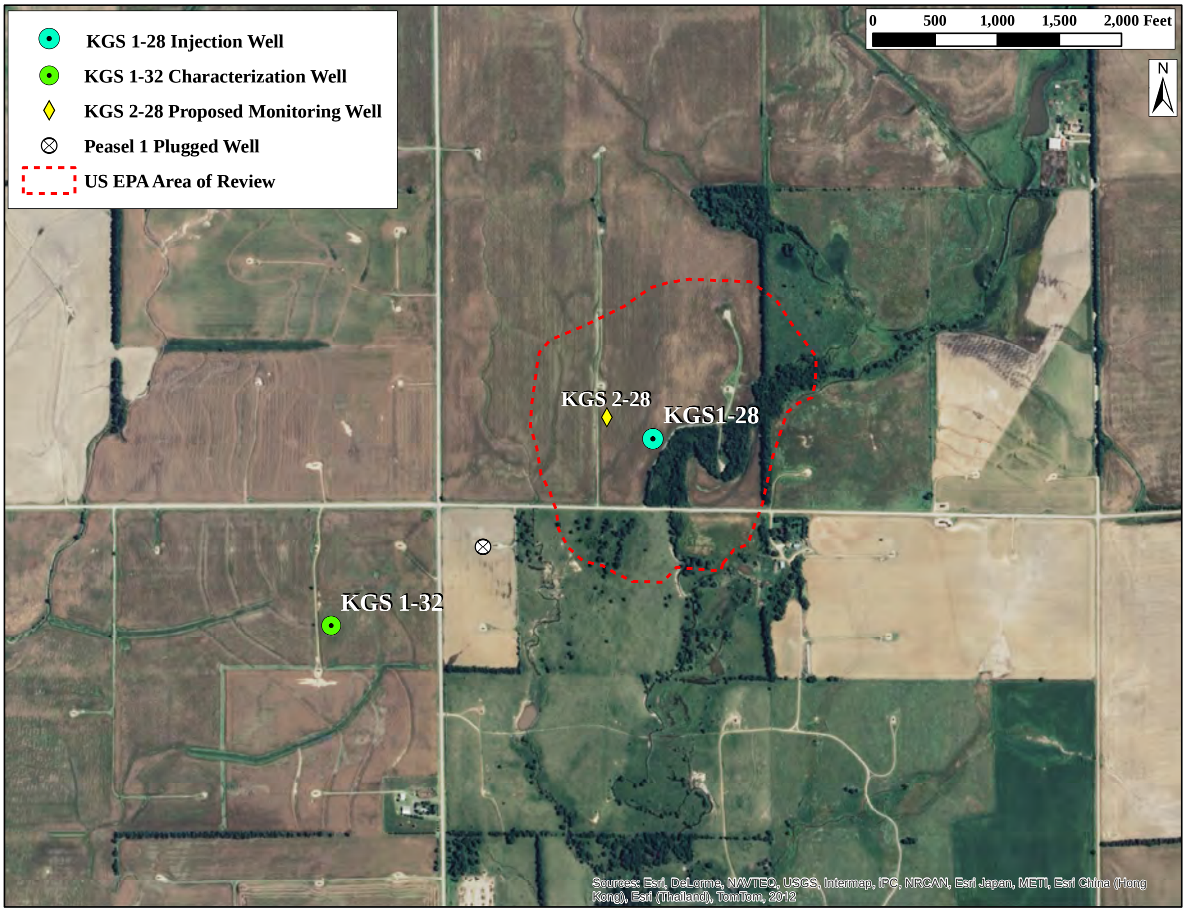


Figure 1.6b—Close-up aerial map of Wellington storage site, Sumner County, Kansas.

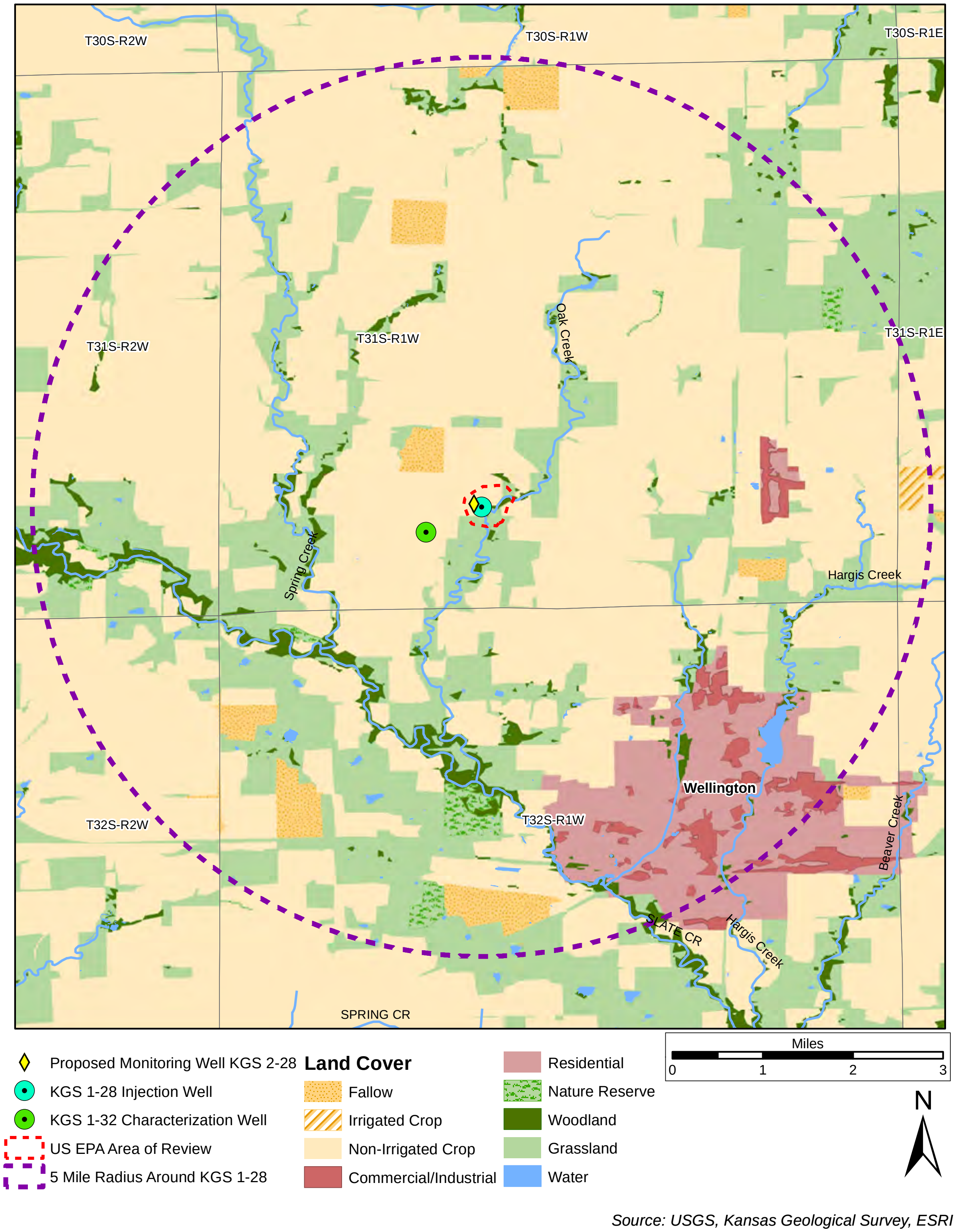


Figure 1.7—Land use in the vicinity of the Wellington small-scale CO_2 storage site.

The geologic formations at the site are presented in Figure 1.8 and further discussed in Sections 3 and 4. Note that in Figure 1.8 and all subsequent figures (and text), the depths are referenced from kelly bushing (KB) unless otherwise stated. The CO_2 injection is to occur in the lower part of the Arbuckle aquifer as shown in Figure 1.8. The top of the Arbuckle Group is approximately 4,170 ft below land surface at the injection site. The 240 ft of shale and argillaceous material overlying the Arbuckle Group from the base of the Simpson Group to the top of the Pierson formation constitute the primary confining zone at the site and are expected to provide impedance to vertical flow and prevent escape of CO_2 from the Arbuckle Group. The lowermost and only USDW at the site lies within the uppermost 250 ft of the Wellington Formation at the surface, as discussed in Section 4.5. The base of the USDW is approximately 4,730 ft above the top of the (Arbuckle) injection interval (4,910–5,050 ft).

Injection well KGS 1-28 is to be perforated in the Arbuckle between 4,910 and 5,050 ft (Figure 1.8). A maximum of 40,000 tons of CO_2 will be injected in the Arbuckle at well KGS 1-28 over the nine-month injection period. Water levels in the Arbuckle are presently 595 ft below water levels in the Upper Wellington Formation (USDW). As discussed in Section 5, injection of CO_2 will cause a water-level rise of less than 595 ft within the Arbuckle aquifer at a few tens of feet from the injection well. Therefore, escape of CO_2 in the dissolved phase from the Arbuckle into the USDW is highly unlikely even if there were a natural geologic pathway or a well penetration (other than the injection well) because the water-level rise regionally in the Arbuckle will be well below the USDW water levels.

Existing and abandoned Arbuckle wells within a 5-mi radius of the injection well KGS 1-28 are presented in Figure 1.9. There are two Arbuckle oil wells within a mile of the injection well, and both wells are abandoned. Existing and abandoned wells that terminate in the upper confining zone at the site (top of the Pierson formation) in the vicinity of the injection well are shown in Figure 1.10. The closest well is approximately 3,000 ft from KGS 1-28 and outside the EPA AoR discussed in Section 9.

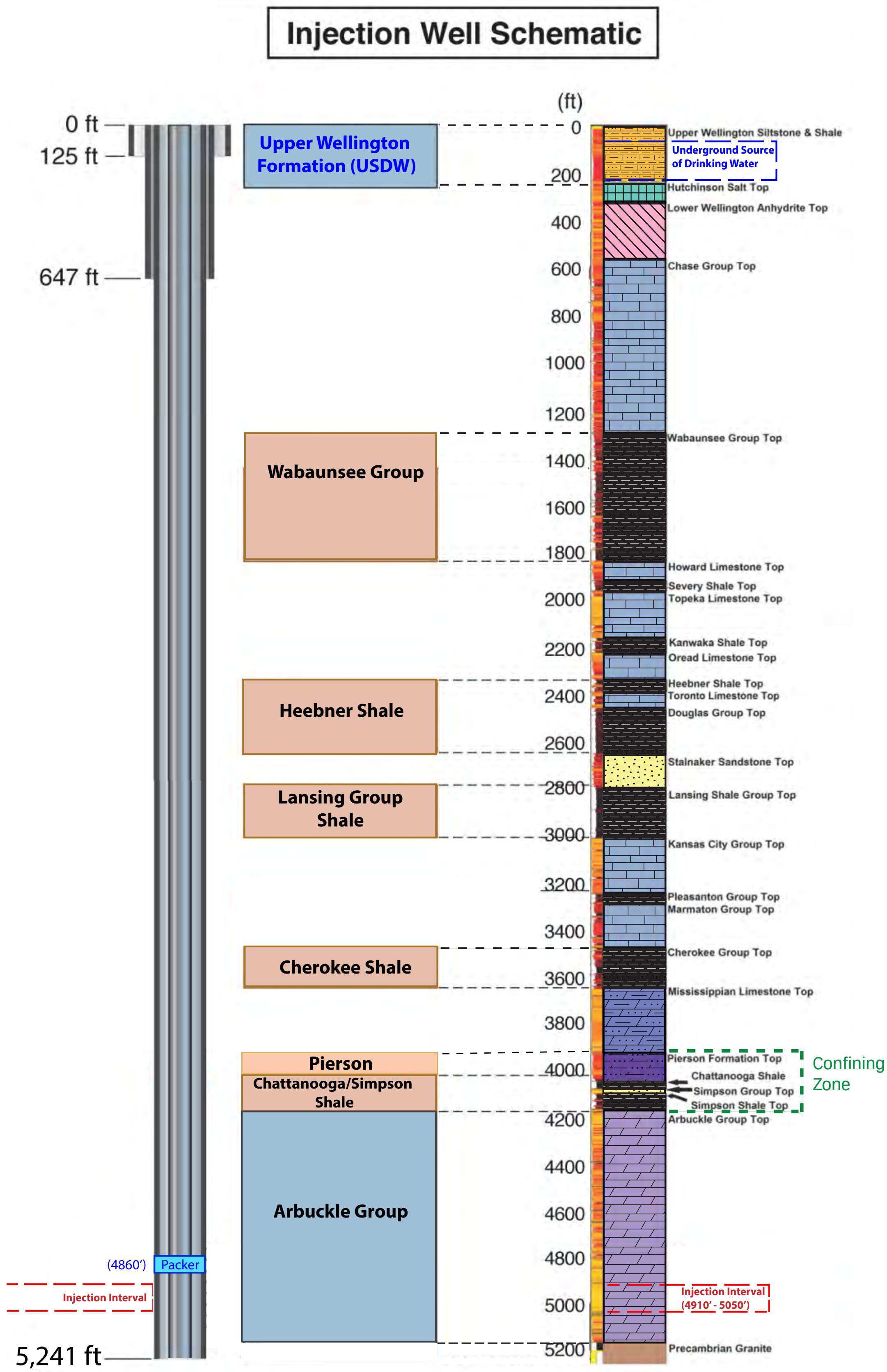


Figure 1.8—Subsurface schematic of proposed injection well (KGS 1-28) showing injection and confining zones along with USDW.

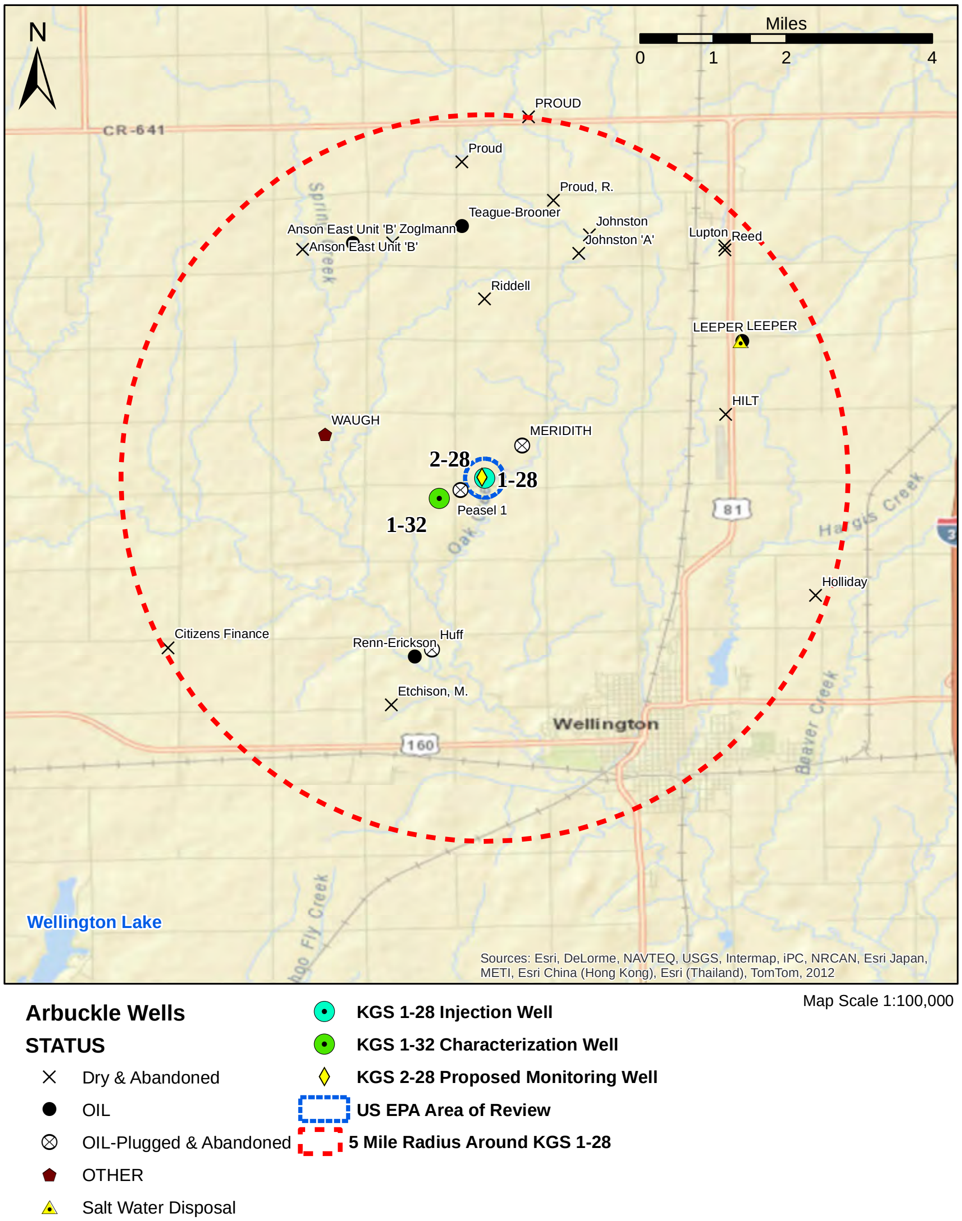
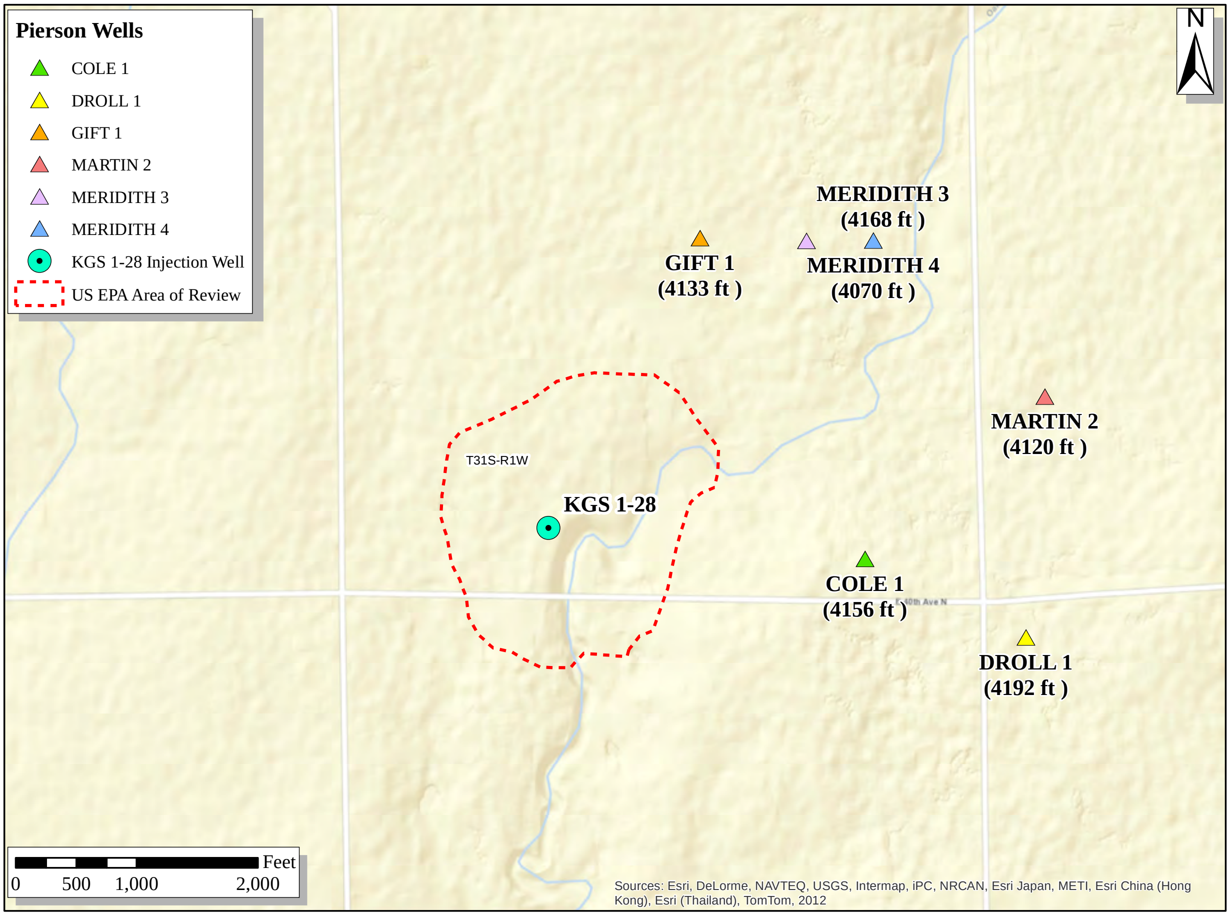


Figure 1.9—Site map of Wellington, Kansas, showing all existing and abandoned wells in the Arbuckle formation.



Additional Sources: Kansas Geological Survey, DASC, Kansas Corporation Commission

Figure 1.10—Site map of Wellington, Kansas, showing wells that terminate in the confining zone (base of Simpson Group to top of Pierson formation) overlying the Arbuckle Group. Injection well KGS 1-28, which terminates in the Arbuckle Group, is shown for references purposes.

As discussed in Section 10, a total of five monitoring wells will be used to track the CO_2 plume and pressure front. Of these, one is an Arbuckle well, two are Mississippian wells, and two will be Upper Wellington (USDW) wells. The Arbuckle monitoring well KGS 2-28 will be located approximately 400 ft from injection well KGS 1-28 (Figure 1.6b). The geographic location of the Arbuckle injection and monitoring wells are specified in Table 1.1.

Table 1.1—Location of Arbuckle injection and monitoring wells for the Wellington project.

Well	Completion Date	Latitude	Longitude	Section	Ground Elevation (ft, MSL)	Total Depth (ft)
1-28	Aug-24-2011	37.319485	-97.4334588	T31S R1W S28 NE SW SE SW	1257	5250
2-28	Future Well	37.3199654	-97.4347393	T31S R1W S28 SW NW SE SW	Est. 1255	Est 5250

The AoR is defined as the region surrounding the geologic storage project where USDW may be endangered by the injection activity. The AoR is determined using computational modeling and is a function of the physical and chemical properties of the injectate and displaced fluid, site characterization, monitoring, and operational data. Modeling results are presented in Section 5 of this permit application and show that the lateral extent of the CO_2 plume has a maximum radial spread of approximately 1,700 ft from the injection well, as shown in Figure 1.11. The plume boundary is defined by 1% free-phase CO_2 saturation isoline.

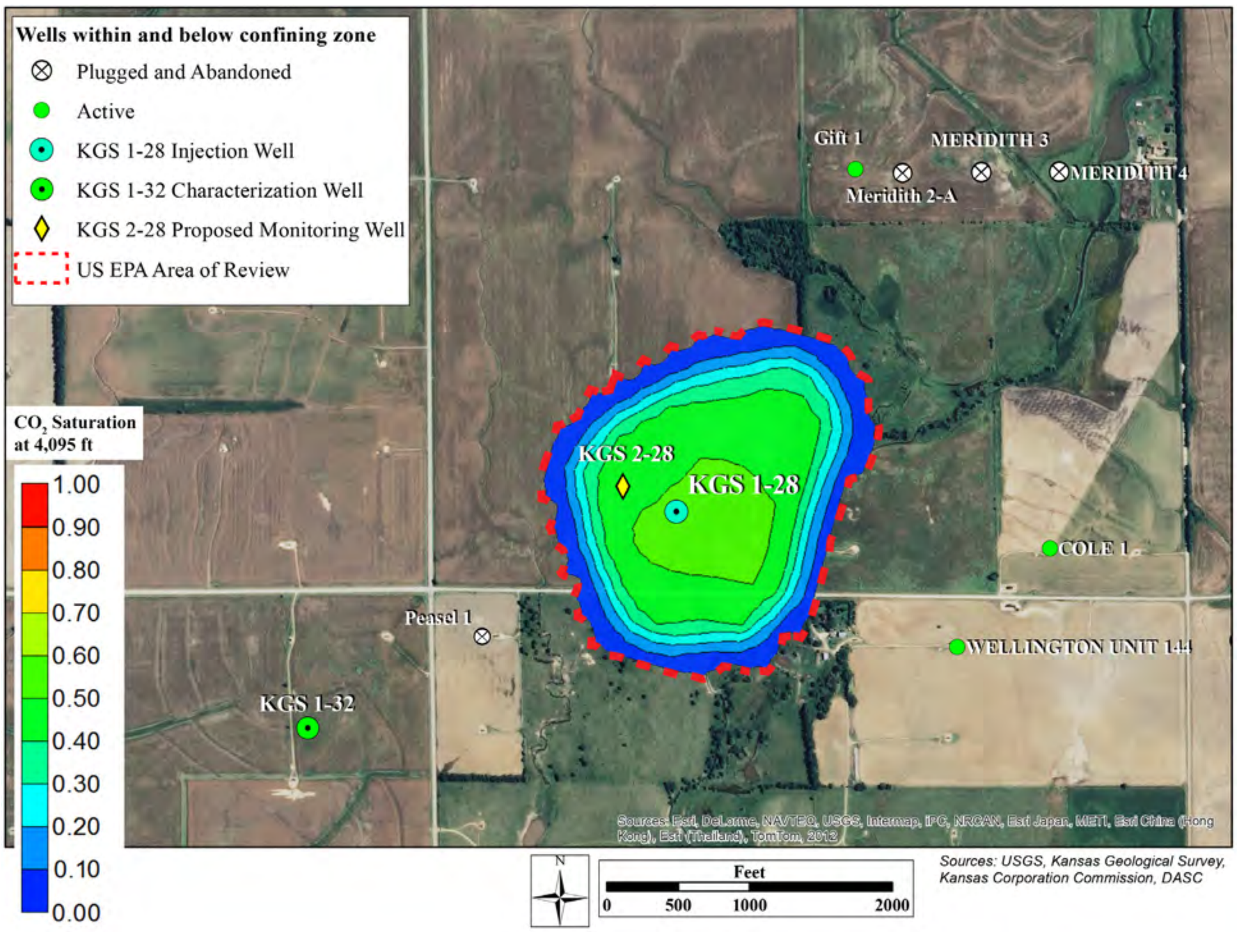


Figure 1.11—Maximal lateral extent of CO_2 plume at 100 years and EPA AoR.

All existing and abandoned wells within the AoR are presented in Figure 1.12 and Table 1.2. The only existing Arbuckle well within the AoR is the newly constructed injection well (KGS 1-28). The only other Arbuckle well that will be within the AoR is the KGS 2-28 monitoring well, which will be constructed upon approval of the injection permit. Both Arbuckle wells will be in compliance with EPA construction guidelines and rules as documented in Sections 8 and 10. In addition to the proposed Arbuckle injection well, there are six Mississippian wells in the AoR, of which three are active and three plugged and abandoned. None of the Mississippian wells penetrate the top of the Pierson formation (3,930 ft), which is the uppermost confining unit at the Wellington site. Therefore, no remedial measures on existing or abandoned wells will be required. There are no known faults within the AoR.

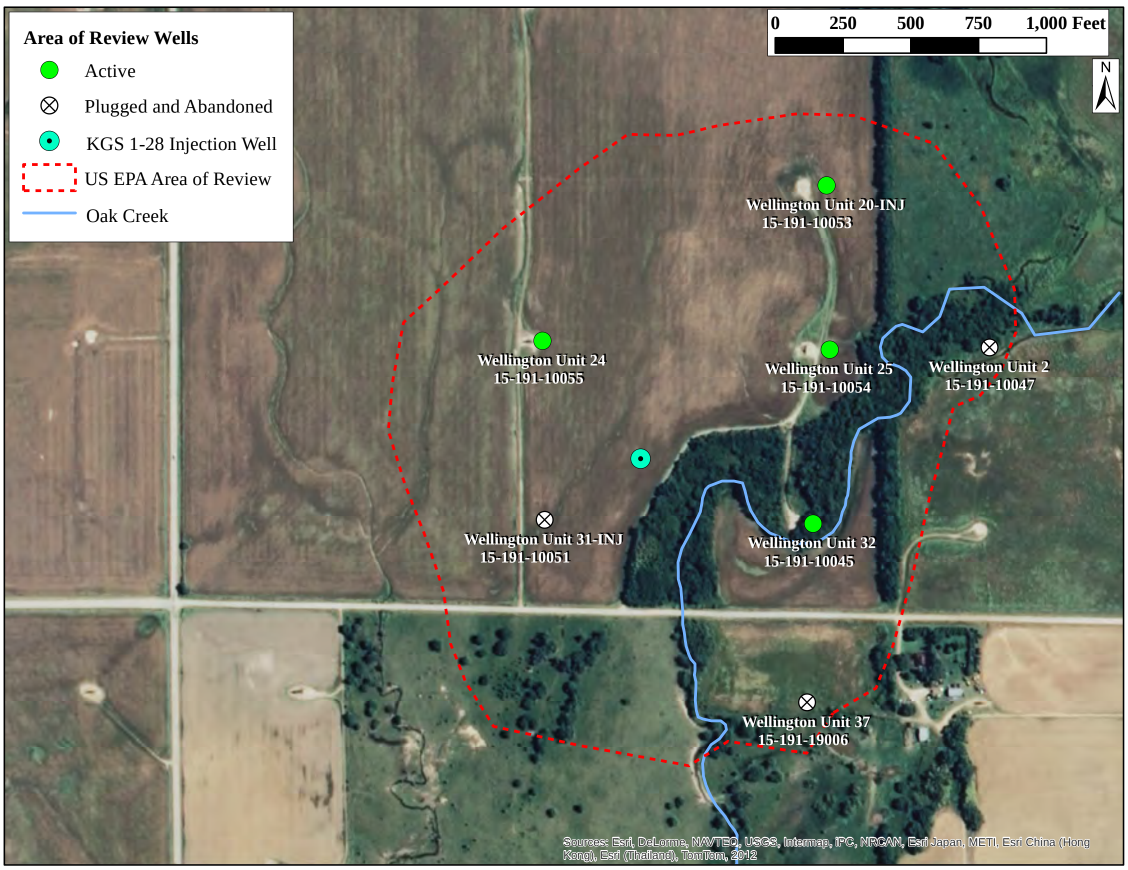


Figure 1.12—All existing and abandoned wells within the EPA Area of Review.

Table 1.2—Construction details and status of all existing and abandoned wells within the AoR.

API Number	Lease Name	Status	Operator Name	Well Class	Spud Date	Completion Date	Plugged Date	Total Depth (ft)	Formation	Elevation (ft, msl)	NAD83 Latitude	NAD83 Longitude
15-191-10045	Wellington Unit 32 (Was Kamas 6)	Producing	Sinclair Prairie Oil Co.	OIL	2/1/36	10/1/36	N/A	3678	Mississippian	1246	37.318829	-97.4316
15-191-10047	Wellington Unit 2	Plugged and Abandoned	Vickers Petroleum Co.	OIL (P&A)	2/19/36	3/21/36	4/1/49	3674	Mississippian	1249	37.320595	-97.42933
15-191-10051	Wellington Unit 31 (Was Frank Kamas 4)	Plugged and Abandoned	Sinclair Prairie Oil Co.	OIL (P&A)	12/30/35	6/18/56	9/21/88	3704	Mississippian	1257	37.3189	-97.43501
15-191-10053	Wellington Unit 20	Injection Well	Beredco, Inc	EOR	Not Available	Not Avaialable	N/A	1271	Chase Group	Not Available	37.322271	-97.43201
15-191-10054	Wellington Unit 25 (Was Kamas 7)	Producing	Sinclair Prairie Oil Co.	OIL	3/26/36	10/1/88	N/A	3681	Mississippian	1258	37.320642	-97.4316
15-191-10055	Wellington Unit 24 (Was Frank Kamas 9)	Producing	Sinclair Prairie Oil Co.	OIL	12/14/36	10/1/37	N/A	3707	Mississippian	1264	37.320713	-97.43501
15-191-19006	Wellington Unit 37	Plugged and Abandoned	BEREXCO LLC	Oil (P&A)	Not Available	Not Available	2/19/04	3671	Mississippian	1245	37.317018	-97.4317
15-191-22590	KGS 1-28	Inactive Well	BEREXCO LLC	CO_2 Injection	2/20/11	8/24/11	N/A	5250	Arbuckle	1270	37.319506	-97.43378

1.5 Project Applicant/Operator Information (§146.82[a][1])

Applicant Information*:*

Applicant: Berexco LLC, Independent Oil and Gas Exploration and Production

USEPA ID No: N/A

Facility Contact: Dana Wreath, Vice President

Mailing Address: 2020 N. Bramblewood Street
Wichita, KS 67206
(316) 265-3311
Fax: (316) 265-8690

Site Information:

County: Sumner

SIC Codes: 1311 Crude Petroleum and Natural Gas
1321 Natural Gas Liquids
1381 Drilling Oil and Gas Wells
1382 Oil and Gas Field Exploration Services
1389 Oil and Gas Field Services, Not Elsewhere Classified

Operator Status: Private, with DOE funding and KGS/contractor technical support

Indian Lands: The site is not located on Indian lands.

Existing Environmental Permits

NPDES Industrial Storm Water Permit: N/A

UIC N/A

RCRA: N/A

Other various air permits, including Title V Clean Air Act Permit: N/A

Other: N/A

Nature of Business and Association with the Wellington Project

Berexco is an independent oil and gas exploration and production company headquartered in Wichita, Kansas. It operates actively in eight mid-continent states and has been a lead industry participant in the U.S. Department of Energy (DOE) south-central Kansas CO_2 Project, a leading initiative to direct research and field activities for characterizing the subsurface, evaluating subsurface CO_2 storage capacity in oil and gas reservoirs and saline aquifers, and investigating climate change mitigation initiatives. The Wellington storage project is one of several projects sponsored by the DOE as part of these initiatives.

1.6 Project Benefits

The proposed small-scale injection project at Wellington will advance the science of geologic storage by improving our understanding of the practices and processes involved in CO_2 geologic storage in saline aquifers. These include the movement and ultimate geochemical fate of the CO_2 within the reservoir; the reservoir storage capacity; the economic viability of CO_2 storage in the reservoir; and the overall risk assessment and consequences of CO_2 leakage. The experience gained from this pilot project will allow further development of advanced technologies and approaches that will significantly improve the efficacy of the geologic carbon storage technology, reduce the cost of implementation, and contribute to possible commercial deployment between 2020 and 2030.

Several novel and experimental MVA technologies may be applied and refined during the project, which may lead to commercial development of cost-effective and environmentally sound technology options. Monitoring, verification, risk assessment, and management technologies developed for the Arbuckle aquifer will be transferable to other sites, enabling commercial-scale applications in the future.

The data and knowledge gathered as part of this research effort and pilot study will be shared with the larger scientific/engineering community and research organizations, including the Southwest Sequestration Partnership (SWP), and integrated into the National Carbon Sequestration Database and Geographic Information System (NATCARB) and the 5th Edition of the Carbon Sequestration Atlas of the United States and Canada.

1.7 State, Tribe, and Territory Information

The AoR does not lie in a tribe or territory. All state communication and correspondence should be directed to:

Cynthia Khan, P.G.,

Kansas Department of Health and Environment

Underground Injection Control Program

1000 SW Jackson Street, Suite 420,

Topeka, KS 66612-1367

Phone: (785) 296-5554

Section 2
CO_2 Storage Potential of Arbuckle Group

2.1 Introduction

The objective of this section is to document the large CO_2 storage potential of the Arbuckle Group throughout Kansas as estimated by the U.S. Department of Energy (NATCARB, DOE, 2012) and to demonstrate the small subsurface footprint of the pilot-scale injection to be conducted at the Wellington CO_2 storage site.

2.2 Arbuckle CO_2 Storage Estimates in Kansas (§146.84[a,c])

Five physical and chemical trapping mechanisms are primarily responsible for effectively storing CO_2 injected in geologic sinks:

- structural trapping
- hydrodynamic trapping
- solubility trapping
- residual trapping
- mineral trapping

Over time, the contribution of each of the above five storage processes in providing long-term storage will change (Benson, 2005). As illustrated in Figure 2.1, structural and hydrodynamic trapping initially will be the dominant mechanism for holding CO_2 in the formation, followed by residual trapping as CO_2 fills the pore space. Over time, as the CO_2 plume grows, larger amounts of CO_2 will dissolve. Mineral trapping is generally slow and occurs over long time scales.

The storage potential of the Arbuckle aquifer estimated for the National Carbon Sequestration Database Project (NATCARB, DOE, 2012) is shown in Figure 2.2. The total amount of CO_2 that could be stored in the Arbuckle Group within Kansas is estimated to be as high 89.5 billion metric tons and equals many years of the annual CO_2 emissions of the entire United States (approximately 6 billion metric tons/year). In Sumner County, between 300,000 and 400,000 tons per square mile can be effectively stored, as shown in Figure 2.2. Based on these estimates, if 40,000 tons of CO_2 are injected at Wellington, it could be stored in approximately 0.13 square mile. The Area of Review (AoR) shown in Figure 1.6b and which corresponds to the plume boundary covers an area of 0.14 square mile, which is of similar magnitude as the DOE estimate. This comparison provides a satisfactory check on results obtained independently by numerical and analytical methods.

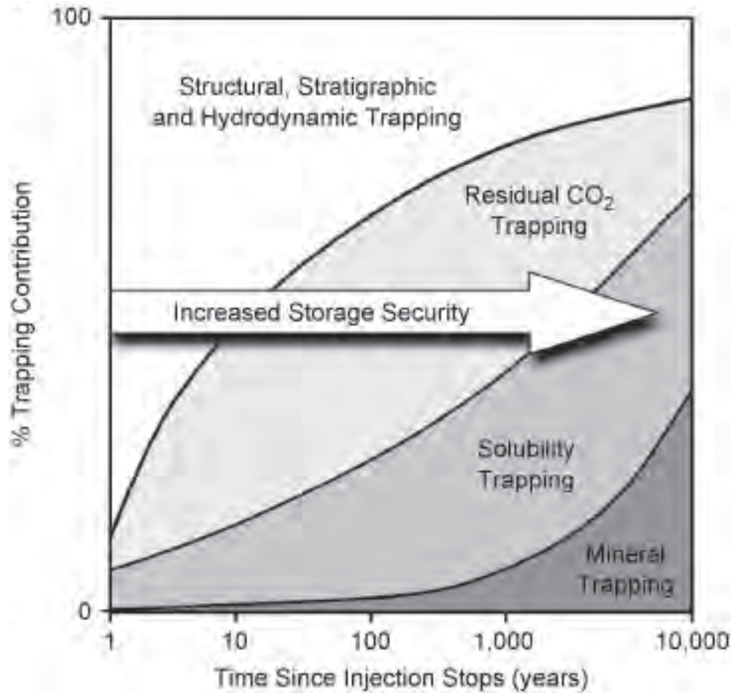


Figure 2.1—Temporal evolution of various CO_2 trapping mechanisms (from Benson, 2006).

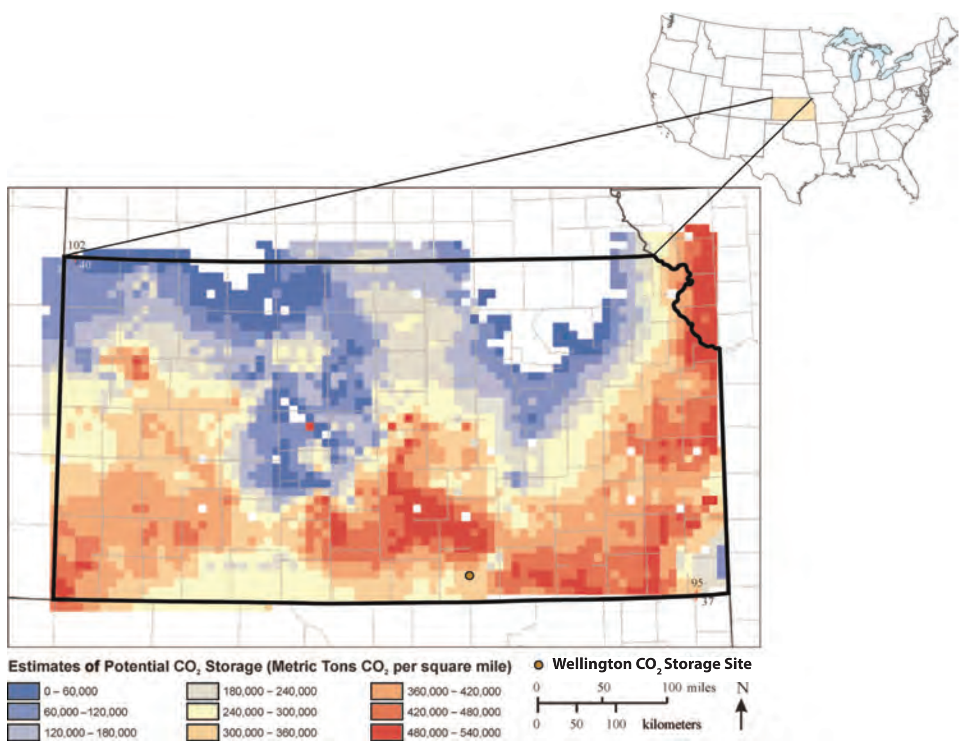


Figure 2.2—Map showing the estimated storage potential in the Arbuckle saline aquifer in metric tons CO_2 per square mile generated for each 5-mi^2 area (source: Carr and White, 2003).

2.3 DOE-Based Estimate of CO_2 Storage Volume

The volume required to store 40,000 tons in the Arbuckle Group at Wellington can be estimated using the technical approach developed by the U.S. DOE (NATCARB, DOE, 2012). The estimated storage area can be compared with the EPA AoR derived in Section 9. The DOE CO_2 storage mass (G_{CO_2}) is estimated by the following volumetric equation,

$$G_{CO_2} = A_t \, h_g \, \O_{tot} \, \rho \, E_{saline} \qquad \text{(I)}$$

where,

the total area (A_t), gross formation thickness (h_g), and total porosity ($\O_{tot}$) terms account for the total bulk volume of pore space available. The CO_2 density (r) converts the reservoir volume of CO_2 to mass. The saline formation efficiency factor (E_{saline}) reflects the fraction of the total pore volume that will be occupied by the injected CO_2 for various probabilities (i.e. P_{10}, P_{50}, and P_{90}, as shown in Table 2.1). The P_{10} notation means that there is a 10 percent probability that the value is less than the P_{10} value, and the P_{90} notation means that there is a 90 percent probability that the value is less than the P_{90} value. E_{saline} takes into account several different efficiency factors as indicated in the Table 2.1 footnote (DOE, 2012)

Assuming an average Arbuckle porosity of 6.8% based on the synthesized data presented in Table 5.3, a lower Arbuckle injection zone thickness of 200 ft, where most of the CO_2 will be sequestered (refer to Figure ES.5a for example), and a CO_2 mass density of 800 kg/m^3, the effective storage radius for the 40,000 tons of CO_2 to be injected at Wellington varies between 867 and 2,541 feet for P_{10} and P_{90} E_{saline} factors (Table 2.2 and Figure 2.3) assuming dolomite as the dominant rock type in Table 2.1. To show how comparatively small the actual volume of CO_2 to be injected is with respect to the calculated radii, the small (52 ft) radius of the injected 40,000 tons CO_2 mass (over 200 ft height) is also shown in Figure 2.3. The average of P_{10} and P_{90} radii is 1,700 feet, which is remarkably similar to the 1,700 feet radius of the AoR derived in Section 9.2.2 based on the maximum extent of CO_2 plume migration. The convergence between the DOE-based empirical estimate and the more sophisticated modeling based estimate of storage volume is confirmatory. The 1,700 ft radius highlights the small subsurface footprint of the pilot scale project at Wellington.

Table 2.1—Saline formation efficiency factors for geologic and displacement terms (from U.S. DOE, 2010)[1].

Saline Formation Efficiency Factors for Geologic and Displacement Terms $E_{saline} = E_{An/At} E_{hn/hg} E_{\phi e/\phi tot} E_v E_d$			
Lithology	**P_{10}**	**P_{50}**	**P_{90}**
Clastics	0.51%	2.0%	5.4%
Dolomite	0.64%	2.2%	5.5%
Limestone	0.40%	1.5%	4.1%

[1] E_{saline} defines the individual parameters needed to estimate the CO_2 storage efficiency factor for saline formations:

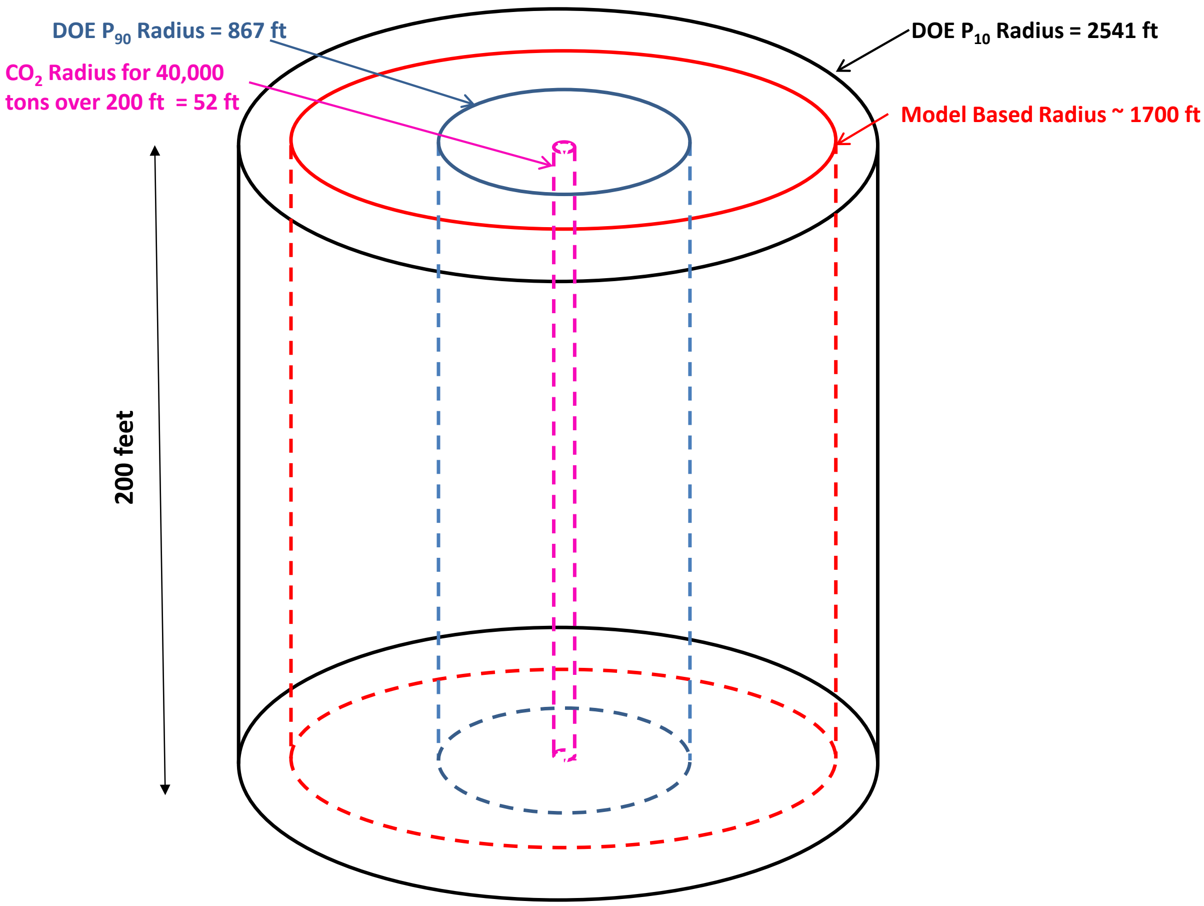
$E_{saline} = E_{An/At} E_{hn/hg} E_{Øe/Øtot} E_{Øe/Øtot} E_v E_d$ where,

The area $E_{An/At}$, thickness $E_{hn/hg}$, and porosity $E_{Øe/Øtot}$ terms gauge the percentage of volume that is amenable to CO_2 sequestration. The volumetric displacement term (E_v) corrects for the effective CO_2 plume shape. The microscopic displacement term (E_d) corrects for the accessible pore volume available to CO_2.

Table 2.2—Calculated subsurface area occupied by injected CO_2 over 200 ft interval at Wellington using Equation I and assuming dolomite as the dominant lithology in the Arbuckle Group for selection of E_{saline} factors in Table 2.1.

Probability	Mass (tons)	Depth (ft)	Porosity	E_{saline}	Density (kg/m3)	Area (m3) = Mass/ Depth/ Porosity/ Esaline/Density	Radius (m)	Radius (ft)
P_{50}	40,000	200	0.068	0.022	800	548,128	418	1,371
P_{10}	40,000	200	0.068	0.0064	800	1,884,191	775	2,541
P_{90}	40,000	200	0.068	0.055	800	219,251	264	867

Figure 2.3—Estimated storage radii for the 40,000 tons of CO_2 to be injected at Wellington, Kansas.



Section 3

Regional Geology and Hydrogeology

3.1 Introduction

This section describes the regional geology and hydrogeology in order to satisfy 40 CFR Part 146.82 (a)(3)(vi), which requires that prior to issuance of a permit to construct a Class VI well or convert an existing injection well to a Class VI well, the following information must be provided:

(vi) Geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the local area.

40 CFR Part 146.3 specifies the following definitions:

- *Confining zone* means a geological formation, group of formations, or part of a formation that is capable of limiting fluid movement above an injection zone.
- *Injection zone* means a geological formation, group of formations, or part of a formation that receives fluids through a well.

40 CFR Part 146.83 (a) provides the minimum siting criteria for owners and operators of Class VI injection wells, which require demonstration to the satisfaction of the director that the wells will be sited in areas with a suitable geologic system. The owners or operators must demonstrate that the geologic system includes:

(1) An injection zone(s) of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the carbon dioxide stream;

(2) Confining zone(s) free of transmissive faults or fractures and of sufficient areal extent and integrity to contain the injected carbon dioxide stream and displaced formation fluids and allow injection at proposed maximum pressures and volumes without initiating in or propagating fractures into the confining zone(s).

In addition to the regional geology and hydrogeology described in this section, site-specific hydrogeology is addressed in detail in Section 4 of this permit application. 40 CFR Part 146.83(b) addresses the potential that the director may require identification and characterization of additional zones that will impede vertical movement. Identification and description of an additional zone is presented in Section 7 of this permit application, although the permit application does not rely on the fluid impediment potential of the zone to demonstrate containment.

3.2 Background

Regional statewide geologic and hydrogeologic data for the injection and confining zones are presented in the following sections. Due to the small-scale nature of the Wellington project, the injected CO_2 will result in an EPA Area of Review (AoR) of approximately 1,700-ft radius as discussed in Section 5 and illustrated in Figure 1.11. Therefore, demonstration of the regional capability of the injection and confining zones to accept and store the CO_2 is not as critical for the Wellington project. However, regional information is provided to demonstrate the presence and continuity of the injection and confining zones and to satisfy the Class VI Final Rule requirements referenced above.

The injection zone at the injection well site (KGS 1-28) lies within the lower Arbuckle aquifer in the interval 4,910–5,050 ft KB as shown in Figure 1.8. The primary confining zone at the injection site comprises the overlying Simpson Group, the Chattanooga Shale, and the Pierson formation in the interval 3,930–4,168 ft. As shown in Figure 1.8, there are several additional shale layers between the injection zone and the base of the USDW at 250 ft (below land surface) that can provide hydraulic confinement. However, for purposes of this project, the interval from the base of the Simpson Group to the top of the Pierson formation comprises the primary confining zone. As demonstrated in Section 4, these zones have low permeabilities and, therefore, are capable of preventing movement of CO_2 and brine from the Arbuckle aquifer.

The general geology in Kansas is presented in Figure 3.1a-b. The CO_2 injection is to occur in the lower portion of the Cambrian/Ordovician-age Arbuckle Group, which as discussed below is a large saline aquifer present throughout the midcontinent region of the United States. It lies above the Precambrian-age granite basement, which as discussed below is also prevalent throughout Kansas and is expected to provide impediment to flow, functioning as the lower confining zone for the project. As discussed in Sections 3.4 and 4.7, the Ordovician-, Devonian-, and Mississippian-age shales within the Simpson Group, Chattanooga Shale, and the lower Osagean/Kinderhookian have sufficient caprock characteristics to function as the top confining zone and effectively prevent upward migration of CO_2 and brine.

The presence and continuity of the injection and confining zones in the study area are demonstrated by structure maps presented in Sections 3.3 and 3.4. Also, Figure 4.2a-d present three cross sections in the Wellington area, which confirm the presence of a thick Arbuckle unit, the Precambrian basement, and a contiguous confining zone above the Arbuckle. Additional shale zones above the Mississippian isolate the Arbuckle injection zone from the USDW in the Upper Wellington Formation above the Hutchinson Salt beds. The Precambrian granitic basement below the Arbuckle aquifer is expected to function as the lower confining zone.

The contents in this section are organized as follows:

3.3 Geology and Hydrogeology of the Injection Zone: Arbuckle Group (§146.82 [a][3][vi], §146.82[c][1])

3.3.1 Arbuckle Regional Geology

The Arbuckle Group includes upper Cambrian and Lower Ordovician carbonate units that underlie the Middle Ordovician Simpson Group (Figure 3.1a). The Cambrian Bonneterre Dolomite may occur below the Arbuckle Group, and the Lamotte (Reagan) Sandstone may occur unconformably below the Bonneterre and above the Precambrian basement. However, neither the Bonneterre Dolomite nor Lamotte (Reagan) Sandstone are present in the Wellington area of Sumner County, so the Arbuckle occurs immediately atop Precambrian granitic basement rock in the Wellington area.

The Arbuckle Group is primarily composed of dolomites deposited about 480 million years ago during the Cambrian and Ordovician periods. The Arbuckle Group is composed (top to bottom) of the Jefferson City/Cotter Dolomite (JCC), Roubidoux Formation, Gasconade with basal Gunter Sandstone, and Eminence Dolomite (Figure 3.1b). Regional data presented by Franseen et al. (2004) indicate that the Eminence Dolomite is missing in areas of southern Kansas, including Sumner County, meaning that the Ordovician Gunter Sandstone occurs uncomformably above the Precambrian basement at this location.

The Arbuckle Group was deposited in an epicontinental sea, and the dominant sediment deposited was calcareous mud that later lithified into limestone during periods of sea recession. Post-depositional alteration of Arbuckle limestone to dolomite occurred when freshwaters rich in magnesium and calcium mixed with the local marine waters (Jorgensen et al., 1993). The Arbuckle consists mainly of white, buff, light-gray, cream, and brown crystalline dolomite (Zeller, 1968). Chert is possible in the upper portion of the Arbuckle Group.

The top of the Arbuckle in the central portion of Sumner County is at a depth of approximately 4,000 ft below land surface. The Arbuckle Group is regionally extensive throughout Kansas with the exception of some structurally high areas on the Central Kansas uplift and the Nemaha anticline (Figure 3.2) where the Arbuckle has been removed by erosion (Carr, 1986). The elevation to the top of the underlying Precambrian basement in Sumner County varies from 0 ft mean sea level (MSL) in the northeast to -6,000 ft MSL in the southwest (Figure 3.3). The elevation to the top of the Arbuckle Group is presented in Figure 3.4, and the thickness of this unit is presented in Figure 3.5a. The Arbuckle generally thickens as a whole from north to south and is thickest (up to 1,100 feet) in south-central Kansas. The east-west and north-south cross sections in Figure 3.5b and 3.5c highlight the lateral continuity of this group at the Wellington site and in Kansas.

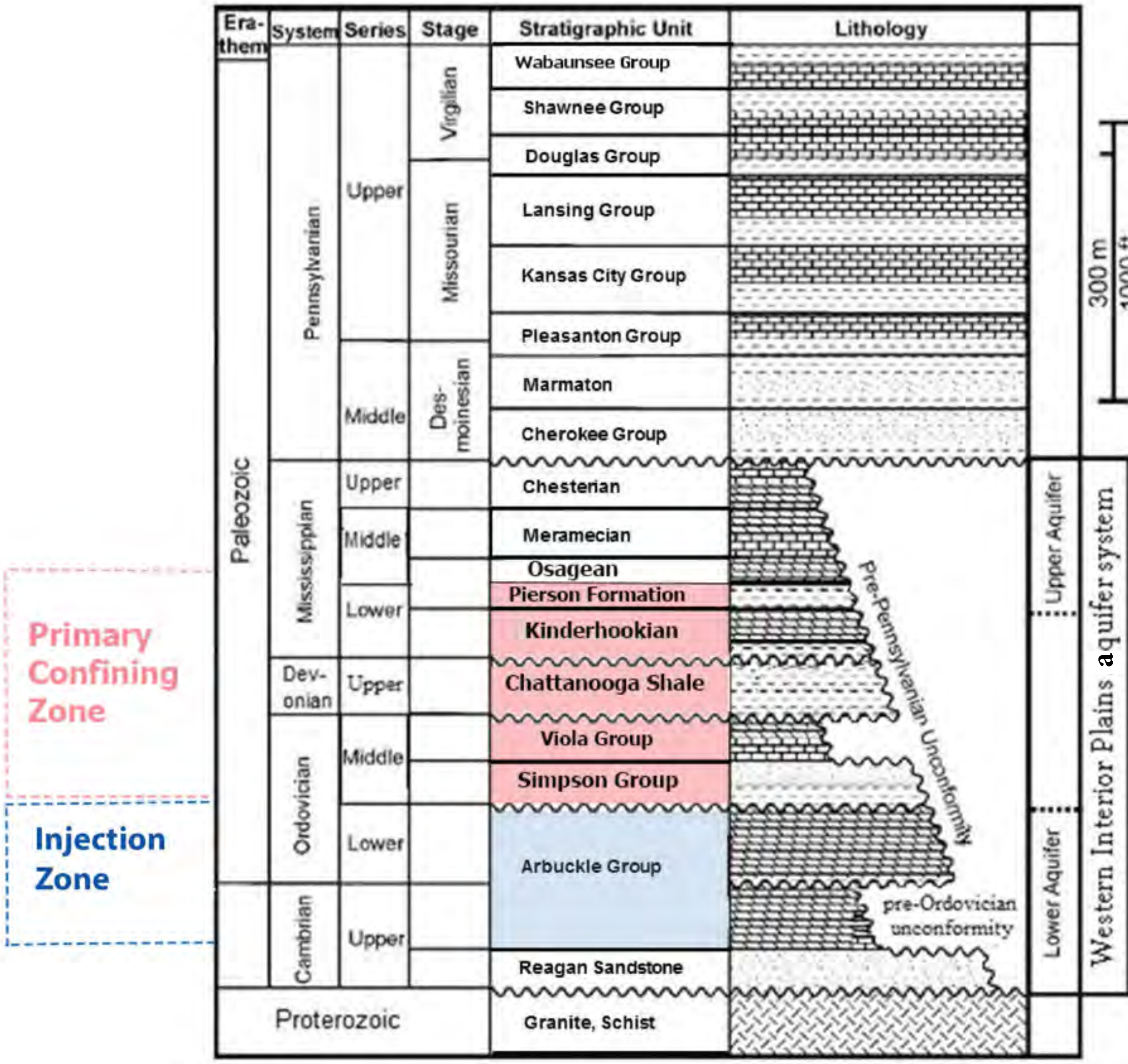


Figure 3.1a—Generalized stratigraphy of Kansas showing the relative position of the lower and upper aquifers of the Ozark Plateaus aquifer system and the adjoining Pennsylvanian and Precambrian systems (from Carr et al., 2005).

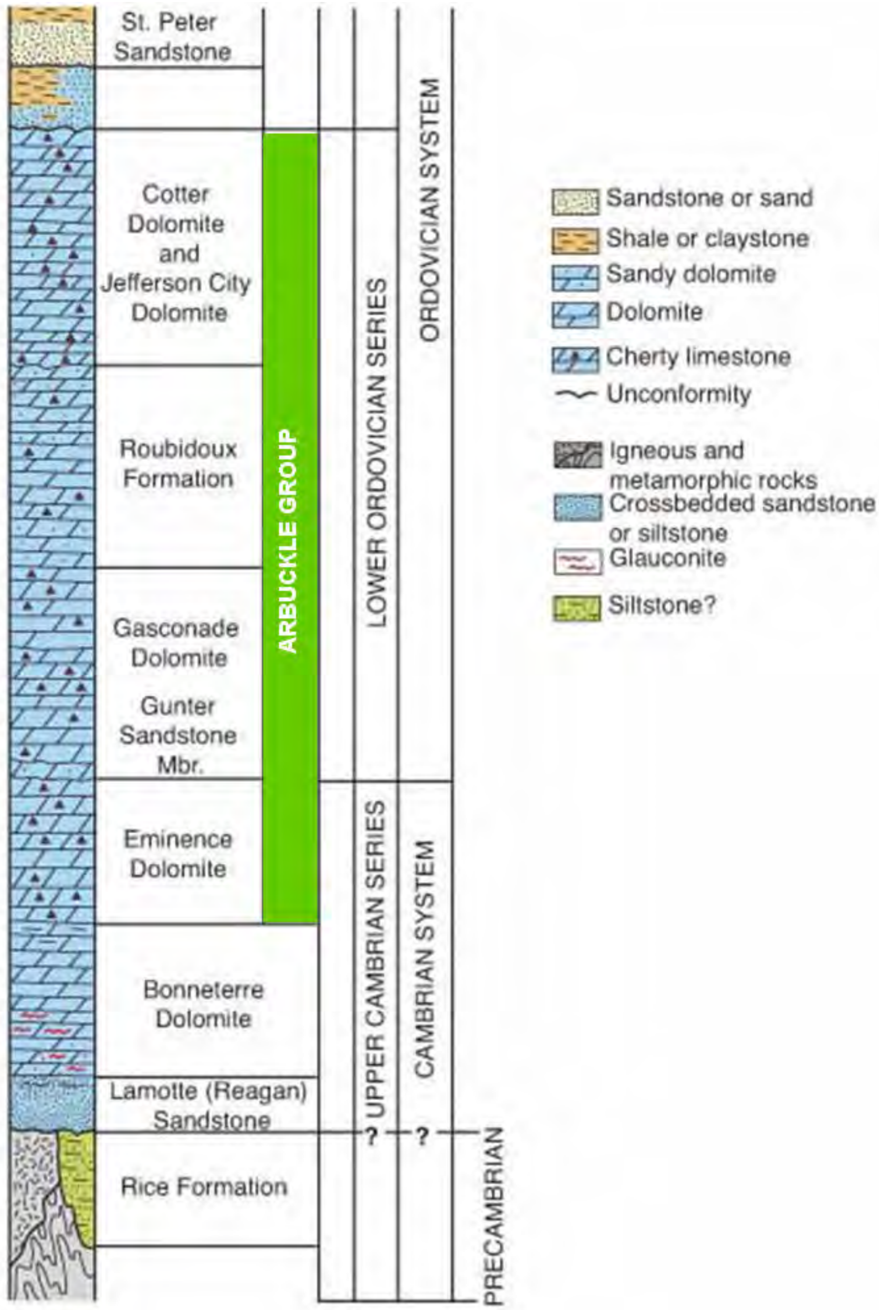


Figure 3.1b—A portion of the stratigraphic chart from Franseen (2004) showing Arbuckle Group units. Note that the Bonneterre and Lamotte formations are not present at the CO_2 injection site.

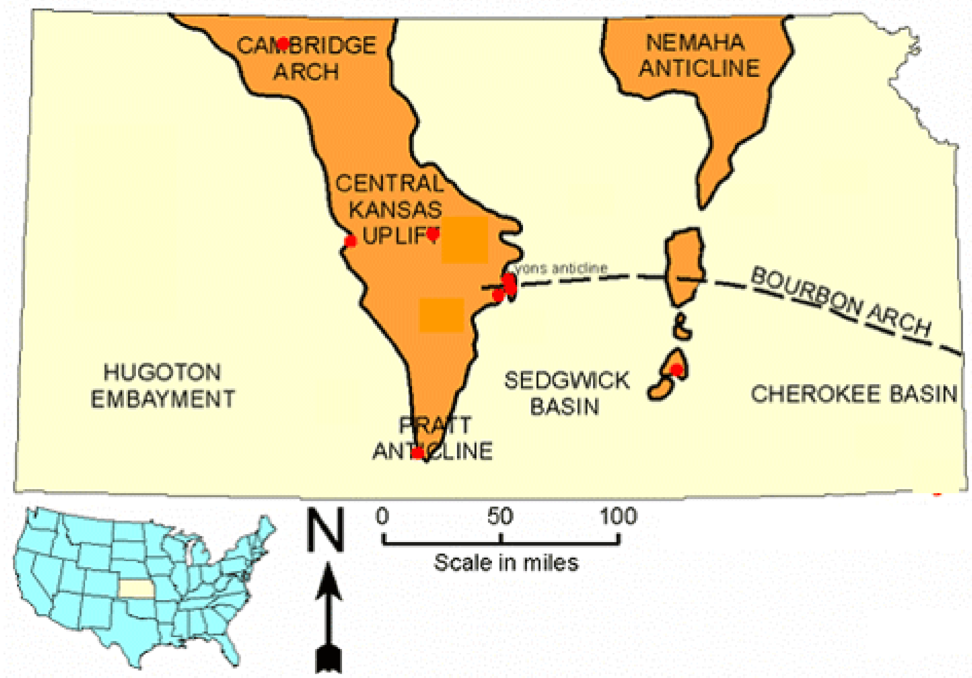


Figure 3.2— Major structural features in Kansas (from Carr et al., 1986).

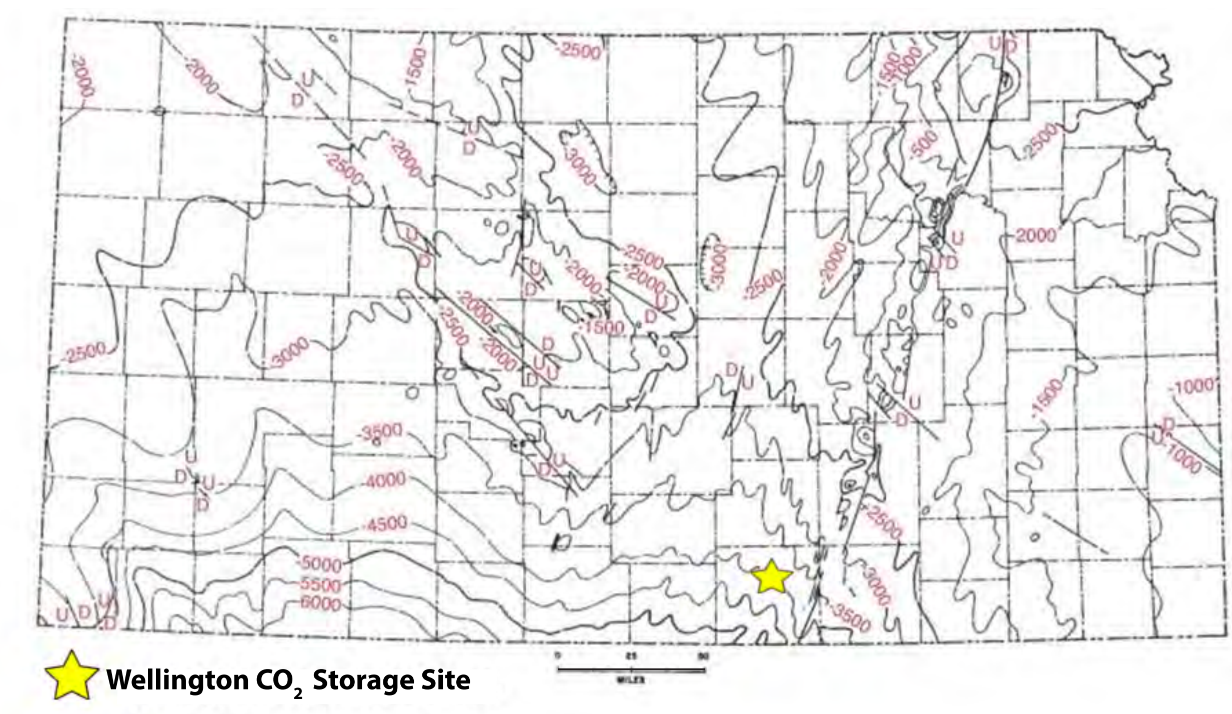


Figure 3.3—Elevation (ft MSL) to top of Precambrian basement complex in Kansas (from Franseen, 2004).

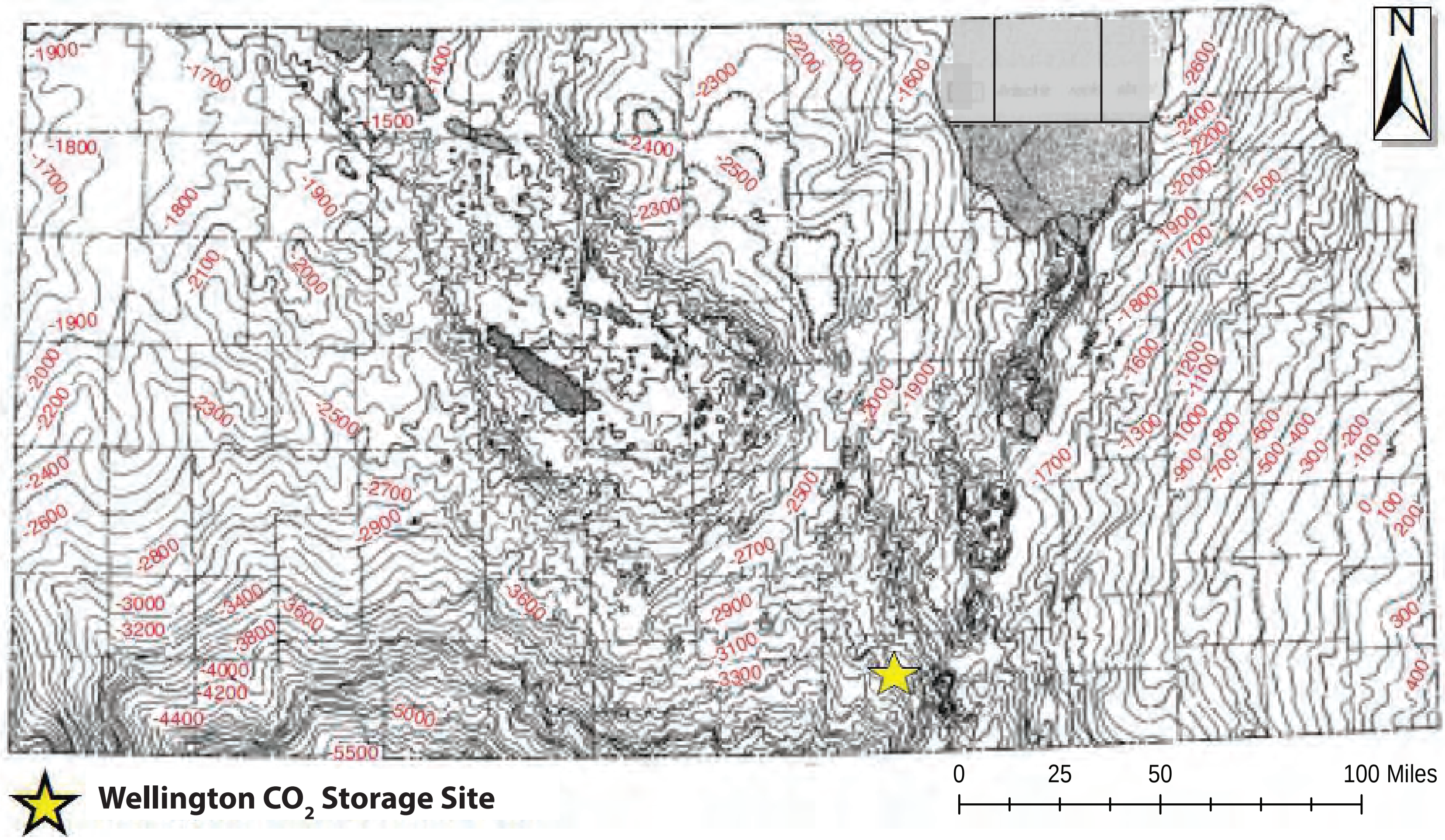


Figure 3.4—Elevation (ft MSL) to top of Arbuckle Group in Kansas.

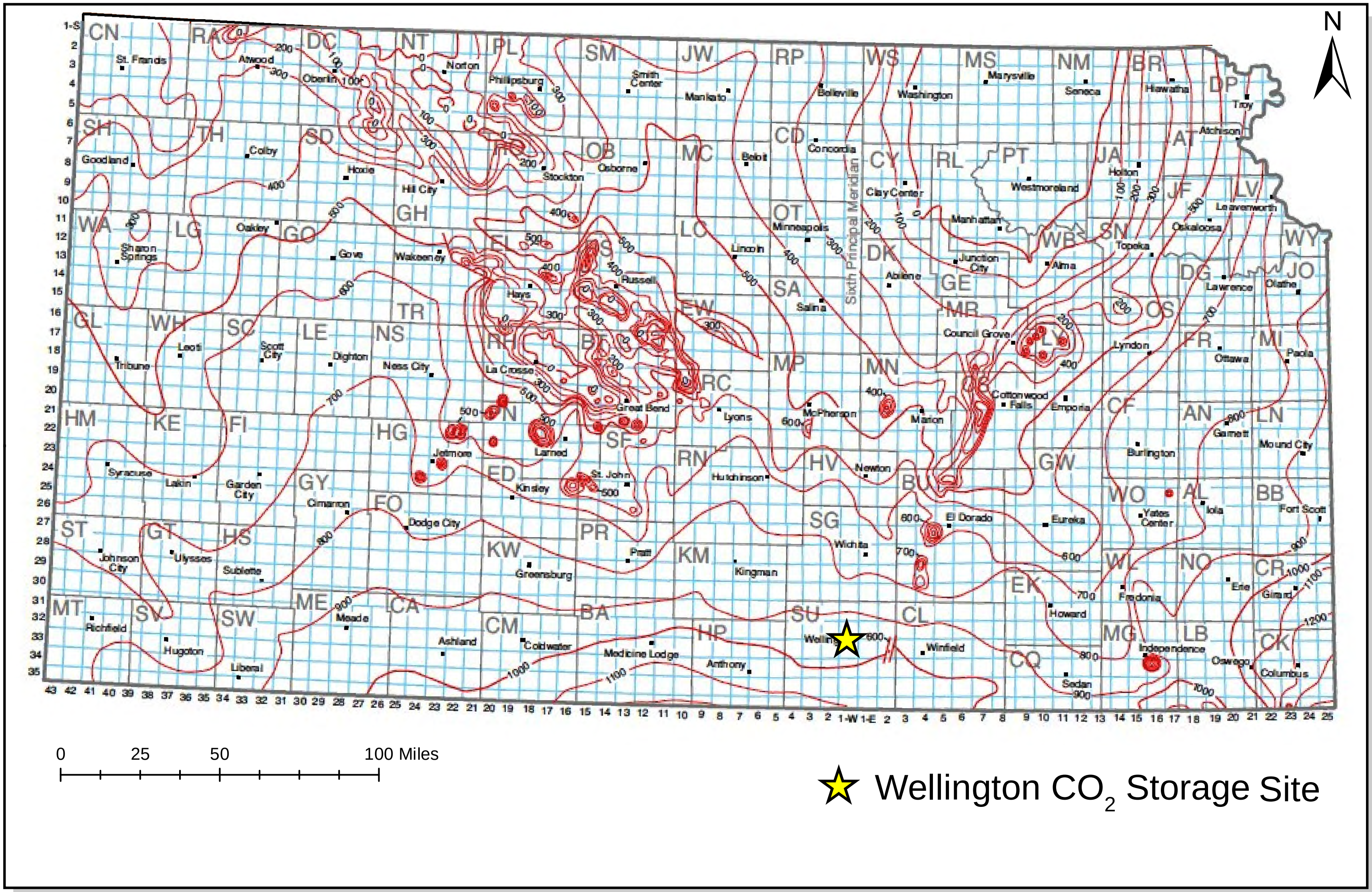


Figure 3.5a—Isopach map of Arbuckle Group strata (base of Simpson to Precambrian) (from Cole, 1975).

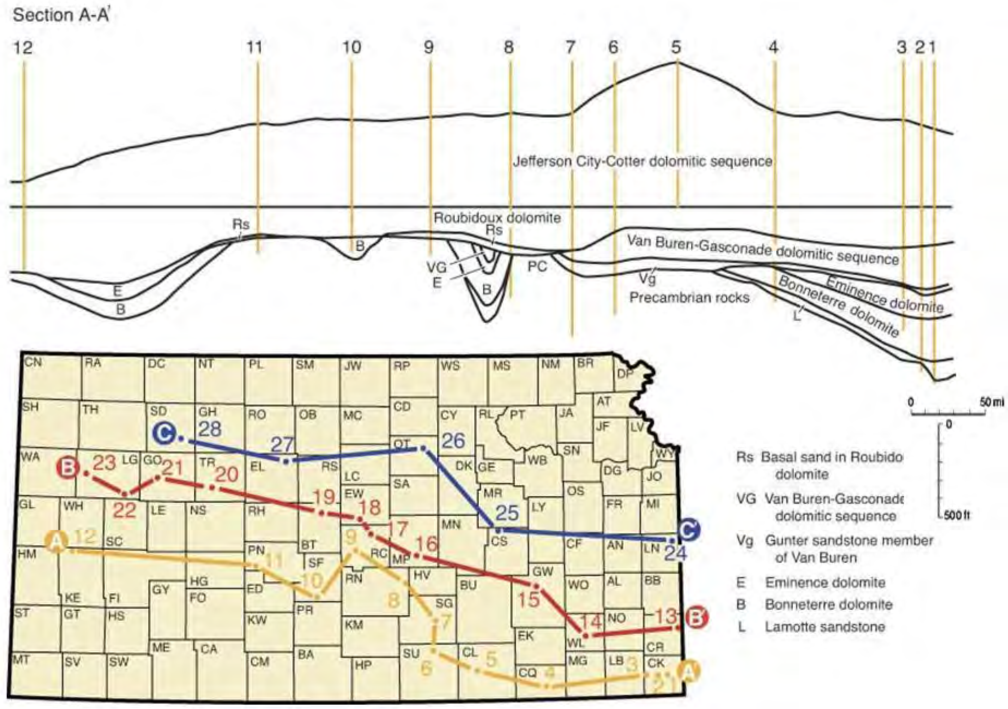


Figure 3.5b—Diagrammatic east-west cross section of Cambrian-Ordovician (Arbuckle Group) strata across Kansas (from Franseen et al., 2004).

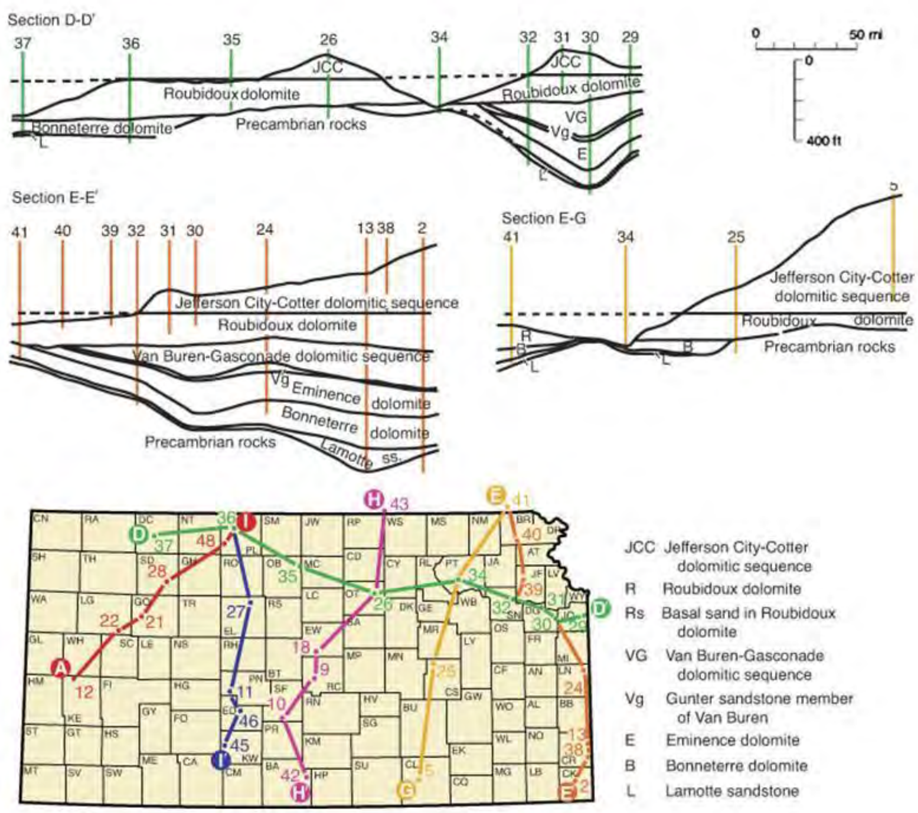


Figure 3.5c—Diagrammatic north-south cross section of Cambrian-Ordovician (Arbuckle Group) strata across Kansas (from Franseen et al., 2004).

On a more regional (multistate) basis, the Arbuckle dips sharply south of the Kansas-Oklahoma border in the Anadarko basin as shown in the top of Arbuckle elevation map shown in Figure 3.6.

As shown in the three cross sections in Sumner County presented in figs 4.2b-d, the Ar-

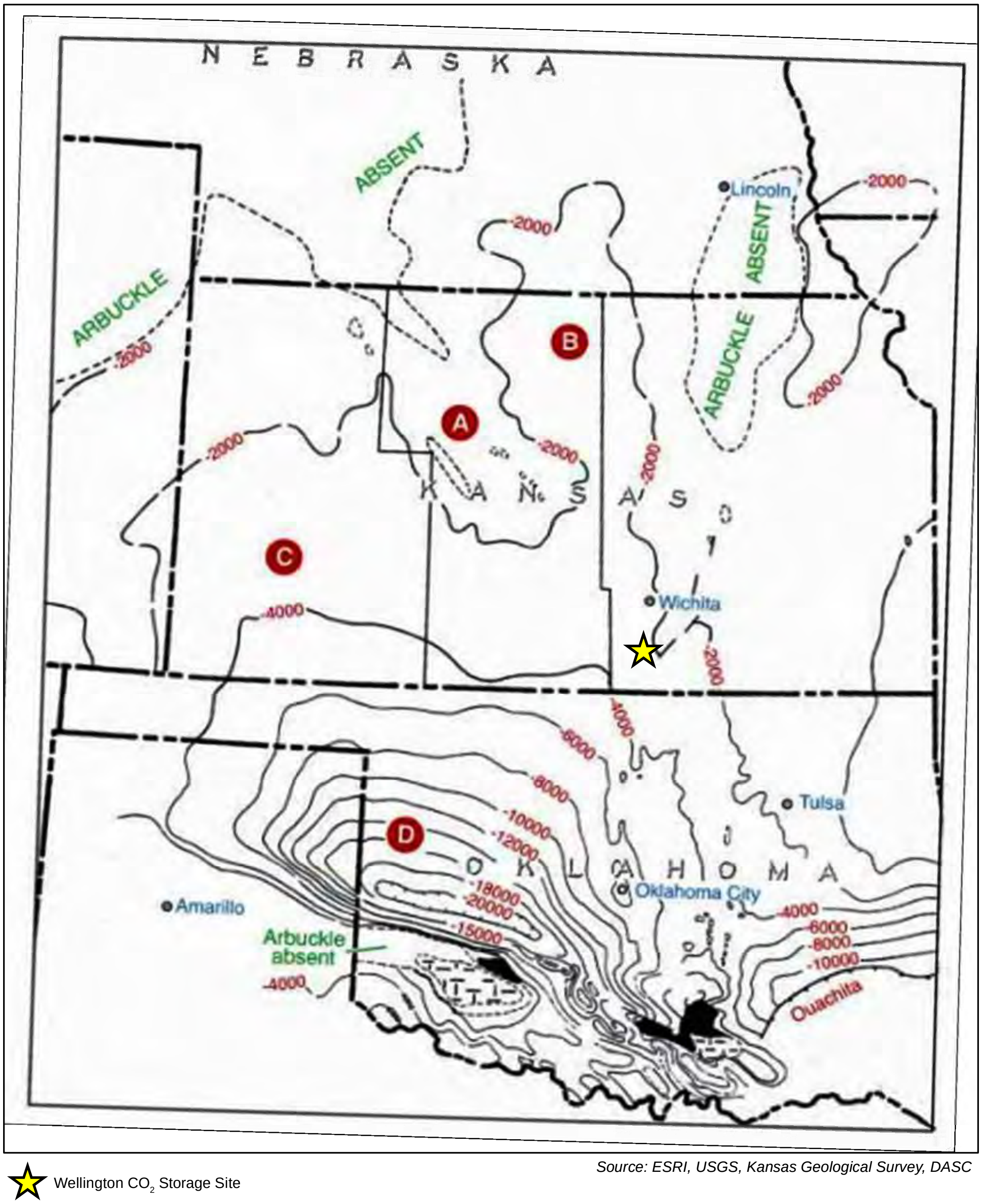


Figure 3.6—Regional structure map on top of Arbuckle Group in feet above mean sea level. (A) Central Kansas uplift; (B) Salina Basin; (C) Hugoton embayment of Anadarko Basin; and (D) Anadarko Basin. Contour interval 2,000+ feet (from Franseen et al., 2004).

buckle Group is also laterally extensive in the vicinity of the Wellington storage site. The Arbuckle Group in Sumner County is approximately 1,000-ft thick and includes the shaley intervals of the undifferentiated Jefferson City and Cotter dolomites (JCC) (approximately 425-ft thick), Roubidoux Formation (approximately 130-ft thick), and Van Buren–Gasconade Dolomite (approximately 400-ft thick) that includes a basal Gunter Sandstone Member (approximately 50-ft thick). The basal Eminence Dolomite is absent in the Wellington area.

3.3.2 Arbuckle Regional Hydrogeology

The Arbuckle aquifer systems in Kansas, Missouri, and Oklahoma make up one of the largest regional-scale saline aquifer systems in North America and are present in both the Western Interior Plains aquifer system (WIPAS) and the Ozark Plateaus aquifer system (OPAS) (Figure 3.7). The WIPAS underlies almost all of Kansas. Table 3.1 lists the stratigraphic units along with the associated geohydrologic units that make up the WIPAS and the geologic units overlying it. The WIPAS is similar to the OPAS, which lies to the east in parts of Missouri and southeastern Kansas. Unlike the OPAS, the WIPAS is naturally saline and yields no freshwater (TDS <1,000 ppm) (Faber, 2010). Sumner County lies in the WIPAS, and Arbuckle brine concentrations within

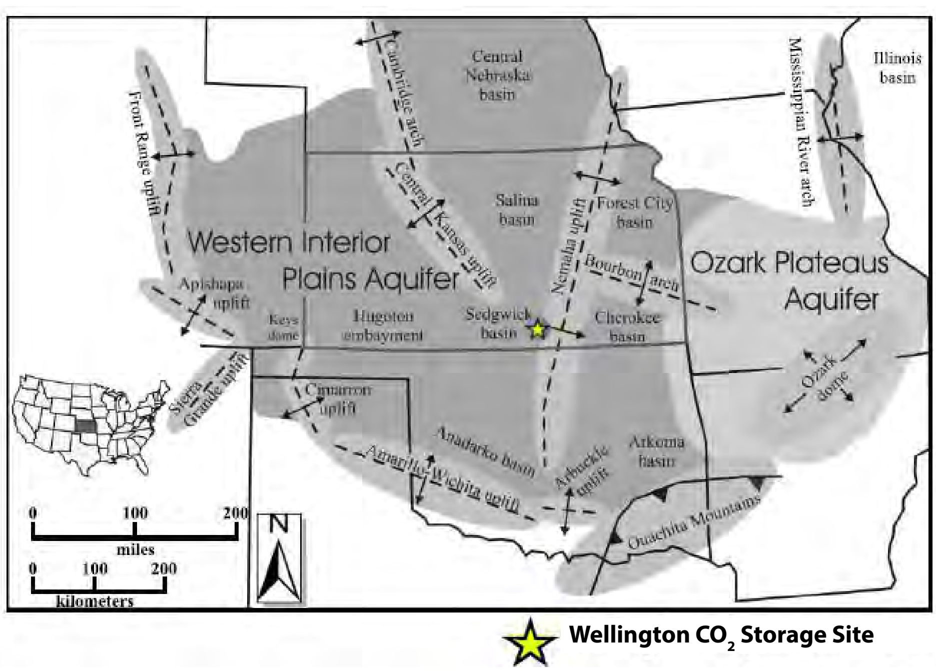


Figure 3.7—Generalized structural features of the midcontinent aquifer systems (from Carr et al., 2005).

Table 3.1—Stratigraphic units from the Quaternary/Neogene to the Precambrian/Cambrian basement rocks (Carr et al., 1986).

Geohydrologic unit		Principal stratigraphic unit(s)	Time-stratigraphic unit
High Plains aquifer		Ogallala Formation and unconsolidated deposits	Quaternary and Tertiary
Great Plains confining system		Pierre Shale, Niobrara Formation, Carlile Shale, Greenhorn Limestone, Graneros Shale (includes Lower Cretaceous)	Upper Cretaceous
Great Plains aquifer system	Maha aquifer	Dakota Sandstone, "D" sandstone, "J" sandstone, and equivalent of Newcastle Sandstone	Lower Cretaceous
	Apishapa confining unit	Kiowa Shale and equivalent of Skull Creek Shale	
	Apishapa aquifer	Cheyenne Sandstone and equivalent of Fall River and Lakota Sandstones	
Western Interior Plains confining system		Morrison Formation, Sundance Formation, Entrada Sandstone, Dockum Formation, Elk City Sandstone, Doxey Shale, Big Basin Sandstone, Cloud Chief Formation, Day Creek Dolomite, Whitehorse Sandstone, Nippewalla Group, Sumner Group, Chase Group, Council Grove Group, Admire Group, Wabaunsee Group, Shawnee Group, Douglas Group, Lansing Group, Kansas City Group, Pleasanton Group, Marmaton Group, Cherokee Group, Atokan rocks, Morrowan rocks, and Springer Group	Jurassic through Upper Mississippian (Chesterian)
Western Interior Plains aquifer system	Upper unit	Meramecian, Osagean, and Kinderhookian rocks	Upper Mississippian through Upper Cambrian
	Confining unit	Chattanooga and Woodford Shales	
	Lower units	Hunton Group, Sylvan Shale, equivalent of Galena Dolomite, Viola Limestone, Simpson Group, Arbuckle Group, and Reagan Group	
Basement confining unit		Mostly igneous and metamorphic rocks	Cambrian and Precambrian

the county are significantly in excess of 10,000 mg/l salinity as discussed in Section 3.3.2.1. As discussed in Section 3.3.1, the Arbuckle is a regionally expansive, thick unit overlain by interbedded shales, sandstones, and carbonates.

Synthesis and integration of groundwater chemistry, temperature, and potentiometric head/pressure data can aid in understanding regional and local subsurface fluid movements in the Arbuckle aquifer and provide a foundation for modeling at the regional scale. The regional geochemical, geothermal, and hydraulic head information of the Arbuckle injection zone is summarized below.

3.3.2.1 Arbuckle Salinity

The Arbuckle in southern and southwestern Kansas is suitable for use as an injection zone from the perspective of salinity. Across Kansas, the Arbuckle TDS concentrations vary from relatively low salinity (TDS < 10,000 ppm) to dense brine (TDS > 250,000 ppm) (Figure 3.8). The salinity decreases significantly in the eastern part of the state, where the WIPAS merges with the OPAS. Another key feature of the Arbuckle salinity distribution in Kansas is the general increase in Arbuckle TDS from north to south.

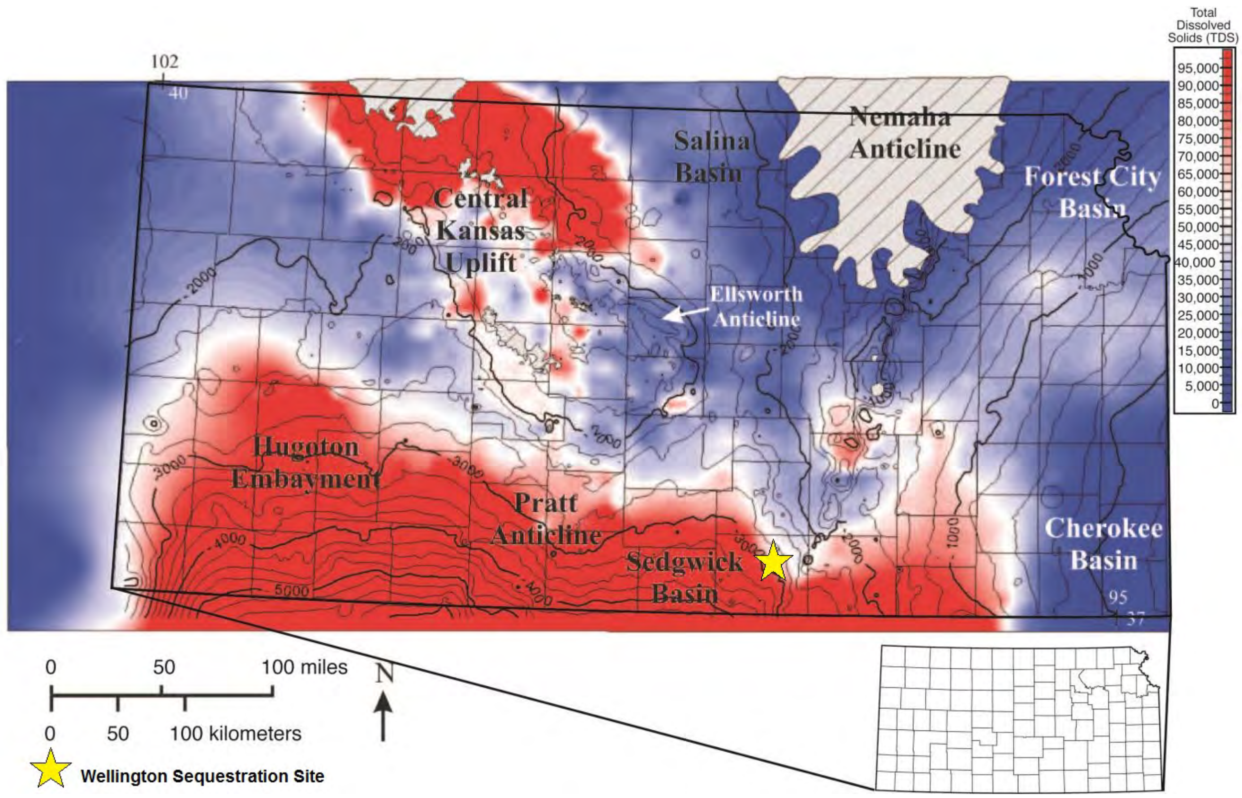


Figure 3.8—Total dissolved solids (ppm) in Arbuckle brines. Overlay is the structure (ft, msl) on top of Arbuckle (from Carr et al., 2005).

Brine salinity distribution in the Arbuckle is also associated with structural features. Dense brines along the Kansas-Oklahoma border are concentrated in Arbuckle structural lows, particularly in southwestern Oklahoma. Arbuckle brine salinity slowly decreases northward and along the eastern side of the Nemaha anticline. An area of relatively dense brine surrounds the Cambridge Arch (northern part of the Central Kansas uplift) and extends southward along the east side of the

Central Kansas uplift. On the Central Kansas uplift, small areas of increased TDS concentrations are associated with areas where the Arbuckle has been removed by erosion, or the high tops may be partly due to brine injection from oil field operations (Jorgensen et al., 1993). Relatively low-salinity WIPAS brines (TDS 5,000–20,000 ppm) are located along the Colorado-Kansas border and in north-central Kansas where the Arbuckle has been removed by erosion. At the Wellington test well sites (KGS 1-28 and KGS 1-32), Arbuckle brines from drill-stem tests (DST) and swab tests had TDS values ranging from approximately 48,000 mg/L in the Upper Arbuckle (4,182 ft) to 180,000 mg/L in the lower Arbuckle (5,005 ft).

3.3.2.2 Arbuckle Hydraulic Head

Recharge occurs by way of precipitation in the Front Range of the Rocky Mountains (Figure 3.9; Jorgensen et al., 1993). Minimal, if any, recharge occurs vertically from overlying aquifers. As groundwater travels east toward Missouri, bedded halite in the Permian confining unit of WIPAS is dissolved into the aquifer, giving the water its characteristically high salinity (Faber, 2010). The eastward-flowing water discharges into the OPAS, where a number of saline springs and artesian

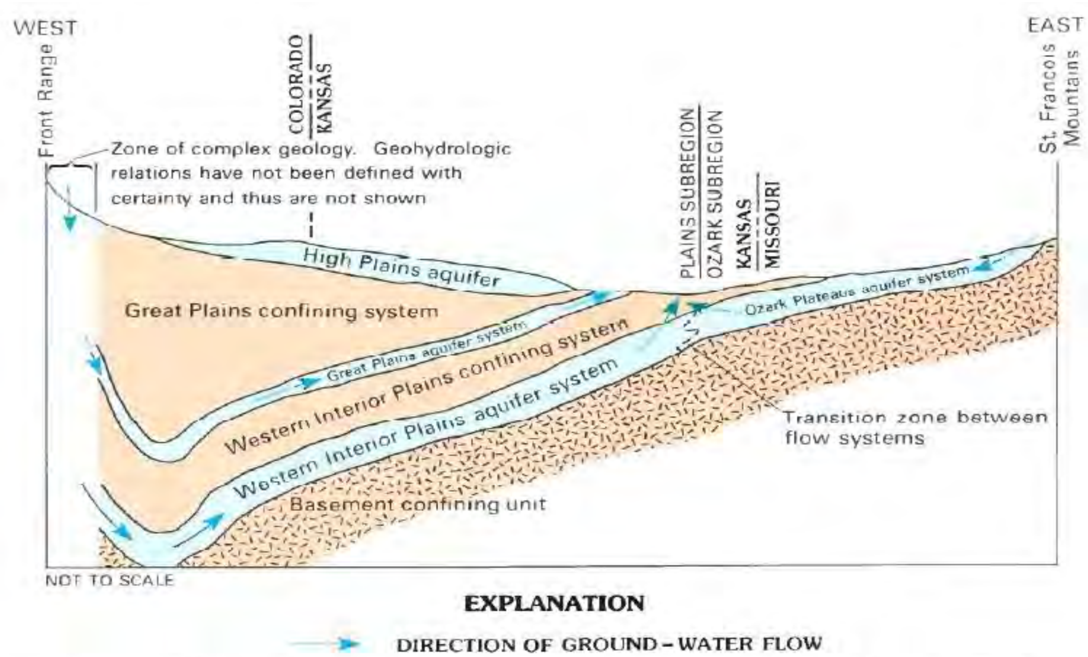


Figure 3.9—Major regional geohydrologic units in the Plains and Ozark subregions. Section extends from central Colorado to St. Francois Mountains in southeastern Missouri (from Jorgensen et al., 1993).

wells have developed in Paleozoic carbonates (Jorgensen et al., 1993). The boundary between the WIPAS and the OPAS, marked by a low in the equivalent freshwater head[1] surface (Figure 3.10), is nearly coincident with the topographic low in eastern Kansas and northeastern Oklahoma (Figure 3.11). The discharge of groundwater into the low-lying areas in southeastern Missouri may provide an explanation for the observed "underpressure" within the Arbuckle Group.

Figure 3.10 shows two flow fields: one emanating from the west and the other from the southwest, merging together in central Kansas and discharging along the eastern boundary of the state. The head drops from approximately 1,200 ft in the west to 700 ft in the east. At the Wellington storage site, an equivalent freshwater head of 1,061 ft MSL was estimated from the DST data as discussed in Section 4.6.7 and documented in Table 4.8. This head value at the Wellington site is in agreement with the regional equivalent freshwater potentiometric surface shown in Figure 3.10.

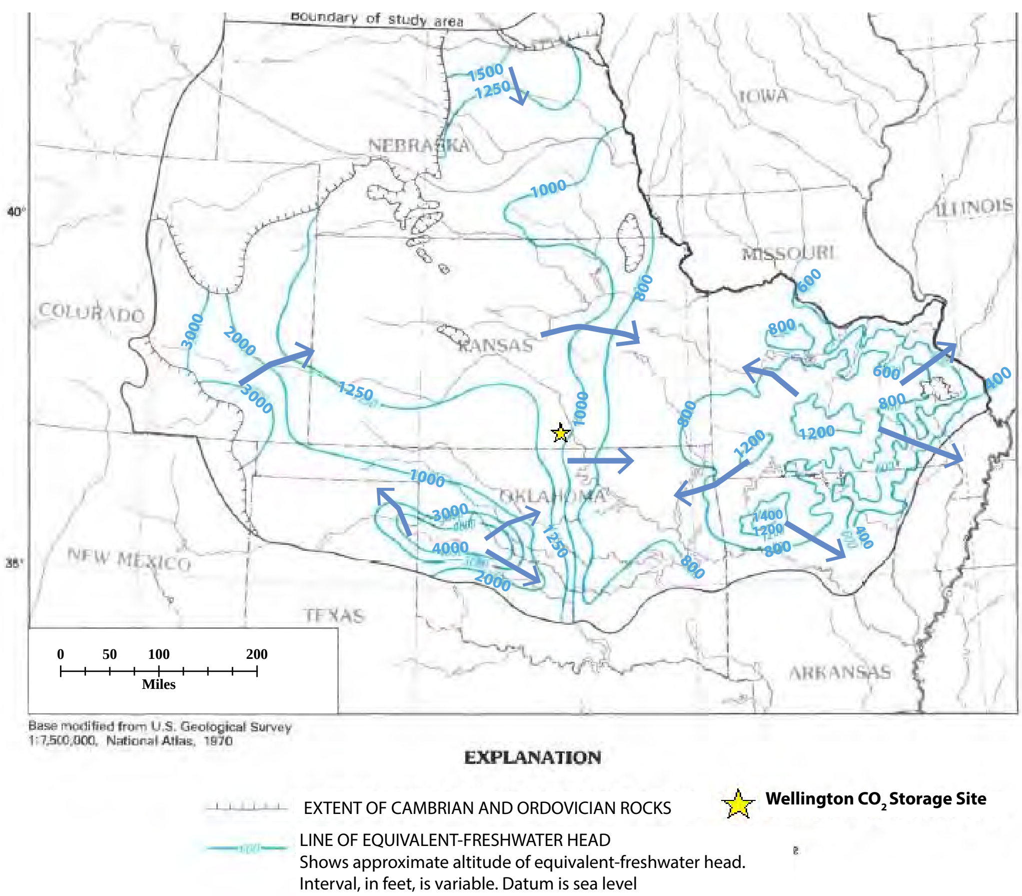


Figure 3.10—Equivalent freshwater heads in Cambrian and Ordovician rocks (from Jorgensen et al., 1993).

1 *Equivalent freshwater head is the height in a column filled with freshwater at the measuring elevation.*

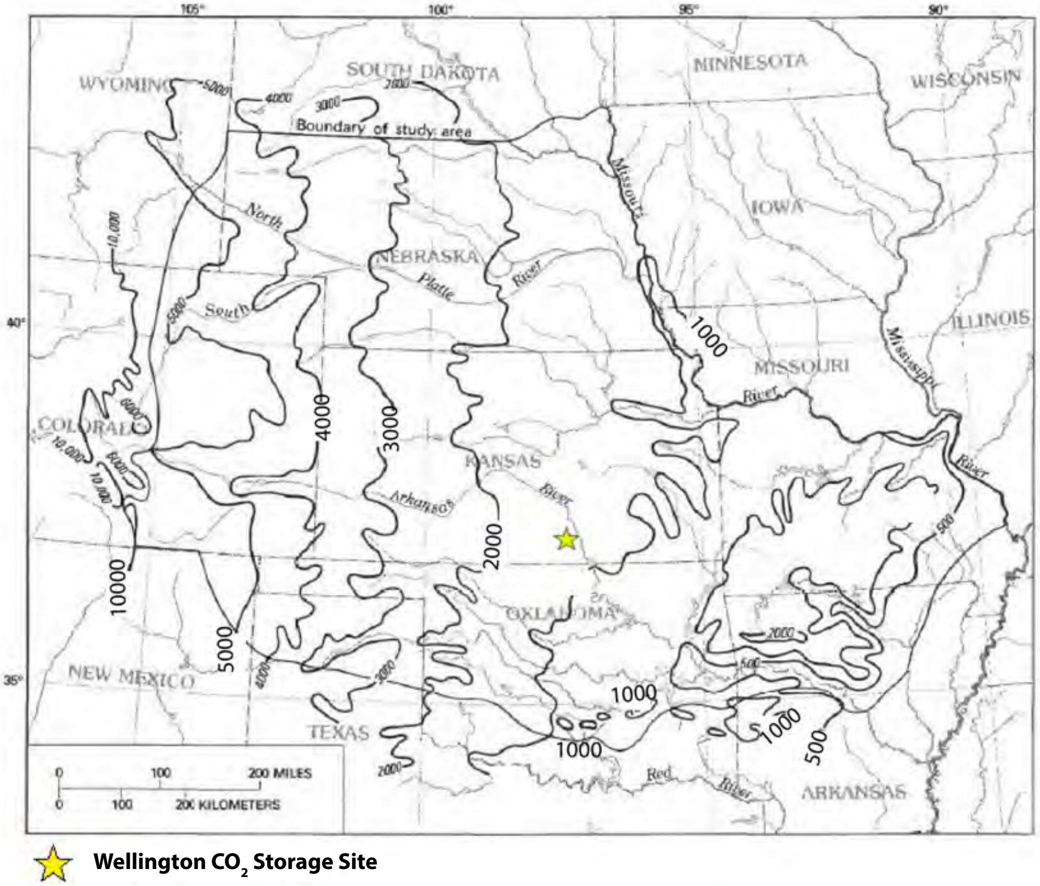


Figure 3.11—Topographic contours showing altitude of land surface, ft MSL (from Jorgensen et al., 1993).

3.3.2.3 Arbuckle Groundwater Temperatures

Figure 3.12 shows a map of borehole temperatures in the Arbuckle Group along with the measured depth to top of the Arbuckle. As expected, the map shows a strong relationship between the temperature and depth. The temperature at the Wellington storage site is projected to be approximately 125ºF. As shown in Figure 4.31, the temperature in the middle of the Arbuckle at KGS 1-28 is approximately 125ºF as well.

3.3.2.4 Arbuckle Aquifer Properties

The majority of the Arbuckle Group is composed of dolomite with porosity enhanced by dolomitization, weathering, and ancient tectonic activities (Carr et al., 1986). A karst-like environment with higher porosity and permeability exists in some areas of the Arbuckle (Jorgensen

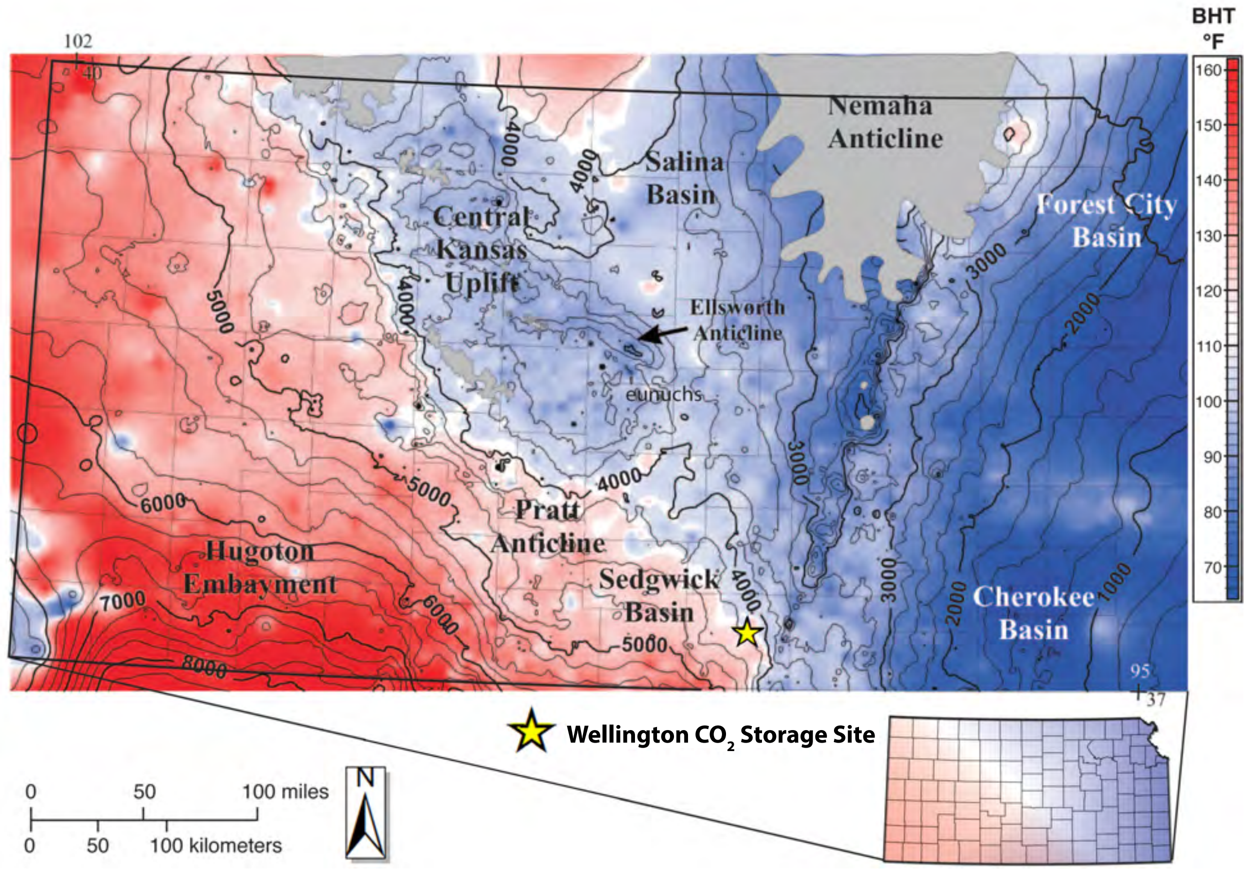


Figure 3.12—Map of borehole temperatures within the Arbuckle Group in Kansas. Contours represent depth to top of Arbuckle in feet (from Carr et al., 2005).

et al., 1993). Based on a synthesis of data from DSTs and numerical modeling, Carr et al. (1986) estimated the permeability in the Arbuckle to vary from 1 millidarcy (mD) to 30 darcys. Based on injection test data only, Carr et al. (1986) estimated an average permeability of 50–300 mD. Jorgensen et al. (1993) developed a map of the intrinsic permeability for the lower units of the WIPAS (Figure 3.13) that includes all units below the Chattanooga Shale and above the Cambrian and Precambrian basement. The intrinsic permeability near the Wellington test site is approximately 10e-15 ft^2, which equates to about 1 mD. In reality, though, the permeability throughout the Arbuckle is highly variable, with relatively large values in vugs and low values in tight dolomitic intervals. As shown in Figure 4.32a, the horizontal permeability at KGS 1-32, where core-based estimates of permeability were obtained, varies between 0.01 mD and 430 mD.

In general, the permeability estimates of Jorgensen et al. (1993, Figure 3.13) are greater

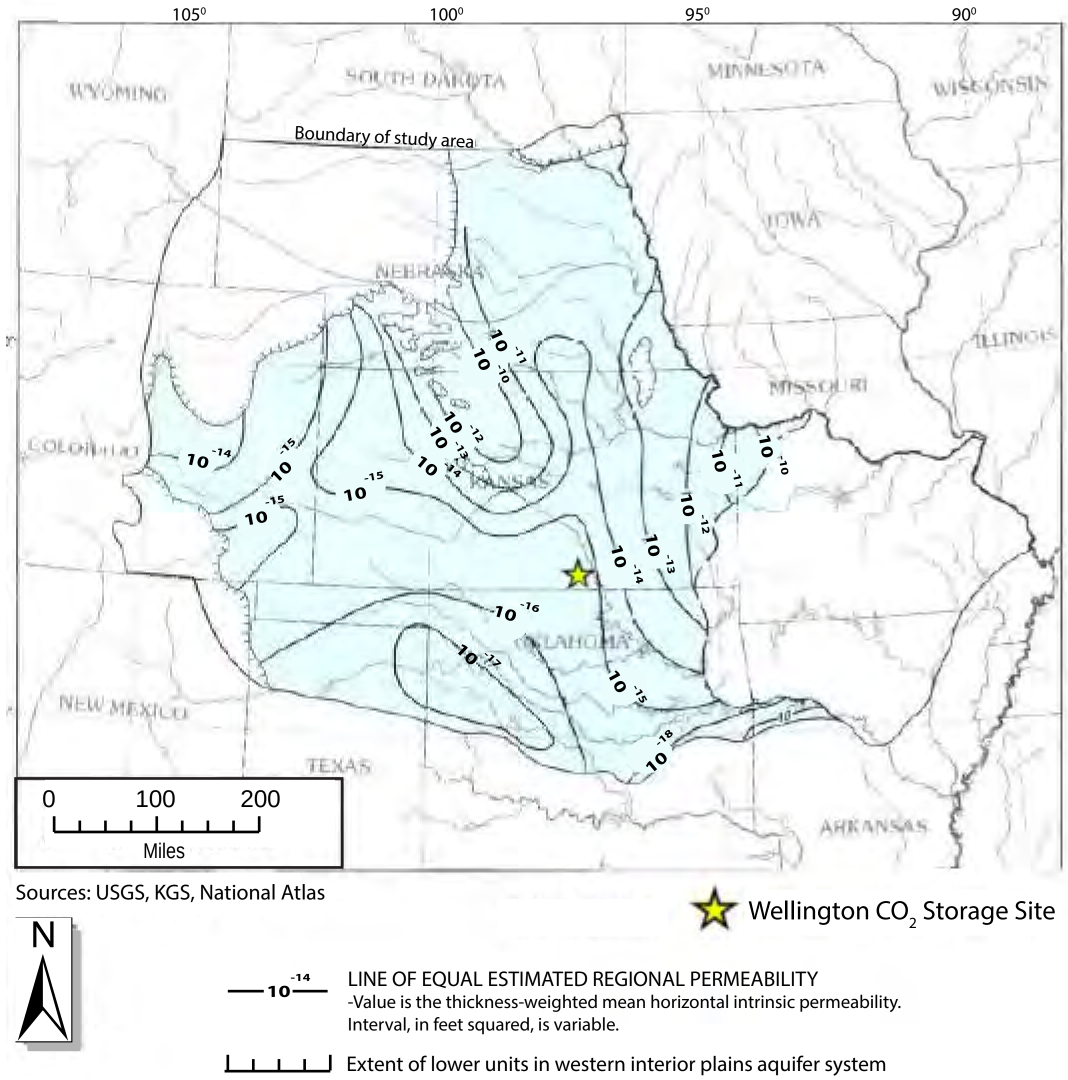


Figure 3.13—Estimated regional intrinsic permeability of lower units of the Western Interior Plains aquifer system (from Jorgensen et al., 1993), which includes units below the Chattanooga Shale and above the Cambrian and Pre-cambrian basement.

along the Central Kansas uplift as compared to the rest of the basin. Carr et al. (1986) derived the same conclusion. The permeability may be larger in the Central Kansas uplift area because rocks were subject to uplift and are probably also more solution enhanced than rocks in the structural basins. Latta (1973) states that the greatest porosity and permeability are found where the Arbuckle strata have undergone erosion on the top and flanks of uplift areas.

Analyses of 76 geophysical logs from Arbuckle wells in Kansas indicate an average porosity of about 12% (Carr et al., 1986). This agrees with information compiled by Gerlach (2012), which shows the average porosity within the Arbuckle Group in southwest Kansas varies between approximately 5% and 15% (Figure 3.14). Estimates of porosity in the Arbuckle based on core and nuclear-magnetic resonance (NMR) were also obtained at the Wellington sites (KGS 1-32 and KGS 1-28) as shown in Figure 4.32a-b. Porosity varies from 0.2% to 34% in the Arbuckle Group, with an average value of 6.4%. Section 4 documents an extensive analysis of the Arbuckle Group permeability, porosity, and other characteristics derived from site-specific geophysical logs and core samples at the Wellington storage site.

The storage coefficient of the Arbuckle Group of the WIPAS ranges from 6.8 x 10^{-5} to 3.2 x 10^{-3} with an average specific storage of 3.25 x 10^{-6} ft^{-1} (Jorgensen et al., 1993).

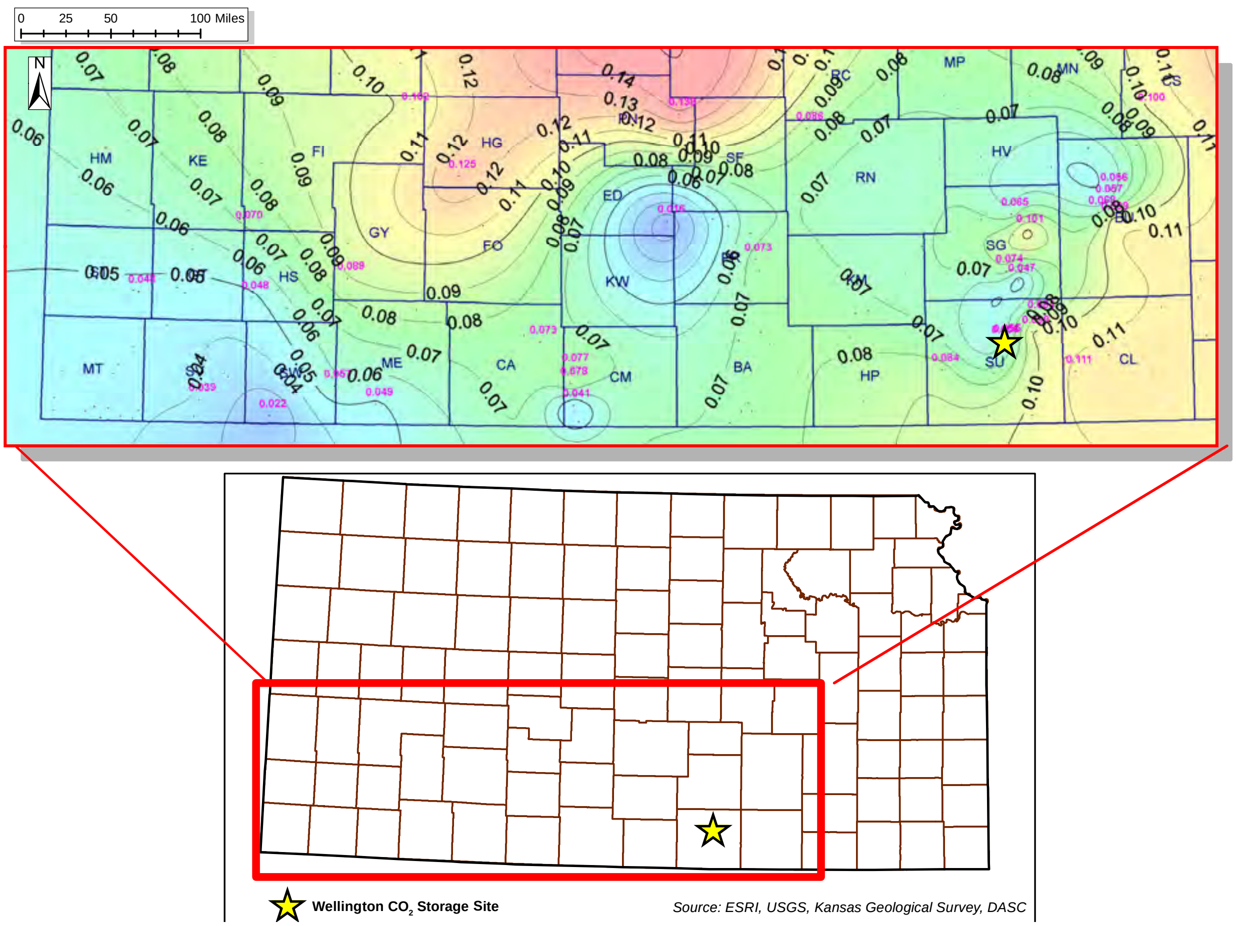


Figure 3.14—Average fractional porosity in the Arbuckle Group in southwest Kansas using density log and assuming matrix density of 2.8 g/cc (from Gerlach, 2012).

3.4 Geology and Hydrogeology of the Regional Scale Confining Zone: Simpson Group, Chattanooga Shale, Lower Osagean/Kinderhookian (§146.82 [a][3][vi], §146.82[c][1])

3.4.1 Confining Zone Geology

The injection zone is vertically segregated from the USDW by multiple shale formations as shown in Figure 1.8. For the Wellington project, the upper confining zone is defined as rock units from the base of the Simpson Group through the top of the Pierson formation, including the Chattanooga Shale (Figure 3.1a). That is, the upper confining zone is composed of Ordovician-Devonian-Mississippian units immediately above the injection zone as presented in Figure 3.1a, including the Simpson Group, Chattanooga Shale, and the Osagean/Kinderhookian (referred to as the Pierson formation in Figure 1.8). The Pierson formation (lower Osage) is an informal stratigraphic nomenclature that is derived from the Pierson Formation of Missouri that refers to an interval that is dolomitic and occasionally argillaceous and silty (Thompson, 1986). It has very low permeability at the Wellington site as documented in Section 4.7. The Viola Limestone between the Chattanooga Shale and the Simpson Group (Figure 3.1a) is missing at the Wellington site.

Confining units of Mississippian and Devonian age are composed primarily of shaley limestone and shale, while confining units of the overlying Ordovician period are composed mostly of shale and varying amounts of sandstone. In addition to the confining zone between the Simpson Group and the Pierson formation, shaley units above this zone provide added measures of confinement as shown in Figure 1.8, but these units are not relied upon as providing confinement for purposes of the Class VI permit.

The elevation to the top of the lower Osage is presented in Figure 3.15a. The combined thickness of the Osage/Kinderhook/Chattanooga is presented in Figure 3.15b. This confining group has thickness exceeding 50 ft in most parts of the state except the northwest, where it is missing, and the southeast, where it is only 25-ft thick.

The elevation to the top of the Simpson Group and its thickness is presented in Figure 3.16a-b. This unit is thin or absent in the northwest and parts of the southeast and is the thickest (> 150 ft) in south-central Kansas. The combined thickness from the base of Simpson to the top

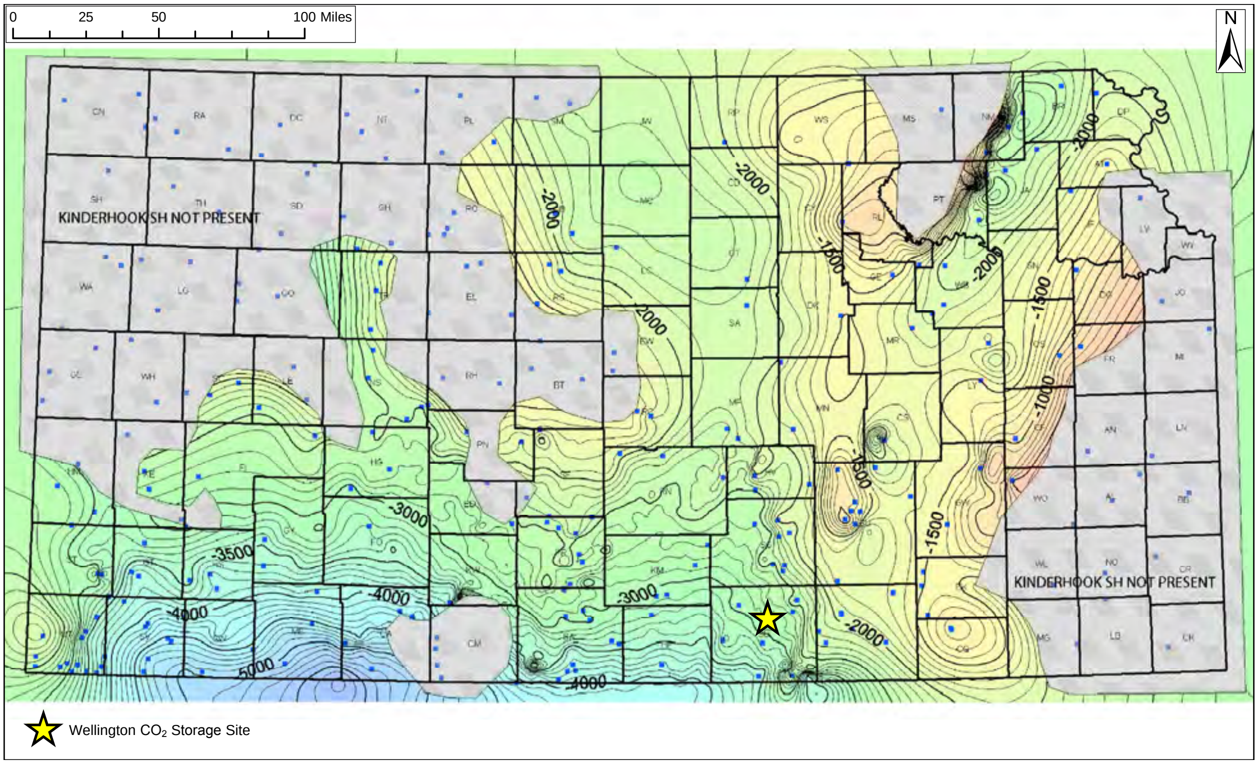


Figure 3.15a—Elevation (ft MSL) to the top of upper confining zone (lower Osagean, Kinderhookian, or Chattanooga Shale) in Kansas.

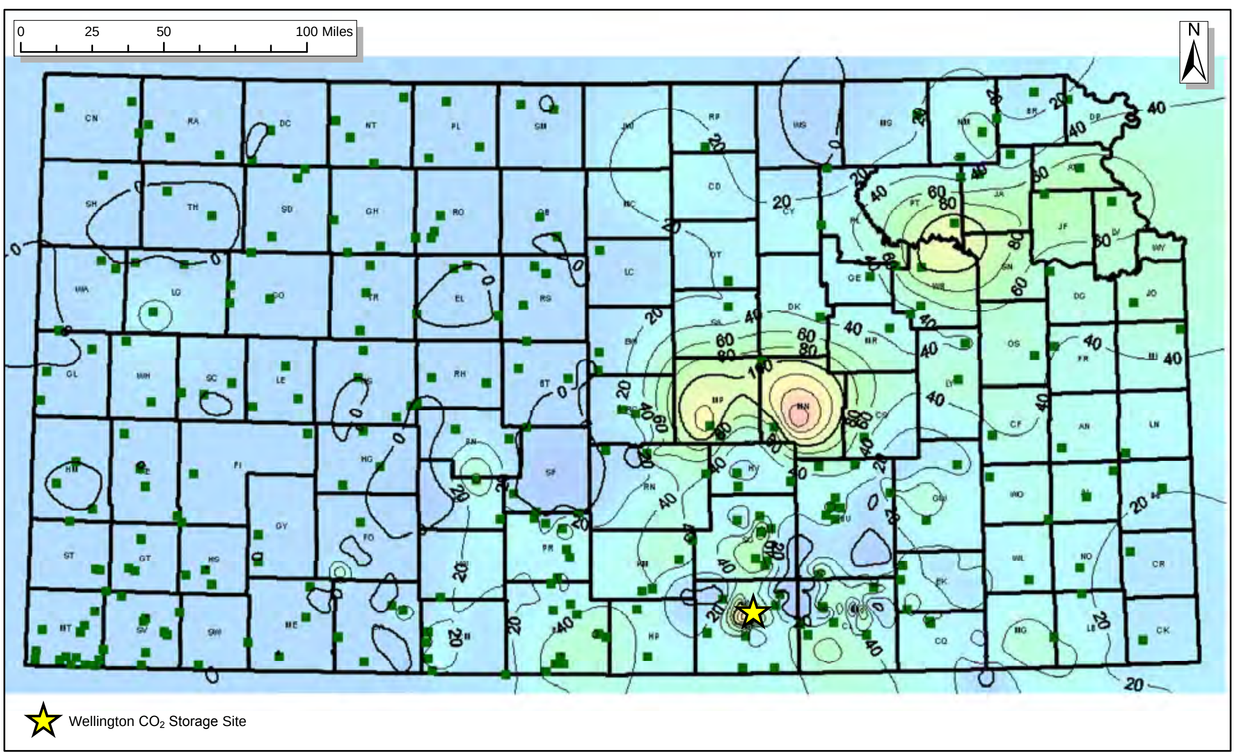


Figure 3.15b—Thickness (ft) of the portion of the upper confining zone above the Viola Group (i.e., lower Osagean, Kinderhookian, and Chattanooga Shale) in Kansas.

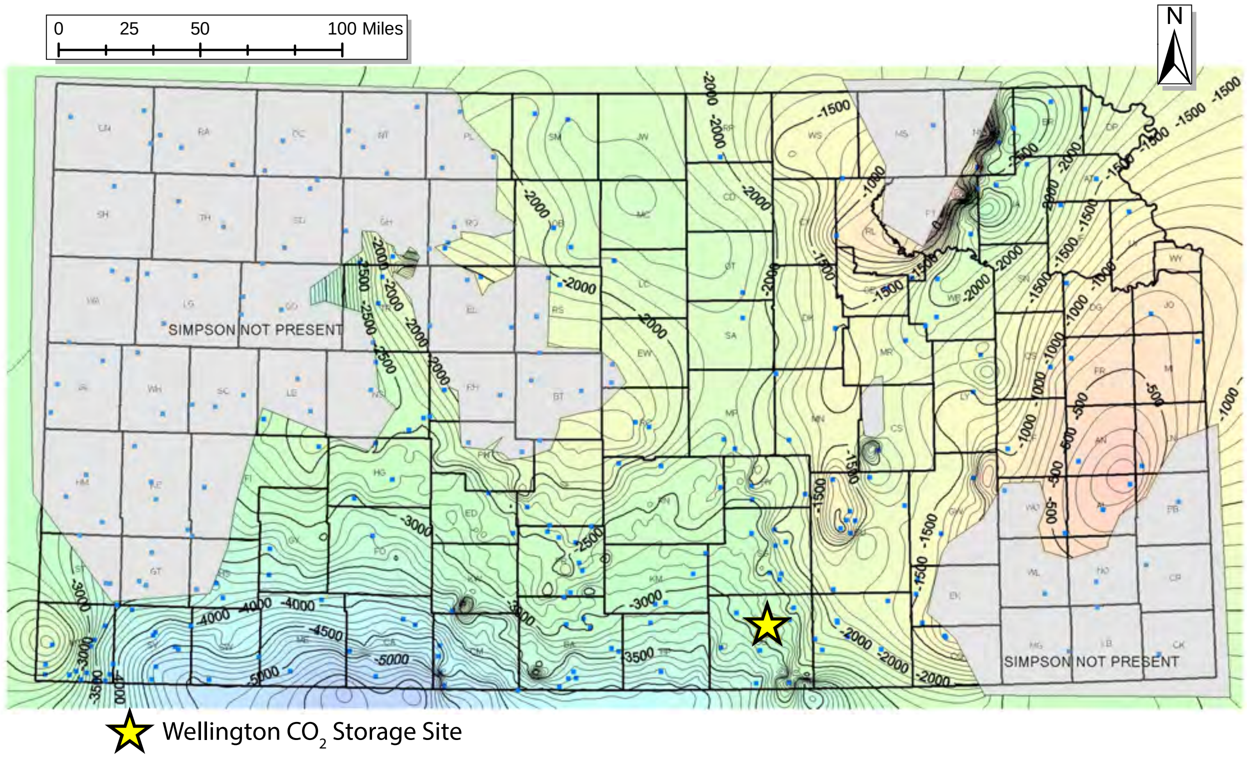


Figure 3.16a—Elevation (ft MSL) to top of Simpson Group in Kansas.

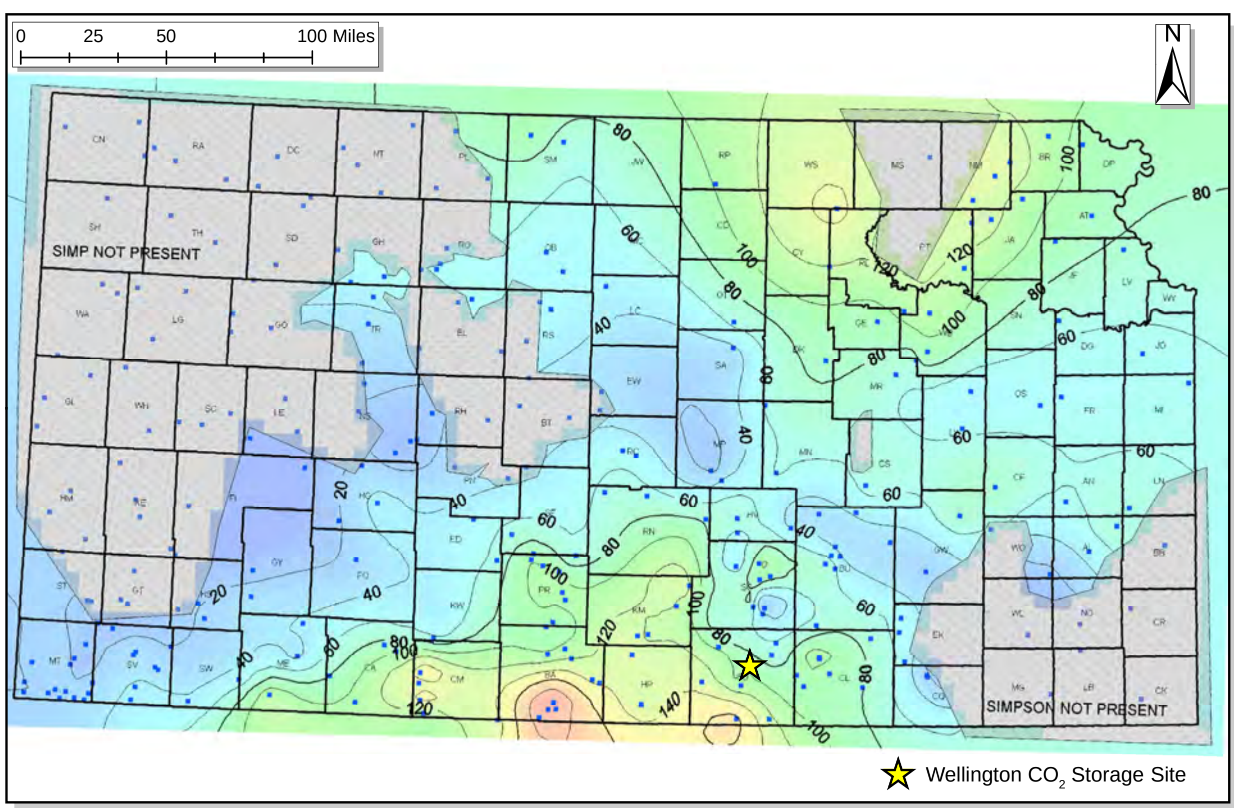


Figure 3.16b—Thickness (ft) of Simpson Group in Kansas.

of the Osage is presented in Figure 3.17, which shows that the confining zone is greater than 50-ft thick in most parts of Kansas, except the northwest where the units are absent. The isopach map of the Chattanooga Shale constructed for this study from geophysical logs in the KGS database is presented in Figure 3.18. The Chattanooga is as little as 20-ft thick in southeast Kansas, nearly 100-ft thick in the northeast, and locally is greater than 100 ft in central Kansas. It is missing in northwest Kansas.

The presence and lateral continuity of the confining zone in the vicinity of the Wellington storage site can also be seen in the geologic cross sections presented in figs. 4.2a-d. The formation tops and bottoms in the cross sections were identified primarily by specific gamma ray, porosity, and resistivity log characteristics. In these cross sections, the confining zone extends from the base of the Simpson to the top of the lower Osage (i.e. Pierson formation).

The geologic logs at the injection well site (KGS 1-28) confirm the presence of the regional-scale confining zone at the Wellington storage site (Figure 4.32b). The Simpson Group is the lowermost unit in the confining zone at KGS 1-28 and occurs between 4,082 and 4,168 ft KB. The second unit in the confining zone is the 42-ft thick Chattanooga Shale unit that overlies the Simpson Group in the interval 4,040 to 4,082 ft at well KGS 1-28. The third unit in the confining zone is the shale-rich interval of the lower Osage (Pierson formation) that occurs in the interval of 3,930 to 4,040 ft KB at well KGS 1-28. These three units at the Wellington storage site are discussed in detail in Section 4.7 and are distinguished by a sharp reduction in the NMR-based porosity, permeability, and T2 relaxation time (related to pore size), increase in gamma ray count, and low resistivity. All of these data suggest the presence of tight shale or argillaceous siltstone throughout the upper confining zone units.

The seismic data acquired for the Wellington project also confirm the presence and lateral continuity of the confining zone above the Arbuckle. For example, the lateral continuity of the (lower Osagean) Pierson formation is very apparent on seismic data as a widespread low impedance zone as shown in Figure 4.58. Additional site-specific seismic data are presented and discussed in Section 4.8.

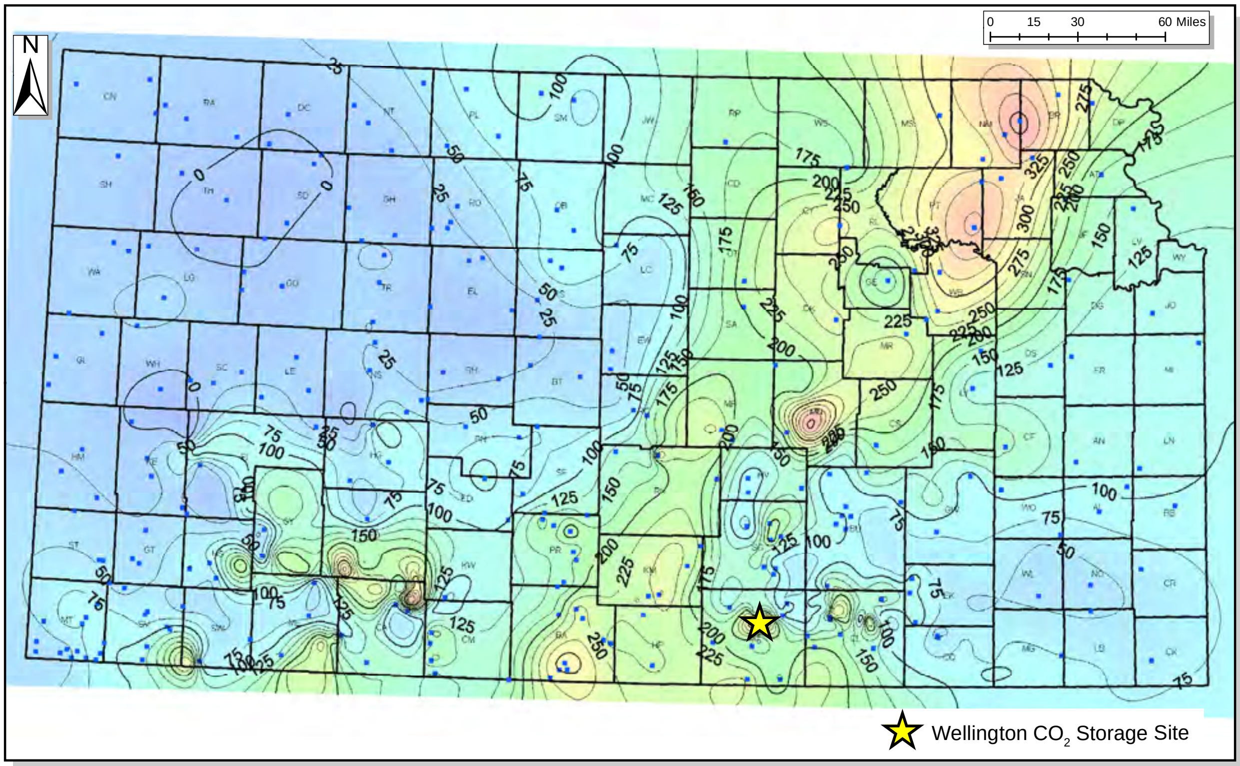


Figure 3.17—Thickness (ft) from the base of the upper confining zone (Simpson Group) to the top of the upper confining zone (lower Osagean, Kinderhookian, or Chattanooga Shale) in Kansas.

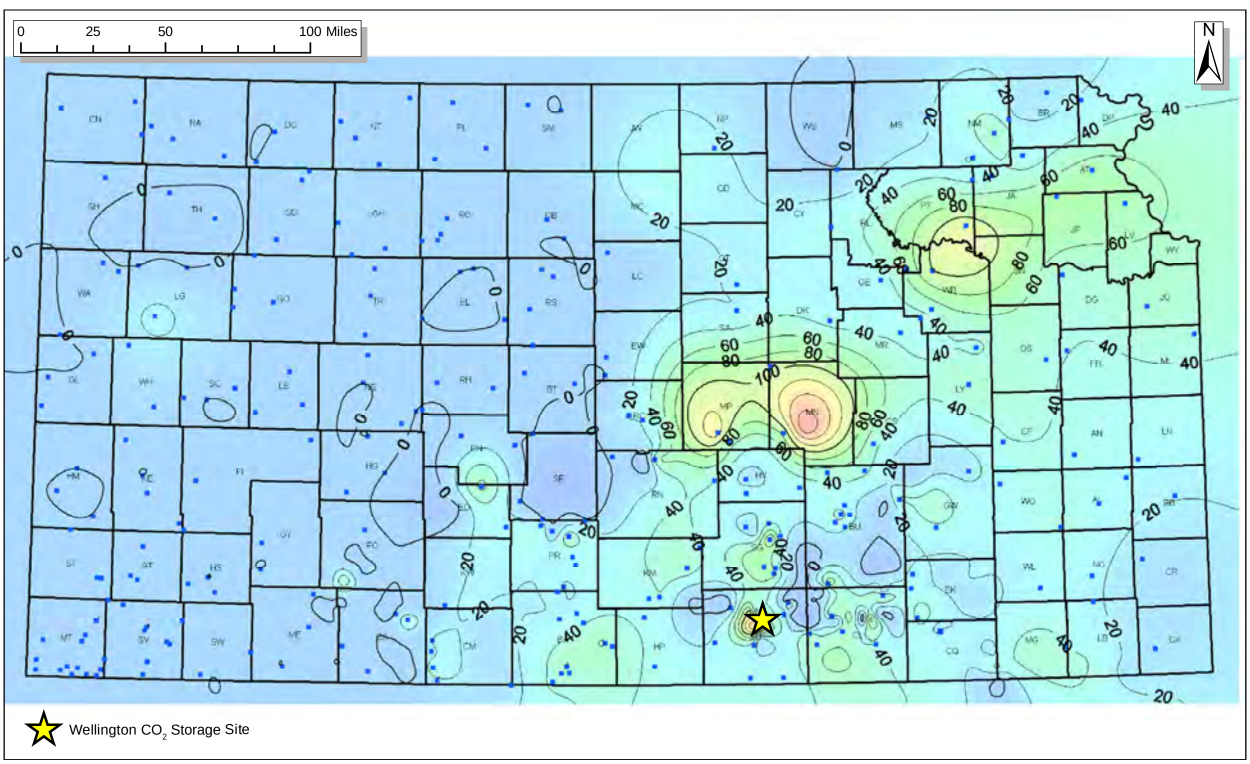


Figure 3.18—Thickness (ft) of the Chattanooga Shale in Kansas (source: KGS database, 2013).

3.4.2 Hydrogeology of the Confining Zone

In comparison to the Arbuckle aquifer, there is relatively less hydrogeologic information available for the confining zone as well as other zones between the Arbuckle Group and the Mississippian producing horizons, with few known estimates of permeability available. Based on core data, Petrotek (2001) estimated a vertical hydraulic conductivity range of 8.5e-06 to 1.7e-04 millidarcy (mD) in the Chattanooga Shale at an injection site in Wichita, Kansas, approximately 30 miles north of the proposed injection well site (KGS 1-28).

Site-specific data are the best source of information about the upper confining zone. The hydraulic impedance characteristics of the upper confining zone can be estimated from the geophysical logs obtained at KGS 1-28 and KGS 1-32. At KGS 1-28 (Figure 4.32b), extremely low horizontal permeabilities (< $1e^{-05}$ mD) are estimated in the Pierson formation and Chattanooga Shale. A wider range of horizontal permeability is noted in the Simpson Group due to the presence of sand beds within the shales. As shown in Figure 4.32b, the horizontal permeability within the Arbuckle is consistently and substantially higher than in the confining zones.

At KGS 1-32, core samples were also obtained in addition to geophysical logs. In general, Figure 4.32a indicates a good agreement between the NMR-based estimates of permeability/porosity and core measurements. The gamma-ray spikes along with the NMR- and core-based estimates of permeability validate the assumption of a competent confining zone above the Arbuckle Group. Section 4.7 presents a detailed discussion of confining zone characteristics at the injection well site.

The vertical permeability in the confining zone at KGS 1-28 and KGS 1-32 is also very low, as shown in Figure 4.32a-b. The vertical permeability in the Chattanooga Shale and Pierson formation are significantly smaller (< 1e-05 mD) than in sand intervals within the Simpson Group. The vertical permeability in the Pierson formation—which consists of firm, organic-bearing, argillaceous dolomitic siltstone—is especially low. Extremely low permeability values of 2.9 and 1.6 nano-Darcy (nD; 1-09 Darcy) in the Pierson formation was also independently estimated at the National Energy Technology Laboratory (NETL) in Pittsburg using the Pulse Decay Method (Scheffer, 2012).

3.5 Geology of the Lower Confining Zone: Precambrian Basement

The Precambrian (Proterozoic) granite basement beneath the Arbuckle aquifer exists throughout Kansas (Figure. 3.3). It is found at shallow depths along structural highs such as the Nemaha anticline and the Central Kansas uplift. It dips from north to southeast of the Nemaha Ridge and was encountered at a depth of 5,160 ft at KGS 1-28. This unit is expected to provide basal confinement, which should prevent CO_2 from migrating downward. The Proterozoic rocks beneath the Wellington project area are composed of medium to coarsely crystalline pink granite that range between 1.098 ± 3 billion to 1,780 ± 20 billion years old (Van Schmus and Bickford, 1993). There are no sedimentary rocks beneath this granite.

The presence and lateral continuity of the Precambrian basement, the Arbuckle aquifer, and the primary confining zones (as well as the formations overlying it) can also be readily seen in the seismic map presented in Figure 4.53. Detailed information pertaining to seismic data acquisition and interpretation is presented in Section 4.8.

Section 4
Local Scale Geology and Hydrogeology

4.1 Introduction

This section describes the local geology and hydrogeology to satisfy 40 CFR Part 146.82 (a)(3)(vi), which requires that before issuance of a permit to construct a Class VI well or convert an existing injection well to a Class VI well, the following information must be provided:

- Information about the geologic structure and hydrogeologic properties of the proposed storage site and overlying formations, including:
  - Maps and cross sections of the area of review;
  - The location, orientation, and properties of known or suspected faults and fractures that may transect the confining zone(s) in the area of review and a determination that they would not interfere with containment;
  - Data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the injection and confining zone(s); including geology/facies changes based on field data, which may include geologic cores, outcrop data, seismic surveys, well logs, and names and lithologic descriptions;
  - Geomechanical information about fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone(s);
  - Information about the seismic history, including the presence and depth of seismic sources and a determination that the seismicity would not interfere with containment; and
  - Geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the local area.
- Maps and stratigraphic cross sections indicating the general vertical and lateral limits of all USDW, water wells, and springs within the area of review; their positions relative to the injection zone(s); and the direction of water movement, where known;

- Baseline geochemical data about subsurface formations, including all USDW in the area of review;

40 CFR Part 146.83 (a) provides the minimum siting criteria for owners and operators of Class VI injection wells, which requires demonstration to the satisfaction of the director that the wells will be sited in areas with a suitable geologic system. The owners or operators must demonstrate that the geologic system includes:

(1) An injection zone(s) of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the CO_2 stream;

(2) Confining zone(s) free of transmissive faults or fractures and of sufficient areal extent and integrity to contain the injected CO_2 stream and displaced formation fluids and allow injection at proposed maximum pressures and volumes without initiating or propagating fractures in the confining zone(s).

40 CFR Part 146.3 specifies the following definitions:

- *Confining zone* means a geological formation, group of formations, or part of a formation that is capable of limiting fluid movement above an injection zone.
- *Injection zone* means a geological formation, group of formations, or part of a formation receiving fluids through a well.

This section, therefore, contains site-specific geologic and hydrogeologic information obtained during construction of geologic characterization well KGS 1-32 and proposed injection well KGS 1-28 in 2009 and 2011, respectively. The information in this section is organized as follows

Section 4.2 Summary of Data Aquired at the Wellington Site

Section 4.3 Site Stratigraphy

Section 4.4 Determination of Lowermost USDW

Section 4.5 Wellington (USDW) and Shallow Formations

Section 4.6 Arbuckle Aquifer (Injection Zone)

Section 4.7 Upper Confining Zones

Section 4.8 3-D Seismic Survey and Analyses

The contents and key findings in each subsection are summarized below.

Summary of Data Acquired at the Wellington Site (Section 4.2)

This section presents a listing of field activities and acquired data in tabular form along with references to the sections in the permit application that document the data and present analysis/interpretation.

Site Stratigraphy (Section 4.3)

This section presents stratigraphy at the Wellington injection site from the surface to the Precambrian basement.

Determination of Lowermost USDW (Section 4.4)

This section documents the technical basis for establishing the upper Wellington Formation as the lowermost USDW at the storage site based on total dissolved solids concentrations in subsurface formations.

The Wellington (USDW) and Shallow Formations (Section 4.5)

The Wellington Formation is the uppermost stratigraphic unit at the storage site. It consists of three zones: the upper Wellington formation (0–about 250 ft), the Hutchinson Salt Beds (about 250–340 ft) , and the lower Wellington formation (about 340–550 ft). The upper Wellington formation is used for withdrawing minor quantities of groundwater as the underlying Hutchinson Salt Beds and the Lower Wellington formation have elevated concentrations of total dissolved solids (> 10,000 mg/L) and do not produce water at an economical rate because of tight shales. The Kansas Department of Health and Environment also recognizes the Upper Wellington as the lowermost USDW. Most groundwater wells in Sumner County are less than 100 ft deep as salinity increases with depth. There are no groundwater or surface-water withdrawals within the EPA AoR.

Arbuckle Aquifer (Injection Zone) (Section 4.6)

The Arbuckle aquifer is approximately 1,000 ft thick at the Wellington site and extends from a depth of approximately 4,170 to 5,160 ft below KB. Based on detailed analyses of core and geophysical log data, the aquifer can be divided into three zones:

- a vuggy and highly permeable lower Arbuckle zone in the lower 100+ ft and referred to as the lower Arbuckle aquifer,
- a low permeability zone in the middle referred to as the mid-Arbuckle baffle zones,
- a high permeability zone in the top approximately 130 ft referred to as the upper Arbuckle aquifer.

The geochemical data and analyses of ion composition and isotopes all support the presence of a low permeability confining interval in the main body of the Arbuckle that separates the upper and lower high permeability zones within the Arbuckle. This suggests that this baffle zone may potentially help to confine the injected CO_2 in the lower Arbuckle aquifer. The laboratory-based estimate of vertical permeability from cores in the mid-Arbuckle also indicates the vertical permeability to be typically less than 0.005 mD, which is the lower estimable limit for the laboratory method employed.

This subsection addresses the compatibility of CO_2 with formation waters and minerals in the Arbuckle aquifer. The analyses suggest that there should not be any compatibility problems that could result in reduced pore space, excessive formation/well pressures, or hindrance to injection operations or geologic storage.

Upper Confining Zones (Section 4.7)

Various approaches demonstrate the confining potential of the confining zone

(Simpson Group, Chattanooga Shale, and Pierson formation) above the Arbuckle. Entry pressure of 956 psi is estimated for the Simpson and Chattanooga shales, which is substantially less than the maximum 13.1 psi increase in pore pressure estimated at the base of the confining zone (Simpson Group) under the worst-case scenario. Laboratory-based estimates of vertical permeability also indicate very tight rock in the confining zone. The Pierson formation at the bottom of the Mississippian System and directly above the Chattanooga Shale has aquiclude-like properties with laboratory-derived estimates of permeability in the nano-Darcy range (1.0^{-09} Darcy).

The chloride concentration in the Arbuckle and the Mississippian reservoir that lies above the confining zone is significantly different, suggesting a very competent confining zone that provides tight confinement and hydraulic separation of the waters in the Arbuckle and the Mississippian systems. The pressure data also corroborate the conclusions derived from the chloride data regarding the hydraulic separation of the Mississippian and Arbuckle systems and competency of the confining zone between these two reservoirs. A significant under-pressurization of the Mississippian was noted from the drill-stem test data, which not only supports the presence of a competent low-permeability confining zone but also highlights the CO_2 trapping potential of the Mississippian System.

No existing or abandoned wells within the EPA AOR penetrate the confining zone at the site except the 5,241-ft deep proposed injection well, KGS 1-28, which is perforated at the bottom of the well in the lower Arbuckle aquifer. The well was constructed in compliance with Class VI injection well requirements as documented in Section 8.

3-D Seismic Survey and Analyses (Section 4.8)

Section 4.8 discusses various seismic analysis techniques implemented in the Wellington project to characterize the subsurface formations. The results demonstrate the ability of the seismic techniques to map key formation horizons and to characterize the geologic fabric in the subsurface. Seismic data confirm the regional presence of the Arbuckle aquifer and provide insight into the potential for containment of CO_2 within the Arbuckle. The analyses indicate that the relatively low impedance region within the middle Arbuckle may act as a hydraulic barrier, preventing or minimizing vertical migration of CO_2 out of the lower Arbuckle injection zone. The low permeability confining zones above the Arbuckle are also clearly identified by seismic impedance analyses.

4.2 Summary of Data Acquired at Wellington Site

An extensive data acquisition effort was initiated to characterize the CO_2 geologic storage site at Wellington. Two 5,000+ ft deep wells (KGS 1-28 and KGS 1-32) penetrating the Precambrian granitic basement were constructed to obtain an extensive suite of geophysical logs and core samples and to conduct an injection test. The focus of the acquired data was on characterizing the injection zone (Arbuckle Group) and the shaley formations above the Arbuckle that comprise the upper confining zone. Table 4.1 presents a summary of the acquired data and refers to the subsections in this chapter that present the data and accompanying analysis.

Table 4.1—Summary of field data acquired at the Wellington storage site.

Acquired Data	Section of Application where Documented/Discussed
Geophysical Logs	
Array Compensated True Resistivity	Appendices B and C, Section 4.4
Temperature	Appendices B and C, Section 4.6.5
Compensated Spectral Gamma Ray	Appendices B and C, Sections 4.6 and 4.7
Microlog	Appendices B and C
Spectral Density Dual Spaced Neutron Log	Appendices B and C, Sections 4.6 and 4.7
Annular Hole Volume Log	Appendices B and C
Extended Range Micro Imager Correlation Plot	Appendices B and C, Section 4.7
Magnetic Resonance Image Log	Appendices B and C, Sections 4.6 and 4.7
Radial Cement Bond Log	Appendices B and C
CT Scan	Section 4.7.5.3
Core Samples (Arbuckle Group)	
Porosity and Permeability	Section 4.6.6
Mineralogy and Soil Characterization	Section 4.6.2
CO_2 Compatibility	Section 4.6.10
Drill-Stem Test	Sections 4.6.3 and 8.15.3
Geochemistry	Section 4.6.7
Pressure and Temperature	Sections 4.6.3 and 4.6.5
Swab Samples	
Geochemistry	Section 4.6.7
Injection Test	
Permeability	Section 4.6.4
Seismic Data	
Structure and Impedance Mapping	Section 4.8
Core Samples (Confining Zone)	
Porosity and Permeability	Section 4.7.3
Mineralogy and Soil Characterization	Section 4.7.2
CO_2 Compatibility	Section 4.7.7
Fracture Studies	Section 4.7.5.1

4.3 Stratigraphy

Based on the geophysical logs and core samples collected at KGS 1-32 and KGS 1-28, the stratigraphic succession (Figure 4.1 and Table 4.2) at the site spans from the Precambrian granite basement to the Permian upper Wellington Formation near the surface, which is also the lowermost USDW at the site as discussed in Sections 4.4 and 4.5. Geologic formations of interest for this permit application are the dolomites of the Arbuckle Group (injection zone), shales and argillaceous siltstone in the confining zone (Simpson Group, the Chattanooga Shale, and the Pierson formation), and silty shales of the upper Wellington Formation (USDW).

The regional extent and continuity of the Arbuckle aquifer, the underlying Proterozoic granite, the overlying confining zone (Simpson Group, Chattanooga Shale, and Pierson formation), the Mississippian carbonates, the various shale intervals between the Arbuckle Group (injection zone) and the Wellington Formation (USDW) are all readily discernible from geophysical logs along three cross-sections (Figure 4.2a-d) prepared for this study. The statewide presence of the injection zone, and the overlying and underlying confining

Table 4.2—Stratigraphy at proposed injection well site KGS 1-28 as derived from geophysical logs..

Formation	Depth (feet)	Notes
Upper Wellington	0	USDW
Hutchinson Salt Beds	238	
Lower Wellington	320	
Chase Group	568	
Wabaunsee Group	1,300	
Howard Limestone	1,846	
Severy Shale	1,930	
Topeka Limestone	1,974	
Kanwaka Shale	2,175	
Oread Limestone	2,237	
Heebner Shale	2,350	
Toronto Limestone	2,406	
Douglas Group	2,470	
Stalnaker Sandstone	2,660	
Lansing Shale Group	2,808	
Kansas City Group	3,020	
Pleasanton Group	3,258	
Marmaton Group	3,297	
Cherokee Group	3,504	
Mississippian Limestone	3,651	
Pierson Formation	3,930	Upper Confining Zone
Chattanooga Shale	4,040	Upper Confining Zone
Simpson Group	4,082	Upper Confining Zone
Simpson Shale	4,105	
Arbuckle	4,168	Injection Zone
Precambrian Granite	5,160	Lower Confining Zone

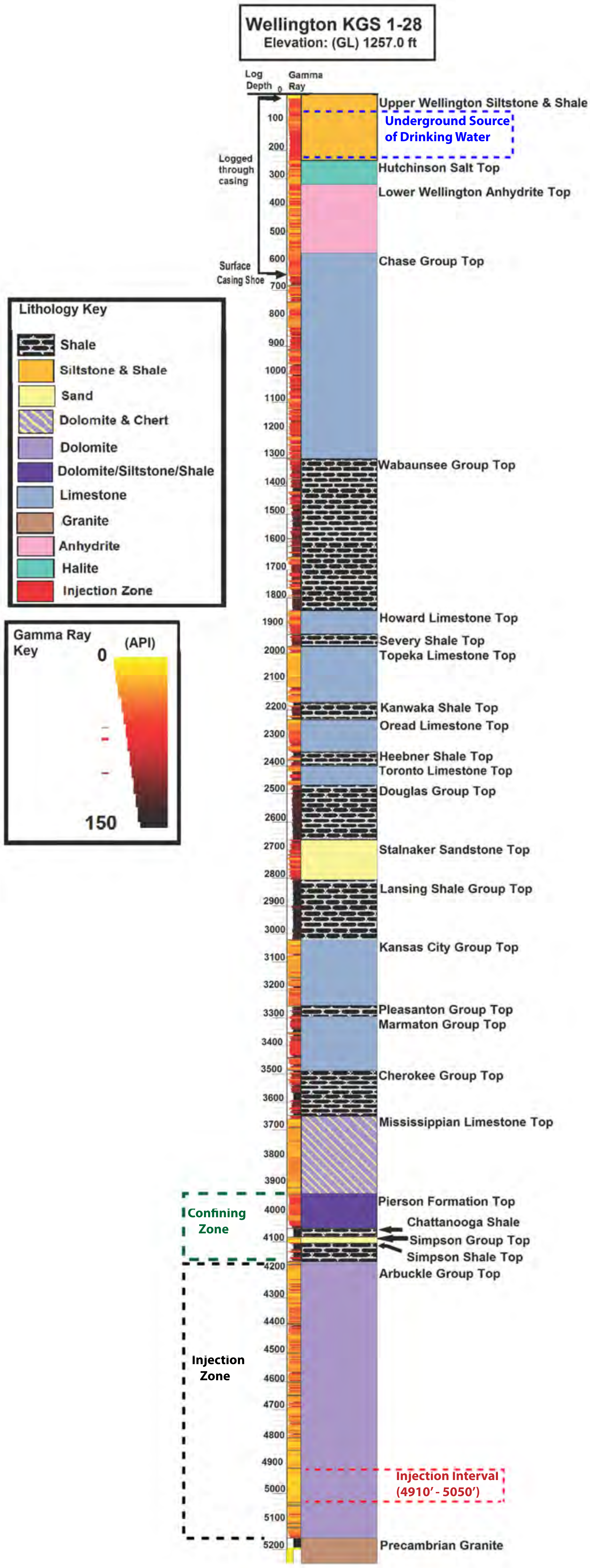


Figure 4.1 - Stratigraphic column at the KGS 1-28 site.

zones are also documented in Section 3 in the form of structure maps. The local presence of the injection and confining zones at the Wellington is documented in Sections 4.6.1 and 4.7.1, where structure and thickness maps are provided (Figures 4.22–4.24 and 4.40–4.42). There is active petroleum production from the Mississippian as documented in Section 7, which indicates that the Cherokee Group could act as a secondary sealing unit. Collectively, this information satisfies the minimum siting criteria specified in 40 CFR 146.83, which requires demonstration of the injection and confining zones of sufficient areal extent.

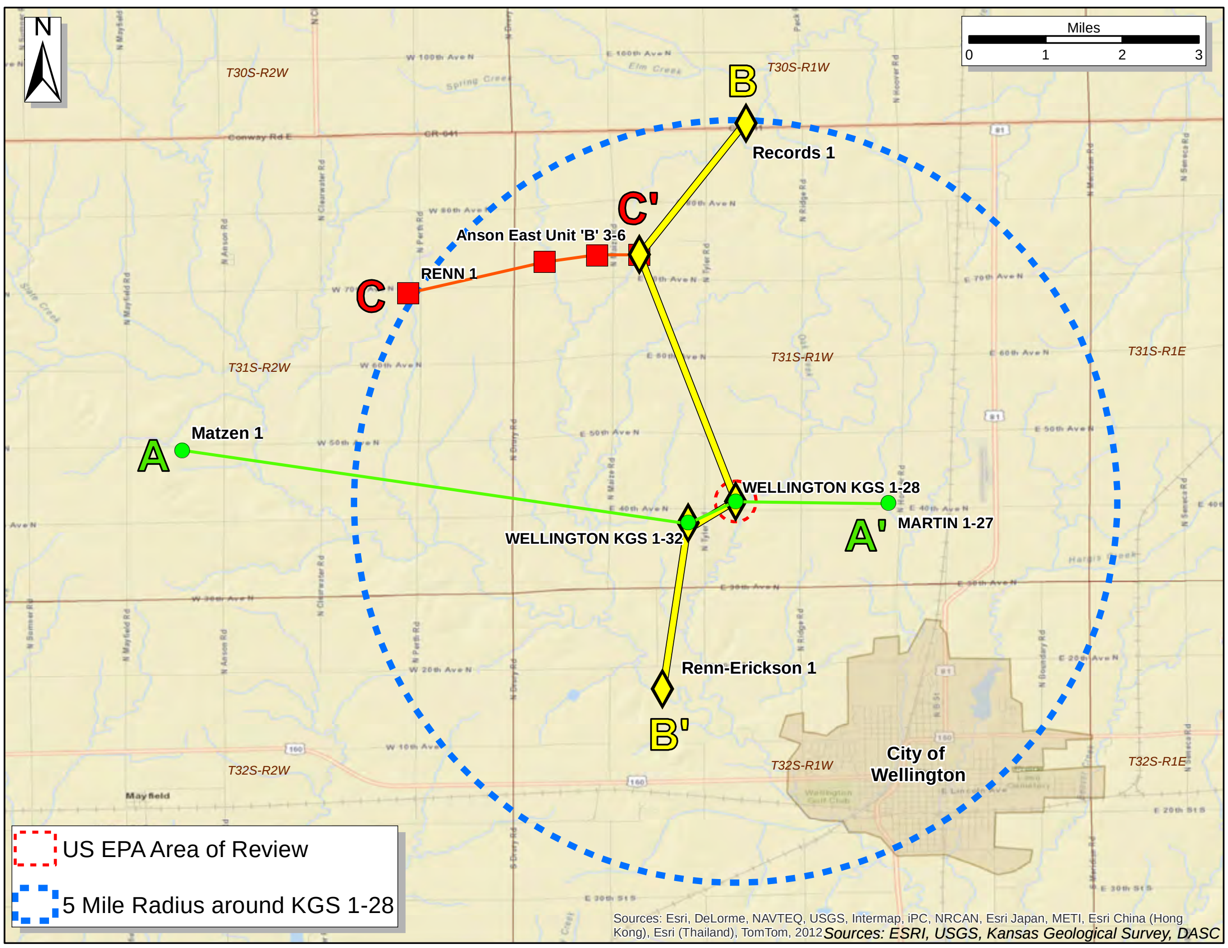


Figure 4.2a—Location of geologic cross sections presented in Figures 4.2b-d.

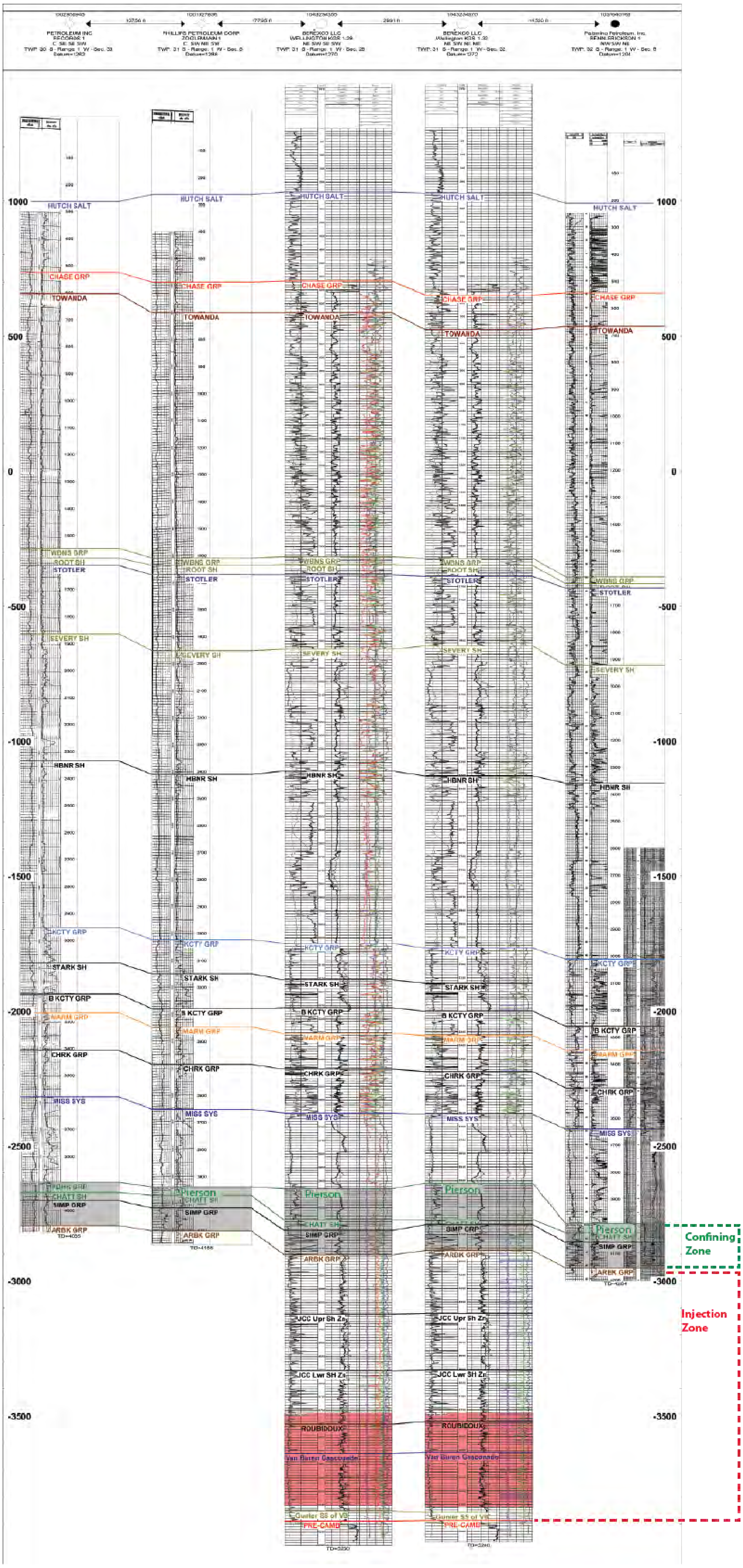


Figure 4.2b—Geologic logs along east-west cross-sectional line A-A' (refer to Figure 4.1b for location of cross-section).

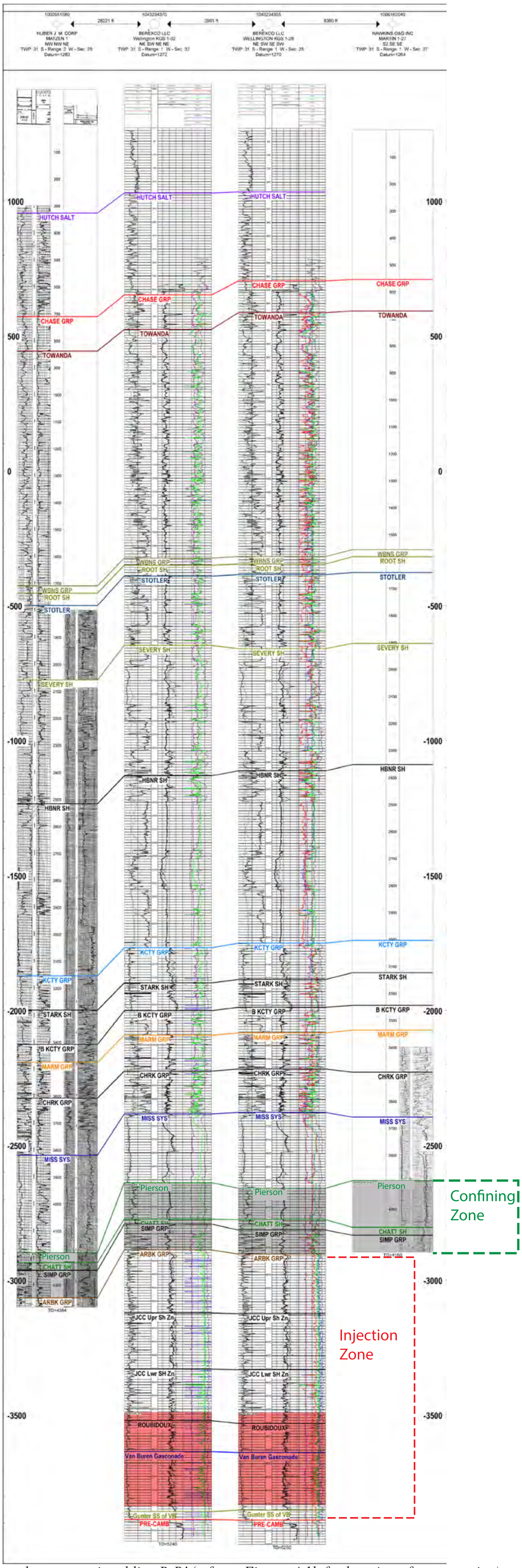


Figure 4.2c—Geologic logs along north-south cross-sectional line B-B' (refer to Figure 4.1b for location of cross-section).

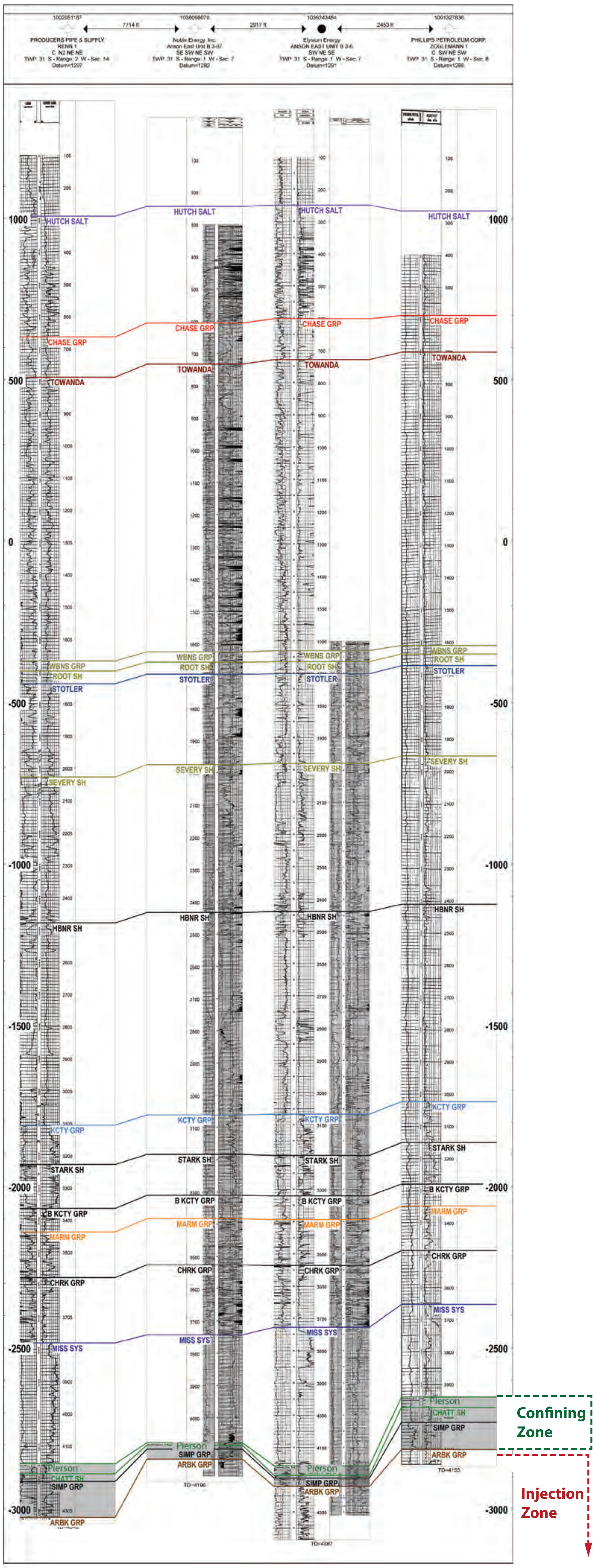


Figure 4.2d—Geologic logs along east-west cross-sectional line C-C' (refer to Figure 4.1b for location of cross-section).

4.4 Determination of Lowermost USDW

As shown in Table 4.2, the Upper Wellington Formation has been identified as the USDW. Section 4.5 provides site-specific geologic, hydrologic, and geochemical data supporting this determination. To further corroborate the USDW determination, resistivity logs were used to estimate total dissolved solids (TDS) throughout the depth at the injection well site (KGS 1-28) to establish the lowermost USDW. The procedure is outlined in Archie (1942) and consists of two steps: a) estimate NaCl content and b) use TDS-NaCl relationship to estimate TDS.

The salinity (NaCl, mg/L) was calculated using a variant of Archie's equation (Archie, 1942):

$$R_w = \left(.0123 + \frac{3647.5}{NaCl^{0.955}}\right) \frac{81.77}{T+6.77} \qquad \text{(Equation 4.1)}$$

$$=> NaCl = \left(\left(\frac{3647.5}{R_w - 0.0123}\right)^{1/0.9558} \right) * T \qquad \text{(Equation 4.2)}$$

where,

R_W = *Resistivity of water (ohm – m)*

T = *Formation temperature (F)*

The water resistivity, R_W, in Equation 4.2 is computed from a version of Archie's equation for 100% saturated pores:

$$R_w = \frac{a}{(\emptyset^m * R_t)}$$

Where,

$\emptyset$ = porosity,

R_t = formation resistivity,

m = cementation exponent, and assumed to be 2 for cemented limestone (Doveton, 1986),

a = coefficient of proportionality, and assumed to be 1 (Maute et al., 1992).

The subsurface water in Kansas is generally of NaCl type. For example, the TDS (by weight) in the Arbuckle is only 1.045 times NaCl (by weight) as shown in Figure 4.3. This suggests that Na and Cl are the dominant minerals in this formation. Therefore, for purposes of estimating TDS from resistivity logs, it was assumed that

$$TDS_{(mg/L)} = 1.045\ NaCl_{(mg/L)} \qquad \text{(Equation 4.3)}$$

Formation resistivity R_t, recorded from the bottom of the surface casing (647 ft) to the bottom of the borehole (5,142 ft) at KGS 1-28, was used to estimate TDS in the subsurface using equations 4.1–4.3. Figure 4.4 presents the resulting TDS distribution. The TDS values estimated from the resitivity log are compared with TDS values derived from water samples obtained during DST and swabbing and also shown in Figure 4.4. In general, the field-based TDS values are higher than the values estimated from the resistivity logs, which highlights the conservative nature of the TDS estimates derived from resistivity logs.

The TDS is greater than 10,000 mg/L from the top of the Chase Group to the base of the Arbuckle, with the exception of isolated intervals at the top of the Mississippian at 3,650 ft and a sandstone bed in the Simpson Group at 4,100 ft. These anomolously low TDS values were derived due to high resistivity associated with the presence of hydrocarbon since oil or gas that has displaced some of the brine is not a conductor of electricity. The low TDS in the highly saline Mississippian is due to anomolously low resistivity values recorded in this oil reservoir at Wellington Field (Scheffer, 2012). For example, the spike at 3,650 ft is associated with oil show at this elevation as is noted in the driller's log shown in Figure 4.5. The presence of oil in the area is expected given the project location in an active oil field.

The resistivity logs did not extend into the Wellington Formation, which constitutes bedrock at the injection site and underlies very thin unconsolidated quaternary deposits (Figure 4.6). The formation consists of three zones: the upper Wellington formation (0–about 250 ft at the Wellington storage site), the Hutchinson Salt Beds (about 250–340 ft), and the lower Wellington

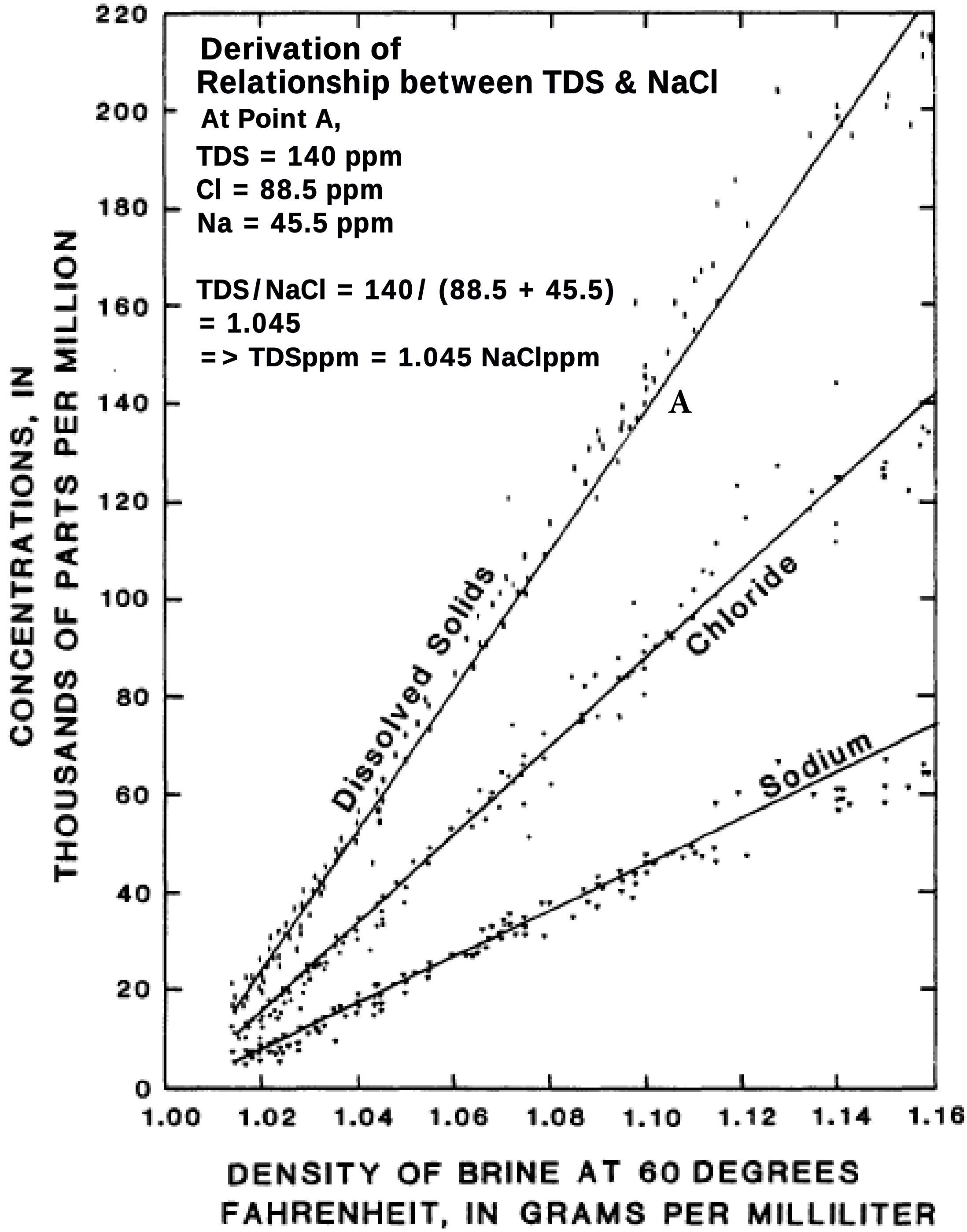


Figure 4.3 —Relation of concentrations of selected chemical constituents to density of brines in Kansas (from Carr et al., 1986).

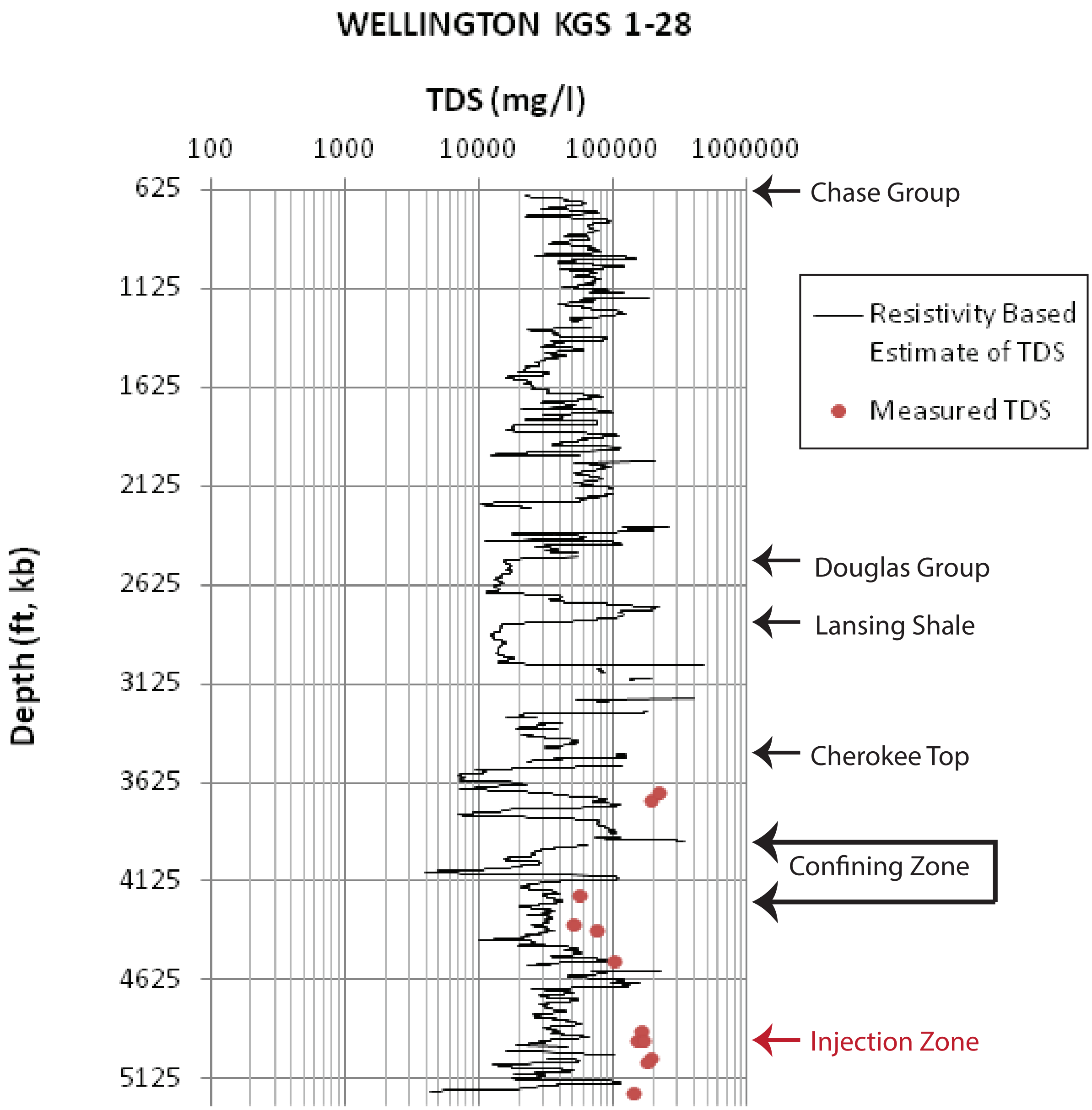


Figure 4.4—Total dissolved solids (TDS) estimated from resistivity logs at KGS 1-28.

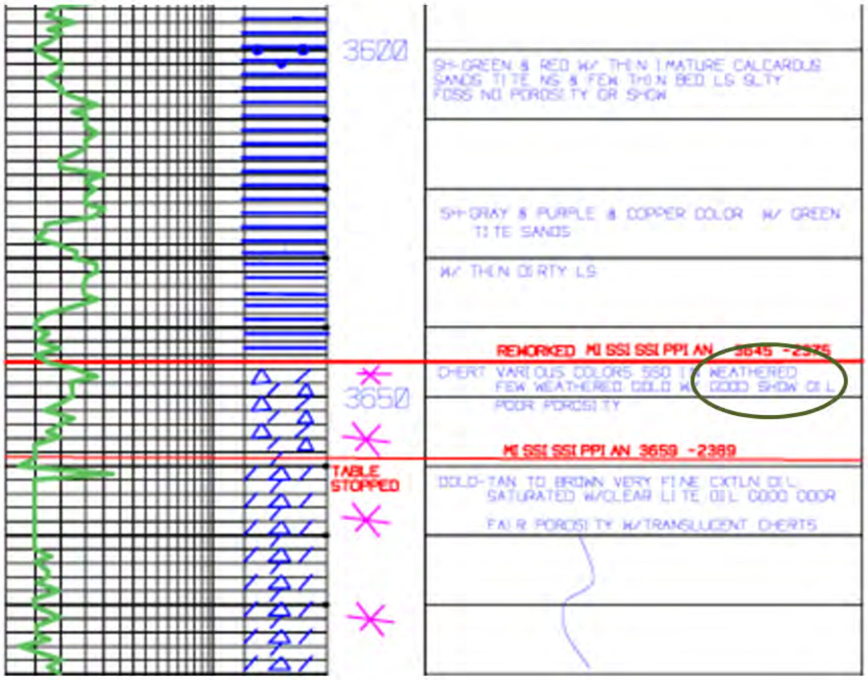


Figure 4.5 —Drillers log at KGS 1-28 documenting oil show at 3,650 ft below KB.

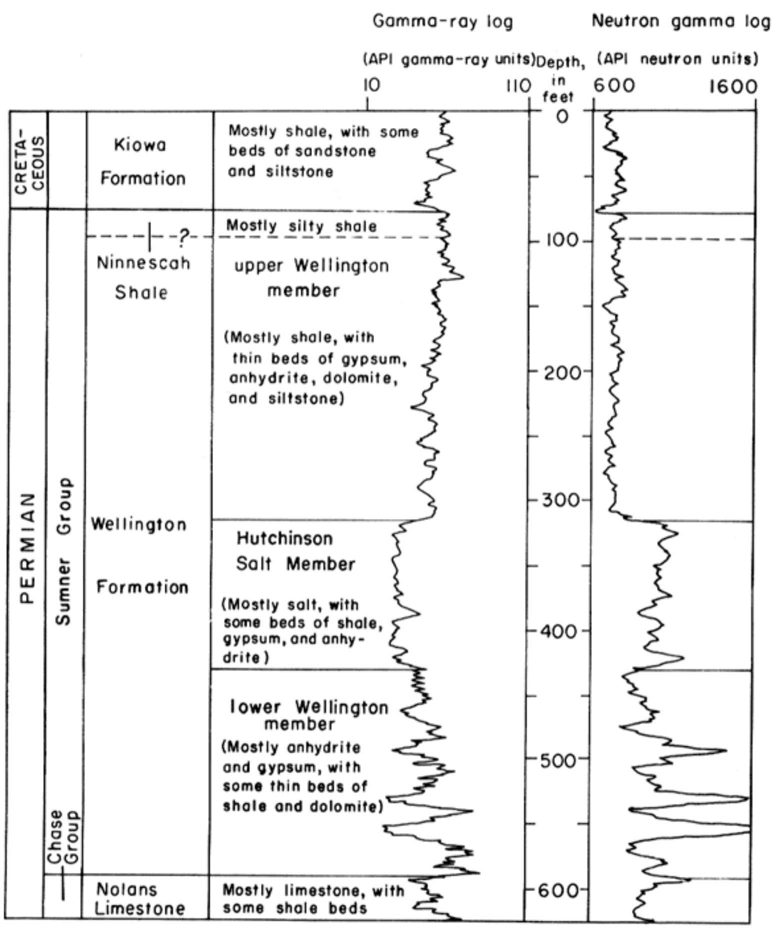


Figure 4.6—Gamma ray–neutron log showing stratigraphic relationship of bedrock in central Kansas (from Gogel, 1981).

formation (about 340–550 ft). The upper Wellington formation is used for withdrawing minor quantities of groundwater as the underlying Hutchinson Salt Beds and the lower Wellington formation, consisting mainly of shale, halite, anhydrite, and gypsum, are too salty (Gogel, 1981). Chloride concentration in the lower parts of the Wellington formation generally exceeds 100,000 mg/L (Figure 4.7). Therefore, the upper Wellington Formation is considered the lowermost USDW at the Wellington site. The Kansas Department of Health and Environment also classifies the upper Wellington as the lowermost USDW, as indicated in Section 4.5.7. Most groundwater wells in Sumner County are less than 100 ft deep as salinity increases with depth, as discussed in Section 4.5.5.

The nearly 100-ft thick succession of halite (rock salt) beds below the upper Wellington formation is indicated by their relatively low gamma ray (30–35 API units) and low interval transit time (delta-t, DT) of 67 microseconds per ft (typical of the velocity of halite) on the sonic log shown in Figure 4.8. A 220-ft thick succession of bedded anhydrite lies below the Hutchinson Salt beds, distinguished by even faster transit time of nearly 50 microseconds per ft (typical of velocity for pure anhydrite) and lower gamma ray (30–35 API) compared to the interbedded shales (90 API GR units and DT values of 115 and 125 microseconds per ft) as shown in Figure 4.8. The sonic porosity of the combined interval is essentially minimal, indicated by apparent porosity for salt beds of about 15% and anhydrite of about 4–5%. The apparent porosity reflects calculations based on a limestone travel time that is less than either anhydrite or halite. The apparent porosity of the shaly intervals is also indicative of slower travel times of clay minerals compared to a limestone and the micropores that comprise the typical shale.

4.5 Wellington (USDW) and Shallow Formations

4.5.1 Shallow Geology and Groundwater Resources

The CO_2 injection site is located in central Sumner County, Kansas, approximately 3 mi northwest of the city of Wellington (Figure 1.5). As shown in Figure 1.7, the site is located in the midst of gently sloping grassland and non-irrigated crop fields. The area is drained by several intermittent streams that flow southward into the (perennial) Slate Creek (Figure 1.6a).

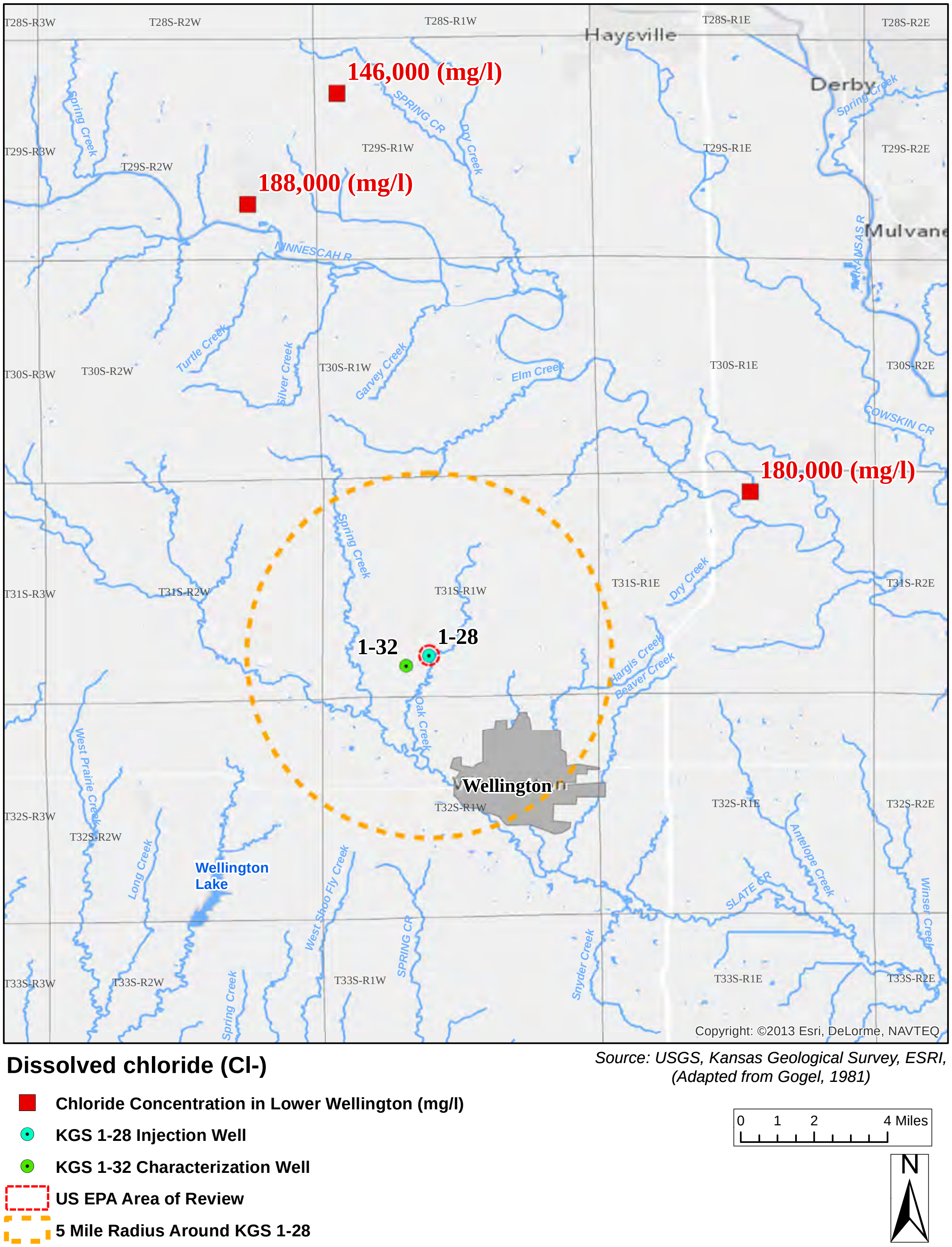


Figure 4.7—Salt concentration in lower parts of the Wellington Formation (from Gogel, 1981).

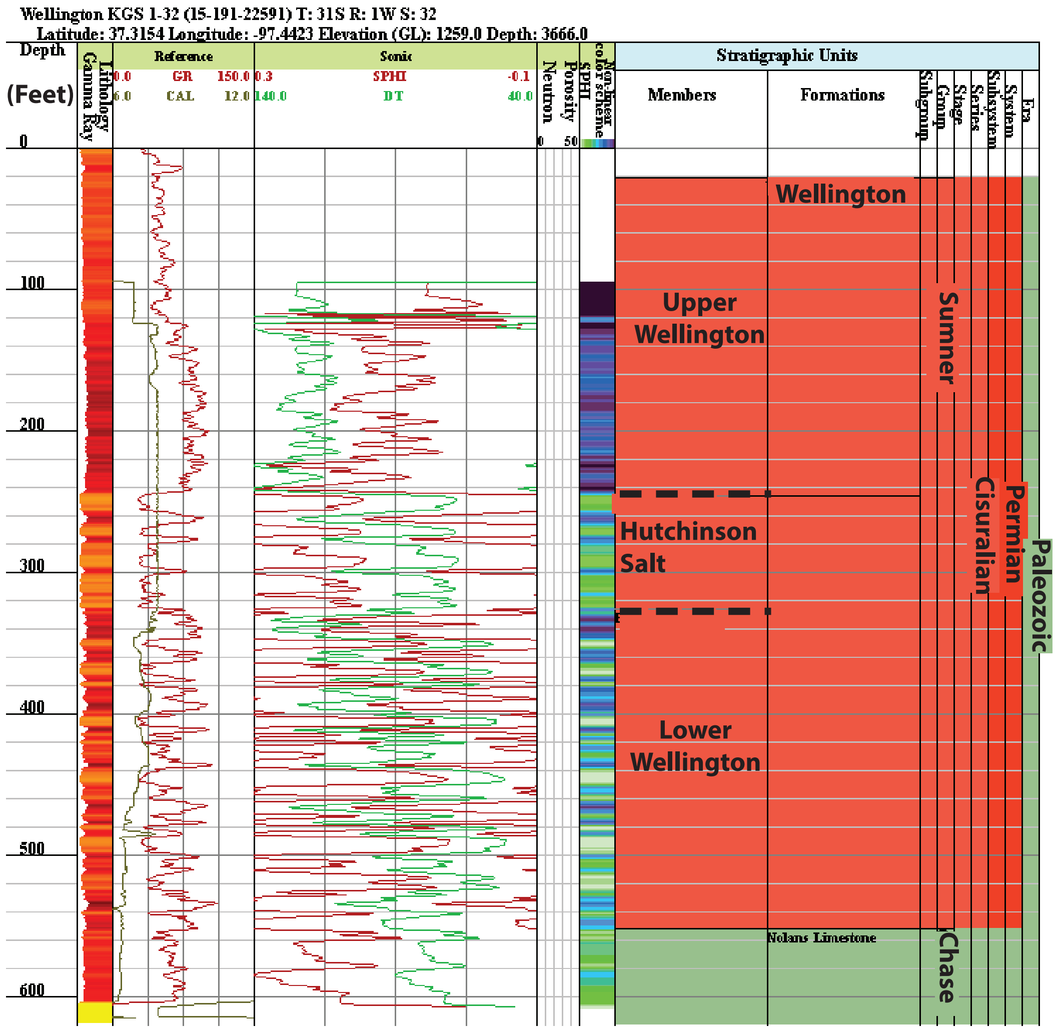


Figure 4.8—Geophysical logs within the Wellington Formation at KGS 1-32.

Table 4.3 provides a generalized section of the rocks that subcrop in Sumner County. Although the table presents all surficial units in the county, only the Wellington, Wisconsinan terrace, and colluvium occur in the Wellington site area and, as such, are the focus of this section. These rocks are sedimentary in origin and range in age from Paleozoic to recent Cenozoic (Walters, 1961). Figure 4.9 presents a surface geologic map of Sumner County and shows the Permian Wellington Formation to be the oldest outcropping unit. The Wellington Formation also outcrops in a narrow band east of the storage site, and the colluvium is at the surface in most of the surrounding areas, except Slate Creek in the south where the stream bed is composed of Wisconsinan terrace deposits.

Table 4.3—Generalized section of rocks that crop out in Sumner County (source: Walters, 1961).

System	Series	Stratigraphic Unit	Thickness (ft)	Physical Character
Quaternary	Pleistocene	Dune sand	0–30	Sand, medium and fine, some silt
		Alluvium	0–75	Chiefly arkosic sand and gravel; contains discontinuous lenses of silt and clay
		Colluvium* Recent to Illinoisan	0–25	Silt and clay, minor amounts of sand and gravel, resembling the underlying bedrock material
		Wisconsinan* terrace deposits	0–75	Chiefly arkosic sand and gravel; contain discontinuous lenses of silt and clay.
		Crete Formation	0–65	Poorly sorted sand and gravel; contains considerable red-brown silt and locally derived limestone and shale fragments
		Kansan and Illinoisan terrace deposits	0–90	Chiefly medium to coarse sand; contain some silt and clay
Permian	Middle Permian	Ninnescah Shale	0–250	Predominantly silty shale, mostly brownish red with gray-green spots; contains beds of dolomite, calcareous siltstone, and fine-grained sandstone
		Wellington Formation*	40–250	Chiefly shale and silty shale, mostly gray and green, some red; contains lenticular beds of gypsum, silty limestone, dolomite, and the thick Hutchinson Salt Member near base

* Primary aquifer at Wellington Site

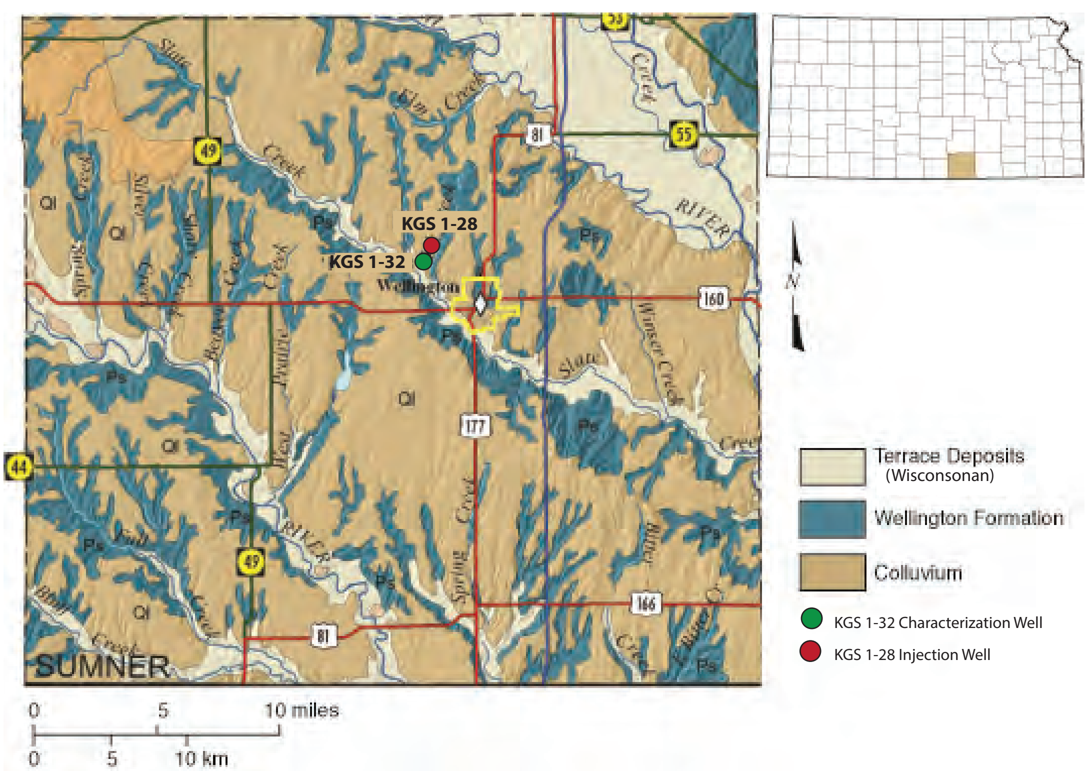


Figure 4.9—Surface geology in Sumner County, Kansas (Source: modified from Walters, 1961).

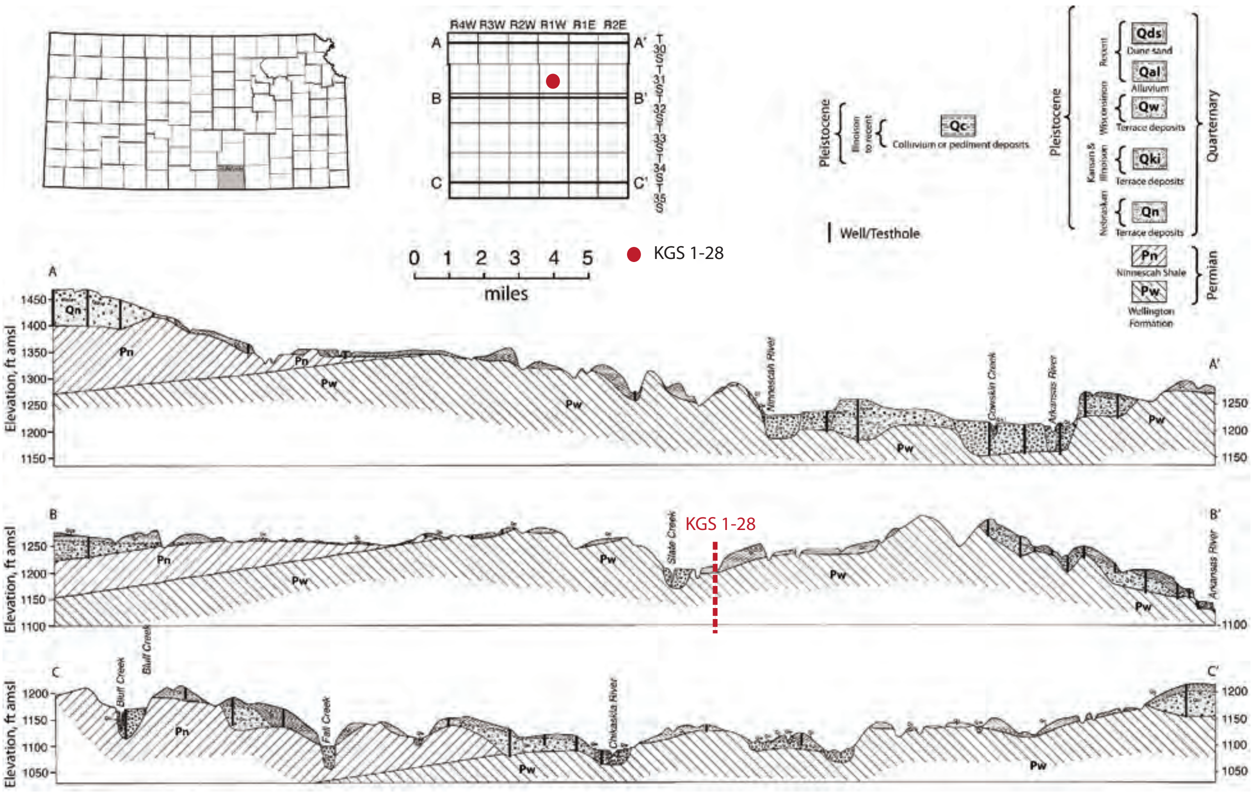


Figure 4.10—Geologic cross section through Sumner County, Kansas (from Walters, 1961).

Figure 4.10 presents three east-west geologic cross sections through Sumner County. The Wellington storage site is in close proximity to Section B–B'. Thin colluvium and terrace deposits overlie the Wellington Formation, which constitutes bedrock at the storage site. The geology and groundwater availability in each of the three rock types at the site are discussed below.

Wellington Formation

The Wellington Formation underlies all of Sumner County and occurs above the limestone of the Chase Group. In most of Sumner County, the formation either crops out or is covered by thin Pleistocene deposits. In the western parts of the county, the Ninnescah Shale overlies the Wellington Formation. The Wellington Formation dips gently westward and southwestward and can be divided into three distinct units in central Kansas: the Lower Wellington, the Hutchinson Salt Member, and the Upper Wellington (Figure 4.6).

The Lower Wellington member, the "anhydrite beds" of Ver Wiebe (1937), consists of gray shale and some dolomite alternating with many thin anhydrite and gypsum beds (Lee, 1956). It is 150–200 ft thick and contains a fairly persistent bed of dolomitic limestone in the bottom 35 to 40 feet of the formation (Walters, 1961).

Overlying the lower Wellington is the Hutchinson Salt Member, which consists mostly of salt, with some beds of shale, gypsum, and anhydrite. Figure 4.11 presents the elevation to the top of the Hutchinson Salt Member, and Figure 4.12 presents the thickness of this unit. The Hutchinson Salt Member is approximately 100–150 ft thick in the vicinity of the Wellington storage site.

The Upper Wellington Formation consists mainly of gray shale with minor amounts of gypsum, anhydrite, dolomite, and siltstone. Thickness of the Upper Wellington averages 250 ft in Sumner County (Gogel, 1981) as indicated by the difference between ground surface elevation (Figure 1.5) and the elevation at the top of the Hutchinson Salt (Figure 4.11). The relative thickness of the three Wellington Formation members presented in the stratigraphic column in Figure 4.6 is representative of the relative thickness of each member at the Wellington site as well.

The Wellington Formation yields only small quantities of water to wells in Sumner County. Most of the material in the formation is almost impermeable, and the water comes from small fracture zones or from thin limestone lenses. For this reason, the Wellington is not a prolific, reliable aquifer (Walters, 1961). As shown in Figure 4.13, most of the wells in the study area are less than 100-ft deep. This is likely because deeper Wellington wells may yield water that is strongly mineralized due to the overlying salt and gypsum beds in the formation. It may also be that the Wellington Formation is less weathered and, therefore, less permeable at greater depths.

Colluvium

Much of Sumner County is mantled by an accumulation of colluvium that rarely exceeds 20 ft in thickness. These deposits above the Upper Wellington are of Illinoisan to recent age and were formed partly by weathering of Permian shales and partly by deposition of silt, clay, and sand by sheet wash (Walters, 1961). The colluvium generally lies above the water table in the study area. Where present below the water table, the formation may yield moderate quantities of water.

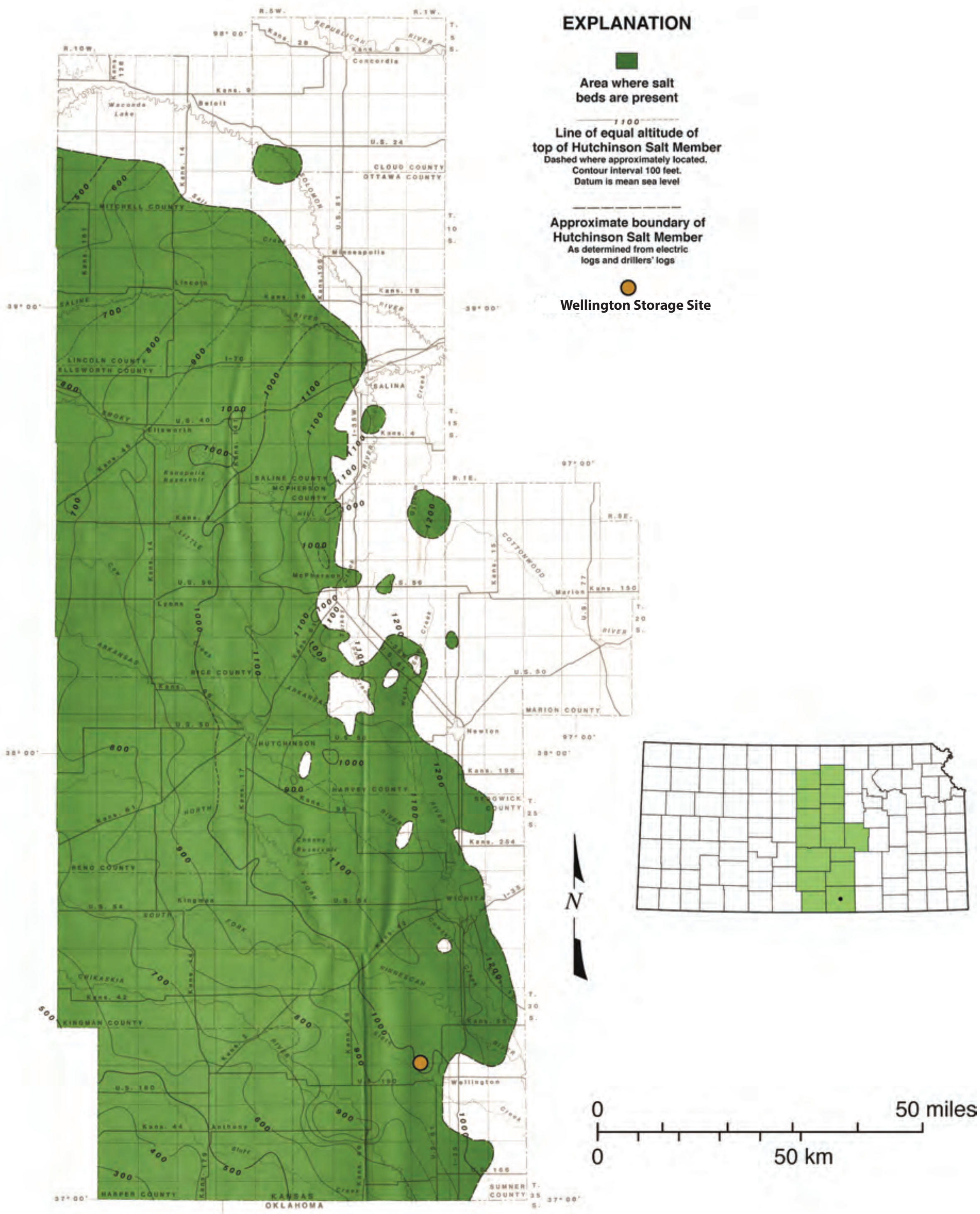


Figure 4.11—Map showing structure on top of Hutchinson Salt Member in central Kansas (modified from Gogel, 1981).

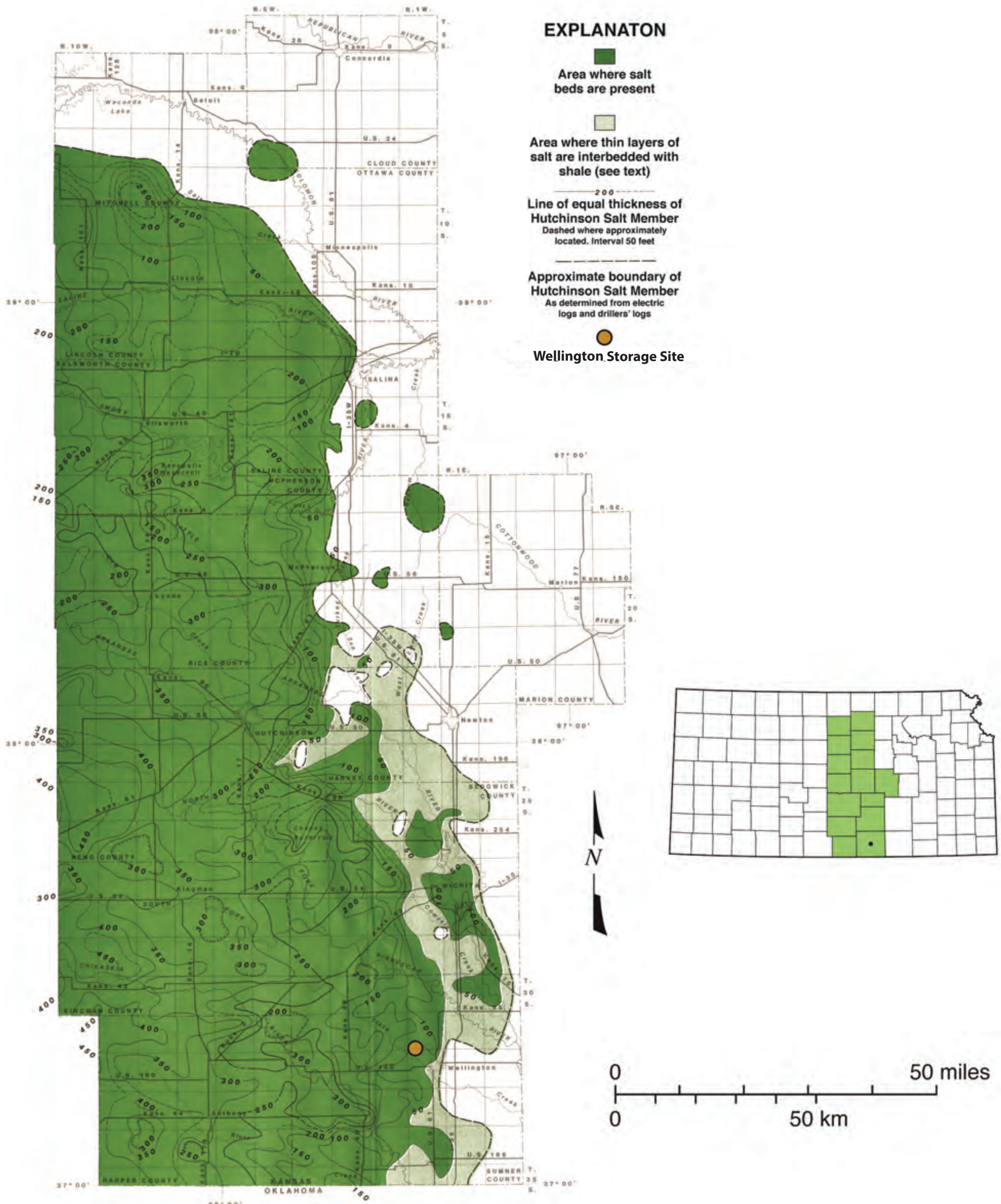


Figure 4.12—Map showing thickness of Hutchinson Salt Member in central Kansas (modified from Gogel, 1981).

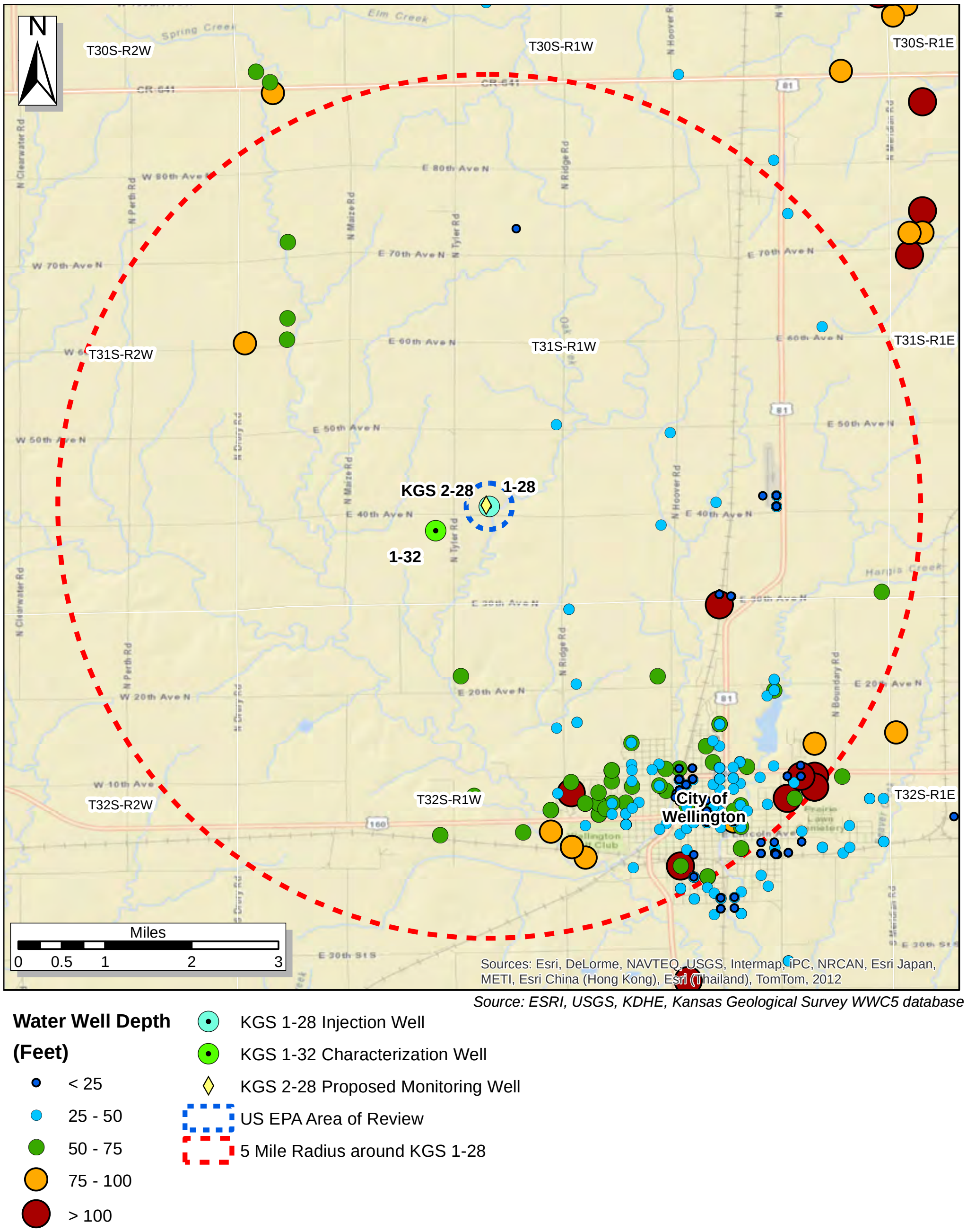


Figure 4.13—Well depths in the vicinity of the Wellington storage site.

Wisconsinan Terrace Deposits

Terrace deposits of Wisconsinan age occur in stream valleys in the Wellington area. These deposits represent the valley-filling phase of Wisconsinan glaciation and range in thickness from a feather edge to as much as 75 ft. The materials composing the Wisconsinan terrace deposits differ greatly from place to place in Sumner County, according to the type of material available to the stream that deposited them. In some places, they are composed chiefly of arkosic sand and gravel, while at other stream locations the rocks are composed primarily of silt and clay (Walters, 1961). Wisconsinan terrace deposits along streams can potentially yield substantial quantities of water.

4.5.2 Recharge/Discharge

The groundwater reservoirs are recharged principally from rain and snow, percolation from streams and other surface bodies of water, and by underflow from adjacent areas. Water is discharged from the groundwater reservoir by seepage into streams, by transpiration and evaporation, by movement into adjacent areas, and through extraction by wells. Water is pumped from wells for domestic, stock, municipal, industrial, and irrigation use.

4.5.3 Water Table

The water table surface in Sumner County conforms in general to the land surface, but the relief is relatively subdued (Figure 4.14). The water table in the study area varies between 1,200 and 1,220 ft MSL and is generally close to the surface, not exceeding a few tens of feet below ground level. Recharge from precipitation generally moves a short distance in the subsurface before discharging in a nearby stream. This has resulted in seasonal and annual water-level fluctuations in response to varying amounts of rainfall, as evidenced from water-level hydrographs at monitoring wells shown in Figure 4.15. As shown in Figure 4.15, there are no declining trends in the Wellington formation because groundwater withdrawals are minimal, as discussed in Section 4.5.5. A notable feature of the water table throughout Sumner County is the tendency of groundwater to migrate towards perennial streams, such as Slate Creek at the Wellington injection site. During periods of flood, the water level in the streams may be higher than the level of the groundwater, thus recharging the aquifers.

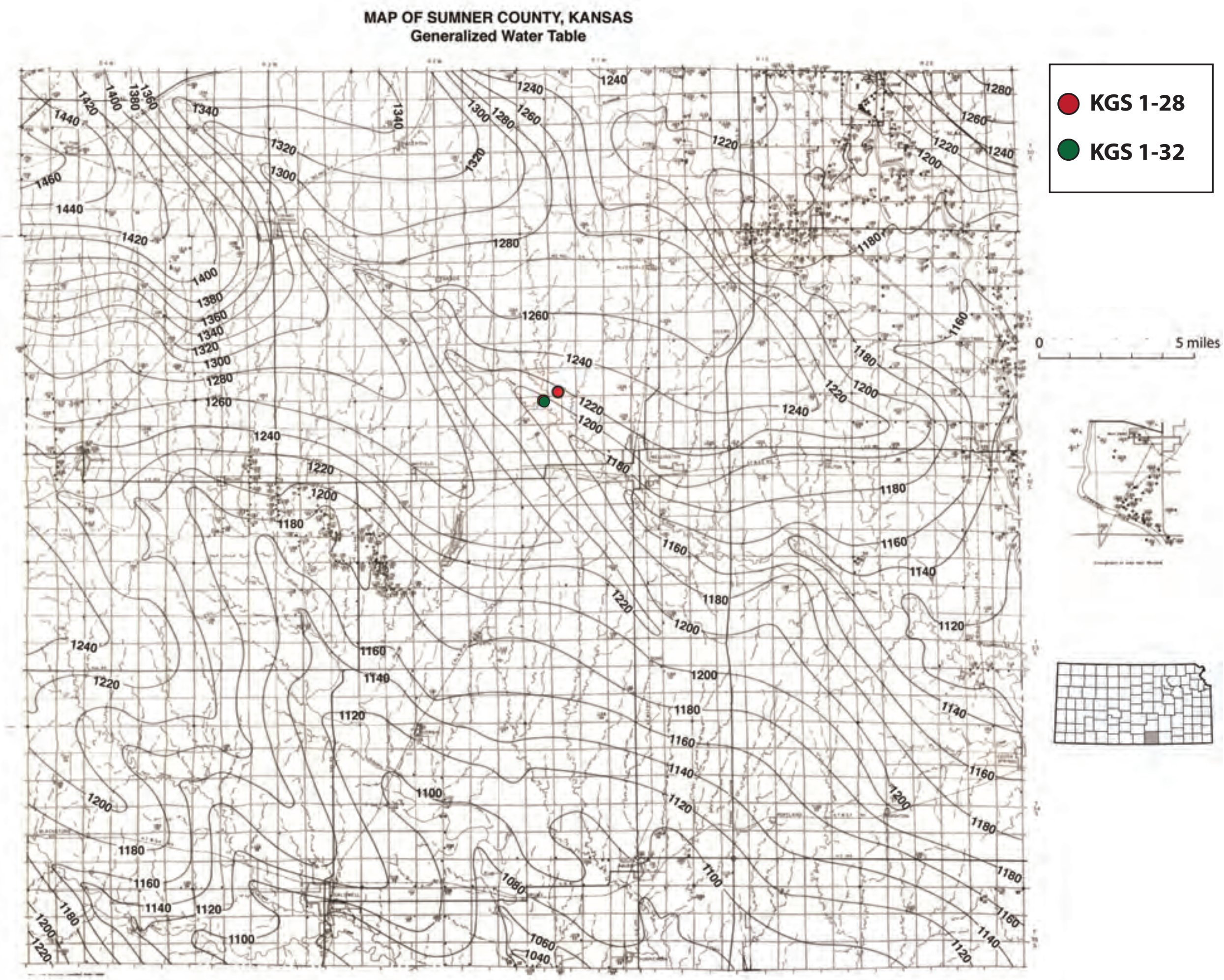


Figure 4.14—Generalized water table (ft, amsl) in Sumner County, Kansas (modified from Walters, 1957).

4.5.4 Surface Water

Most of Sumner County is drained by southeastward flowing streams, as evidenced from the potentiometric surface map shown in Figure 4.14. In the vicinity of the Wellington injection well KGS 1-28, three intermittent streams (Spring, Oak, and Hargis creeks) drain southward into the perennial Slate Creek (Figure 1.6a). Slate Creek has its headwaters northwest of Conway Springs about 20 mi northeast of KGS 1-28 and joins the Arkansas River near Geuda Springs about 20 mi southeast of Wellington.

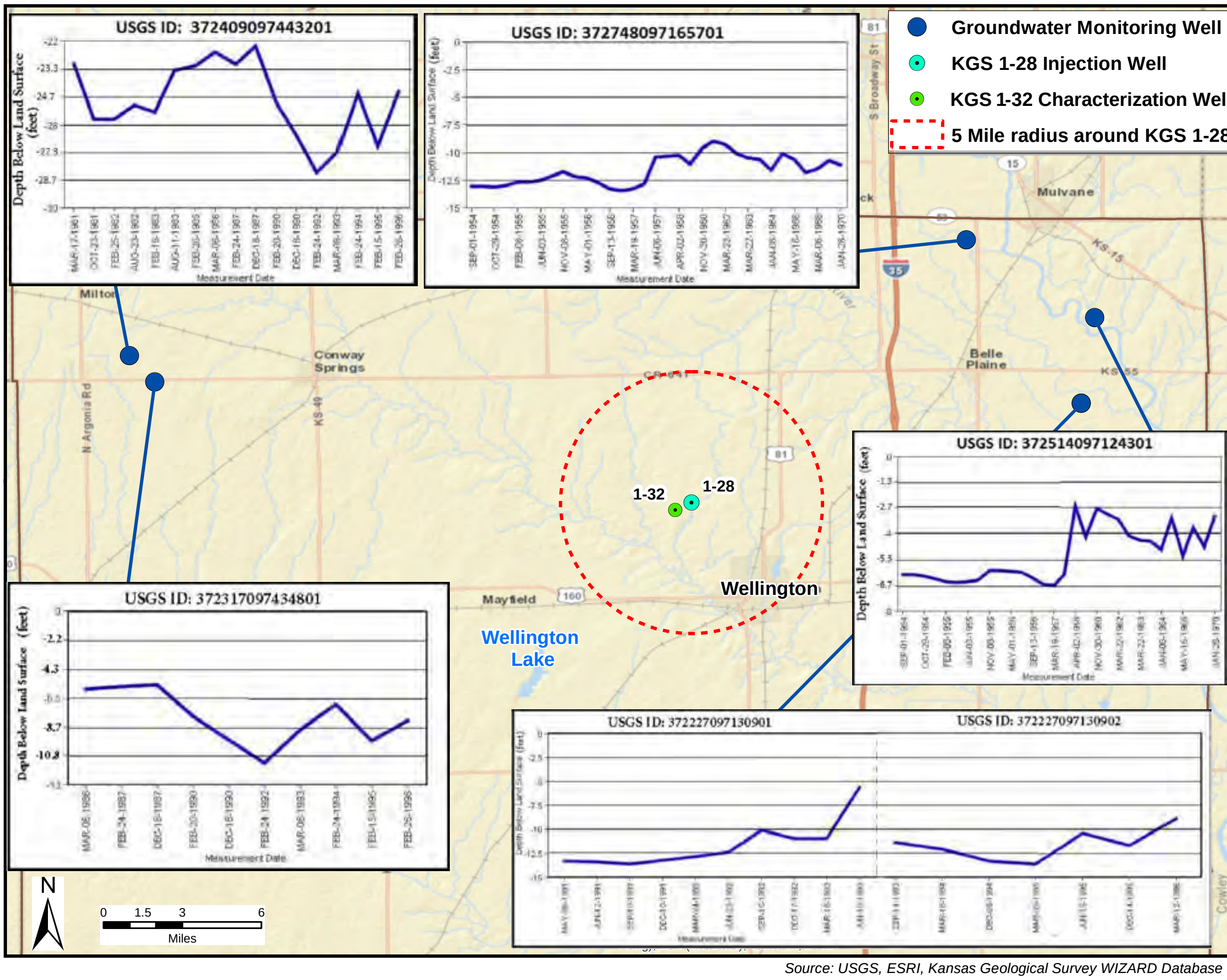


Figure 4.15—Water level hydrographs at observation wells in Sumner County, Kansas (source: KGS WIZARD groundwater database).

4.5.5 Water Use

Groundwater is withdrawn from several wells in the area for a variety of purposes as shown in Figure 4.16. Most of the wells, however, withdraw water from shallow fractured bedrock (Upper Wellington Formation) as the underlying water in the salt beds is highly saline. Figure 4.13 presents the depths of the wells and shows that a large majority of the wells are less than 100-ft deep and draw water from the Upper Wellington Formation since Quaternary deposits are very thin in the area. The drillers' logs for shallow water wells also indicate that these wells are screened in the shales of the Upper Wellington Formation. As shown in Figure 4.16, there are no municipal water supply wells within a 5-mi radius of the injection well KGS 1-28. Groundwater production

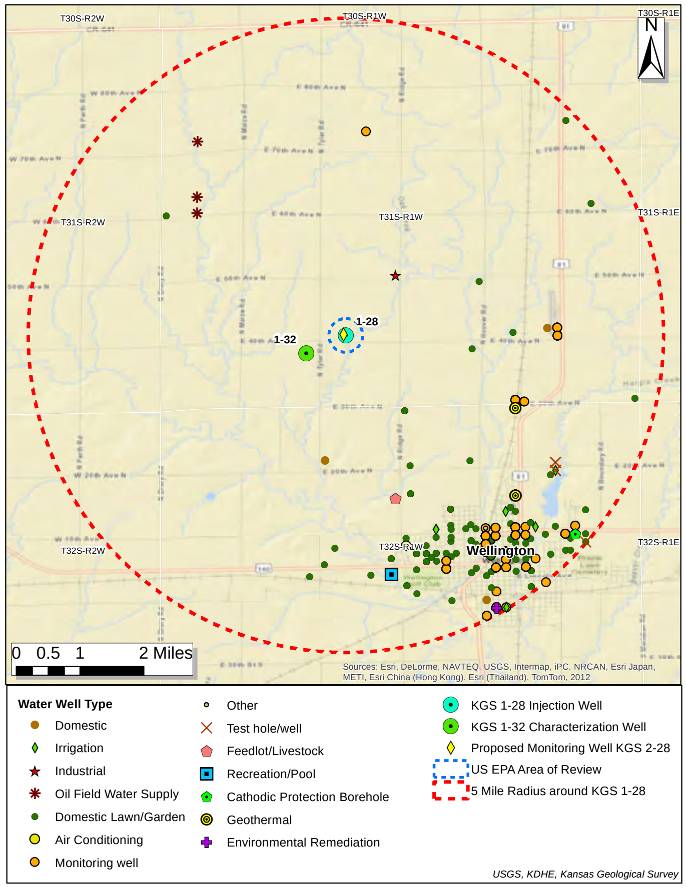


Figure 4.16—Groundwater use type in the vicinity of the Wellington storage site.

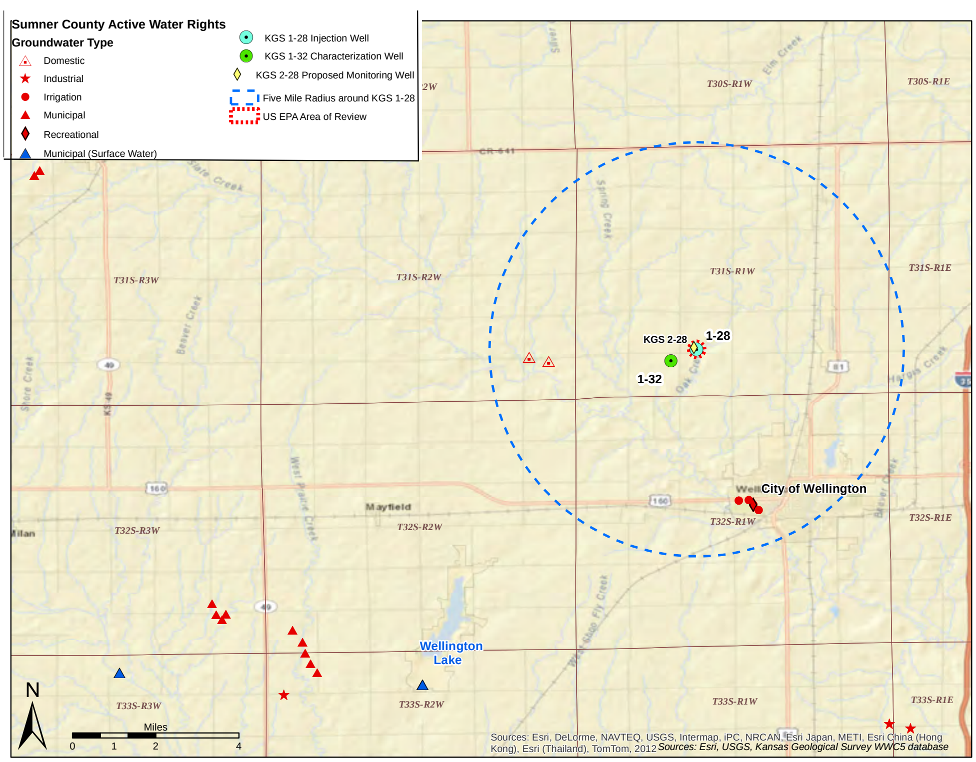


Figure 4.17—Permitted ground- and surface-water withdrawal locations for the city of Wellington, Kansas.

wells of the city of Wellington are located more than 10 mi southwest of the injection well site, as shown in Figure 4.17.

Based on reported use, an average of 28.9 acre-feet of water per year was withdrawn between 2005 and 2010 within a 5-mi radius of the injection well KGS 1-28. This equates to less than 0.01 in/yr over the 5-radial mile area, which attests to the small quantity of groundwater withdrawn

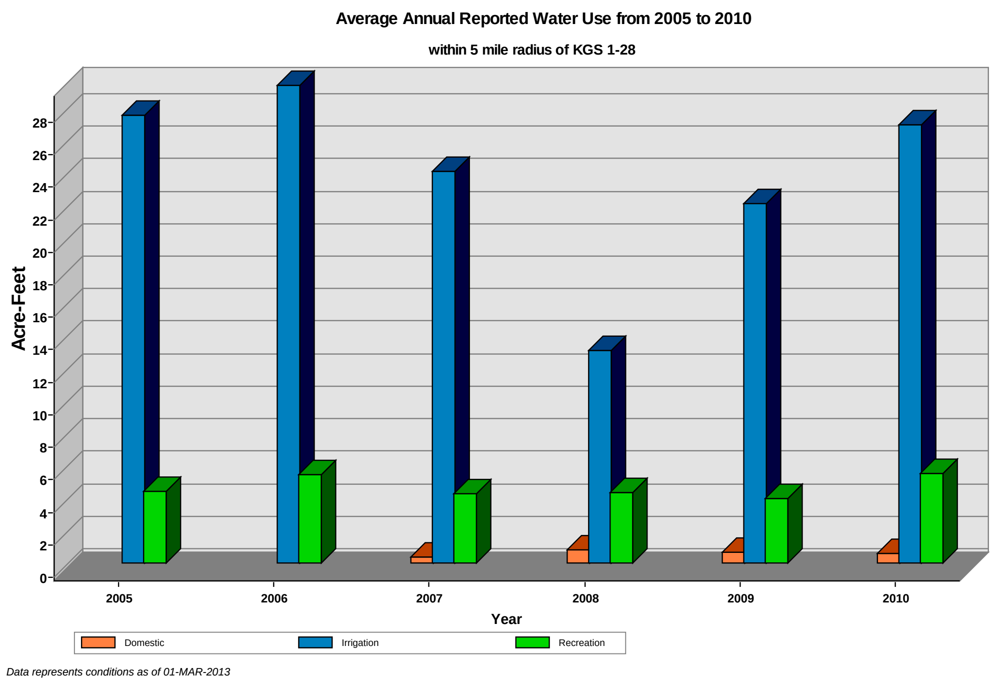


Figure 4.18—Average annual water consumption for 2005–2010 by use type within a 5-mile radius of the Wellington injection well, KGS 1-28.

in the area. Figure 4.18 presents the withdrawn water by use type and shows that most of the extracted water is used for irrigation purposes.

4.5.6 Water Quality

Figure 4.19 presents the chloride concentration in ground and surface water in samples collected primarily east and south of the well site by Walters (1961) . In the larger Wellington area, the groundwater chloride content is fairly low as most wells are shallow and draw water from the Upper Wellington and Pleistocene deposits as discussed above. The chloride content of surface-water samples from Slate Creek increased greatly from 81 ppm just southeast of Wellington to 13,700 ppm along the eastern border of Sumner County. This increase is due to dissolution of

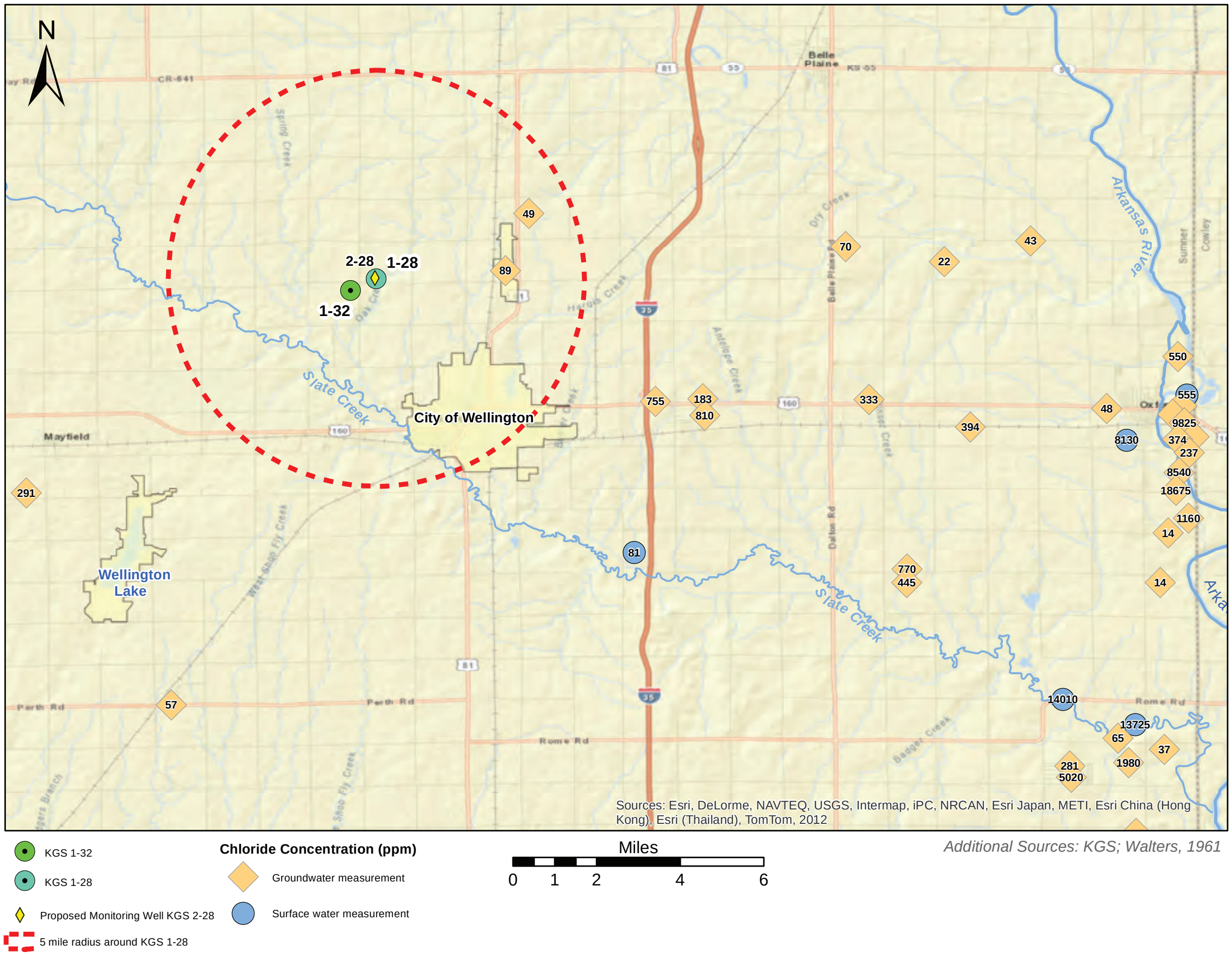


Figure 4.19—Chloride concentration in groundwater and surface-water samples in northeast Sumner County (source: Walters, 1961).

salt from the Hutchinson Salt beds and the Lower Wellington Formation, which may be incised by streams (Walters, 1961).

As discussed above, the Hutchinson Salt beds under the Upper Wellington contain salt and gypsum beds and, therefore, the water quality in the units underlying the Upper Wellington is expected to be poor, which was confirmed with resistivity logs (Section 4.4). Based on analysis of wireline logs run in KGS 1-28 and KGS 1-32, there are no known drinking water aquifers beneath the Wellington Formation containing chloride concentrations less than 10,000 ppm as discussed in Section 4.4. Water-quality samples will be collected during drilling of the new monitoring well in the Wellington Formation and the Arbuckle aquifer as discussed in Section 10 to validate the conceptualization that the Upper Wellington is the lowermost USDW.

4.5.7 Summary of USDW in the Wellington Project Area

In the Wellington area, almost all wells are less than 100 ft deep (Figure 4.13) and completed in the shallow Upper Wellington shale as water quality deteriorates rapidly with depth due to the presence of the underlying Hutchinson Salt beds. There are no known drinking water aquifers beneath the Wellington Formation in Sumner County. Based on the analyses presented in Section 4.4, the Upper Wellington aquifer is defined as the lowermost USDW as the estimated TDS is greater than 10,000 mg/l in the underlying formations. The KDHE has also designated the upper 200 ft (Upper Wellington Formation) as the lowermost USDW in the area (Richard Harper, KDHE, personal communication with Jennifer Raney of KGS, dated 2/14/2013). The water-quality samples to be collected during drilling of the new Arbuckle and the Wellington monitoring wells discussed in Section 10 will be used to validate the selection of the Upper Wellington aquifer as the lowermost USDW at the site.

4.6 Arbuckle Aquifer (Injection Zone)

4.6.1 Geology and Stratigraphy

The Arbuckle Group is of Late Cambrian/Early Ordovician age as shown in Figure 3.1a, during which period the study area was part of an epicontinental sea with a warm and humid climate. The dominant sediment deposited was calcareous mud, which later lithified into limestone during periods of sea recession and was further altered into dolomite as a result of fresh waters rich in magnesium and calcium mixing with the local marine waters (Jorgensen 1986).

As shown in Figure 4.1, the top of the Arbuckle in the Wellington area is at a depth of approximately 4,170 ft, which is well below the 2,500+ ft depth required for maintaining CO_2 in the supercritical state. The Arbuckle strata at the Wellington site is limited to the early Ordovician portion of the Arbuckle Group with the Gunter Sandstone Member present at its base and not the Cambrian Reagan Sandstone. The Precambrian (Proterozoic to be more precise in terms of geologic age) granite basement beneath the Arbuckle aquifer is at approximately 5,160 ft below ground, and this unit is expected to provide basal confinement, which should prevent CO_2 from migrating downward.

As shown in Figure 4.1, the Arbuckle extends from approximately 4,170 ft to 5,160 ft and is located approximately 3,900 ft below the USDW (Upper Wellington Formation) at the Wellington storage site. A side-by-side comparison of the geophysical logs and formation at wells KGS 1-28 and KGS 1-32 (Figure 4.20), which are approximately 3,500 ft apart, shows remarkable similarity at the two sites. The logs confirm the presence of the granitic basement, the Arbuckle Group, the confining zone (consisting of the Simpson Group, the Chattanooga Shale, and the Pierson formation), and the Mississippian System at approximately the same elevation at both sites.

Core samples were obtained from the bottom 1,600 ft (3,540–5,179 ft, MSL) at KGS 1-32 (Figure 4.21), which spans from the granitic basement up into the Cherokee Shale. The cored section within the Arbuckle dolomite exhibits diverse lithologies, including the following:

- very porous medium pelleted dolomitic packstones and coarse grainstones (4,380 ft),
- tightly cemented peloidal dolomitic packstones with no porosity, vugs, or fractures (4,530 ft),
- dense micritic dolomite (4,640 ft),
- dolomitic breccias with discontinuous solution-enhanced fractures (4,740 ft), and
- micritic dolomitic mudstones with millimeter-sized pyrite clusters and fossil fragments (4,805 ft). Fractures are common but are characteristically vertical, short, unconnected, and bedding constrained (Scheffer, 2012).

Based on examination of core and geophysical logs, the description of the Arbuckle Group members—i.e., the undifferentiated Jefferson City–Cotter dolomites (JCC), Roubidoux, and undifferentiated Gasconade dolomite–Gunter sandstone—is presented below. The Eminence dolomite typically encountered at the base of the Arbuckle (Figure 3.1a) is not present in the study area.

Jefferson City–Cotter dolomite (JCC)

The rocks of the Jefferson City–Cotter dolomite (JCC) were described by Zeller (1968) as consisting mainly of coarsely granular, cherty dolomite with the upper part of the unit being oolitic chert transitioning to tripolitic chert toward the base of the unit. An examination of the KGS 1-32

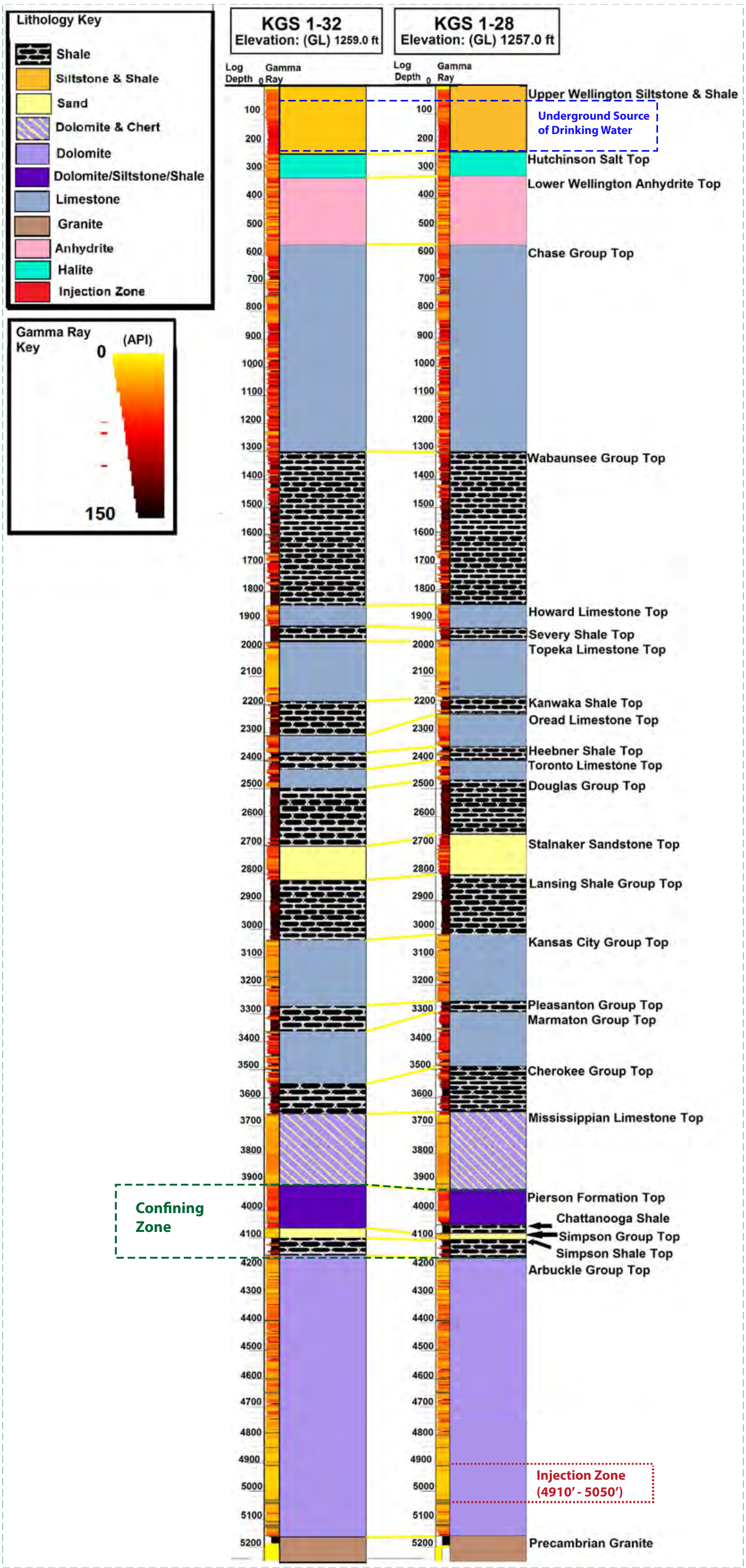


Figure 4.20—Comparison of geophysical logs and stratigraphy at KGS 1-28 and KGS 1-32.

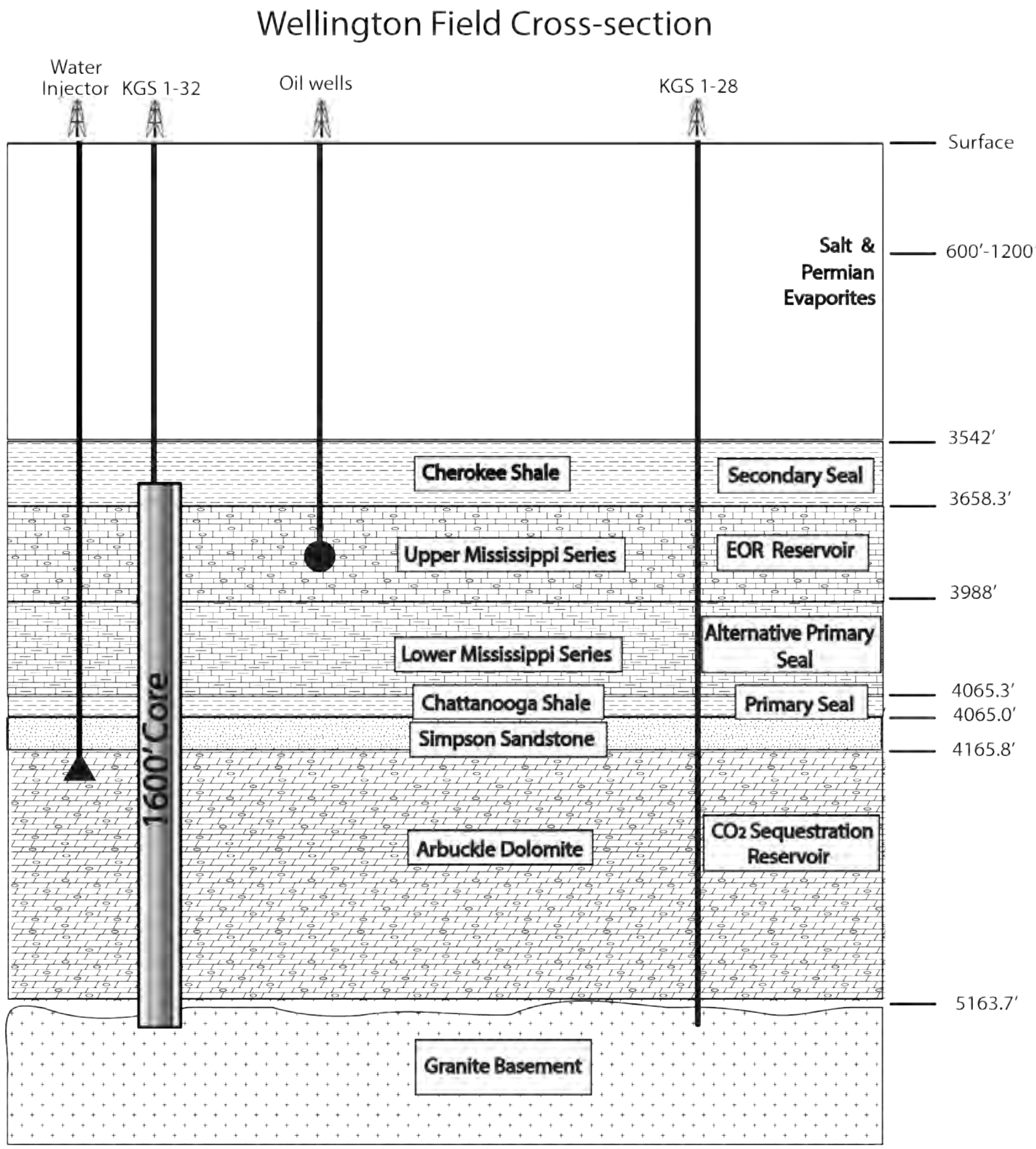


Figure 4.21—Geologic units at KGS 1-32 from which core samples were obtained for formation characterization and determining petrophysical properties.

core indicates the JCC is nearly 485-ft thick, with the upper part of the unit being medium-grained packstone to grainstones interbedded with argillaceous dolomites and the lower portion being dominantly composed of micritic dolomite. Correlations between the core and geophysical, geochemical, and seismic data indicate that the lower JCC at KGS 1-32 consists of tight, dense rock (Scheffer, 2012).

Roubidoux

The rocks of the Roubidoux Formation are approximately 260-ft thick at KGS 1-32. They were described by Zeller (1968) as mainly sandy dolomite and fine-grained sandstone. The 4,655 ft to 4,680 ft and 4,900 ft core sections were not recovered, but NMR logs indicated the presence of large vugs and fractures in each of these zones, which likely caused the lack of recovery.

Gasconade Dolomite

The rocks of the Gasconade were described by Zeller (1968) as a cherty, coarsely granular dolomite with a prominent basal sandy dolomite member known as the Gunter Sandstone. The Gasconade is 251-ft thick at KGS 1-32 and rests unconformably on the Precambrian basement at a depth of 5,160 ft. The 4,997.6 ft to 5,049.5 ft core section could not be recovered, and NMR logs indicated the presence of large vugs and fractures in this zone, which likely caused the lack of recovery.

Figures 4.22 and 4.23 present the elevation of the top and the base of the Arbuckle Group in Sumner County. Figure 4.24 presents the thickness of this group, which shows a thickness of approximately 1,000 ft at the injection site. Geophysical logs at KGS 1-28 and KGS 1-32 also indicate a thickness of 1,000 ft at these sites

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4.6.2 Hydrogeologic Zones in the Arbuckle Group and Associated Mineralogy

The core samples along with geophysical logs, geochemical information, laboratory-based estimates of permeability, and seismic data all indicate the presence of three distinct hydrogeologic zones within the Arbuckle: a tight (low impedance) baffle zone in the middle and relatively more permeable zones above and below the baffle zone. The various lines of evidence in support of this characterization are presented and discussed below.

The three hydrogeologic zones can also be deduced from the gamma-ray log at the injection site, KGS 1-28 (Figure 4.25): a high-porosity medium pelleted dolomitic packstone and grainstone at the top from 4,168 to 4,290 ft (refer to Figure 4.26 for representative core sample)

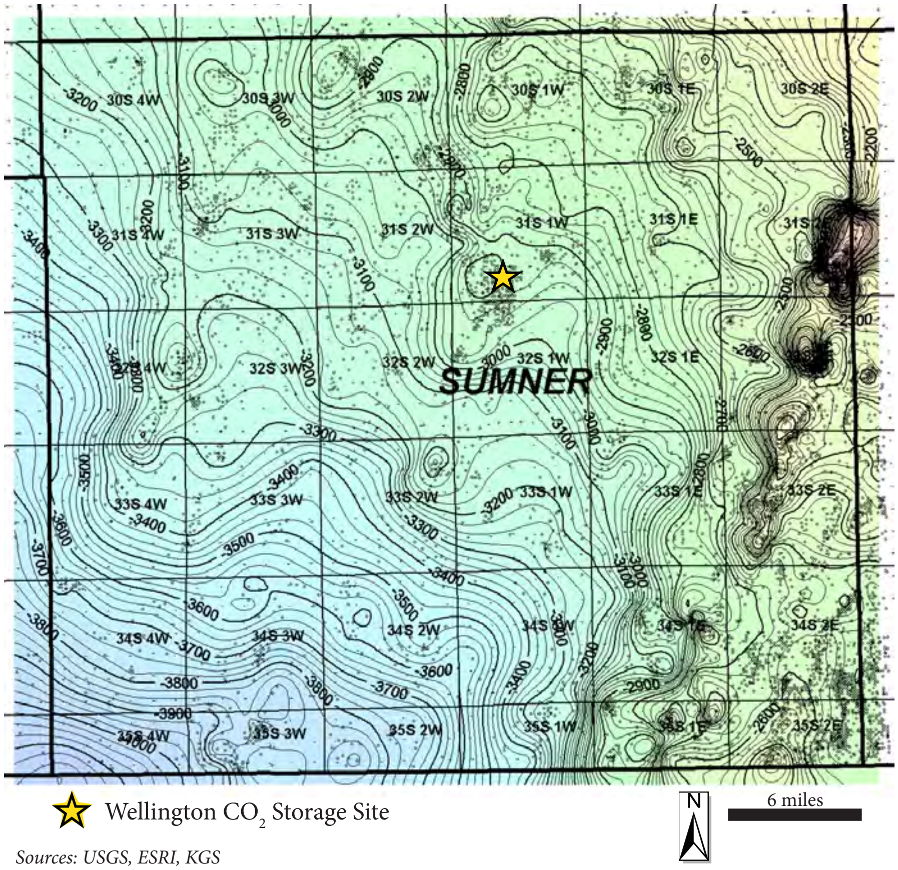


Figure 4.22—Elevation (ft, MSL) to top of Arbuckle Group in Sumner County, Kansas. (Source: KGS database.)

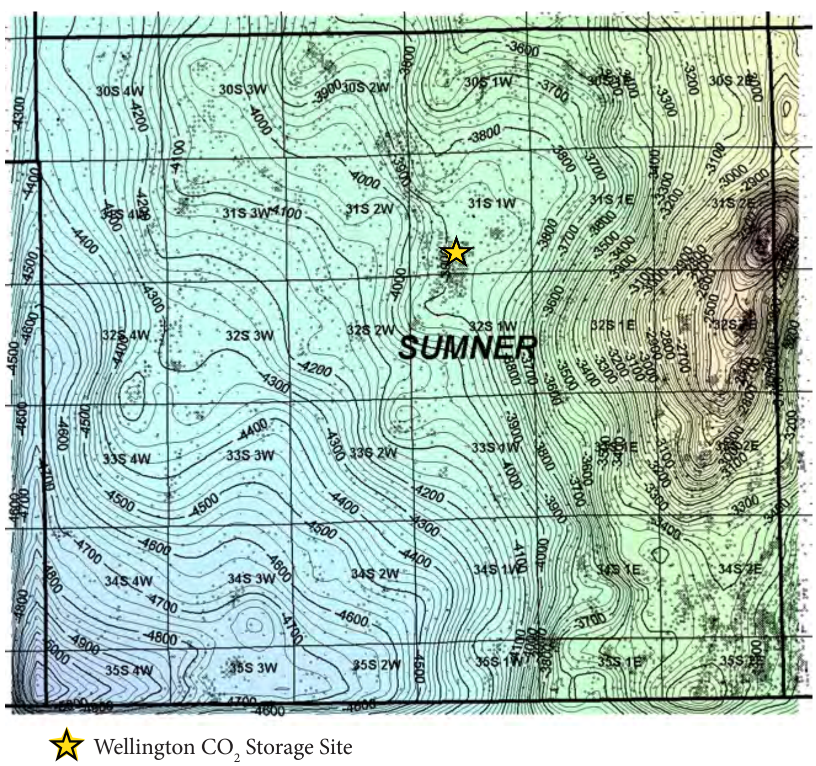


Figure 4.23—Elevation (ft, MSL) to base of Arbuckle Group in Sumner County, Kansas.

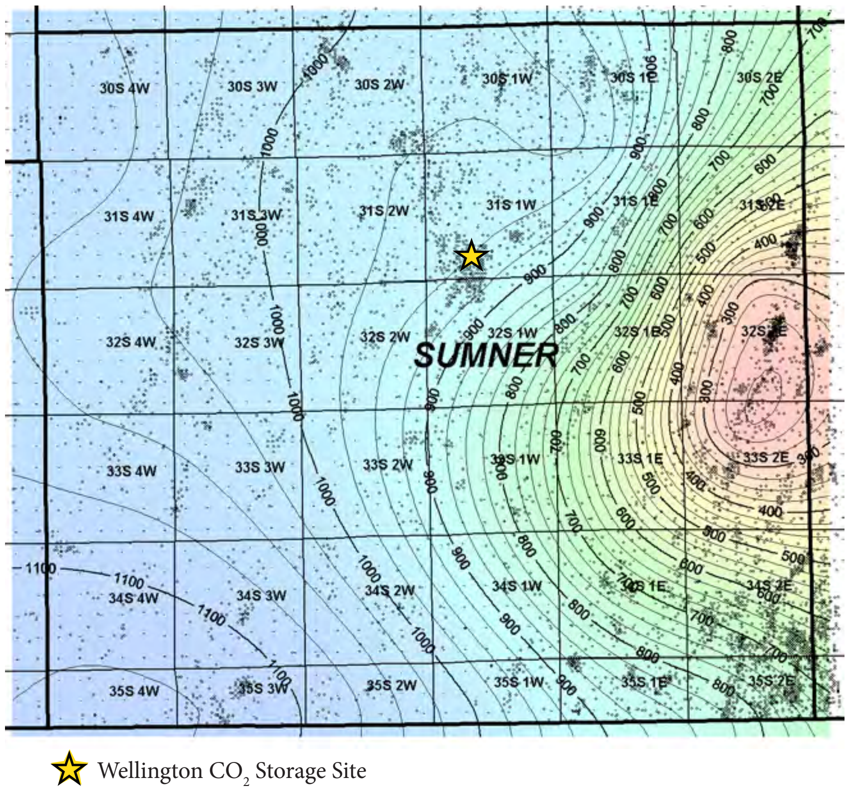


Figure 4.24—Thickness (ft) of Arbuckle Group in Sumner County, Kansas.

within the upper JCC; a tight, dense, micritic dolomite zone in the middle within the middle and lower JCC and Roubidoux Formation; and dolomitic breccias, packstones, and grainstones with discontinuous solution-enhanced fractures in the bottom approximately 100+ ft in the Gasconade.

An examination of the cored section of KGS 1-32 showed the Arbuckle Group is mostly cherty dolomite (SiO_2 and $CaMgCO_3$). Along with dolomite, microcrystalline quartz is the other most dominant mineral found within the Arbuckle Group (Scheffer, 2012). The mineralogical composition in the three Arbuckle hydrogeologic zones are discussed below.

Upper Arbuckle

The upper Arbuckle lies in the upper zones of the Cotter and Jefferson City Dolomite. It contains several high-permeability intervals as discussed in Section 4.6.6.2. The upper Arbuckle consists of low-porosity dolomitic mudstone and pelloidal wackestone to variably porous and permeable dolomitic grainstone and brecciated intervals that contain interparticle pores, dissolution

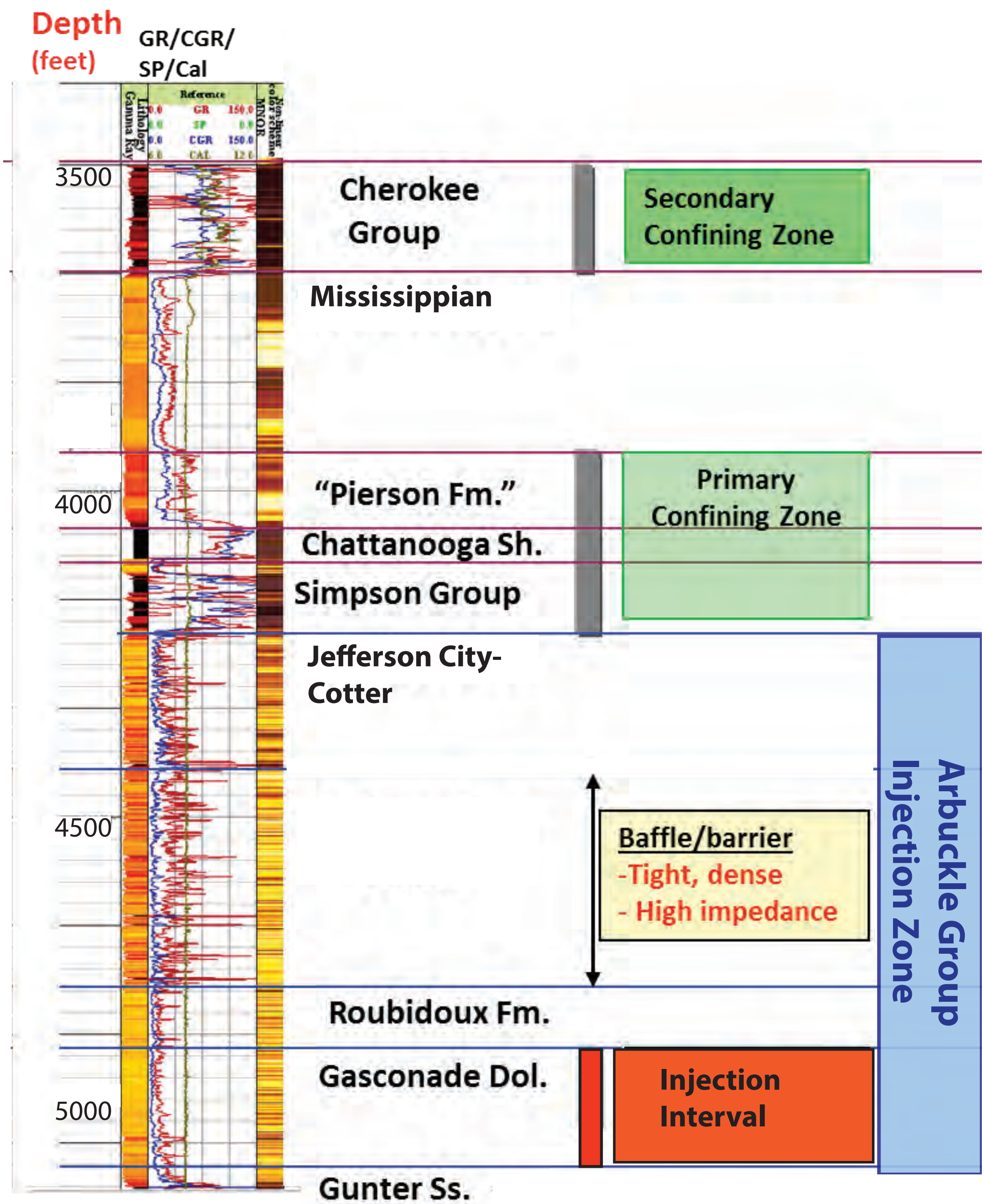


Figure 4.25—Triple Combo logs along with the synthetic seismogram and seismic impedance at KGS 1-28.

vugs of centimeter-scale, and molds of grains including intervals that are oolitic (millimeter-scale round carbonate grains). Some of the vugs range up to multiple centimeters in diameter and are partially filled by coarse dolomite crystals. Brecciated zones that resemble karst fill are developed near the top of the Arbuckle and appear to be closely linked to this major unconformity. Beds of

A
B
C

Figure 4.26—Core samples. A. upper Arbuckle (4,267–4,273 ft). B. Mid-Arbuckle Baffle Zone (4,491–4,497 ft). C. Lower Arbuckle injection zone (4,918–4,924 ft).

shaly dolomitic mudstone are present but are minor in comparison to the dominant clear dolomitic carbonate. Fractures vary in abundance and augment the matrix porosity in the more porous intervals. Overall, the upper Arbuckle consists of meter-scale bedding presenting very shallow water marine deposition. The strata consist of shallowing upward successions that are often capped with diagnostic features, such as increased vug and brecciation, that indicate the strata were intermittently weathered and that carbonate dissolution occurred. Minor anhydrite and brecciated textures suggest that evaporite-containing layers were present and were subsequently dissolved, resulting in this stacked, layered porosity system. Silica in the form of chert is common throughout this predominately dolomitic carbonate. Some of the chert is vuggy and microporous, contributing to total porosity of this distinct hydrostratigraphic unit.

Mid-Arbuckle Baffle Zone

The mid-Arbuckle baffle zone lies in the middle and lower parts of the JCC Dolomite. It consists of tight, dense, micritic dolomite and contains multiple low-permeability intervals as discussed in Section 4.6. Extensive pore space silicification and infilling by argillaceous material has been observed in thin section and could be a major factor controlling porosity reduction in the baffle zone. Geochemical data confirm high Si concentration throughout the baffle zone with some depths showing extensive silicification (Figure 4.27a). The

Baffle Zone

(4515.3 ft)

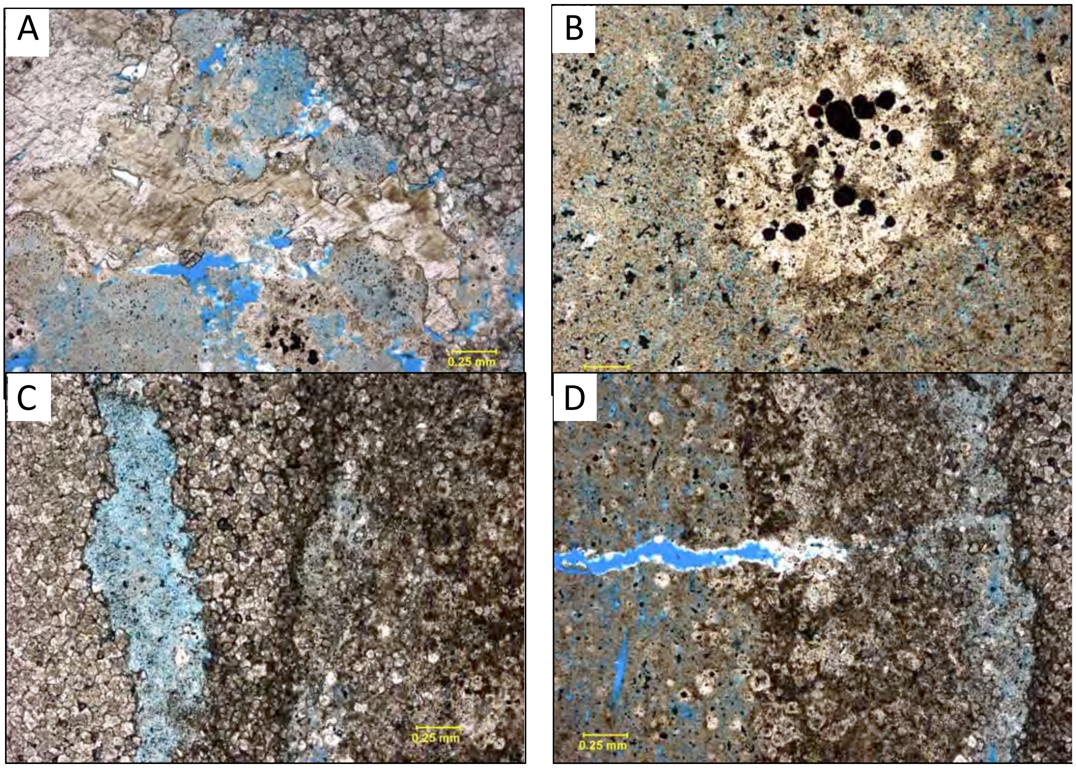


Figure 4.27a—Coarse- to fine-grained intergrowth of crystalline dolomite with subhedral to anhedral habit in mid-Arbuckle baffle zone (4,513.3 ft sub-KB). Some areas of fine-grained dolomite with silicified porous matrix (B). Chert nodules (0.5mm) with pyrite in porous, silicified matrix (B). Zone of porous argillaceous/silicic material with abundance of opaque oxide/sulfide minerals (pyrite) (C and D). Dissolution of large-grained dolomite evident in A, with porous silica infilling around dolomite crystals.

potential of a geologic baffle, or low-permeability zone, within the Arbuckle has important implications for the movement of the injected $CO_{2.}$ As the CO_2 plume migrates vertically, it could be trapped within or under the baffle. This would slow the vertical migration and increase the reactivity of the plume as it has a longer time to dissolve into brine and react with minerals. Such an outcome was observed in the model simulations results discussed in Section 5.

Lower Arbuckle

The formation minerals in the lower Arbuckle (injection zone) will be the first to react with CO_2. This zone is predominantly dolomite occurring as dolomicrite, coarsely to finely crystalline anhedral to subhedral replacement mosaic, fracture and pore filling, and saddle dolomite (Fig-

Injection Zone

(4949.4 ft)

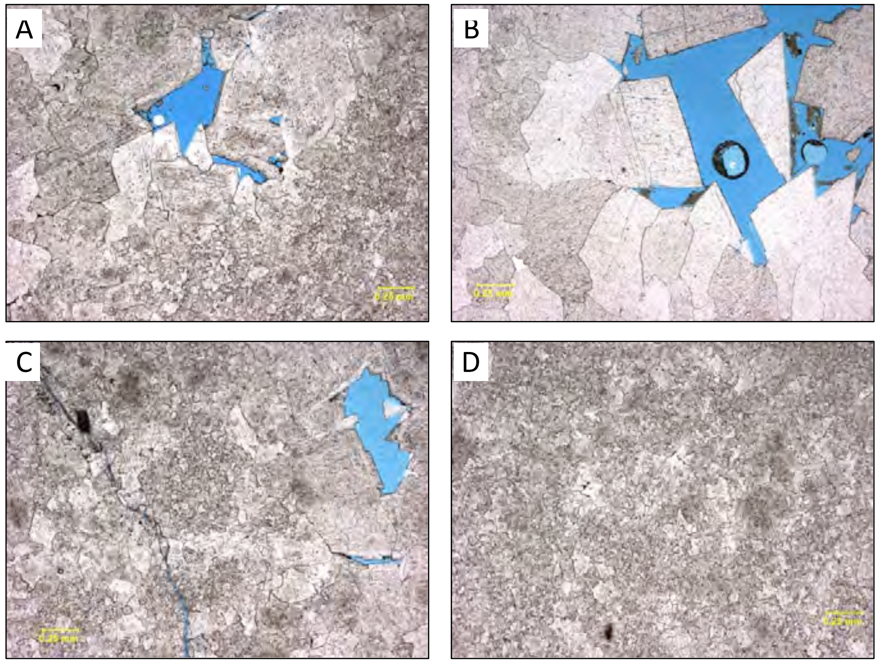


Figure 4.27b—Fine- to coarse-grained crystalline dolomite grains with subhedral to anhedral habit (replacement mosaic) (D) in lower Arbuckle injection zone (4,949.4 ft sub-KB). No distinct zones of separation between fine- and coarse-grained dolomites. Some large euhedral dolomite are noticed in porous zones (B). Isolated intercrystalline porosity throughout (C and A). A few zones of opaque oxide/sulfide infilling the pores around dolomite. No silicification evident at this depth.

Injection Zone

(4967.5 ft)

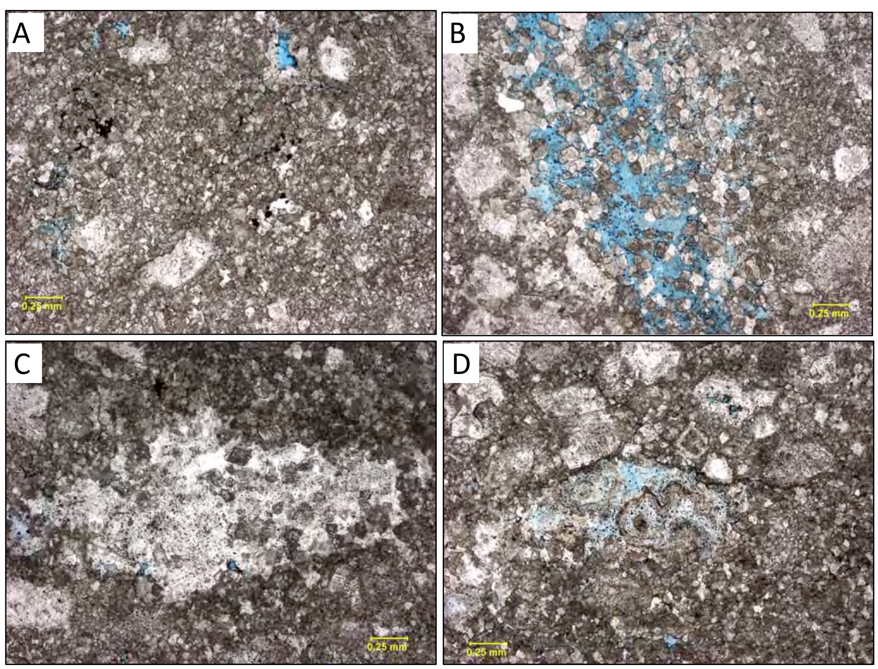


Figure 4.27c—Fine- to coarse-grained intergrown crystalline dolomite mosaic with subhedral to anhedral habit in lower Arbuckle injection zone (4,967.5 ft sub-KB). Coarse- and fine-grained dolomite are well mixed and do not appear in distinct zones (all). Chert/chalcedony is observed infilling porosity with some 2.5 mm nodules of microcrystalline chert (C). Matrix of dolomicrite in some areas. Some opaque oxide/sulfide minerals throughout. Peloids visible in some porous zones (D). Low fracture and isolated intercrystalline porosity.

ure 4.27b-c). Microcrystalline quartz is common, increasing in abundance toward the base of the lower injection zone, and is particularly high between 4,950 and 5,030 ft. Unlike the baffle zone, though, high silica in the injection zone corresponds with high-porosity values due to the presence of extensive silica microporosity (Scheffer, 2012). Microporous regions have high surface area, which increases reaction rates that could lead to rapid dissolution. CO_2 could become more soluble in brine in these zones due to increased mixing in the micropores. Preferential dissolution could occur along the silica-carbonate interface, inducing the formation of preferential pathways where injected CO_2 could flow (Barker et al, 2012).

4.6.3 Drill-Stem Tests

Drill-stem tests (DST) were conducted in both KGS 1-28 and KGS 1-32 during well construction. DST activities and details are presented in Section 8. The test intervals are shown in Figure 4.28. At the proposed injection well (KGS 1-28), four DSTs were conducted within the injection zone. At KGS 1-32, three DSTs were conducted at various Arbuckle depths, and one DST was conducted in the Mississippian formation. The results of the DSTs are presented in Scheffer (2012) and summarized in Tables 4.4 and 4.5.

Horner's plots were constructed to estimate hydraulic permeability in the DST intervals (Scheffer, 2012). As noted in Table 4.4, the estimated permeability in the proposed injection interval (i.e., the lower Arbuckle) is relatively high, exceeding 200 mD. Permeabilities are more than an order of magnitude lower for DSTs conducted outside the proposed injection zone.

The ambient fluid pressure versus depth as measured at KGS 1-32 and KGS 1-28 are plotted in Figure 4.29. The data presented in this figure indicate that if the Arbuckle pressure gradient (of approximately 0.48 psi/ft) were extended up to a depth of 3,664 ft KB in the Mississippian, the pressure should be 1,506 psi instead of the 1,048 psi measured during the DST. This indicates that the Mississippian is highly under-pressurized and further supports the hypothesis of separation of the Mississippian and Arbuckle rock units. Please refer to Section 7 for additional information about the under-pressurized Mississippian formation.

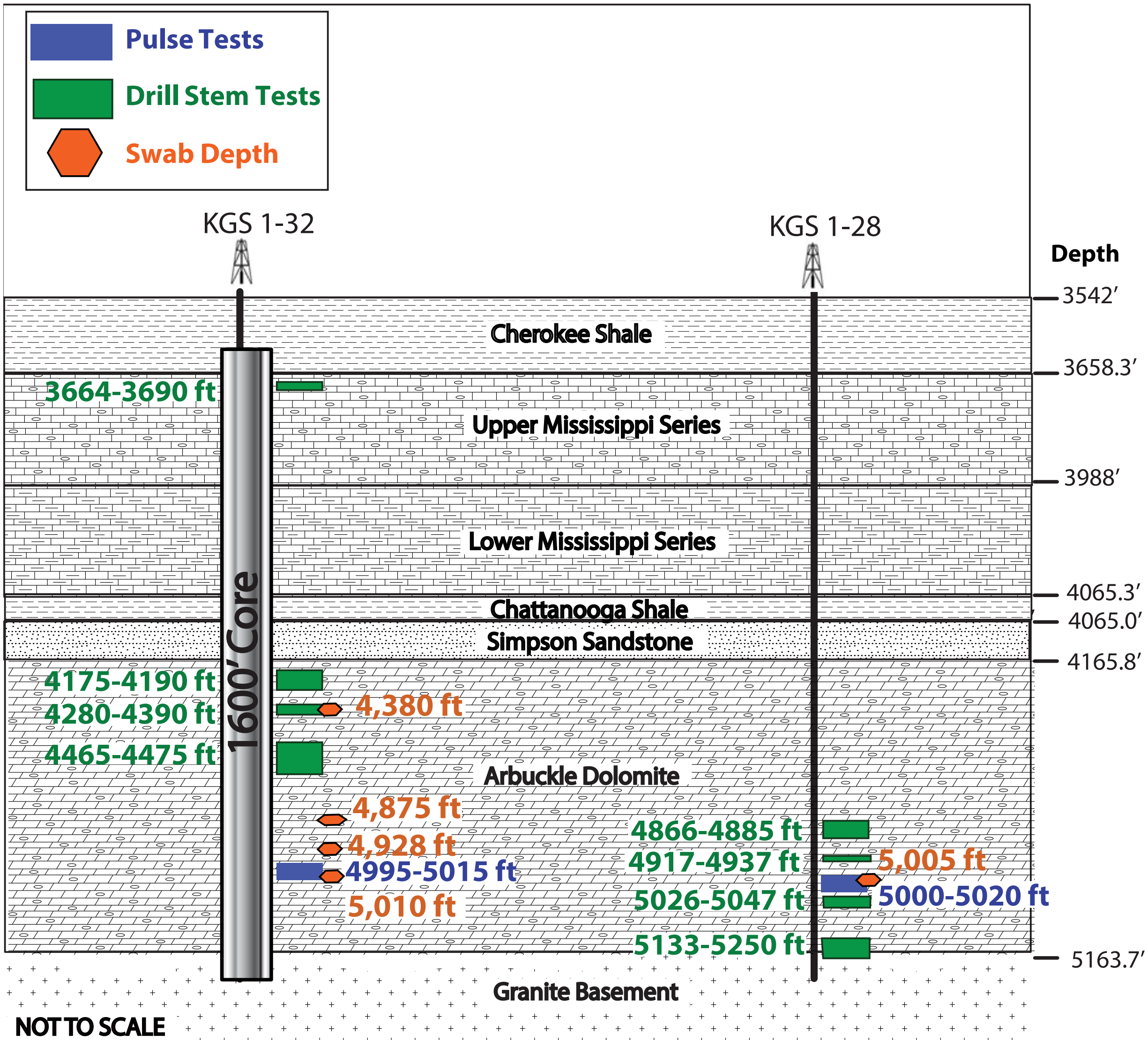


Figure 4.28—Drill-stem test interval in wells KGS 1-28 and KGS 1-32.

Table 4.4—Summary of DST data at KGS 1-28

DST Top (ft, KB)	DST Bottom (ft, KB)	Average Depth (ft, KB)	Formation	Ambient Pressure (psi)	Temperature (F)	Permeability (mD)
5,133	5,250	5,191.5	Arbuckle /Precambrian	2,189	130.5	1.3
5,026	5,047	5,036.5	Arbuckle (lower)	2,137	131.9	216.7
4,917	4,937	4,927	Arbuckle (lower	2,082	129	228.7
4,866	4,885	4,875.5	Arbuckle (lower)	2,061	130.6	––

Table 4.5—Summary of DST data at KGS 1-32

DST Top (ft, KB)	DST Bottom (ft, KB)	Average Depth (ft, KB)	Formation	Ambient pressure (psi)	Temperature (F)	Permeability (mD)
3,664	3,690	3,677	Mississippian	1,048	116.7	––
4,465	4,570	4,517.5	Arbuckle (mid)	1,867	123	––
4,280	4,390	4,335	Arbuckle (upper)	1,783	120	28.7
4,175	4,190	4,182.5	Arbuckle (upper)	1,716	116.6	2.1

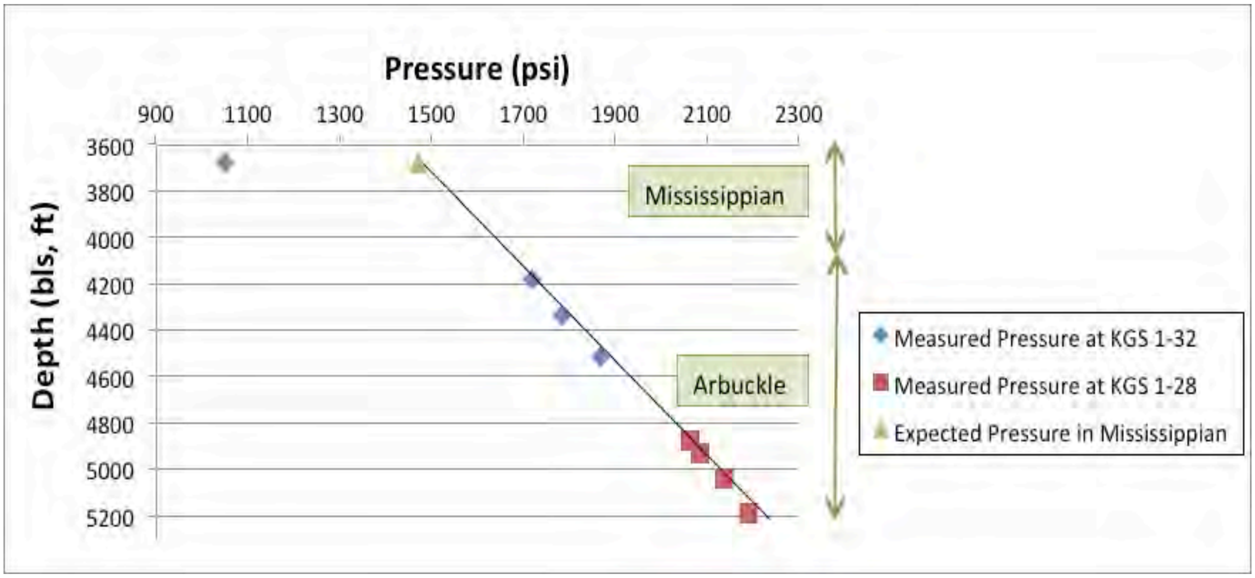


Figure 4.29—Ambient pressure distribution measured during drill-stem tests in wells KGS 1-28 and KGS 1-32.

4.6.4 Pulse Test

A pulse test was conducted at KGS 1-32 on August 23, 2010, to estimate transmissivity and hydraulic conductivity of the injection interval. A 20-ft thick flow unit (4,995–5,015 ft) was perforated in the lower Arbuckle to evaluate the potential of this interval as a viable injection zone.

Water was injected in eight cycles at increasing volumetric rates. The pulse test data were analyzed by the Fekete F.A.S.T. Well Test modeling software (Fekete, 2013). The aquifer model consists of a single 15-ft thick porous layer in the lower Arbuckle that will serve as an injection zone for CO_2. This injection interval is overlain by a low-porosity/lower permeability baffle zone, which was assumed to provide hydraulic confinement. The data were input into the software and the automatic parameter estimation option of the F.A.S.T Well Test was invoked to estimate formation properties.

As shown in Figure 4.30, results yielded a reasonably good match between the observed and simulated response at observation well KGS 1-32 with a permeability value of 250 mD. The estimated permeability is also in conformance with permeability derived from other sources, such as the DST documented in Section 4.6.3, the core, and log-based permeabilities estimated at KGS 1-32 and KGS 1-28 (refer to Section 4.6.6.2).

4.6.5 Temperature

The thermal logs at KGS 1-28 and KGS 1-32 are presented in Appendices B and C. Figure 4.31 presents a temperature profile, constructed from the temperature logs at the two sites. Interestingly, the thermal gradients are similar in both wells but the temperatures in KGS 1-28 are higher by about 10°F.

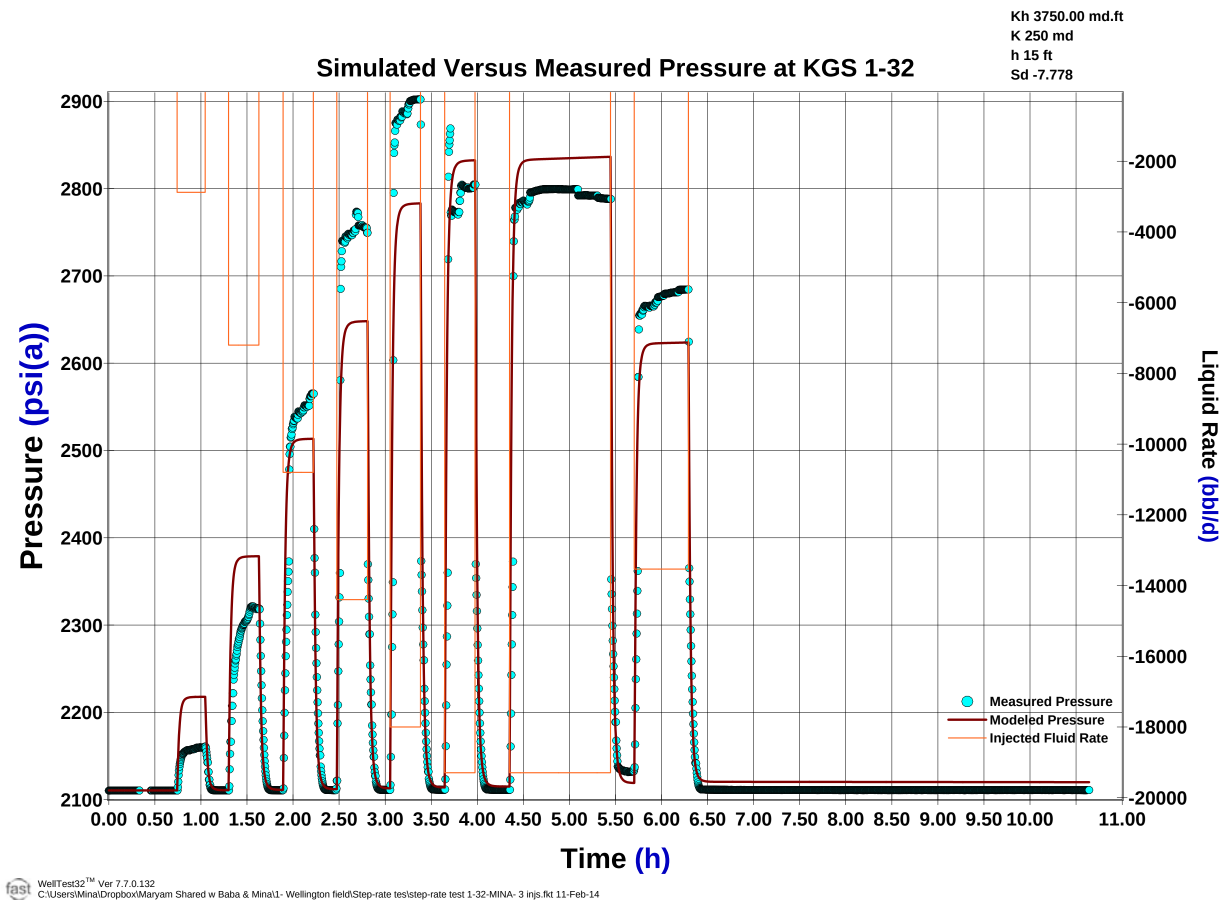


Figure 4.30—Simulated (maroon line) and observed (blue dots) pressures at injection well KGS 1-32 during pulse test conducted on 8/23/2011 at KGS 1-32. Water injection rate shown in red.

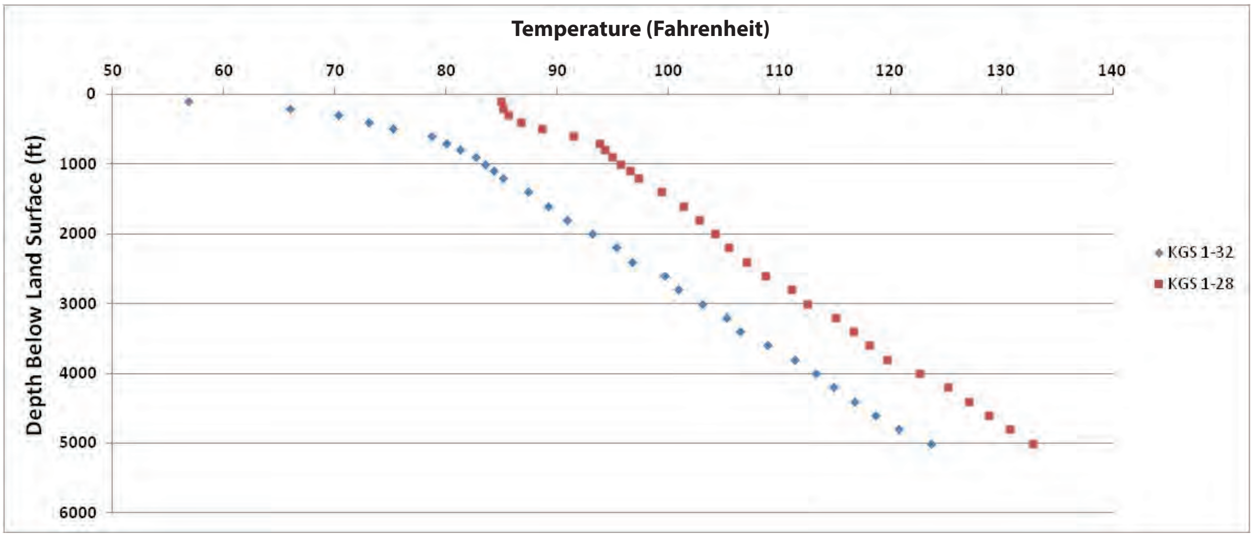


Figure 4.31—Geothermal profile at Wellington wells KGS 1-28 and KGS 1-32.

4.6.6 Petrophysical Properties

The log and core data in the Arbuckle Group indicate a heterogeneous and stratified system with highly varying permeability and porosity. As a result, the hydrogeologic properties in the reservoir simulation model discussed in Section 5 were assigned by extrapolating the petrophysical properties at KGS 1-32 and KGS 1-28 to the 3-D model domain using Schlumberger's Petrel geo-cellular software, which is discussed in Section 5.3.

A continuous vertical distribution of porosity in both KGS 1-28 and KGS 1-32 was derived using NMR logs (Figure 4.32a-b). NMR is emerging as one of the most sophisticated logging techniques for characterizing petrophysical properties. A continuous permeability profile in the Arbuckle Group (injection zone) and the overlying confining zones at KGS 1-28 and KGS 1-32 was derived (Figure 4.32a-b) using the Flow Zone Interval method of Fazelalavi (2013).

4.6.6.1 Arbuckle Porosity

Porosity is variable throughout the formation and exists due to small, isolated intercrystalline to large vuggy openings. The core-based estimate of porosity at KGS 1-32 is presented in Figure 4.32a and key statistics are specified in Table 4.6a. The porosity varies over a large interval

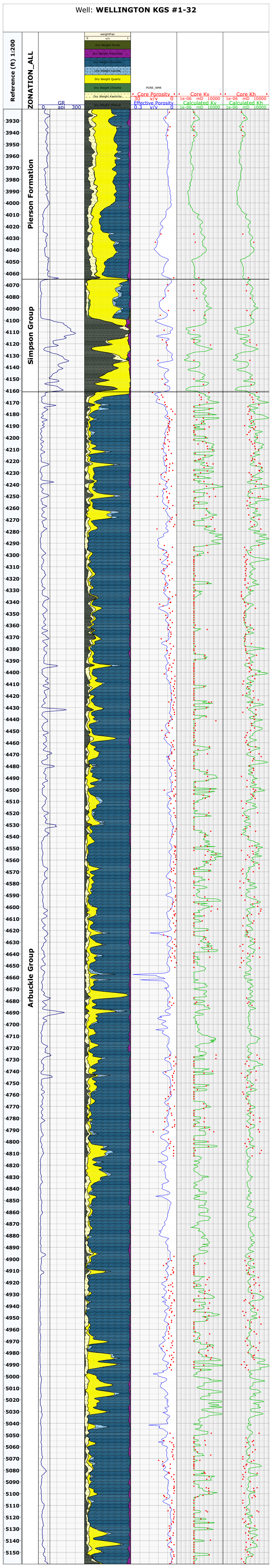


Figure 4.32a—Geophysical logs and core based estimates of porosity and permeability at KGS 1-32.

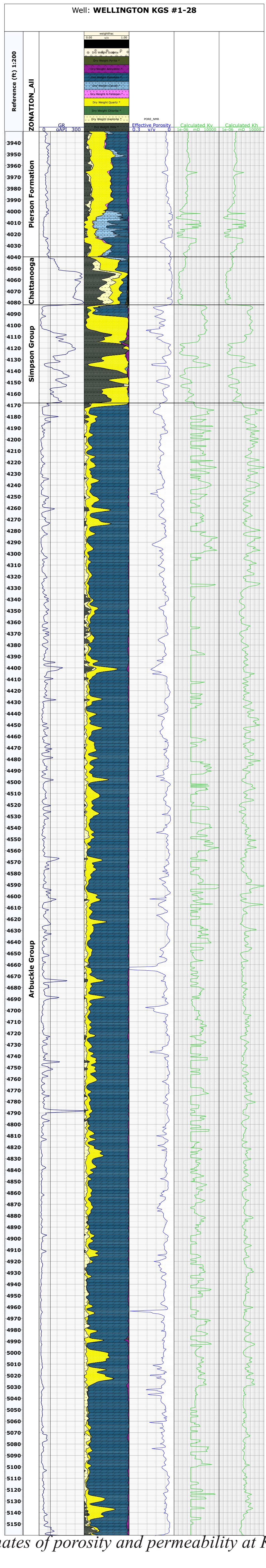


Figure 4.32b—Geophysical logs and core based estimates of porosity and permeability at KGS 1-28.

(0.3–27.3%) with an average value of 3.4%. As shown in Figure 4.32a, the porosity is highest in the upper and lower portions of the Arbuckle, and there is relatively smaller porosity in the middle Arbuckle.

Table 4.6a—Core-based porosity statistics at KGS 1-32.

Minimum	Maximum	Average	Standard Deviation
0.3%	27.3%	3.4%	5.0%

The NMR-based porosity estimates at KGS 1-28 and KGS 1-32 are presented in Figure 4.32a-b along with the core-based estimates at KGS 1-32. In general, a good match can be inferred for the core-based laboratory and log-based NMR estimates. Table 4.6b documents the minimum, maximum, and average porosity at both sites. In general, the NMR-based porosity is higher than the core-based porosity, which may be due to the tendency of core samples to be obtained in relatively firm intervals (Scheffer, 2012).

Table 4.6b—NMR-based porosity statistics at KGS 1-32 and KGS 1-28.

Well	Minimum	Maximum	Average	Standard Deviation
KGS 1-28	2.3%	34%	6.4%	2.5%
KGS 1-32	2.0%	28%	6.4%	2.4%

4.6.6.2 Arbuckle Horizontal Permeability

The horizontal permeability distribution throughout the Arbuckle Group was estimated at both KGS 1-28 and KGS 1-32 using the Flow Zone Interval approach (Fazelalavi et al., 2013) and is presented in Figure 4.32a-b. Figure 4.32a also presents the core-based estimates of permeability at KGS 1-32, which indicate a reasonable match between the core- and log-based permeabilities. The highest permeability zones are in the upper Arbuckle (4,168–4,290 ft) and in 4,990–5,030 ft within the injection interval, which should facilitate injection. The seismic data discussed in Section 4.8 also indicate high impedance in the mid-Arbuckle, suggesting the presence of high-density rocks, which correspond to the zones of low permeability observed in well logs (Scheffer, 2012).

As observed for porosity, there is a highly generalized correspondence for permeabilities at KGS 1-28 and KGS 1-32, as shown in permeability histograms at the two sites (Figure 4.33). The permeability in most of the Arbuckle Group at both sites is within the 1–10 mD range. The core-based estimates (also presented in Figure 4.33) are biased to the low end of the permeability range due to the tendency of the samples to be more easily collected in tight rock. The log-based horizontal permeability distribution is in agreement with permeability estimates for the Arbuckle obtained from various sources (Table 4.6c). Specifically, the step-rate test conducted at KGS 1-32 and documented in Section 4.6.4 resulted in a permeability of approximately 250 mD in the injection interval. This compares well with average log-based permeability of 263 mD in the injection interval at KGS 1-32, which is also listed in Table 4.6c.

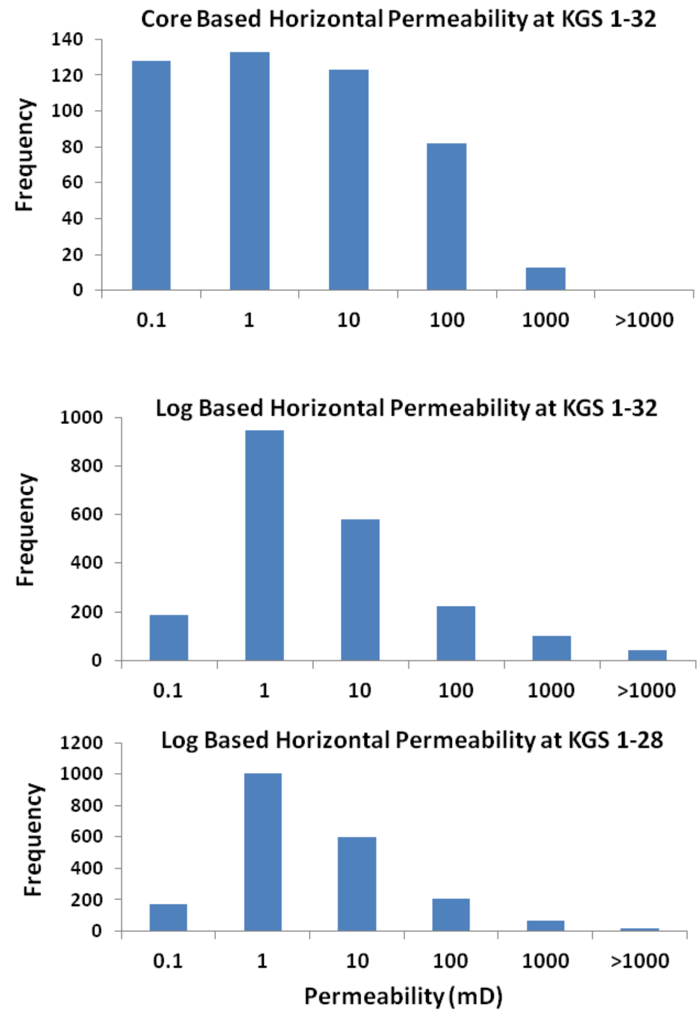


Figure 4.33—Histogram of core- and log-based horizontal permeability at KGS 1-32 and log-based horizontal permeability at KGS 1-28.

Table 4.6c—Literature-based estimates of horizontal permeability (mD) in the Arbuckle Group in Kansas.

Data Source (Reference)	Injection Interval at Wellington	Above Injection Interval at Wellington	Undifferentiated
Drill-Stem Tests at Wellington (Tables 4.4 and 4.5)	200	1–30	N/A
Step-Rate Test at KGS 1-32 (Section 4.6.4)	250	N/A	N/A
Log-Based Permeability at KGS 1-32	263		
Cutter Test Well (Appendix D)	N/A	N/A	200
Drill Stem Tests in Kansas (Carr, 1986) – 52 tests evaluated	N/A	N/A	1–755 (average permeability =134 mD)
Injection Tests at Salina and Parsons, Kansas (Carr, 1986)	N/A	N/A	100–300

4.6.6.3 Arbuckle Vertical Permeability

Figure 4.32a presents the core-based vertical permeability at KGS 1-32. As expected, there are large intervals in the mid-Arbuckle baffle zone in which the vertical permeability is 0.005 mD, which is the lower estimable limit for this parameter by the laboratory testing method. The vertical permeability in the upper Arbuckle (4,168–4,290 ft) and the injection zone within the lower Arbuckle (4,910–5,050 ft) is higher. The histograms for vertical permeability in the upper Arbuckle, mid-Arbuckle, and the injection zone are presented in Figure 4.34. The histogram for each Arbuckle zone at wells KGS 1-28 and KGS 1-32 are fairly similar, and they also quantitatively confirm the presence of a low-permeability baffle zone in between the high-permeability upper Arbuckle and the injection interval in the lower Arbuckle.

4.6.7 Geochemistry

Table 4.7 documents the baseline chemical composition of brine in the Mississippian, Arbuckle, and Precambrian basement. The Arbuckle Group, as most formations in Kansas, contains an NaCl-type brine. Arbuckle groundwater pH ranges from 5.7 to 7.1, with total alkalinity values between 67 and 403 mg/L HCO_3^-. The baseline geochemistry data in Table 4.7 will be used to track the CO_2 plume during and after injection at the Wellington site.

An analysis of the geochemical data supports the hypothesis (derived from geophysical logs and core samples) of a stratified Arbuckle system with high hydraulic permeability in the

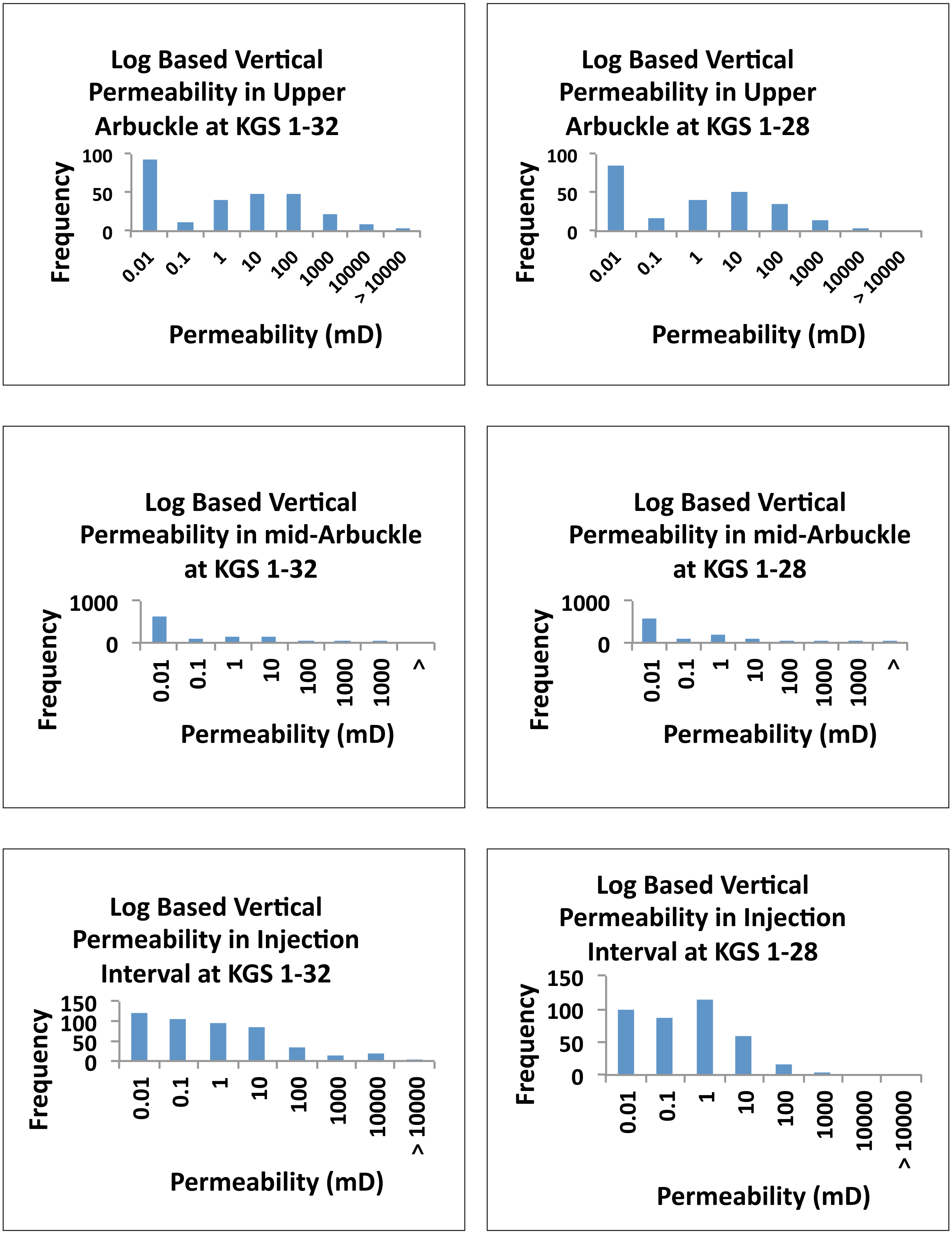


Figure 4.34—Histograms of log-based vertical permeability (mD) in Arbuckle zones at KGS 1-28 and KGS 1-32. Upper Arbuckle = 4,168–4,290 ft; mid-Arbuckle = 4,291–4,909; and lower Arbuckle = 4,910–5,050.

Table 4.7—Geochemistry from DST and swab samples.

Well	Sample Name	Formation	Depth	pH	K	Mg	Mn	Ca	Fe	Na	S	Sr	Cl	Br	SO_4	CO_3	HCO_3
			ft		mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	ug/L	mg/L	mg/L	mg/L	mg/L	mg/l
1-32	DST 1	Mississippian	3,677	*	702	1,890	0.9	11,300	0.3	58,000	233	417,000	119,000	464	703	42	*
1-32	DST 4	Arbuckle	4,182	7.1	347	347	1.2	1,500	0.1	15,900	271	55,400	30,500	80	873	192	378
1-32	DST 3	Arbuckle	4,335	6.9	424	460	.6	2,150	0.1	17,400	533	71,300	32,000	76	1,610	180	403
1-32	Swab 5	Arbuckle	4,380	6.7	398	933	3.8	3,907	12.8	25,585	*	132,335	47,598	97	986	375	244
1-32	DST 2	Arbuckle	4,520	6.4	834	880	1.1	5,030	0.1	31,500	345	158,000	65,800	120	1,060	124	256
1-32	Swab 4	Arbuckle	4,875	6.2	900	1,764	2.2	10,527	1.8	50,565	*	324,045	103,326	191	543	280	171
1-28	DST 8	Arbuckle	4,876	*	1,280	1,450	0.6	8,670	0.2	48,400	247	262,000	102,000	176	3,320	134	*
1-28	DST 7	Arbuckle	4,927	6.3	1,280	1,430	0.7	8,820	0.1	48,600	208	274,000	103,000	198	3,140	132	116
1-32	Swab 3	Arbuckle	4,928	6.2	907	1,802	3.1	10,550	11.0	49,842	*	330,609	104,390	196	478	378	159
1-28	Swab 1	Arbuckle	5,005	*	1,160	1,790	0.2	10,600	0.0	57,500	136	335,000	114,000	235	425	199	*
1-32	Swab 2	Arbuckle	5,010	5.7	961	1,910	1.3	11,784	8.7	54,791	*	383,469	106,013	226	389	155	98
1-28	DST 6	Arbuckle	5,036	6	1,430	1,630	0.8	10,300	0.1	54,300	148	334,000	118,000	235	336	74	67
1-28	DST 5	Precambrian Basement	5,183	6.8	1,080	1,160	2.2	7,310	0.2	38,300	136	253,000	84,400	190	346	*	*

* Not Analyzed

upper and lower portions separated by low-permeability baffle zones in between. Additionally, the geochemical data also supports the hypothesis of a competent (low permeability) upper confining zone as indicated by the DST pressure data, where a sharp drop of fluid pressure in the Mississippian reservoir was noted compared to the Arbuckle Group (Figure 4.29). The geochemical data and the analyses conducted to support a) the presence of high-permeability upper and lower zones in the Arbuckle and b) the hydraulic separation of the Mississippian System and the Arbuckle Group is presented below.

Figure 4.35 presents the chloride distribution in the Arbuckle and Mississippian systems at KGS 1-28 and KGS 1-32, obtained from data collected during DST and swabbing. The chloride gradient in the Arbuckle approximates a linear trend with chloride concentration increasing from approximately 30,500 mg/L in the Upper Arbuckle to as much as 118,000 mg/L in the injection zone. Chloride concentration in the Mississippian formation at 119,000 mg/L is substantially higher than in the upper Arbuckle. The large difference in chloride concentrations between the Mississippian and upper Arbuckle supports the conceptualization that the confining zone separating the Arbuckle aquifer from the Mississippian reservoir is tight and that there are no conductive faults in

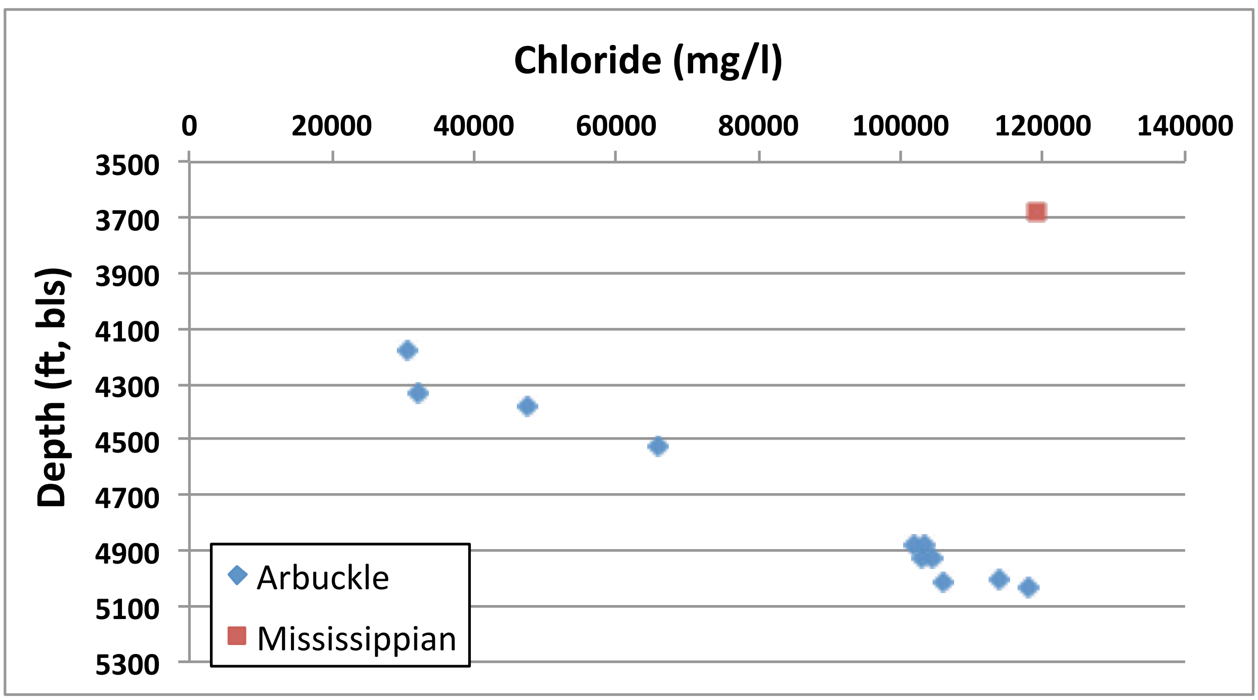


Figure 4.35—Chloride distribution within the Arbuckle aquifer and Mississippian reservoir at KGS 1-28 and KGS 1-32.

the vicinity of the Wellington site that hydraulically link the two systems. Additional geochemical data supporting the hydraulic separation of the Mississippian and Arbuckle systems is presented in Appendix E. Geochemical data and analyses conducted to support the presence of high-permeability upper and lower zones in the Arbuckle also are presented in Appendix E.

4.6.8 Arbuckle Heads

The head in the Arbuckle Group was estimated from data collected during the DSTs. The head data provide an estimate of the difference in water levels between the injection interval and the USDW. The data also may be used to evaluate potential interconnection within the Arbuckle and overlying units.

4.6.8.1 Head Distribution within the Arbuckle Group

Using the DST salinity information along with the density relationship presented in Figure 4.3, Table 4.8 presents the estimated Arbuckle heads at the DST elevations in KGS 1-32 and KGS 1-28. The equivalent freshwater head ranges between 1,130 and 1,165 ft in the lower Arbuckle, drops to approximately 1,061 ft in the mid-Arbuckle, and drops further to 1,050 ft in the upper Arbuckle. The head differential in the Arbuckle further supports the hypothesis of a low-permeability baffle zone in the middle of the Arbuckle that separates the upper and lower portions of the Arbuckle aquifer.

Table 4.8—Equivalent freshwater head in the Arbuckle Group at KGS 1-32

DST Top (ft, KB)	DST Bottom (ft, KB)	Average Depth (ft, KB)	Formation	Pressure (psi)	Chloride (ppm)	Equivalent Freshwater Head (ft, amsl)
4,465	4,570	4,517.5	Arbuckle (mid)	1,867	71,000	1,061
4,280	4,390	4,335	Arbuckle (upper)	1,783	30,000	1,050
4,175	4,190	4,182.5	Arbuckle (upper)	1,716	44,000	1,048

4.6.8.2 Head Difference between Injection Interval and USDW

The average in situ head[1] at the four DST elevations (Table 4.9) in the proposed injection interval at KGS 1-28 is equal to 4,387 ft, which is approximately 608 ft below land surface (Figure 4.36). As discussed in Section 4.5.3, the head in the USDW (the Upper Wellington formation) is less than 15 ft below land surface. Therefore, the heads in the Arbuckle aquifer would have to rise by at least 593 ft to enter the USDW via a highly permeable artificial penetration or a geologic fault. There is no evidence of the existence of any conducting fault(s) between the Arbuckle and the Upper Wellington Formation in the immediate vicinity of the Wellington storage site. If there were any conduits, such a large head differential between the Arbuckle and the USDW would not exist.

Table 4.9—Equivalent freshwater head and in situ head estimate in injection interval at KGS 1-28

DST Top (ft, KB)	DST Bottom (ft, KB)	Average Depth (ft, KB)	Formation	Pressure (psi)	Chloride (ppm)	Freshwater Density Multiplier	In-Situ Head (ft)	In-Situ Head, bls (ft)	Equivalent Freshwater Head (ft, amsl)
5,133	5,250	5,191.5	Arbuckle (lower)	2,189	88,907	1.101	4,588	590	1,130
5,026	5,047	5,036.5	Arbuckle (lower)	2,137	110,422	1.123	4,391	632	1,165
4,917	4,937	4,927	Arbuckle (lower)	2,082	102,621	1.116	4,305	609	1,148
4,866	4,885	4,875.5	Arbuckle (lower)	2,061	101,877	1.116	4,262	601	1,151

4.6.8.3 Relationship with Regional Potentiometric Surface

Figure 4.37 presents the regional potentiometric surface in the middle of the Arbuckle aquifer, from which an equivalent freshwater head of approximately 1,000 ft MSL can be inferred in central Sumner County near the Wellington storage site. Using the formation pressures from the DST tests at KGS 1-32 in which tests were conducted throughout the depth of the Arbuckle, an equivalent freshwater head of 1,061 ft MSL in the middle of the Arbuckle is derived (Table 4.8),

1 The in situ head is equal to the height of a column filled with fluid consisting of density at the measuring point. It is also equivalent to the piezometric head at the measuring point.

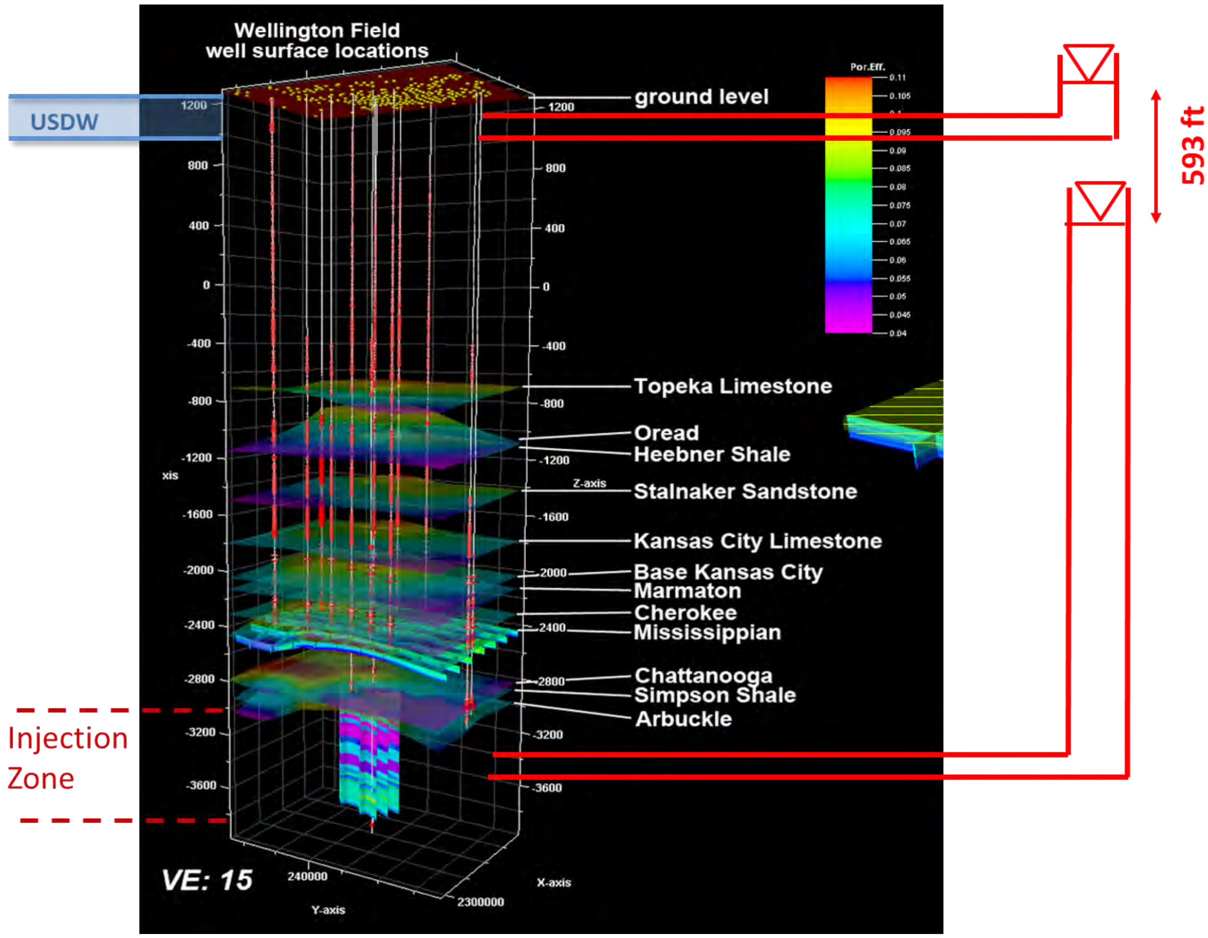


Figure 4.36—Illustration of head difference between the injection zone in the Arbuckle saline aquifer and the Upper Wellington Formation (USDW) at the proposed injection well site, KGS 1-28.

which validates the configuration of the potentiometric surface of this aquifer at the Wellington site presented in Figure 4.37.

4.6.9 Arbuckle Fracture Gradient

The fracture gradient in Kansas is typically assumed to be 0.75 psi/ft by the Kansas Department of Health and Environment for purposes of permitting Class I injection wells (KDHE, 2013). This is the default value assumed in this permit application.

An estimate of the fracture gradient at the Wellington site was also obtained using the density log and pore pressure information at the injection well site (KGS 1-28). In a tectonically

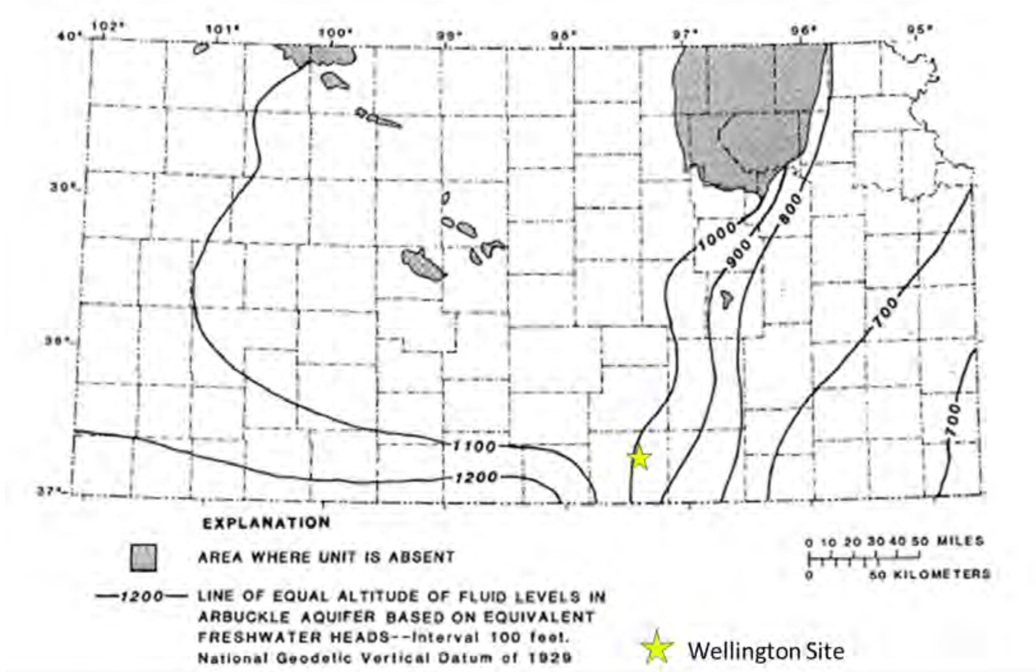


Figure 4.37—Altitude of equivalent freshwater head in Arbuckle aquifer (from Carr and others, 1986).

relaxed region such as Kansas, the fracture gradient can be estimated by Eaton's equation (Eaton, 1969), which is a function of the overburden pressure, pore pressure, and Poisson's ratio:

$$F = \left(\frac{\vartheta}{1-v}\right)\left(\frac{P_{ob} - P_p}{D}\right) + \left(\frac{P_p}{D}\right)$$

Where:

F=Fracture Gradient (psi)

ϑ = Poisson ratio

P_{ob}= Overburden Pressure (psi)

P_p=Pore Pressure of formation fluid (psi)

D = Depth (ft)

At the injection well site (KGS 1-28), a pore pressure of 2090.25 psi was measured at a depth of 5,010 ft on 8/11/2011. An average Poisson ration of 0.30 in the Arbuckle was derived from five laboratory samples (Table 6.1). Substituting these values in Eaton's equation above, a fracture gradient of 0.72 psi/ft is derived, which is fairly close to the 0.75 psi assumed for this application. As indicated in the following sections, the (model-based) maximum projected pressure gradient is less than 0.51 psi/ft.

4.6.10 Compatibility of CO_2 with Arbuckle Brine and Minerals

No compatibility problems are anticipated in the injection zone. Conclusions from preliminary modeling results indicate that the CO_2–brine formation interactions and reactions from chemical processes will have a negligible impact on reservoir porosity. Additionally, the effects of mineralization and mineral precipitation are not expected to meaningfully reduce the formation permeability. The injection interval is mainly a dolomitic peloidal packstone-wackestone becoming a cherty packstone. Zones of autoclastic breccia have also been identified. Thin-section studies reveal extensive silica micro-porosity that contributes to high porosity values in the lower injection interval and that should facilitate injection. Microporous regions have high surface areas that increase reaction rates, which may lead to rapid dissolution. Iron is a potentially important mineral in the Arbuckle that could store CO_2 by precipitating Fe carbonates such as siderite. However, the amount of mineral precipitation during the short nine-month injection period is not expected to appreciably reduce the formation permeability or porosity.

4.7 Upper Confining Zones (146.82[a][3][c], 146.83[a][2], 146.84[c][1], 146.86[b], and 146.87[b][c])

The presence and identification of the confining zone is vital for the successful injection and storage of CO_2. Without an adequate confining zone immediately above the injection zone, the buoyant CO_2 may migrate to the surface. The major sealing units immediately above the Arbuckle injection zone at the Wellington site area comprise shales and argillaceous siltstone within the Simpson Group, the Chattanooga Shale, and the Pierson formation (Figure 4.1). Therefore, for purposes of the Wellington Class VI permit application, the confining zone is defined as the interval between the base of the Simpson Group and the top of the Pierson formation. As discussed below, these units have sufficient sealing potential to confine the injected CO_2 in the Arbuckle aquifer.

The characteristics of several additional shale zones above the Mississippian Formation shown in Figure 1.8 are discussed in Section 4.7.6. The information in Section 4.7.6, however, is provided to the EPA primarily for highlighting additional sealing potential at the Wellington injection and storage site, and the applicant does not rely upon it to demonstrate confining potential for procurement of the Class VI injection permit.

The stratigraphy, hydrogeologic properties, entry pressures, and fracture characteristics of the upper confining zone are discussed below.

4.7.1 Stratigraphy of the Upper Confining Zone

The stratigraphic units at the injection well site KGS 1-28 are presented in Figure 4.1. Table 4.10 indicates the depth to each of the three units that comprise the confining zone.

Table 4.10—Depth to formations comprising the upper confining zone at the injection well site (KGS 1-28).

Formation	Depth (ft)
Top/Bottom of Pierson Formation	3,930/4,040
Top/Bottom of Chattanooga Shale	4,040/4,082
Top/Bottom of Simpson Group	4,082/4,168

Simpson Group

Approximately 85 ft of Simpson Group, consisting of interbedded sandstone and shale, lies immediately above the Arbuckle Group at the injection site. The Simpson is generally dark greenish gray dolomitic siltstone to claystone with wispy shale laminations.

Chattanooga Shale

Approximately 40 ft of tight Chattanooga Shale overlies the Simpson Group. The Chattanooga Shale is Upper Devonian to Lower Mississippian in age and exists as firm black shale at the injection site.

Pierson Formation (Lower Mississippian Series)

Above the Chattanooga is the Osagean Pierson formation in the lower Mississippian between approximately 3,930 and 4,040 ft. This formation is informally referred to as the Pierson formation since it resembles the strata present along exposures in southwest Missouri and northeast Oklahoma (Thompson, 1986; Figure 4.38). It is generally made up of reddish and greenish colored calcareous shale and dark gray argillaceous shale (Goebel, 1966). In Kansas, it is equivalent to the St. Joe Limestone Member (Figure 4.39). This formation has previously not been studied as extensively as the Simpson Group and the Chattanooga Shale in Kansas, and therefore its geologic char-

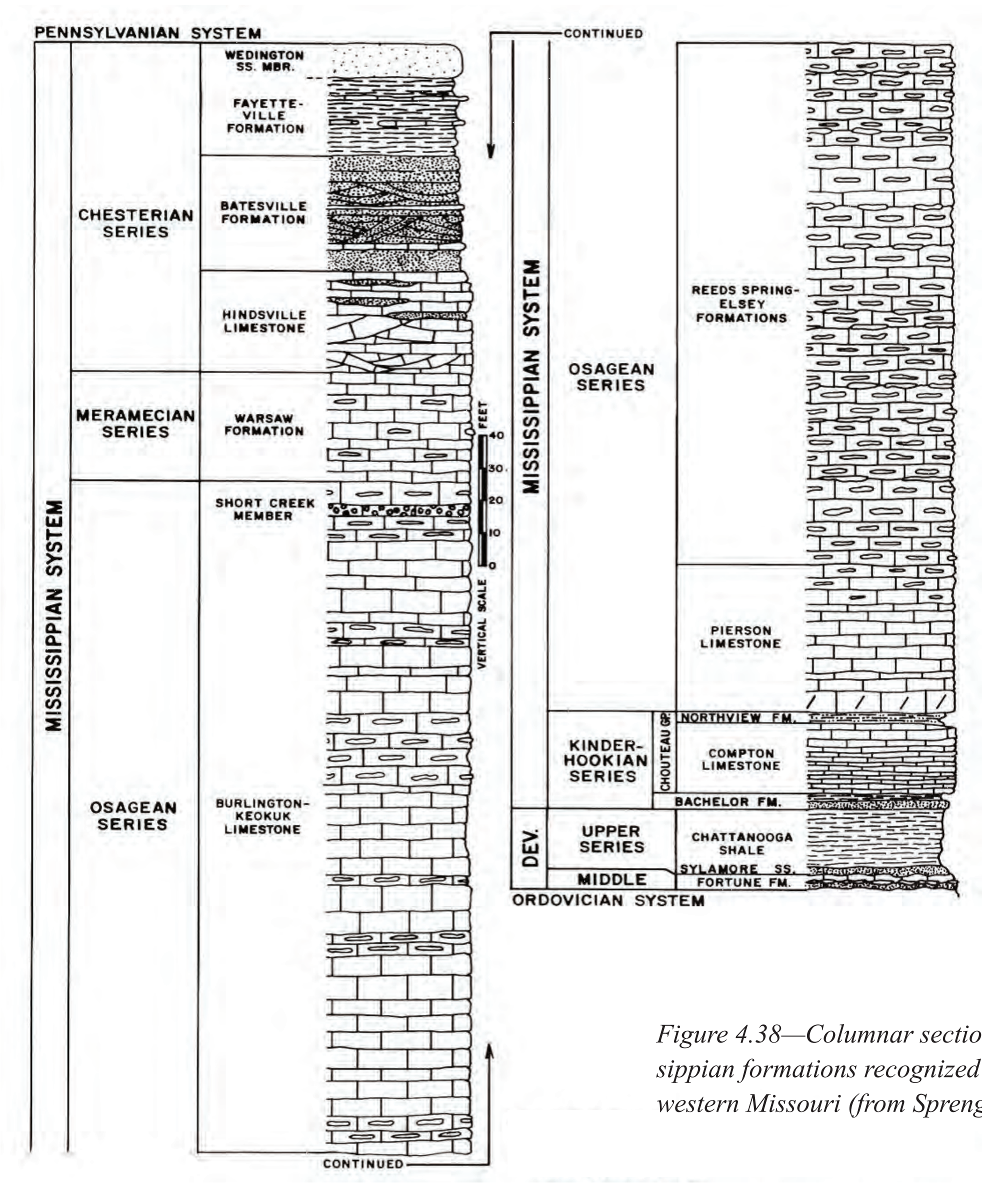


Figure 4.38—Columnar section of Mississippian formations recognized in southwestern Missouri (from Spreng, 1961).

acteristics as determined from core samples at the Wellington site are discussed below in Section 4.7.2. The Pierson formation at the storage site consists of firm, organic-bearing, argillaceous dolomitic siltstone.

The confining zone is laterally continuous at the Wellington storage site as shown in geologic cross sections presented in Figure 4.2a-d. The structure maps of the top and base of the confining zone, i.e., the top of the Pierson formation and bottom of the Simpson Group respectively, are presented in Figures 4.40–4.41. The thickness of the confining zone is presented in Figure 4.42. The presence and lateral continuity of the confining zone at the Wellington site are also evident from the seismic analyses as discussed in Section 4.8.

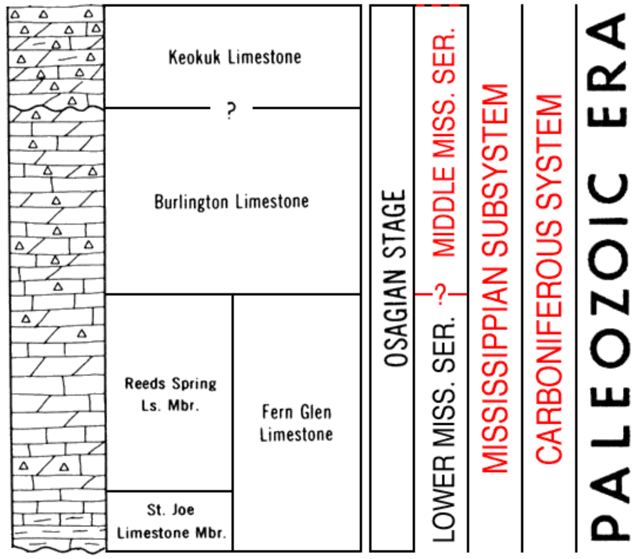


Figure 4.39—Lower and middle Mississippian formations recognized in Kansas (source: Zeller, 1968).

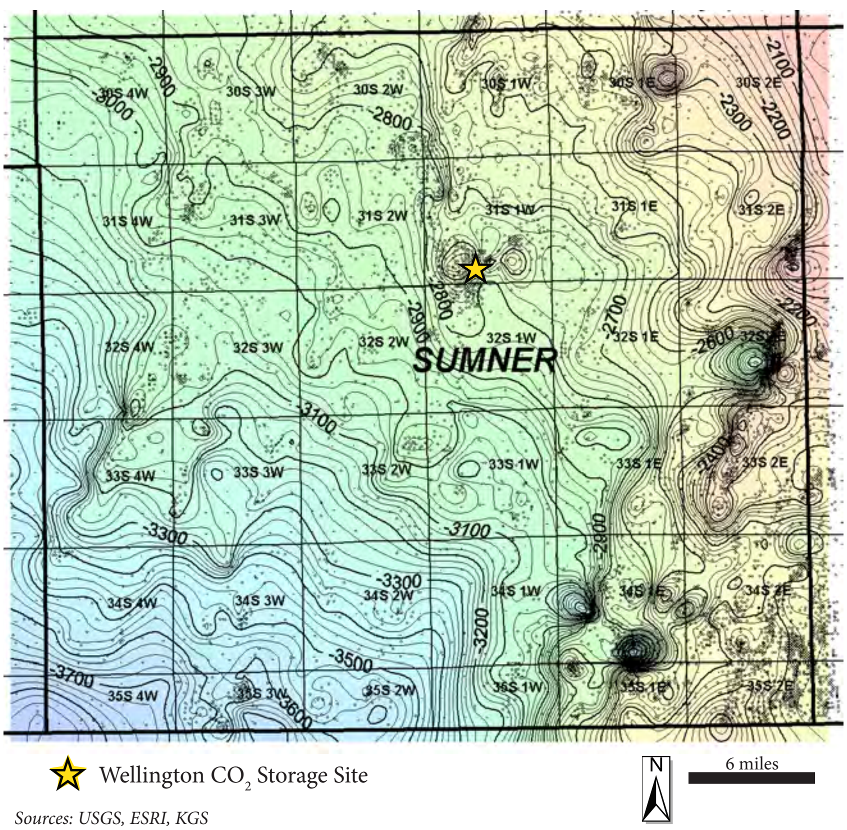
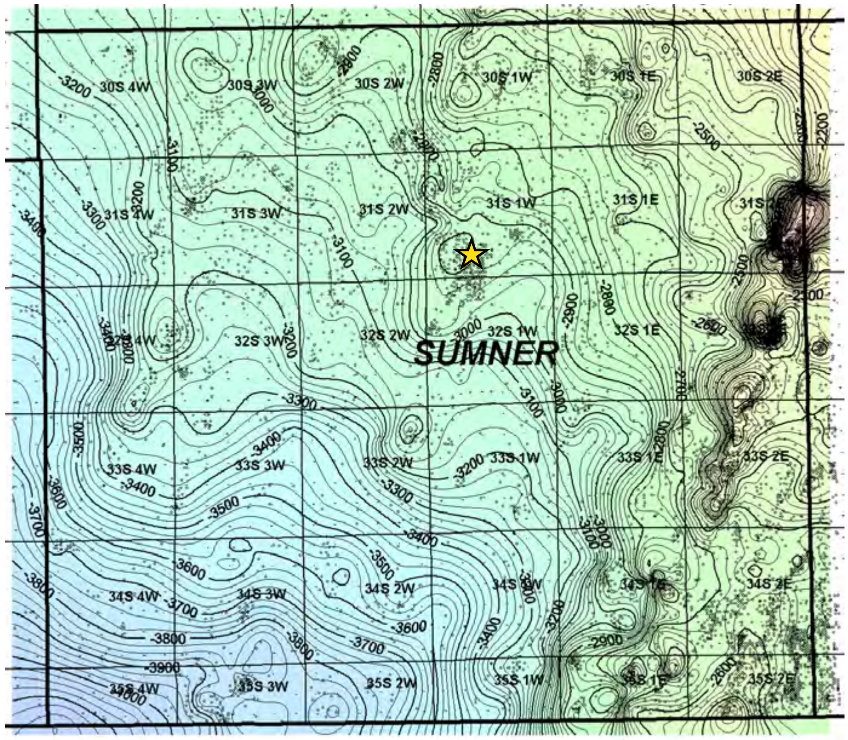
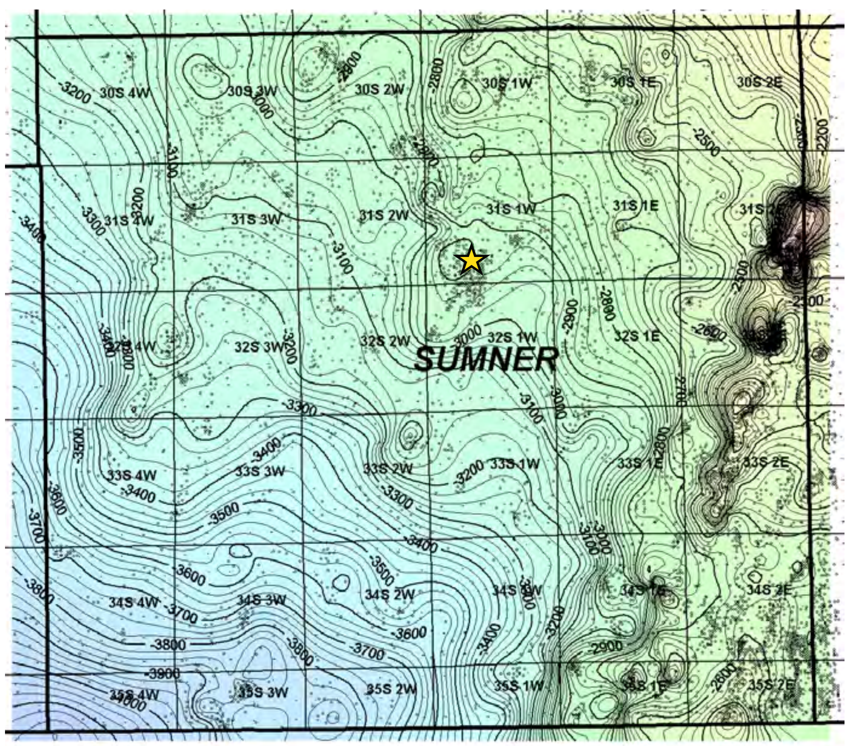


Figure 4.40 —The structure of the top of the Pierson formation at the Wellington storage site. (Source: KGS database.)



Wellington CO_2 Storage Site

Figure 4.41—The structure of the base of the Simpson Group (top of Arbuckle) at the Wellington storage site. (Source: KGS database.)



Wellington CO_2 Storage Site

Figure 4.42—The thickness of the upper confining zone (base of Simpson Group to top of Pierson formation) at the Wellington storage site. (Source: KGS database.)

4.7.2 Mineralogy and Geologic Characteristics of the Pierson Formation

The gamma ray and core-based estimates of vertical permeability suggest the potential of the Pierson to provide a high level of hydraulic confinement (Figure 4.32b). The permeability in large intervals within this group is less than 0.005 mD, which was the lower estimable limit for this parameter by the testing method employed by Weatherford Laboratories. Figure 4.43 presents the core images for the interval 3,983 to 3,992 ft (sub-KB) in the Pierson at KGS 1-32, which indicate very tight dark shale material. Helical Computed Tomography Scan images presented in Section 4.7.5.3 indicate a tight geologic medium without visual fractures. Averaging several sets of mea-

Figure 4.43—Core samples in the interval 3,983 to 3,992 ft (sub-KB) within the Pierson formation in the lower Mississippian Series at KGS 1-32.

surements, each of which was derived using a Helium Porosimeter (Scheffer, 2012), yielded a porosity of 0.5%.

Two thin sections at the elevation of 3,989.5 ft (sub-KB) are presented in Figure 4.44, which indicates the presence of clay-rich silt with organic macerals, dolomite, sponge spicule, and glauconite deposits (green). Figure 4.45 presents additional core images within the Pierson at KGS 1-32 for the interval 3,990–4,005 ft. As indicated in Figure 4.45, thin sections were obtained at elevation of 4,003.7 ft, x-ray diffractions analysis was conducted at 3,998 and 4,001 ft, and permeability tests were conducted at 4,002.6 ft. The thin-section photomicrograph (Figure 4.46) indicates the presence of a gray organic siliceous dolosiltstone with dolomite crystals, organic macerals, and clay to silt-sized quartz grains. X-ray diffraction and spectral gamma-ray analyses presented in Appendix F confirm that the Pierson rock is mainly fine silt-sized quartz with scattered dolomite crystals.

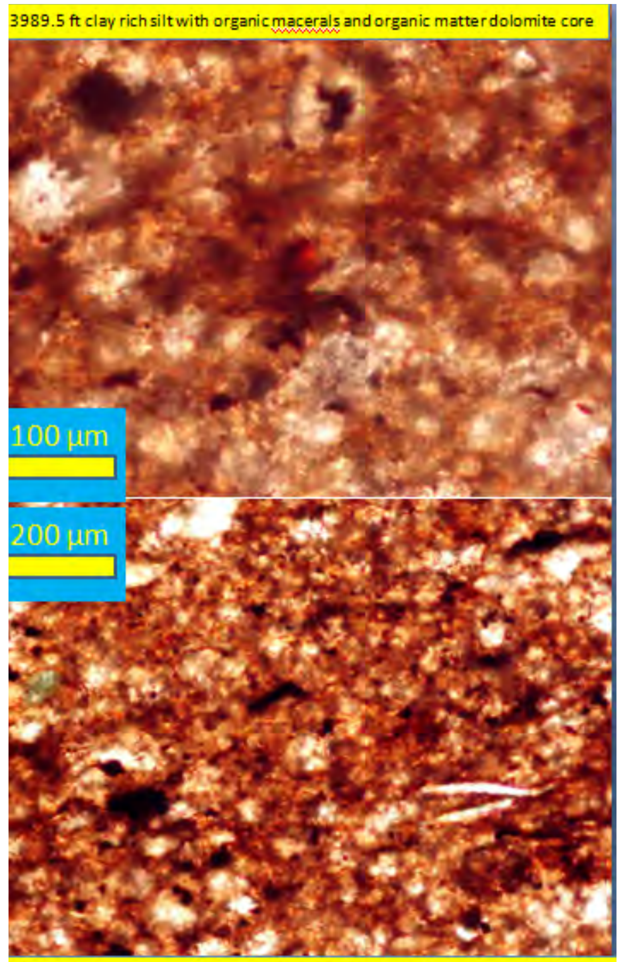
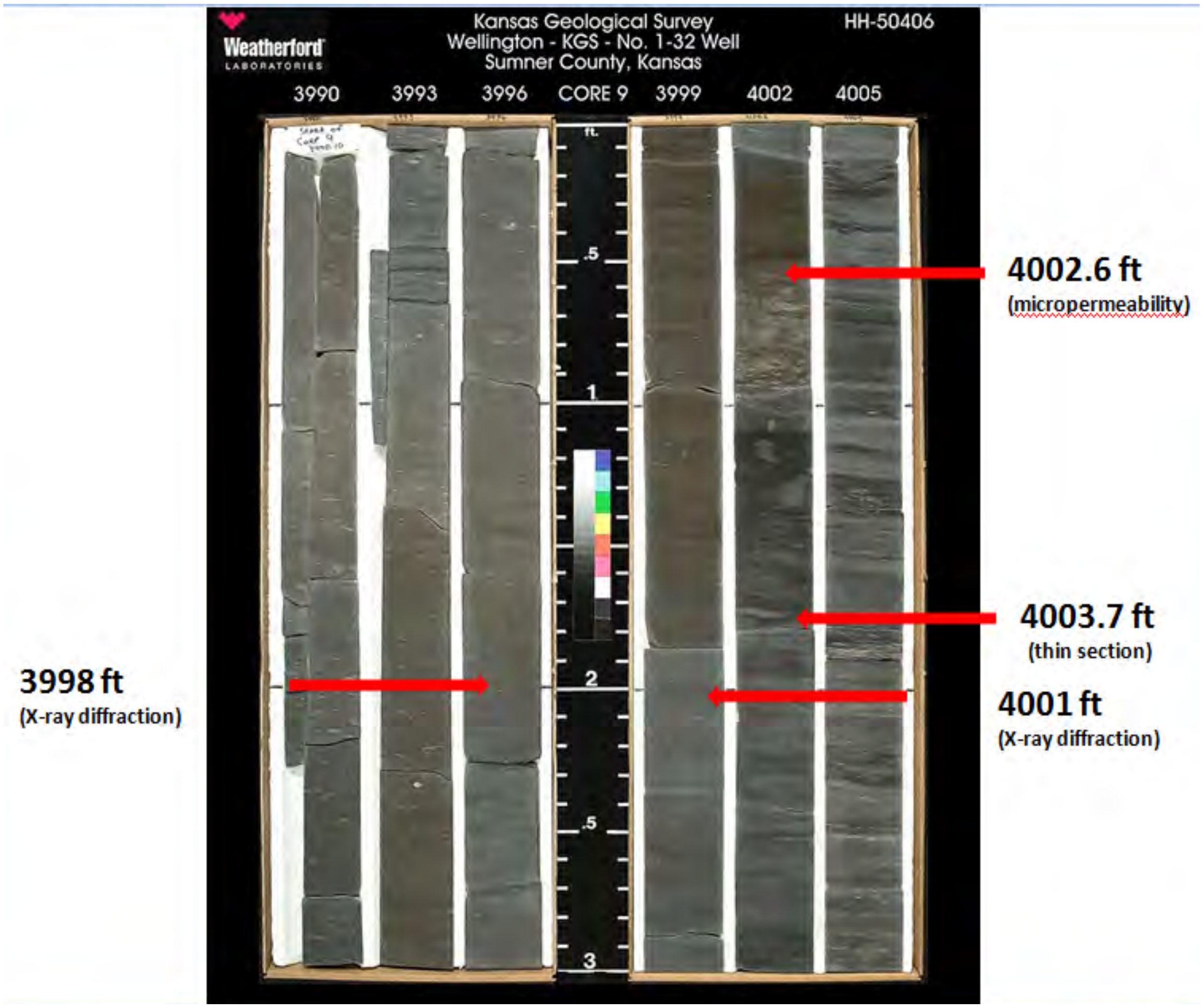


Figure 4.44—Thin sections at elevation of 3,989.5 ft in KGS 1-32 showing clay-rich silt with organic macarels and dolomite core (top) and sponge spicules and galuconite deposits (green) (bottom).

4.7.3 Hydrogeologic Properties of the Upper Confining Zone

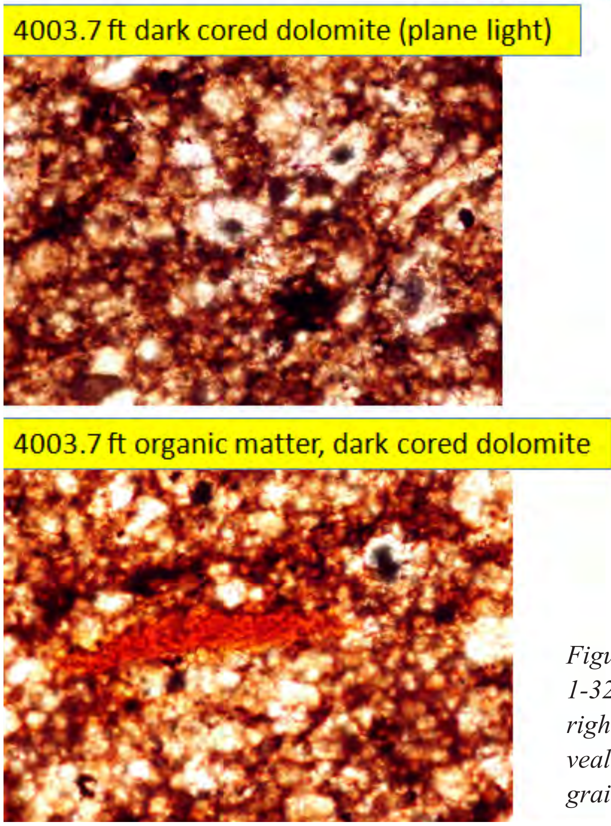
Weatherford Laboratories prepared the core-based estimate of horizontal and vertical permeability at KGS 1-32 (Figure 4.32a). The vertical permeability in most of the confining zone is less than 0.005 mD, which was the lower estimable limit for the testing method employed by Weatherford Laboratories. As expected, the horizontal permeability is higher than the vertical permeability, and the overall permeabilities within the Pierson formation are much lower than the



Figures 4.45—Core samples in the interval 3990 to 4005 ft (sub-KB) within the Pierson formation in the lower Mississippian.

Simpson Group, which has interspersed layers of sand and shale. The R35-based estimate of horizontal permeability (Spearing et al., 2001) was derived for the confining zone and, as shown in Figure 4.32b, the results represent a reasonably good match with the core-based estimates.

Core samples were not obtained at KGS 1-28, and therefore the horizontal permeability was estimated at this site using the methodology of Fazelalavi et al. (2013). Figure 4.32b presents the results. In general, the horizontal permeability is very low in the Pierson formation and the Chattanooga Shale. In the Simpson Group, the permeability is higher in the sand intervals and much lower in the shale zones. Overall, the sharp permeability contrast between the confining and



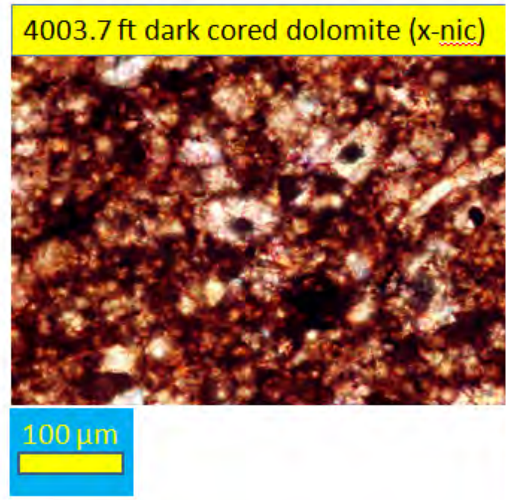


Figure 4.46—Thin sections at elevation of 4,003.7 ft in KGS 1-32 showing organic dolosiltstone in (top left) plane light, (top right) Nichols/polarized light, and (bottom left) plane light revealing organic macerals as well as clay and silt-sized quartz grains and dolomite crystals.

injection zones is readily obvious in Figure 4.32a-b, with the Arbuckle dolomites having substantially larger permeability than the shales and argillaceous siltstones of the Simpson Group, Chattanooga Shale, and the Pierson formation.

The National Energy Technology Laboratory (NETL) in Pittsburgh also estimated the permeability in the Pierson formation using the Pulse Decay Method (Dicker and Smits, 1988). As shown in Figure 4.47, results indicated an extremely low permeability of 2.9 and 1.6 nanoDarcy (nD; 10^{-09} Darcy) (Scheffer, 2012).

In addition to the data obtained at the Wellington storage site, Petrotek (2001) estimated a very low core-based vertical hydraulic conductivity range of 8.5e-06 to 1.7e-04 millidarcy (mD) in the Chattanooga Shale at an injection site in Wichita, Kansas, approximately 30 mi north of the proposed injection well site KGS 1-28.

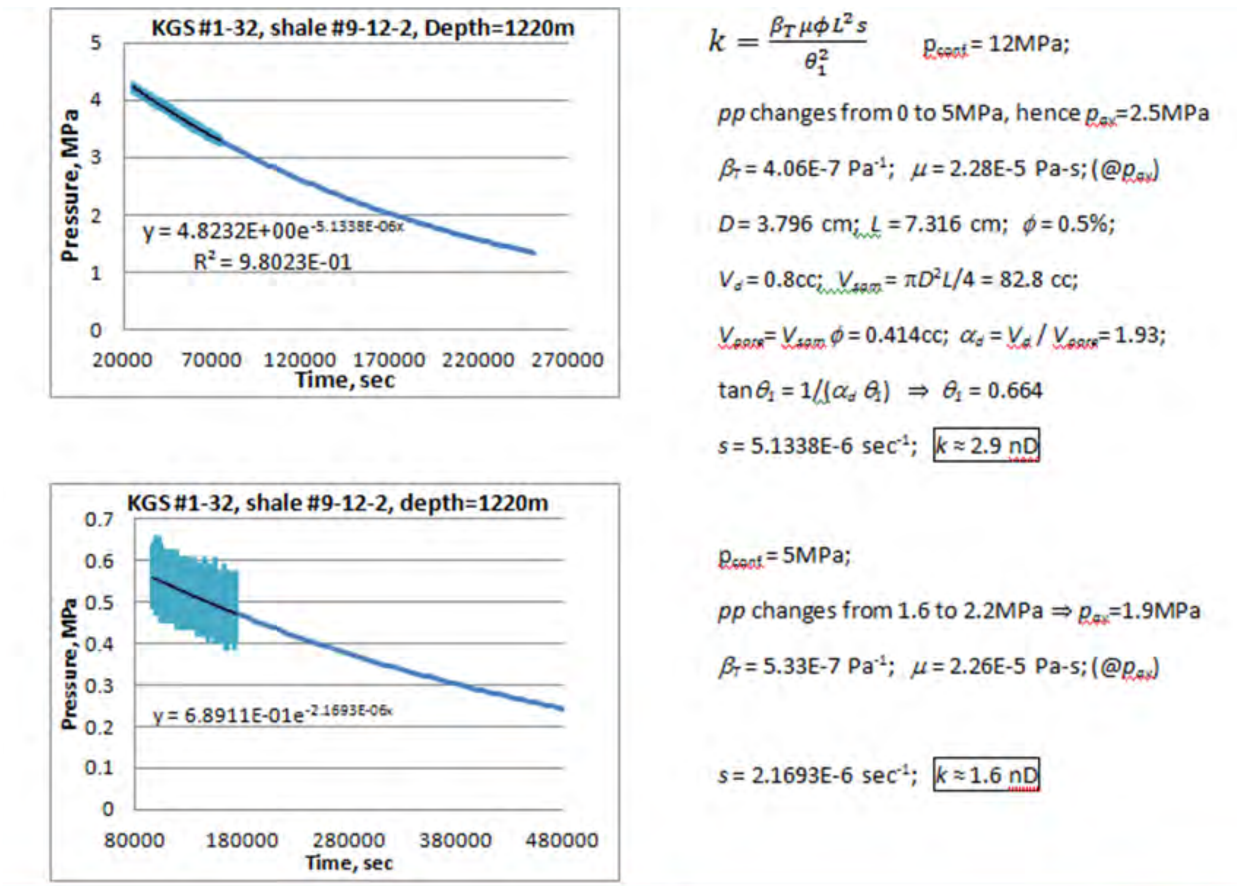


Figure 4.47—Permeability estimates in the Pierson Group at depth of 1220 m (4002 ft) using the Pulse Decay Method (source: Scheffer, 2012).

4.7.4 Entry Pressure Analyses

In addition to the log analyses and results of laboratory-based estimates of permeability and porosity, the sealing potential also can be estimated from the pore entry pressure. Entry pressure is defined as the capillary pressure at which the non-wetting phase enters the largest pores, i.e., the pressure at which the wetting phase saturation is approximately 85% (Volokin et al., 2001). The higher the entry pressure, the tighter the rock formation. Entry pressure in the confining zone was calculated in KGS wells 1-32 and 1-28 using the Techlog wellbore software platform (by Schlumberger) and the method and analyses are documented in Appendix A.

The entry pressures within the confining zone at Wellington wells KGS 1-28 and KGS 1-32 are presented in Figure 4.48 and 4.49. The maximum entry pressures at KGS 1-28 and KGS 1-32 are 956 and 182 psi respectively (Table 4.11). Entry pressure is higher at KGS 1-28 due to the presence of smaller pores at this site as compared to KGS 1-32. As discussed in the modeling section (Section 5), the maximum induced CO_2 pressure at the top of the Arbuckle/base of the Simpson Shale is approximately 13.1 psi. Therefore, the likelihood of the injected CO_2 escaping through or compromising the confining zone is negligible.

Table 4.11—Maximum CO_2–brine entry pressure in the confining zone at KGS 1-28 and KGS 1-32

Well	Maximum Entry Pressure (psi)
KGS 1-28	956
KGS 1-32	182

4.7.5 Fractures in Confining Zones

The objective of the discussion and analyses in this section is to demonstrate that the upper confining zone above the Arbuckle Group at Wellington is relatively free of conductive fractures and that this zone will function as an effective hydraulic barrier, preventing escape of CO_2 from the Arbuckle Group. The information is provided in support of the following Class VI rules:

- 146.82 (3) (ii), which requires documenting the location, orientation, and properties of known or suspected faults and fractures that may transect the confining zone(s) in the area of review;
- 146.83 (2), which requires demonstrating that the confining zones are free of transmissive faults or fractures;
- 146.93 (c) (1) (vi) which requires a characterization of the confining zone(s) including a demonstration that it is free of transmissive faults, fractures, and micro-fractures;

Section 6 presents information pertaining to geologic faults and geomechanical stability. This subsection focuses on fracture analyses and is based on:

- Core-based fracture studies (Section 4.7.5.1)
- XMRI log-based fracture investigations (Section 4.7.5.2)
- CT scan analysis (Section 4.7.5.3)

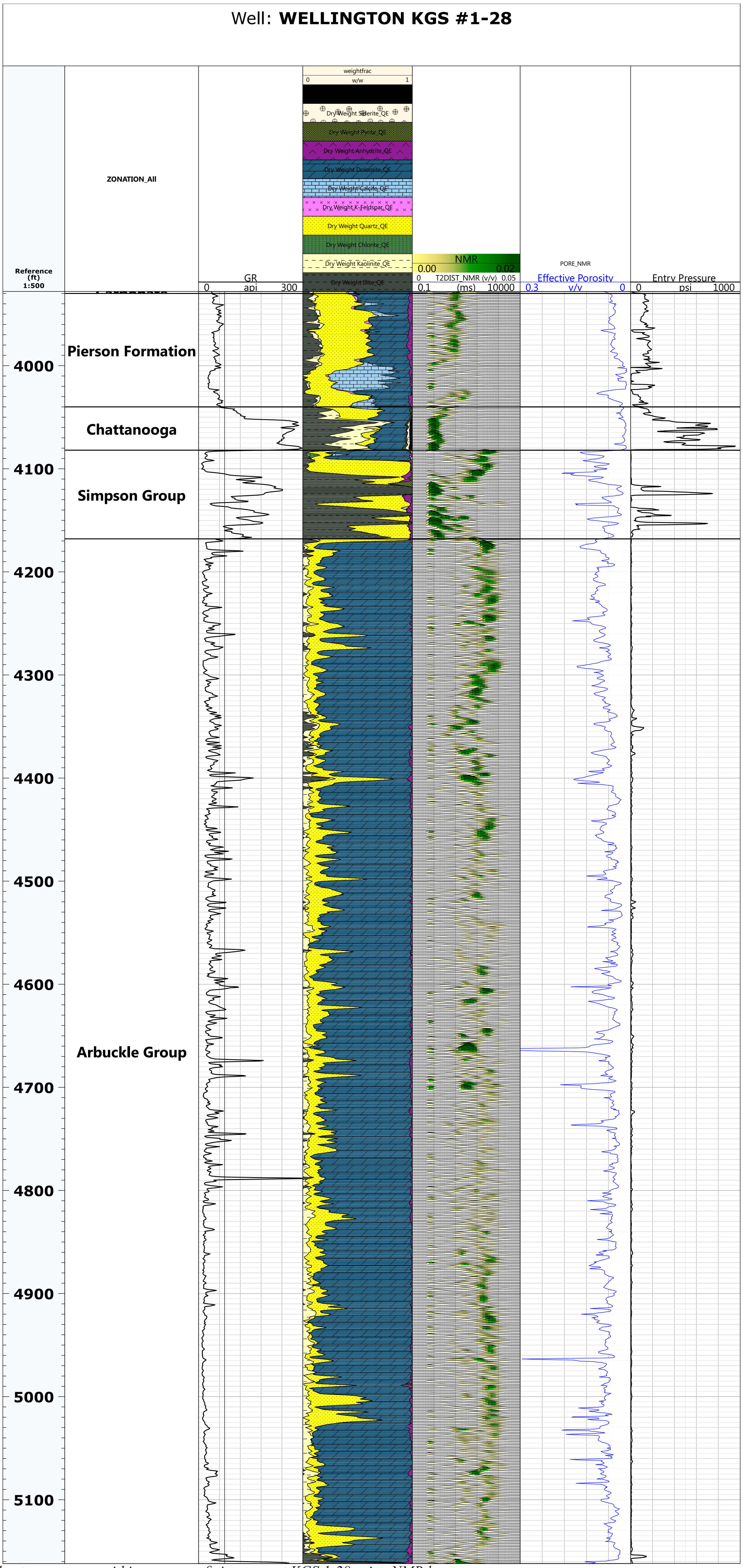


Figure 4.48—Estimated entry pressures within upper confining zone at KGS 1-28 using NMR log.

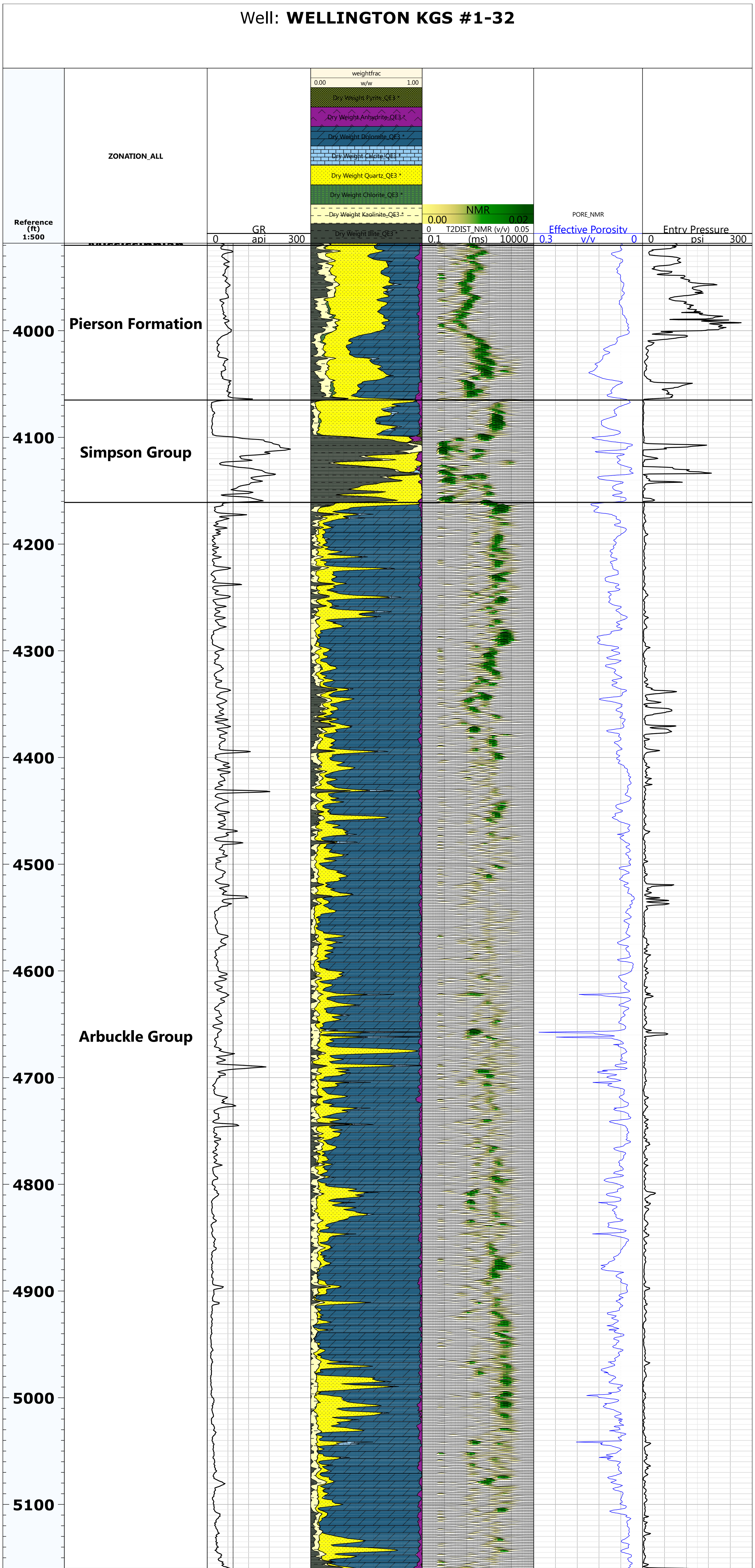


Figure 4.49—Estimated entry pressures within upper confining zone at KGS 1-32 using NMR log.

4.7.5.1 Core-Based Fracture Studies

Weatherford Industries analyzed fractures using core data at KGS 1-32 between the depths of 3,540 and 5,179 ft. Continuous core was cut through the entire confining zone from the base of the Simpson Group and the top of the Pierson formation. The core was generally intact as soon as it was extruded from the aluminum liner, which was used to maintain the integrity of the core from the time it was cut at the bottom of the hole. The core was analyzed with a vertical resolution of less than one inch allowing for many sized structural features to be considered, recognized, and characterized. The preservation of the core in the confining layer was excellent.

Table 4.12 presents the fracture data in the confining zone. Most of the fractures in Table 4.12 are completely occluded by mineralization (quartz, dolomite, and calcite). Although there are many fractures in the Simpson Group, these are mainly confined to chert nodules, which are not a result of tectonic forces but a consequence of diagenesis (crystallization of the silica) and fracturing during burial of the more brittle chert nodule. These fractures in the early formed chert do not negatively affect the sealing nature of the confining zones (Watney, 2001). Also, almost all of the fractures within the Simpson Group are in the sands and dolomite and not the shaley intervals (which provide hydraulic confinement).

Table 4.12—Fracture data in the confining zone at KGS 1-32.

Depth to Top of Fracture (ft)	No. of Factures	Fracture type	Mineralization	Fracture height (ft)	Fracture Width (mm)	Estimated Remnant Porosity %	Spacing (mm)	Lithology	Formation
3937.40	1	Vertical	ca	0.80	0.20	0		shaley dolo	Pierson
3940.70	1	Vertical	none	0.10	0.05	100		shaley gy dolo	Pierson
4026.60	1	Vertical	none	0.30	0.08	0	N/A	dk dolo	Pierson
4033.60	1	Inclined	quartz	0.05	0.50	0	N/A	chert	Pierson
4037.35	1	Vertical	quartz	0.05	0.50	0	N/A	chert	Pierson
4038.70	4	Chert	quartz	0.03	0.50	0	12		Pierson
4038.70	N/A	Chert	quartz	0.03	0.50	0	12		Pierson
4038.70	N/A	Chert	quartz	0.03	0.50	0	18		Pierson
4038.70	N/A	Chert	quartz	0.03	0.50	0	N/A		Pierson
4066.10	1	Vertical	bitumen	1.20	0.20	15	N/A	white sandstone	Simpson
4066.30	1	Vertical	quartz	3.80	0.20	60	N/A	white sandstone	Simpson
4077.90	1	Inclined	none	0.65	0.20	100	N/A	silty dolo	Simpson
4080.10	2	Vertical	none	0.20	0.20	100	15	silty dolo	Simpson
4080.10	N/A	Vertical	none	0.70	0.20	100	N/A	silty dolo	Simpson
4080.85	1	Vertical	quartz	0.30	0.30	0	N/A	sandy dolo	Simpson

4082.40	1	Inclined	bitumen/quartz	0.45	0.20	0	N/A	sandy dolo	Simpson
4114.45	1	Inclined	none	0.20	0.10	0	N/A	clay-rich shale	Simpson
4123.80	1	Vertical	quartz	0.70	0.20	0	N/A	sandstone	Simpson
4124.00	1	Vertical	quartz	0.50	0.20	0	31	sandstone	Simpson
4124.55	2	Vertical	quartz	1.55	0.20	0	N/A	sandstone	Simpson
4124.55	N/A	Vertical	quartz	0.45	0.20	0	42	sandstone	Simpson
4126.00	1	Vertical	quartz	1.10	0.20	0	63	sandstone	Simpson
4155.2	1	Vertical	quartz	0.50	0.08	0	N/A	sandstone	Simpson

4.7.5.2 XMRI Based Fracture Investigations

The Schlumberger extended-range micro imager, the XMRI tool, was used to identify fractures, including the extent of healing that has occurred due to mineralization and changes in the stress field. XMRI imaging well logs were run in KGS 1-32 and KGS 1-28 for the interval from the Upper Pennsylvanian age Lower Shawnee Group to the basement to augment and extend observations of bedding and structures observed in core.

Figure 4.50a-b presents the XMRI-based rose diagrams of open fractures at KGS 1-28 and KGS 1-32. There are 12 open fractures with a predominantly north-northeast–south-southwest orientation at both sites. All 12 fractures at KGS 1-32 are within the Arbuckle Group and the underlying Precambrian granitic bedrock. At KGS 1-28 (Figure 4.50b), most of the open fractures are within the Precambrian bedrock. Only one open fracture is within the Arbuckle Group, and two exist above the Pierson formation, which is the uppermost formation within the confining zone at Wellington.

4.7.5.3 Helical Computerized Tomography (CT) Scan Based Fracture Analysis

As discussed by Cnudde et. al. (2006), CT scan is rapidly gaining reputation as an important non-destructive research technique for characterizing rock material. The technique has the ability to scan rock specimens for very minute fractures (see Figure 4.51 for an example). Due to the tight nature of the Pierson formation, it was decided to capture the texture of the whole core in a continuous helical CT scan before the core was slabbed. Figure 4.52 presents a typical CT scan in the Pierson from 4,060 to 4,065 ft. The scan reveals a very tight formation with no discernible natural fractures.

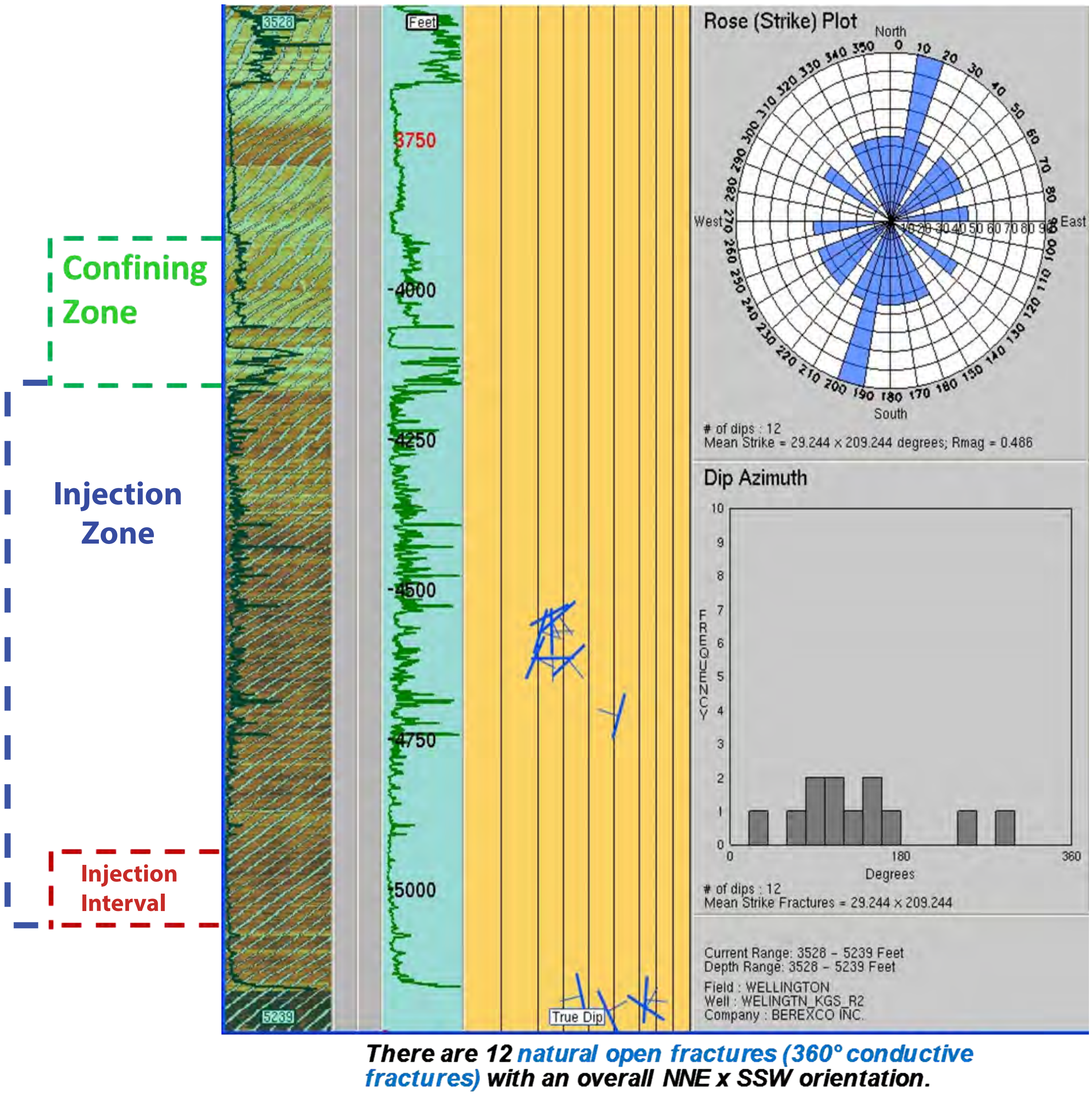


Figure 4.50a—Location and orientation of fully open fractures derived from XMRI logs at KGS 1-32.

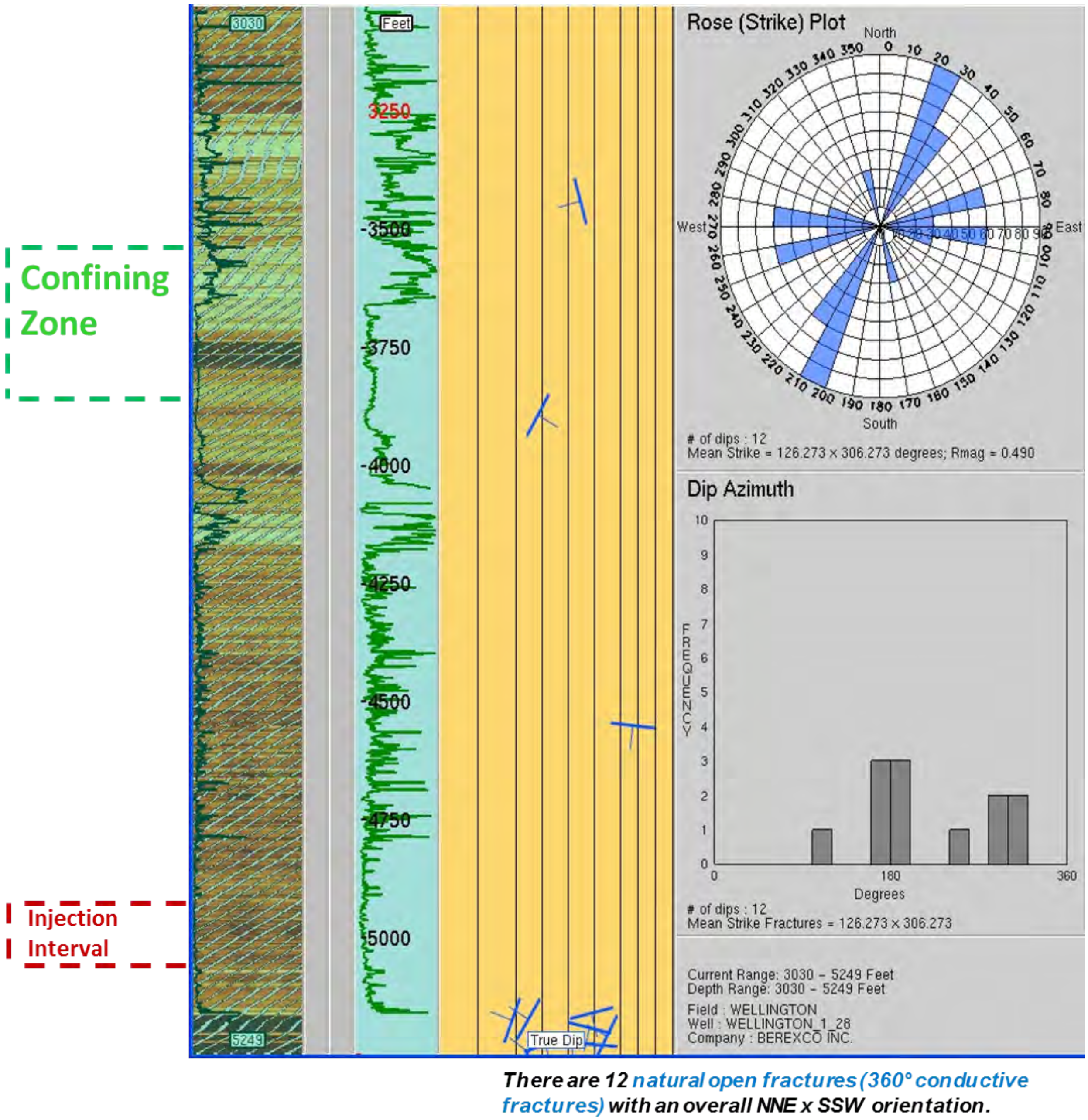


Figure 4.50b—Location and orientation of fully open fractures derived from XMRI logs at KGS 1-28.

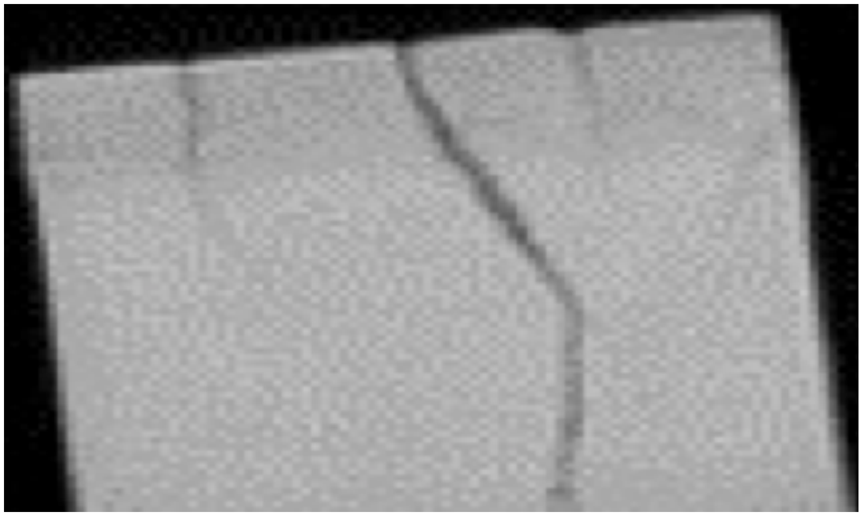


Figure 4.51—CT scan of fractured quartzitic sandstone (source: Cnudde et al., 2006).

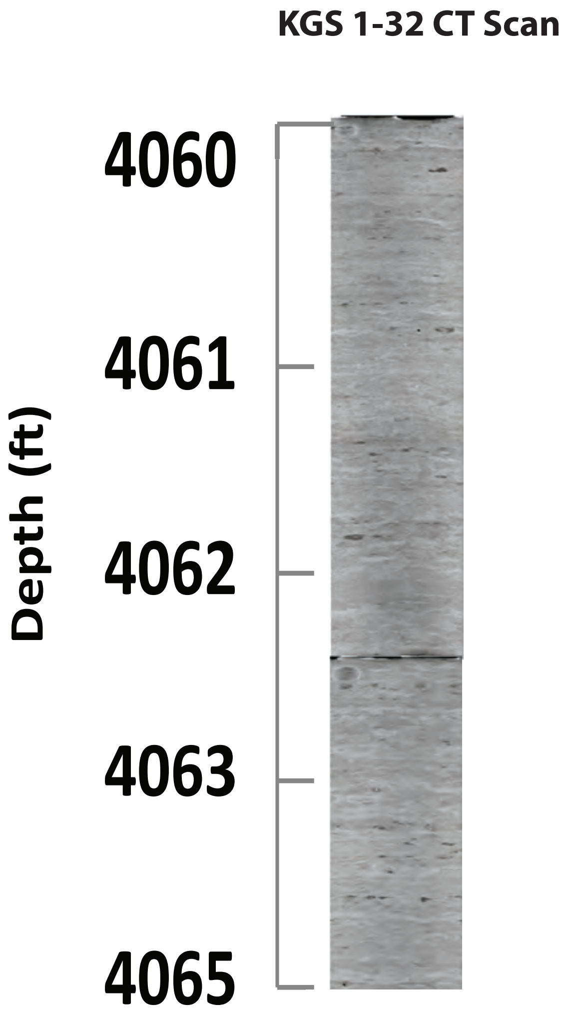


Figure 4.52—CT scan in the Pierson formation from 4,060 to 4,065 ft at KGS 1-32 highlighting the absence of fractures and the bedding nature of the formation.

4.7.6 Secondary Confining Zones

In addition to the Chattanooga and Simpson shales, tight shaly formations between the Chattanooga Shale and the Chase Group provide multiple levels of potential confinement (Figure 1.8). These shales are expected to provide additional confinement in the unlikely event that CO_2 escapes from the confining zone. The documentation and discussion of the secondary confining zones in the Pennsylvanian System and the Permian Wellington Formation is presented below.

Vertical Confinement in the Pennsylvanian System

There are several shale intervals in the formation overlying the Pierson at KGS 1-28 as indicated in Figure 1.8. Thick (>100 ft) shales are noted in the Cherokee Group, above and below the Upper Pennsylvanian Stalnaker Sandstone, and the shale interval within the Upper Pennsylvanian Wabaunsee Group. The gamma ray count in some of these shale intervals is as high as in the Chattanooga Shale.

A Rhomaa-Umaa (Doveton, 1991) based rock column is also shown in Figure 1.8 to easily identify confining intervals. The numerous thick shale intervals between the Chase Group and the Mississippian System can be easily identified with the high percentage of gray (shale) in the rock column profile in Figure 1.8. These intervals are expected to provide vertical confinement in the unlikely event of breach of the primary confining zone.

Vertical Confinement in the Wellington Formation

The lower 360 ft of the Wellington Formation below the USDW (upper 200+ ft) is also expected to provide hydraulic confinement. As shown in Figure 4.8, there is an 80+ ft thick interval of bedded halite (rock salt) and thin shales that overlie about 230 ft of interbedded anhydrite and shale. The beds of halite would have dissolved if there was not an effective seal in the lower portions of the upper Wellington Formation. The gamma logs in Figure 4.8 clearly delineate the approximately 20-ft thick beds of halite and anhydrite by their lower gamma ray values (30–35 API units) from the higher gamma ray values (about 90 API units) of the thin interbedded shales.

Core acquired from this interval near Hutchinson, Kansas, indicates beds of solid, medium crystalline halite and finely crystalline, dense anhydrite interbedded with uniform gray to dark-gray shale (Watney et al., 1988). This stratigraphic succession is very widespread, extending from eastern Sumner County to near Dodge City (to the west) and Hays, Kansas, (to the north), serving as an important hydraulic barrier that prevents exchange of fluids between the overlying and underlying aquifers (Watney et al., 1988; Nelson and Gianoutsos, 2011).

4.7.7 CO_2 Compatibility in Primary Caprock

Controlled batch experiments were conducted to assess the geochemical alterations to be expected if the CO_2 were to migrate into the caprock (Scheffer, 2012). These experiments used core samples from the Chattanooga Shale. Gypsum precipitation occurred when the Chattanooga Shale containing pyrite was exposed to CO_2. These results suggest that pyrite-bearing intervals, in particular, may precipitate secondary gypsum in the presence of CO_2 and oxygenated brine fluids. Gypsum precipitation under these conditions could fill existing pore space or micro-fractures within the seals to create an even more effective seal. However, as discussed and shown in Section 5, the injected CO_2 is expected to remain confined in the injection interval in the lower Arbuckle and not migrate vertically into the confining zone due to the presence of the many low-permeability baffle zones in the middle Arbuckle Group.

4.8 3-D Seismic Survey and Analysis

4.8.1 Introduction

The seismic data acquired to characterize the subsurface in the Wellington area have yielded important new information about both the structure and stratigraphy of the field. Various seismic analyses techniques implemented to define the subsurface formations are discussed below. The results demonstrate the ability of the seismic techniques to map the key formation horizons and formation thickness and to characterize the geologic fabric in the subsurface. Importantly, seismic results verify the lateral continuity of the injection and confining zones.

Also, the seismic data provide insight into the potential for containment of CO_2 within the Arbuckle itself. The relatively low impedance region within the middle Arbuckle is expected to act as a permeability barrier or at least a baffle to vertical migration that would effectively contain or decrease the vertical flow of the injectate. This tight and variably argillaceous dolomitic zone is a continuous interval on the seismic imaging, providing further evidence of the presence of low permeability baffle zones in the Arbuckle as discussed above. The seismic impedance data also confirm the presence of confining zones overlying the Arbuckle injection zone.

The information in this section is organized as follows:

- Sections 4.8.2 (Data Acquisition)—presents a summary of seismic data acquisition.
- Section 4.8.3 (Stratigraphic Mapping)—documents the ability of the processed seismic data to confirm the presence and continuity of the injection zone and the underlying and overlying confining zones.
- Section 4.8.4 (Structure Mapping Using Seismic Data)—discusses the process of mapping the structure and thickness of key formations from the seismic data.
- Section 4.8.5 (Impedance Mapping)—documents the ability to identify the formation fabric (especially the confining potential).

4.8.2 Data Acquisition

A 3-D survey incorporated the acquisition of multi-component data via geophones capable of detecting ground motion in three directions: vertical, x-component, and y-component. These data types yield both p-wave (vertical acceleration) and converted shear waves, which are recorded in the x and y components.

The survey also incorporated the acquisition of two 2-dimensional shear-to-shear recordings, in which the shear wave source was applied via vibrating devices mounted on the underside of a heavy truck capable of delivering approximately 41,000 pounds peak force, with the energy being recorded by multi-component geophones, which again captured ground motion in three dimensions. Appendix I presents the recording parameters and other information pertaining to the 2-D and 3-D surveys.

4.8.3 Stratigraphic Mapping

Seismic results have been analyzed for structural characterization as well as stratigraphic analyses. Figure 4.53 presents a zero-phase correlation with appropriately adjusted synthetic seismogram. Figure 4.54 presents the index map showing locations of the control well. The pres-

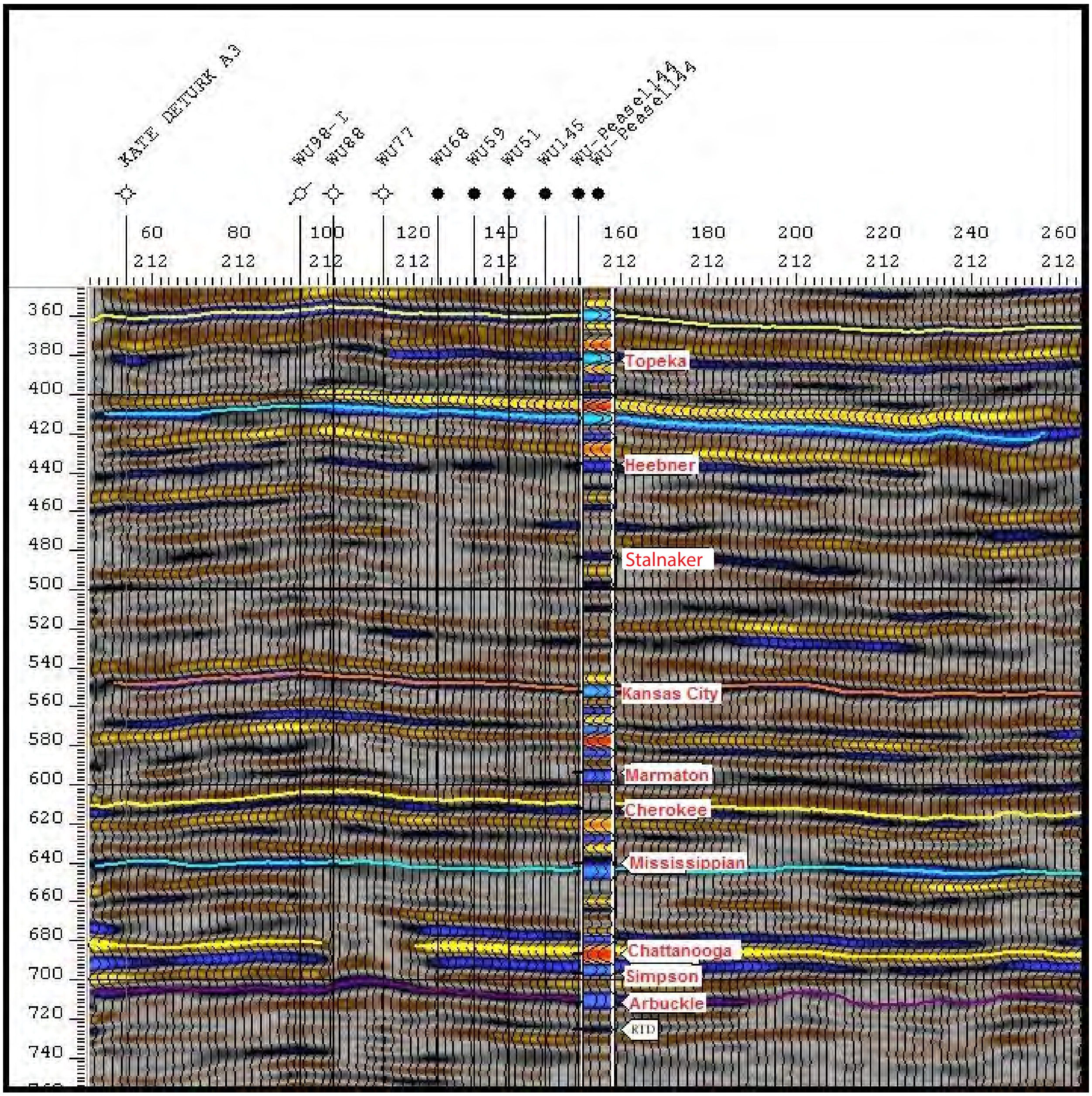


Figure 4.53—Correlated Arbitrary Profile (color scale = seismic amplitude), illustrating the tie to the synthetic seismogram located at approximately Crossline 212, Inline 157. The vertical extents of the profile cover a range from approximately 1,750 to 4,250 ft below surface. Contents of the image are variable density amplitude with conventional wiggle trace overlay. (Y-axis = two-way travel time, in milliseconds; X-axis = distance, trace spacing = 165 ft.). Figure 4.54 presents the index map.

ence of a continuous injection zone (Arbuckle Group) and the overlying confining zone (Simpson Group, Chattanooga Shale, and Pierson formation) can be readily inferred from Figure 4.53.

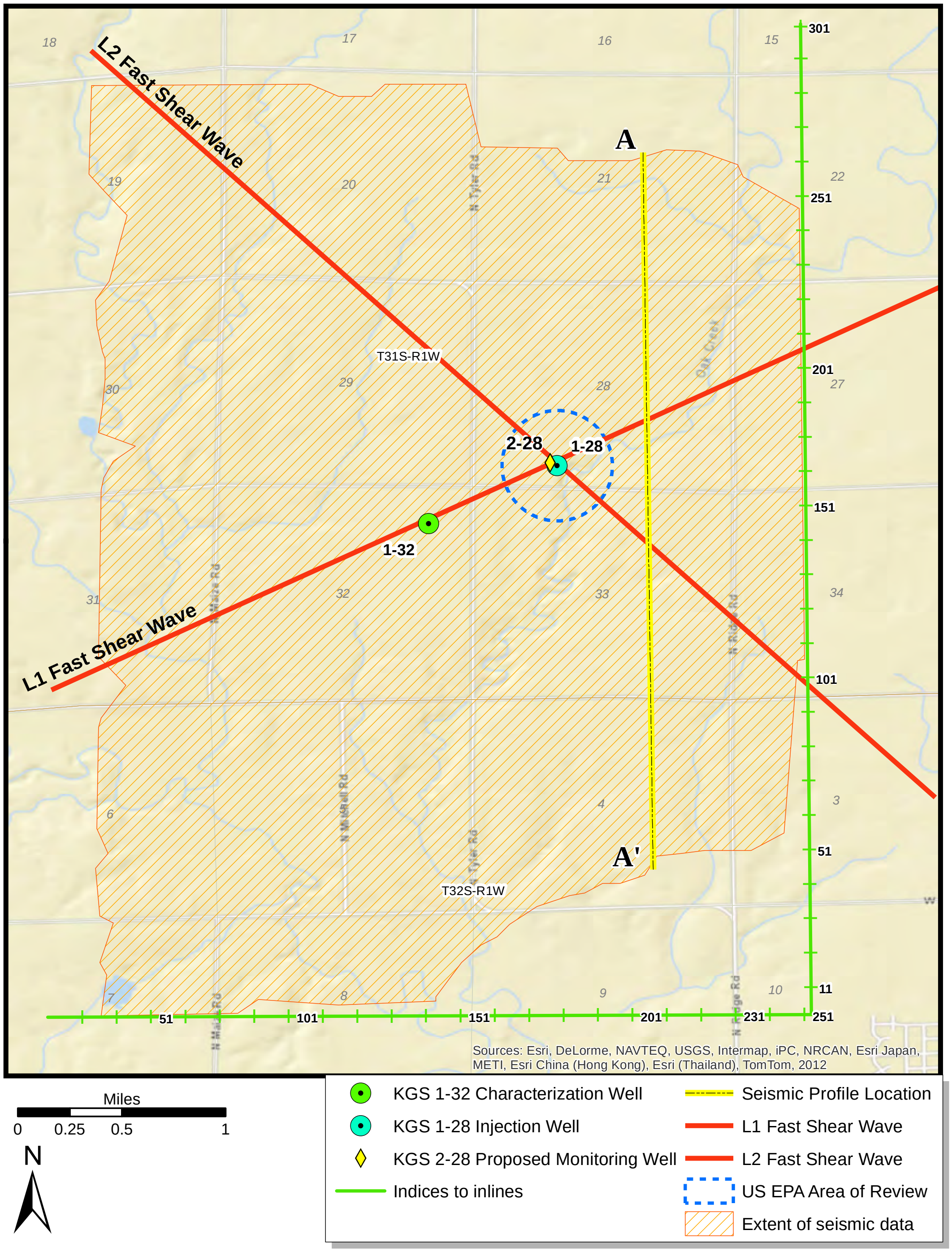


Figure 4.54—Index map illustrating the location of the seismic profile shown in Figure 4.53 (heavy yellow north-south line). Also shown are locations of 2-D shear wave profiles: L1 oriented west-southwest–east-northeast and L2 oriented northwest-southeast. Indices to inlines appear on the east edge of the green boundary and indexes to crosslines (also referred to as traces) appear on the south boundary of the green outline. Extents of seismic data are indicated within the red line.

4.8.4 Structure Mapping Using Seismic Data

Seismic event tracking within a seismic volume can be rendered in map form, also known as time structure mapping. Time structure mapping of the confining zone was performed to confirm the continuity of the confining zone at the Wellington site. Figure 4.55a-b shows the structure of the top of the confining zone (top of Pierson formation) and the base of the confining zone (base of Simpson Group/top of Arbuckle group).

Figure 4.56 presents an estimate of the thickness of the confining zone, based on the time structure maps of the top and bottom of the confining zone. In the Wellington area, the thickness varies from approximately 150 ft in the northwest to 250 ft in the south. At the injection well site (KGS 1-28), the seismic-based thickness of 230 ft in Figure 4.56 is fairly close to the geophysical log-based thickness of 238 ft documented in Table 4.10.

4.8.5 Impedance Mapping

Figure 4.57 shows a typical profile from the inverted acoustic impedance volume, along the north-south seismic profile line. Higher porosity, lower velocity/lower density rocks are indicated in yellow. There is a consistently higher impedance zone in the lower Mississippian at 680 ms. This unit is overlain by a widespread low impedance (brown and gray color corresponding to the argillaceous siltstone described earlier as the highly confining Pierson formation. Note also the high impedance strata throughout the Arbuckle, which agrees with core, log, and geochemical data that suggest there to be low-permeability baffle zones throughout the mid-Arbuckle. The highest impedance (lowest porosity) zone in the Arbuckle is in the upper third of the Arbuckle, which coincides with the thickest low vertical permeability interval from 4,290 to 4,490 ft as shown in Figure 4.32a.

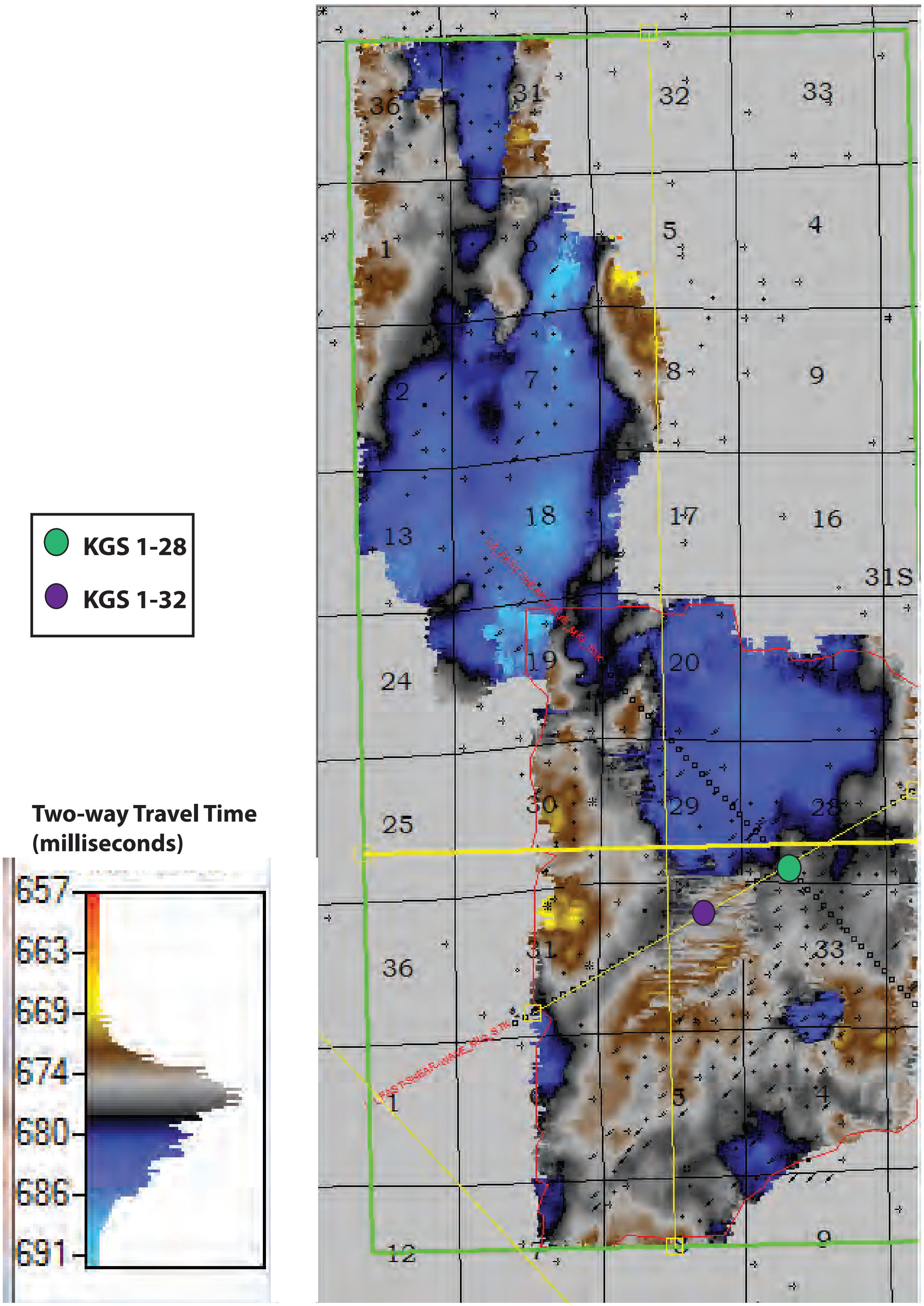


Figure 4.55a—Time structural variation of the Pierson surface in the Wellington area.

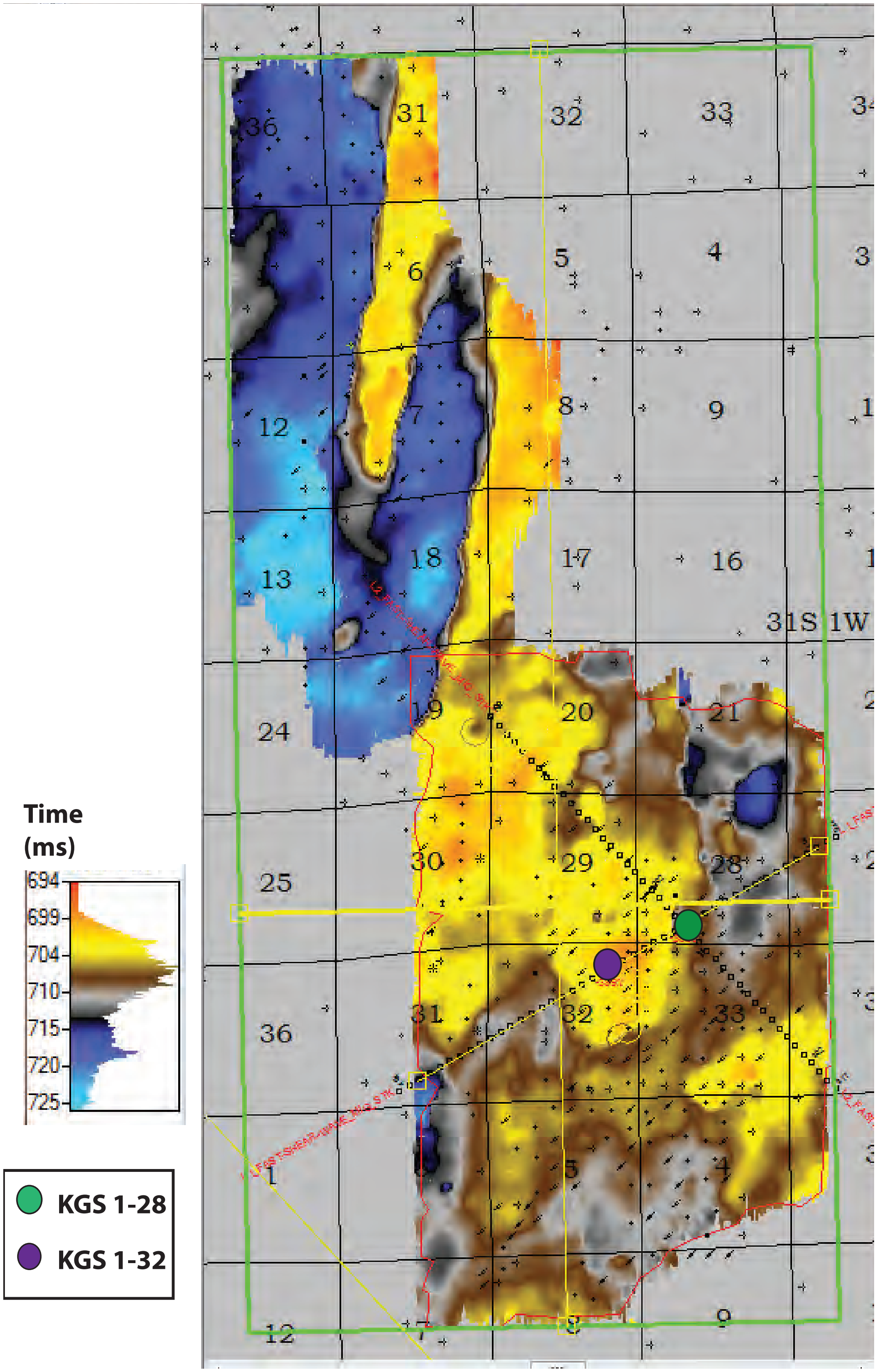


Figure 4.55b—Time structural variation of the Arbuckle surface (base of Simpson Group).

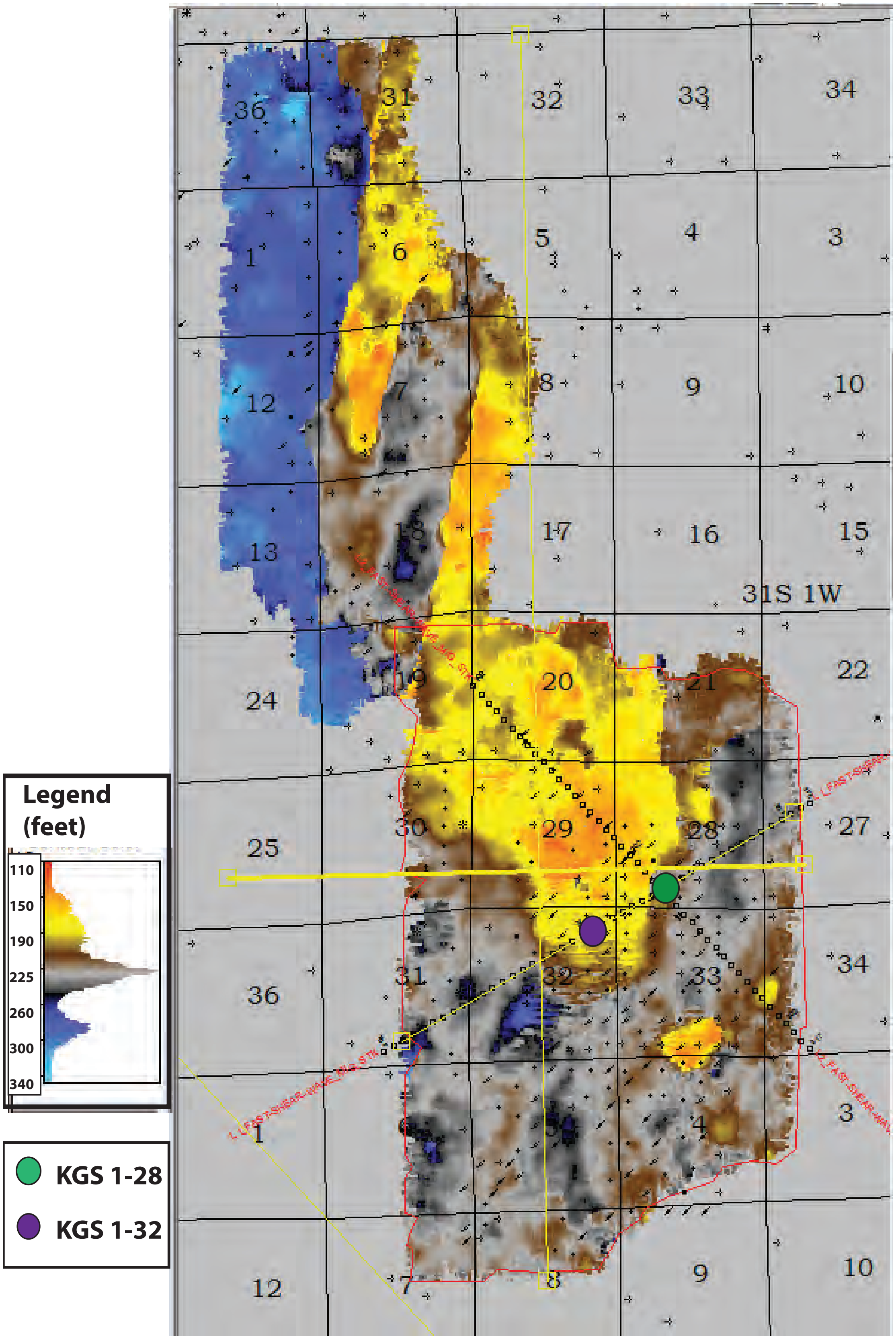


Figure 4.56—Seismic impedance based thickness (feet) from top of Pierson formation to top of Arbuckle Group.

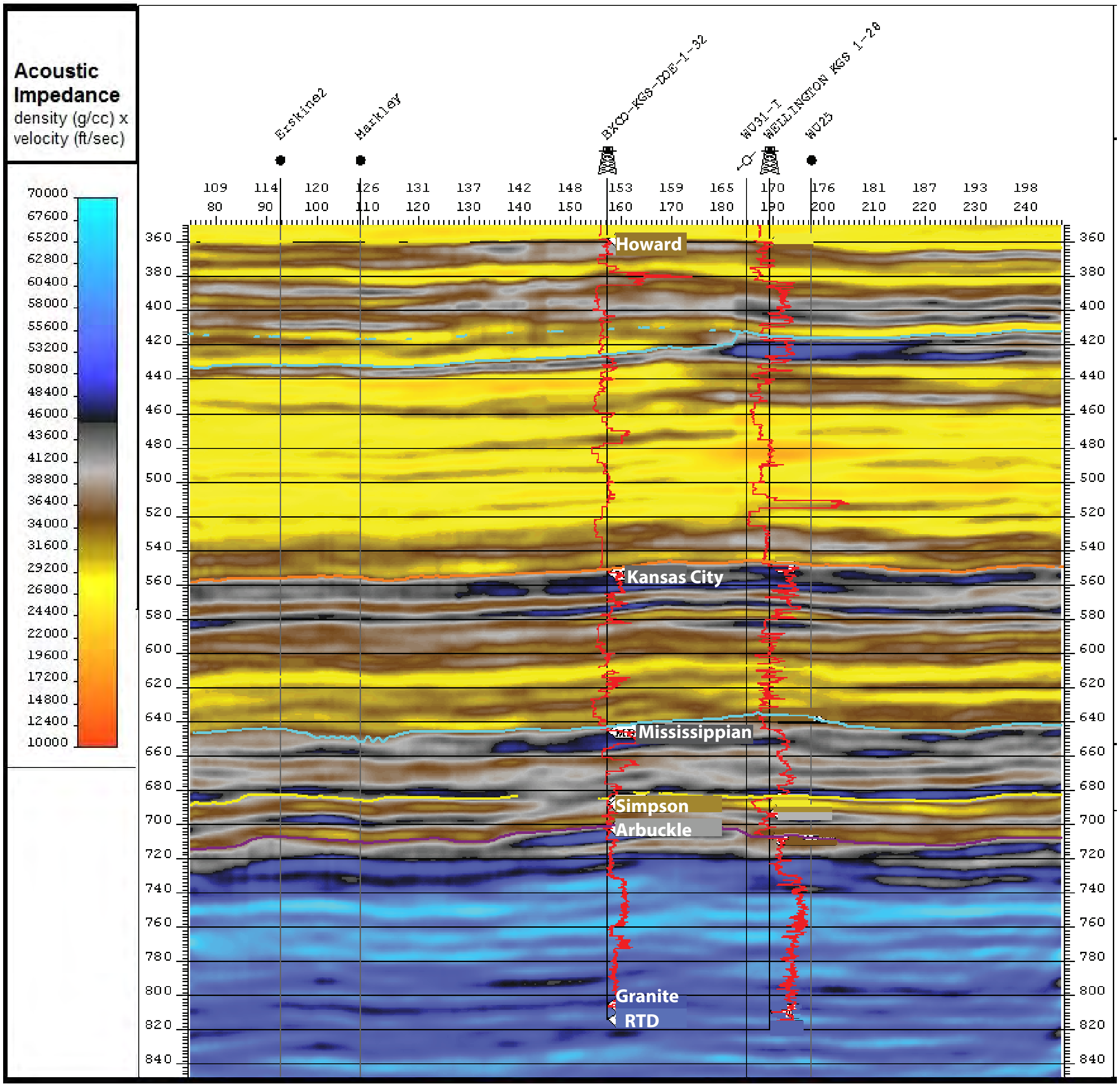


Figure 4.57—Arbitrary profile from acoustic impedance volume. Log trace overlay (red) from p-wave velocity. Vertical scale two-way travel time, ms. Color scale = acoustic impedance. Profile location same as Figure 4.54.

Figure 4.58 presents the average impedance in the Pierson formation. This map confirms that the Pierson is present throughout the Wellington area with impedance ranging from 37,000 to 40,000 ft/sec x g/cm3. The average impedance in the entire confining zone (base of the Simpson Group to top of the Pierson formation) is presented in Figure 4.59, which confirms the presence and continuity of this critical zone in the project area. In general, the average impedance is slightly lower in the entire confining zone due to the presence of the relatively high porosity Chattanooga Shale. Although the Pierson does not have as much shale content as the Chattanooga, the argillaceous siltstone of this formation has extremely low permeability (nano-Darcy level), as documented in Section 4.7.3.

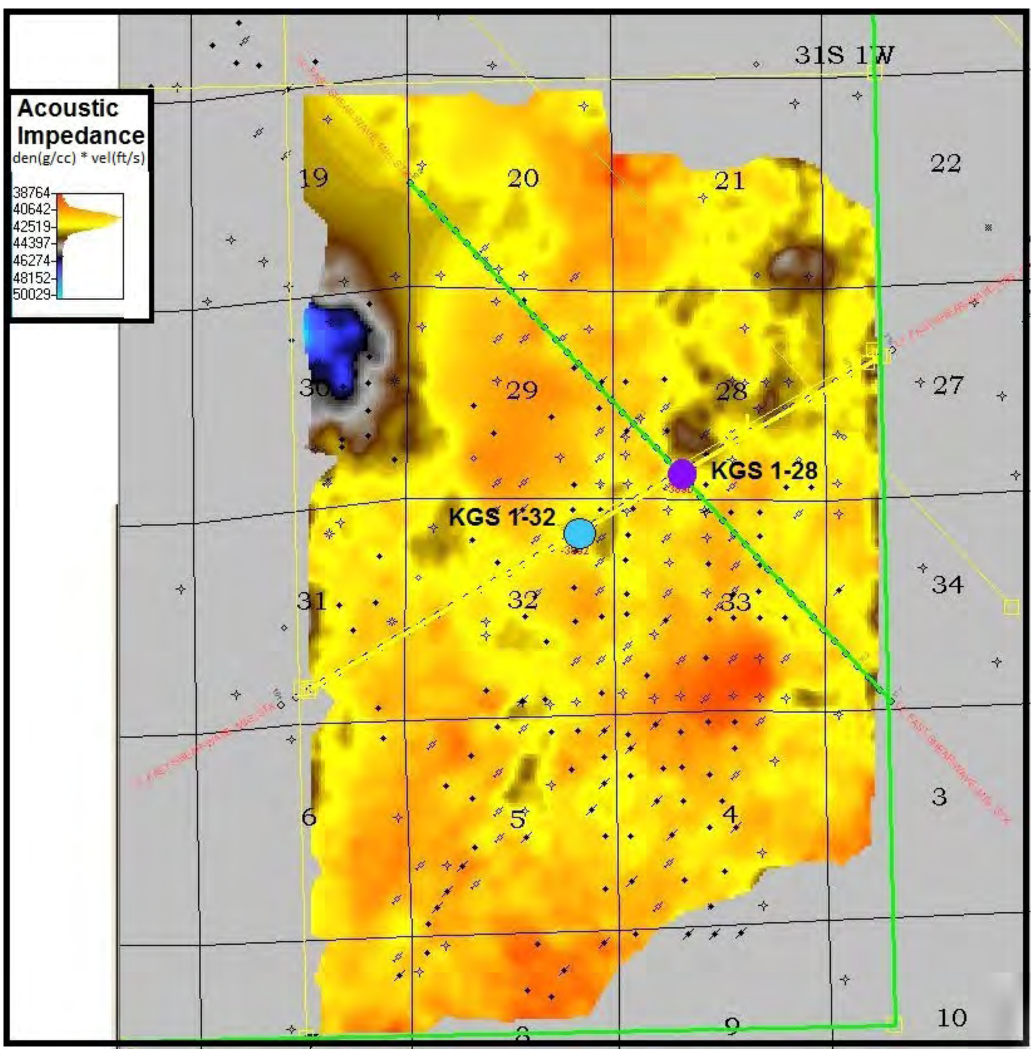


Figure 4.58—Acoustic impedance variance within the Lower Mississippian Pierson, the tight argillacous siltstone.

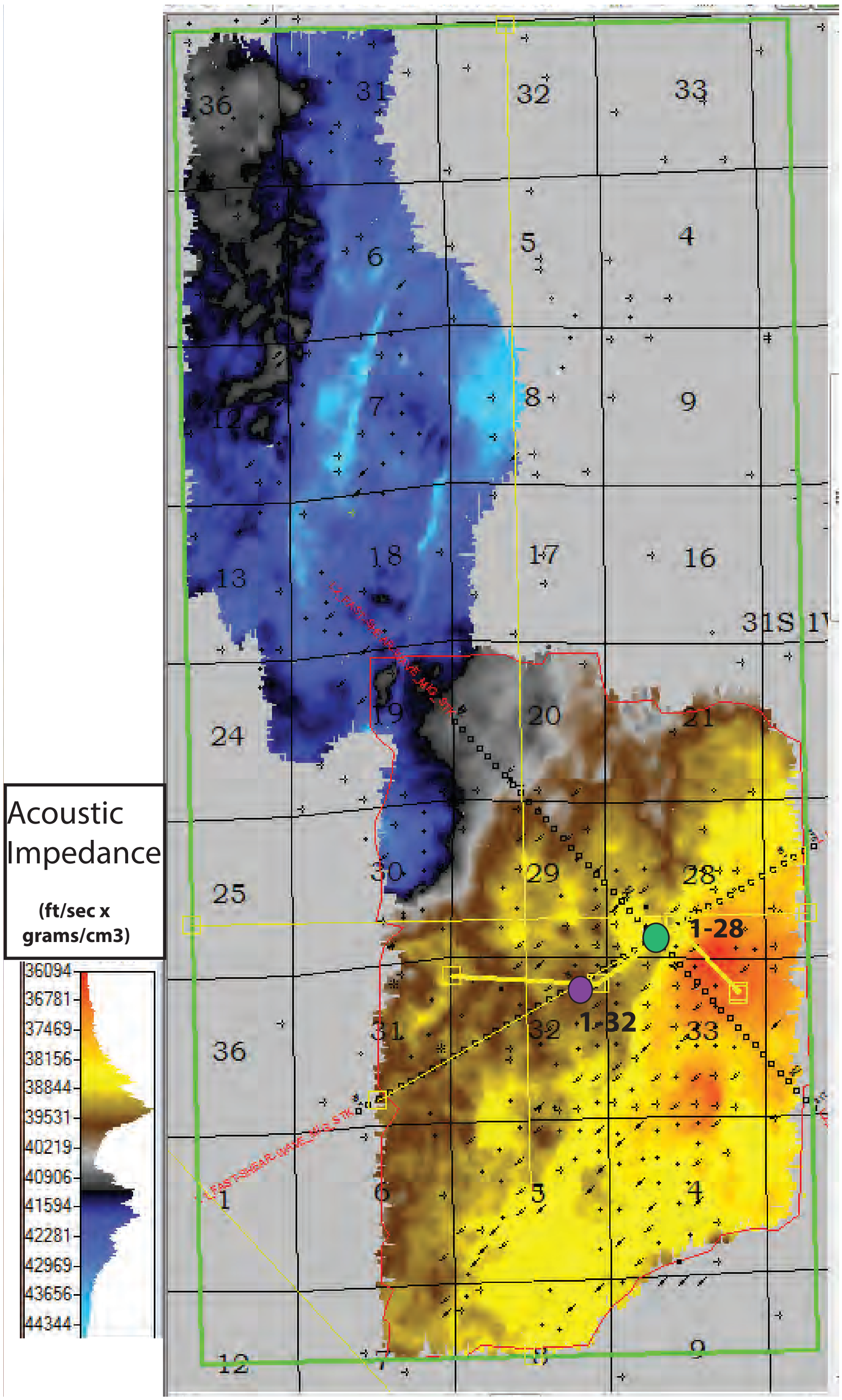


Figure 4.59—Acoustic impedance variance within the upper confining zone (base of Simpson Group to top of Pierson).

Section 5
Reservoir Modeling

5.1 Introduction

This section presents details of the Arbuckle reservoir simulation model that was constructed to project the results of the Wellington Field short-term Arbuckle CO_2 pilot injection project and delineate the EPA Area of Review (AoR) documented in Section 9. As required under §146.84(c), the AoR must be delineated using a computational model than can accurately predict the projected lateral and vertical migration of the CO_2 plume and formation fluids in the subsurface from the commencement of injection activities until the plume movement ceases and until pressure differentials sufficient to cause the movement of injected fluids or formation fluids into a USDW are no longer present. The model must:

(i) Be based on detailed geologic data collected to characterize the injection zone(s), confining zone(s), and any additional zones; and anticipated operating data, including injection pressures, rates, and total volumes over the proposed life of the geologic sequestration project;

(ii) Take into account any geologic heterogeneities, other discontinuities, data quality, and their possible impact on model predictions; and

(iii) Consider potential migration through faults, fractures, and artificial penetrations.

This section presents the reservoir simulations conducted to fulfill §146.84 requirements stated above. The simulations were conducted assuming a maximum injection of 40,000 metric tons of CO_2 over a period of nine months. As indicated in Section 1, the exact quantity of CO2 to be injected is subject to budgetary considerations and availability of CO_2 and could be as low as 10,000 tons. The simulation results, therefore, represent impacts of the maximum quantity of CO_2 that may be injected during the Wellington Arbuckle injection pilot project.

The modeling results indicate that the induced pore pressures in the Arbuckle aquifer away from the injection well are of insufficient magnitude to cause the Arbuckle brines to migrate up into the USDW even if there were any artificial or natural penetration in the Arbuckle Group or the overlying confining units.

The simulation results also indicate that the free-phase CO_2 plume is contained within the total CO_2 plume (i.e., in the free plus dissolved phases) and that it extends to a maximum lateral distance of 1,700 ft from the injection well. The EPA Area of Review (AoR) is defined by the 1% saturation isoline of the stablized free-phase plume.

5.2 Conceptual Model and Arbuckle Hydrogeologic State Information

5.2.1 Modeled Formation

The simulation model spans the entire thickness of the Arbuckle aquifer (Figure 5.1). The CO_2 is to be injected in the lower portion of the Arbuckle in the interval 4,910–5,050 feet which has relatively high permeability based on the core data collected at the site. Preliminary simulations indicated that the bulk of the CO_2 will remain confined in the lower portions of the Arbuckle because of the low permeability intervals in the baffle zones as discussed in Section 4.6.6 and also shown in analysis of geologic logs at wells KGS 1-28 and KGS 1-32 (Figure 4.32 a-b). Therefore, no-flow boundary conditions were specified along the top of the Arbuckle. The specification of a no-flow boundary at the top is also in agreement with hydrogeologic analyses presented in Section 4.7, which indicates that the upper confining zone—comprising the Simpson Group, the Chattanooga Shale, and the Pierson formation—has very low permeability, which should impede any vertical movement of groundwater from the Arbuckle Group. Additionally, entry pressure analyses (documented in Section 4.7.4) indicate that an increase in pore pressure of more than 956 psi within the confining zone at the injection well site is required for the CO_2-brine to penetrate through the confining zone. As discussed in the model simulation results section below (Section 5.4.6), the maximum increase in pore pressure at the top of the Arbuckle is approximately 13.1 psi under the worst-case scenario, which corresponds to a low permeability–low porosity alternative model case as discussed in Section 5.4.5. This small pressure rise at the top of the Arbuckle is due to CO_2 injection below the lower vertical-permeability baffle zones present in the middle of the Arbuck-

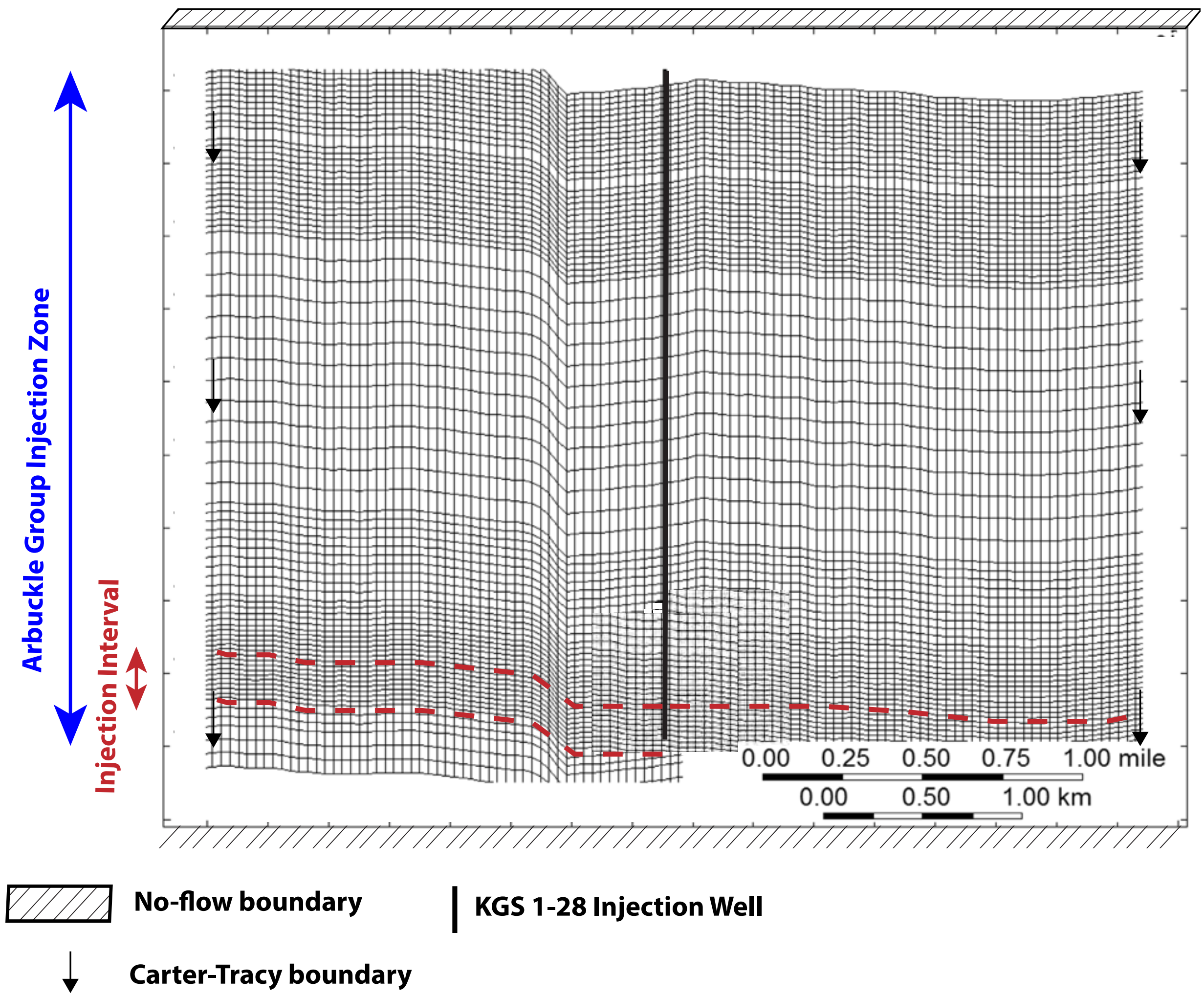


Figure 5.1—Typical east-west cross section of model grid showing boundary conditions.

le Group, which confines the CO_2 in the injection interval in the lower portions of the Arbuckle Group. The confining zone is also documented to be locally free of transmissive fractures based on fracture analysis conducted at KGS 1-28 (injection well) and documented in Section 4.7.5. There are no known faults in the area, as documented in Section 6. Based on the above evidence, it is technically appropriate to restrict the simulation region within the Arbuckle Group for purposes of numerical efficiency, without compromising predictions of the effects of injection on the plume or pressure fronts. Because of the presence of the Precambrian granitic basement under the Arbuckle Group, which is expected to provide hydraulic confinement, the bottom of the model domain was also specified as a no-flow boundary.

5.2.2 Modeled Processes

Physical processes modeled in the reservoir simulations included isothermal multi-phase flow and transport of brine and CO_2. Isothermal conditions were modeled because the total variation in subsurface temperature in the Arbuckle Group from the top to the base is only slightly more than 10°F, which should not significantly affect the various storage modes away from the injection well, and because it is assumed that the temperature of the injected CO_2 will equilibrate to formation temperature close to the well. Uniform salinity concentration was assumed because geochemical evidence shows a lack of communication between upper and lower layers and because of the relatively small area of impact due to CO_2 injection. Subsurface storage of CO_2 occurs via the following four main mechanisms:

- structural trapping,
- aqueous dissolution,
- hydraulic trapping, and
- mineralization.

The first three mechanisms were simulated in the Wellington model. Mineralization was not simulated as preliminary geochemical modeling indicated that due to the short-term and small-scale nature of the pilot project, mineral precipitation is not expected to cause any problems with clogging of pore space that may reduce permeability and negatively impact injectivity. Therefore, any mineral storage that may occur will only result in faster stabilization of the CO_2 plume and make projections presented in this model somewhat more conservative.

5.2.3 Geologic Structure

There are no faults in the Arbuckle Group or the overlying confining zone or in proximity to the AoR derived from the model results. The closest fault is approximately 12.5 mi southeast of Wellington, as shown in Figure 6.4. Known faults mapped on top of Arbuckle and Mississippian system structures are presented in Figure 6.8. The seismic data at the Wellington site, presented in Section 4.8, also points to the absence of faults in the vicinity of Wellington.

5.2.4 Arbuckle Hydrogeologic State Information

As shown in Figures 4.29, 4.31, and 4.35, the ambient pore pressure, temperature, and salinity vary nearly linearly with depth in the Arbuckle Group. By linear extrapolation, the relationship between depth and these three parameters can be expressed by the following equations using the data in Figures 4.29, 4.31, and 4.35:

$$\text{Temperature (°F)} = (0.011 * \text{Depth} + 73.25)$$

$$\text{Pressure (psi)} = (0.487 * \text{Depth} - 324.8)$$

$$\text{Chloride (mg/l)} = (100.9 * \text{Depth} - 394.786)$$

where depth is in feet below kelly bushing (KB)

Using the above relationships, the temperature, pressure, and salinity at the top and bottom of the Arbuckle Group at the injection well site (KGS 1-28) are presented in Table 5.1.

Table 5.1—Temperature, pressure, and salinity at the top and bottom of the Arbuckle Group at the injection well site (KGS 1-28).

	Top of Arbuckle (4,168 ft)	Bottom of Arbuckle (5,160 ft)
Temperature (°F)	115	130
Pressure (psi)	1,705	2,188
Chloride (mg/l)	25,765	125,858

5.2.5 Arbuckle Groundwater Velocity

On a regional basis in the Arbuckle, groundwater flows from east to west, as shown in the potentiometric surface map presented in Figure 4.37. Groundwater velocity, however, is estimated to be very slow. The head in Sumner County drops approximately 100 ft over 20 mi (Figure 4.37), resulting in a head gradient of approximately 1.0e-03 ft/ft. Assuming an average large-scale Arbuckle porosity of approximately 6% and an average permeability of 10 mD, the pore velocity in the Arbuckle is approximately 0.2 ft/year, which is fairly small and can be neglected in specification of ambient boundary conditions for the purpose of this modeling study.

5.2.6 Model Operational Constraints

The bottomhole injection pressure in the Arbuckle should not exceed 90% of the estimated fracture gradient of 0.75 psi/ft (measured from land surface) as derived in Section 4.6.9. Therefore, the maximum induced pressure at the top and bottom of the Arbuckle Group should be less than 2,813 and 3,483 psi, respectively, as specified in Table 5.2. At the top of the perforations (4,910 ft), pressure will not exceed 2,563 psi.

Table 5.2—Maximum allowable pressure at the top and bottom of the Arbuckle Group based on 90% fracture gradient of 0.675 psi/ft.

Depth (feet, bls)	Maximum Pore Pressure (psi)
4,168 (Top of Arbuckle)	2,813
4,910 (Top of Perforation)	3,314
5,050 (Bottom of Perforation)	3,408
5,160 (Bottom of Arbuckle)	3,483

5.3 Geostatistical Reservoir Characterization of Arbuckle Group

Statistical reservoir geomodeling software packages have been used in the oil and gas industry for decades. The motivation for developing reservoir models was to provide a tool for better reconciliation and use of available hard and soft data (Figure 5.2). Benefits of such numerical models include 1) transfer of data between disciplines, 2) a tool to focus attention on critical unknowns, and 3) a 3-D visualization tool to present spatial variations to optimize reservoir development. Other reasons for creating high-resolution geologic models include the following:

- volumetric estimates
- multiple realizations that allow unbiased evaluation of uncertainties before finalizing a drilling program
- lateral and top seal analyses
- integration (i.e., by gridding) of 3-D seismic surveys and their derived attributes
- assessments of 3-D connectivity

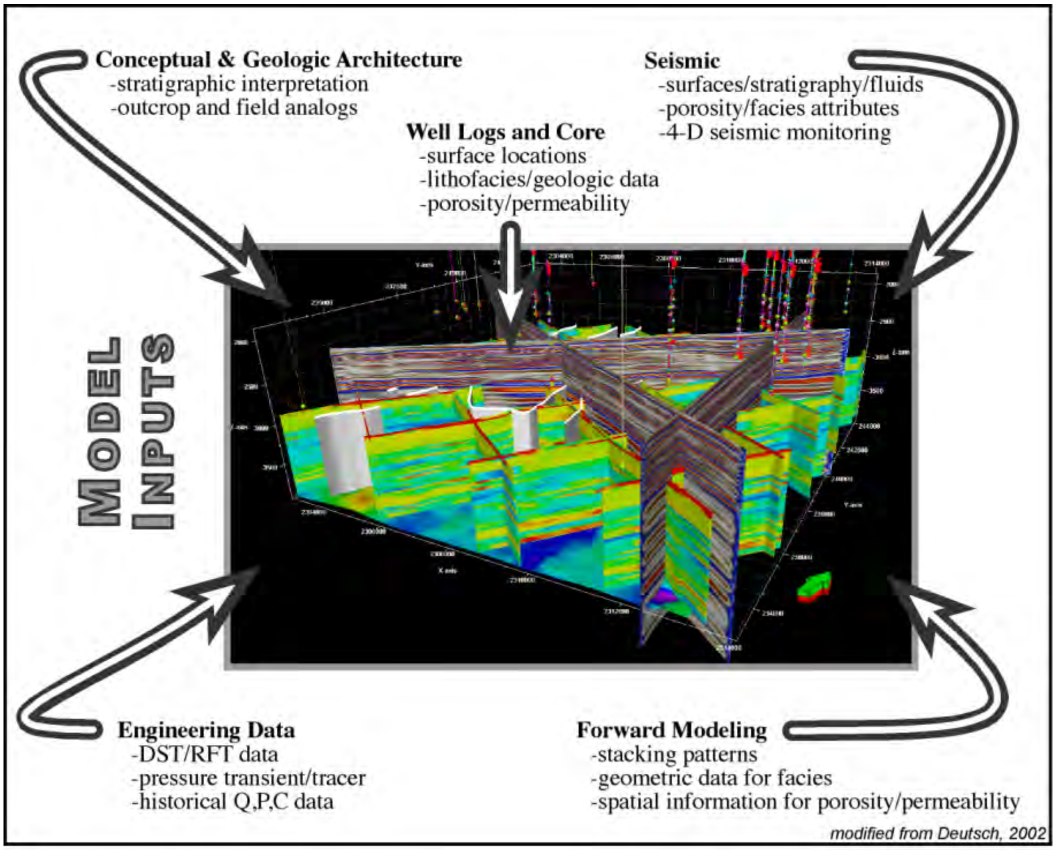


Figure 5.2—A static, geocellular reservoir model showing the categories of data that can be incorporated (source: modified from Deutsch, 2002)

- flow-simulation-based production forecasting using different well designs
- optimizing long-term development strategies to maximize return on investment.

Although geocellular modeling software has largely flourished in the energy industry, its utility can be important for reservoir characterization in CO_2 research and geologic storage projects, such as the Wellington Field. The objective in the Wellington project is to integrate various data sets of different scales into a cohesive model of key petrophysical properties, especially porosity and permeability. The general steps for applying this technology are to model the large-scale features followed by modeling progressively smaller, more uncertain, features. The first step applied at the Wellington field was to establish a conceptual depositional model and its characteristic stratigraphic layering. The stratigraphic architecture provided a first-order constraint on the spatial continuity of facies, porosity, permeability, saturations, and other attributes within each layer. Next, facies (i.e., rock fabrics) were modeled for each stratigraphic layer using cell-based or object-based techniques. Porosity was modeled by facies and conditioned to “soft” trend data, such as seismic inversion attribute volumes. Likewise, permeability was modeled by facies and collocated, co-Kriged to the porosity model.

5.3.1 Conceptual Model

Lower Arbuckle core from Wellington reflects sub-meter-scale, shallowing-upward peritidal cycles. The two common motifs are cycles passing from basal dolo-mudstones/wackestones into algal dolo-laminites or matrix-poor monomict breccias. Bioclasts are conspicuously absent. Breccias are clast-supported, monomictic, and angular, and their matrix dominantly consists of cement (Figure 5.3). They are best classified as crackle to mosaic breccias (Loucks, 1999) because there is little evidence of transportation. Lithofacies and stacking patterns (i.e., sub-meter scale, peritidal cycles) are consistent with an intertidal to supratidal setting. Breccia morphologies, scale (<0.1 m), mineralogy (e.g., dolomite, anhydrite, length-slow chalcedony), depositional setting, greenhouse climate, and paleo-latitude (~15º S) support mechanical breakdown processes associated with evaporite dissolution. The Arbuckle-Simpson contact (~800 ft above the proposed injection interval) records the super-sequence scale, Sauk-Tippecanoe unconformity, which records subaerial-related karst landforms across the Early Phanerozoic supercontinent Laurentia.

5.3.2 Facies Modeling

The primary depositional lithofacies were documented during core description at KGS 1-32. A key issue was reconciling inconsistencies (order of magnitude) between permeability measurements derived from wireline logs (i.e., nuclear resonance tool), whole core, and step-rate tests. Poor core recovery from the injection zone resulted from persistent jamming, which is commonly experienced in fractured or vuggy rocks. Image logs acquired over this interval record some intervals with large pores (cm scale) that are likely solution-enlarged vugs (touching-vugs of Lucia, 1999; Figure 5.4). Touching-vug fabrics commonly form a reservoir-scale, interconnected pore system characterized by Darcy-scale permeability. It is hypothesized that a touching-vug pore

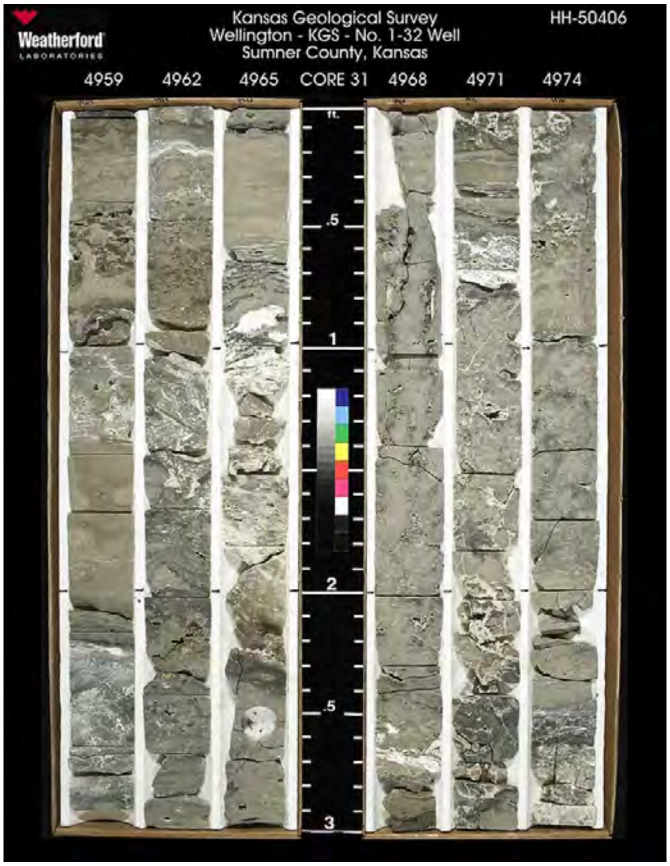


Figure 5.3—Example of the carbonate facies and porosity in the injection zone in the lower Arbuckle (part of the Gasconade Dolomite Formation). Upper half is light olive-gray, medium-grained dolomitic packstone with crackle breccia. Scattered subvertical fractures and limited cross stratification. Lower half of interval shown has occasional large vugs that crosscut the core consisting of a light olive-gray dolopackstone that is medium grained. Variable-sized vugs range from cm-size irregular to subhorizontal.

system preferentially developed within fracture-dominated crackle and mosaic breccias—*formed in response to evaporite removal*—which functioned as a strataform conduit for undersaturated meteoric fluids (Figure 5.5). As such, this high-permeability, interwell-scale, touching-vug pore system is largely strataform and, therefore, predictable.

5.3.3 Petrophysical Properties Modeling

The approach taken for modeling a particular reservoir can vary greatly based on available information and often involves a complicated orchestration of well logs, core analysis, seismic surveys, literature, depositional analogs, and statistics. Because well log data were available in only two wells (KGS 1-28 and KGS 1-32) that penetrate the Arbuckle reservoir at the Wellington site, the geologic model also relied on seismic data, step-rate test, and drill-stem test information. Schlumberger's Petrel™ geologic modeling software package was used to produce the current geologic model of the Arbuckle saline aquifer for the pilot project area. This geomodel extends

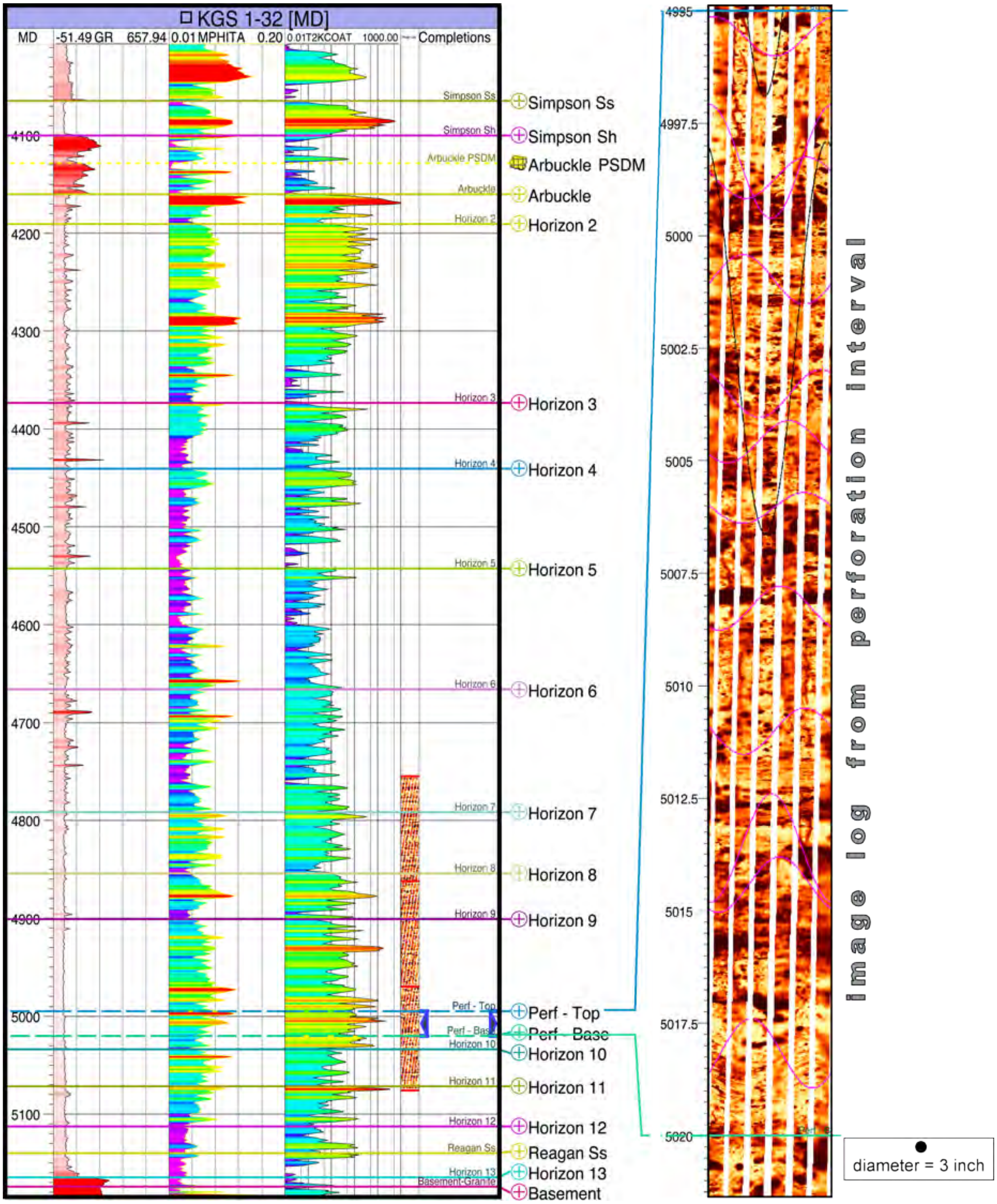


Figure 5.4—Geophysical logs within the Arbuckle Group at KGS 1-32. (Notes: MPHITA represents Haliburton porosity. Horizon markers represent porosity package. Image log on right presented to provide example of vugs; 3-in diameter symbol represents size of vug).

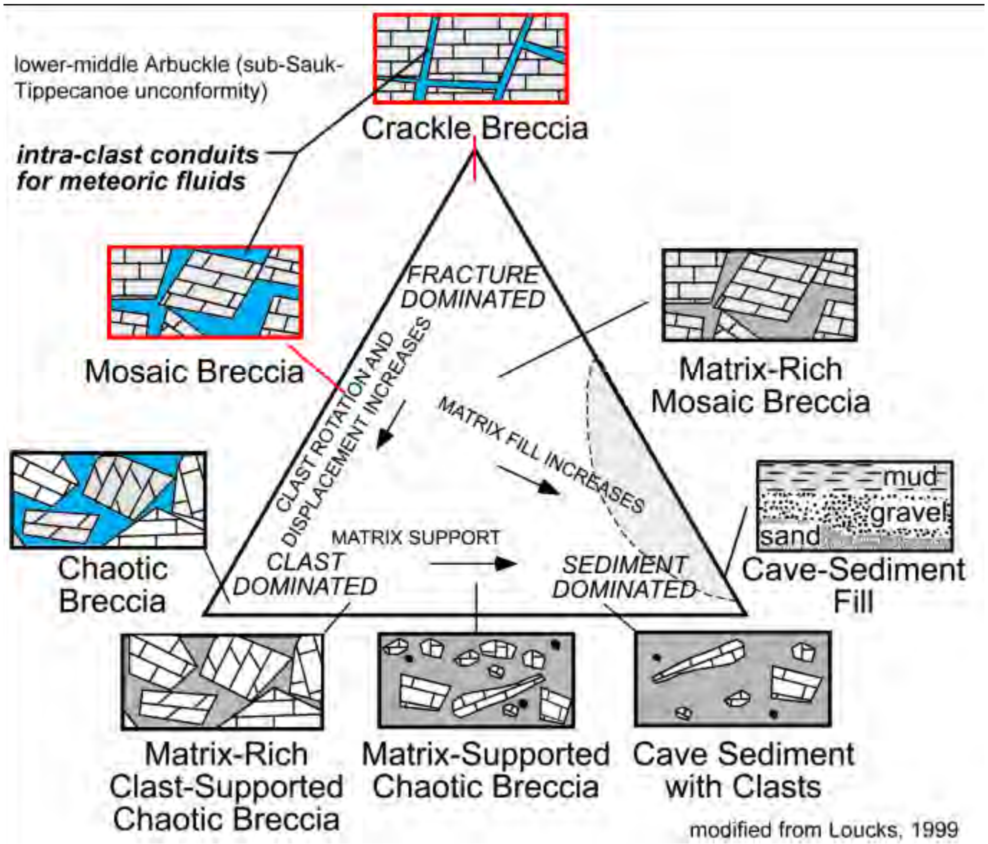


Figure 5.5—Classification of breccias and clastic deposits in cave systems exhibiting relationship between chaotic breccias, crackle breccias, and cave-sediment fill (source: Loucks, 1999).

4.25 mi by 4 mi laterally and is 1,075 ft deep, spanning the entire Arbuckle Group as well as a portion of the sealing units (Simpson/Chattanooga shale).

Porosity Modeling

In contrast to well data, seismic data are extensive over the reservoir and are, therefore, of great value for constraining facies and porosity trends within the geomodel. Petrel's volume attribute processing (i.e., genetic inversion) was used to derive a porosity attribute from the prestack depth migration (PSDM) volume to generate the porosity model (Figure 5.6). The seismic volume was created by re-sampling (using the original exact amplitude values) the PSDM 50 ft above the Arbuckle and 500 ft below the Arbuckle (i.e., approximate basement). The cropped PSDM volume and conditioned porosity logs were used as learning inputs during neural network processing. A correlation threshold of 0.85 was selected and 10,000 iterations were run to provide the best correlation. The resulting porosity attribute was then re-sampled, or upscaled (by averaging), into the corresponding 3-D property grid cell.

The porosity model was constructed using sequential Guassian simulation (SGS). The porosity logs were upscaled using arithmetic averaging. The raw upscaled porosity histogram was used during SGS. The final porosity model was then smoothed. The following parameters were used as inputs:

I. Variogram

a. Type: spherical

b. Nugget: 0.001

c. Anisotropy range and orientation

i. Lateral range (isotropic): 5,000 ft

ii. Vertical range: 10 ft

II. Distribution: actual histogram range (0.06–0.11) from upscaled logs

III. Co-Kriging

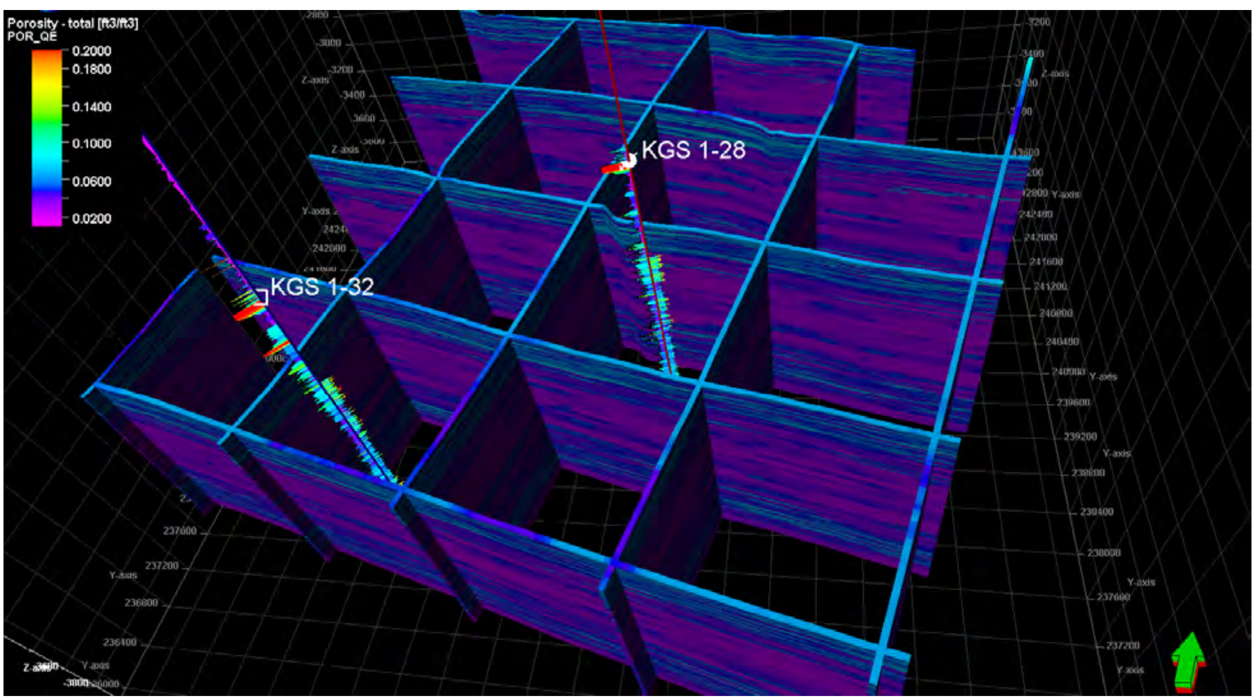


Figure 5.6—Upscaled porosity distribution in the Arbuckle Group based on the Petrel geomodel.

a. Secondary 3-D variable: inverted porosity attribute grid

b. Correlation coefficient: 0.75

Table 5.3 presents the minimum, maximum, and average porosity within the Arbuckle Group in the geomodel.

Table 5.3—Hydrogeologic property statistics in hydrogeologic characterization and simulation models.

	Reservoir Characterization Geomodel			Reservoir Simulation Numerical Model		
Property	min	max	avg	min	max	avg
Porosity (%)	3.2	12.9	6.8	3.2	12.9	6.7
Horizontal Permeability (mD)	0.05	2,955	134.2	0.05	2,955	130.7
Vertical Permeability (mD)	.005	1,567	387	0.005	1,567	385

Permeability Modeling

The upscaled permeability logs shown in Figure 5.4 were created using the following controls: geometric averaging method; logs were treated as points; and method was set to simple. The permeability model was constructed using SGS. Isotropic semi-variogram ranges were set to 3,000 ft horizontally and 10 ft vertically. The permeability was collocated and co-Kriged to the porosity model using the calculated correlation coefficient (~0.70). The resulting SGS-based horizontal and vertical permeability distributions are presented in Figure 5.7a-b.

Table 5.3 presents the minimum, maximum, and average permeabilities within the Arbuckle Group in the geomodel. An east-west cross-section of horizontal permeability through injection well (KGS 1-28) is presented in Figure 5.7c, which shows the relatively high permeability zone selected for completion within the injection interval.

5.4 Arbuckle Reservoir Flow and Transport Model

An extensive set of computer simulations were conducted to estimate the potential impacts of CO_2 injection in the Arbuckle injection zone. The key objectives were to determine the resulting rise in pore fluid pressure and the extent of CO_2 plume migration. The underlying motivation was to determine whether the injected CO_2 could affect the USDW or potentially escape into the atmosphere

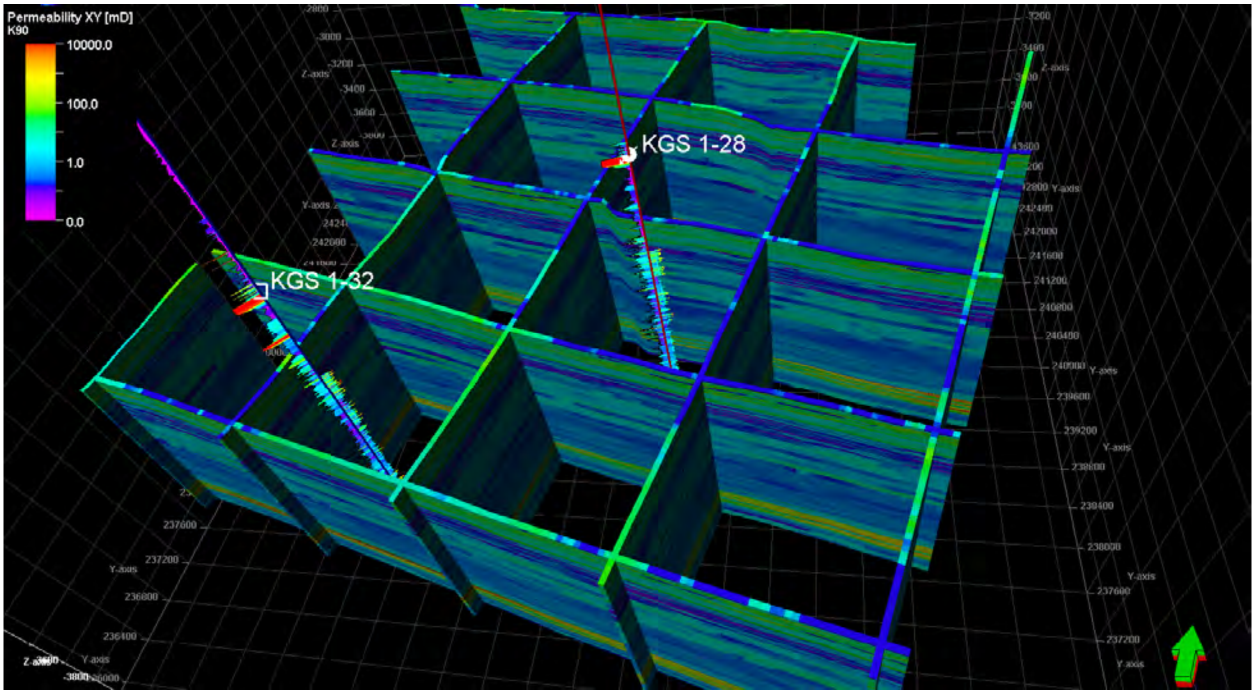


Figure 5.7a—Upscaled horizontal permeability (mD) distributions in the Arbuckle Group derived from Petrel geomodel .

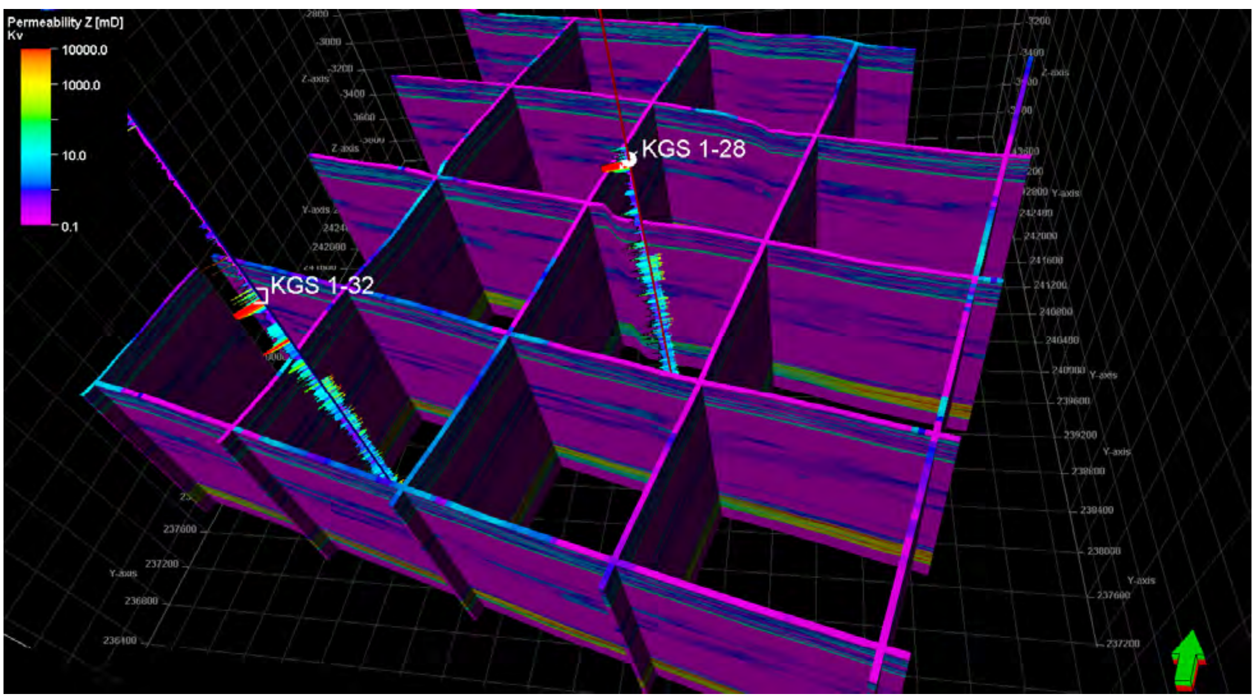


Figure 5.7b—Upscaled vertical permeability (mD) distributions in the Arbuckle Group derived from Petrel geomodel.

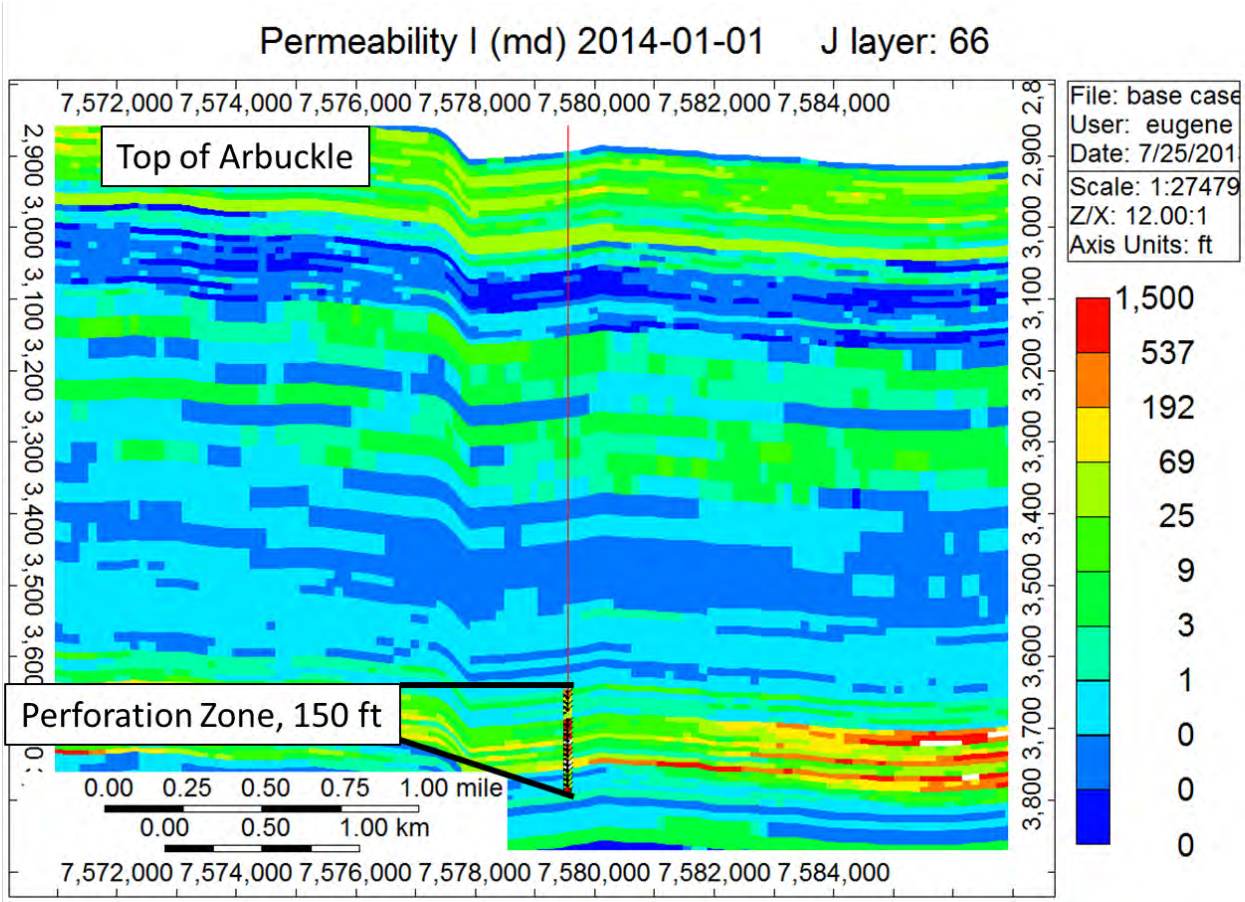


Figure 5.7c—Horizontal permeability (mD) distribution within an east-west cross section through the injection well (KGS 1-28).

through existing wells or hypothetical faults/fractures that might be affected by the injected fluid.

As in all reservoirs, there are data gaps that prevent an absolute or unique characterization of the geology and petrophysical properties. This results in conceptual, parametric, and boundary condition uncertainties. To address these uncertainties, a comprehensive set of simulations were conducted to perform a sensitivity analysis using alternative parameter sets. A key objective was to ensure specification of parameter sets that would result in the most negative impacts (the worst-case scenario; i.e., maximum formation pressures and largest extent of plume migration). However, simulations involving alternative parameter and boundary conditions that resulted in more favorable outcomes were also conducted to bracket the range of possible induced system states and outcomes.

5.4.1 Simulation Software Description

The reservoir simulations were conducted using the Computer Modeling Group (CMG) GEM simulator. GEM is a full equation of state compositional reservoir simulator with advanced features for modeling the flow of three-phase, multi-component fluids and has been used to conduct numerous CO_2 studies (Chang et al., 2009; Bui et al., 2010). It is considered by DOE to be an industry standard for oil/gas and CO_2 geologic storage applications. GEM is an essential engineering tool for modeling complex reservoirs with complicated phase behavior interactions that have the potential to impact CO_2 injection and transport. The code can account for the thermodynamic interactions between three phases: liquid, gas, and solid (for salt precipitates). Mutual solubilities and physical properties can be dynamic variables depending on the phase composition/system state and are subject to well-established constitutive relationships that are a function of the system state (pressures, saturation, concentrations, temperatures, etc.). In particular, the following assumptions govern the phase interactions:

- Gas solubility obeys Henry's Law (Li and Nghiem, June 1986)
- The fluid phase is calculated using Schmit-Wenzel or Peng-Robinson (SW-PR) equations of state (Soreide-Whitson, 1992)
- Changes in aqueous phase density with CO_2 solubility, mineral precipitations, etc., are accounted for with the standard or Rowe and Chou correlations.
- Aqueous phase viscosity is calculated based on Kestin, Khalifa, and Correia (1981).

5.4.2 Model Mesh and Boundary Conditions

The Petrel-based geomodel mesh discussed above consists of a 706 x 654 horizontal grid and 79 vertical layers for a total of 36,476,196 cells. The model domain encompasses a 17 mi^2 area and the formations from the base of the Arbuckle Group to Chattanooga and Simpson Group formations from depths of 4,100 to 5,175 ft BGL at KGS 1-28. To reduce reservoir simulation time, this model was upscaled to a 157 x 145 horizontal mesh with 79 layers for a total of 1,798,435 cells to represent the same rock volume for use in the CMG simulator. The fluid flow model was divided into 79 layers. The thickness of the layers varies from 5 to 20 ft based on the geomodel, with an average of 13 feet.

Based on preliminary simulations, it was determined that due to the small scale of injection and the presence of a competent confining zone, the plume would be contained within the Arbuckle system for all alternative realizations of reservoir parameters. Therefore, the reservoir model domain was restricted to the Arbuckle aquifer with no-flow boundaries specified along the top (Simpson Group) and bottom (Precambrian basement) of the Arbuckle group. As discussed in Section 5.2.1, the specification of no-flow boundaries along the top and bottom of the Arbuckle Group is justified because of the low permeabilities in the overlying and underlying confining zones as discussed in Section 4.7.3. The permeability in the Pierson formation was estimated to be as low as 1.6 nanoDarcy (nD; 1.0^{-9} Darcy).

The simulation model, centered approximately on the injection well (KGS 1-28), extends approximately 4 mi in the east-west and 4.25 mi in the north-south orientations. Vertically, the model extends approximately 1,050 ft from the top of the Precambrian basement to the bottom of the Simpson Group. As discussed above, the model domain was discretized laterally by 157 x 145 cells in the east-west and north-south directions and vertically in 79 layers. The lateral boundary conditions were set as an infinite-acting Carter-Tracy aquifer (Dake, 1978; Carter and Tracy, 1960) without leakage. Sensitivity analyses indicated that there was negligible difference in the simulation results pressures due to specification of non-leaky Carter-Tracy boundary as compared to a leaky Carter-Tracy boundary or a closed no-flow lateral boundary.

5.4.3 Hydrogeologic Properties

Geologic and hydrologic data pertaining to the Arbuckle Group are detailed in Sections 3 and 4 of the permit application. As discussed in Section 5.3, site-specific hydrogeologic properties were used to construct a geomodel at the Wellington site. The porosity and permeability of the geomodel were upscaled to the coarser grid using a weighted averaging approach so that the total pore space volume (2.99×10^{10} ft^3) in the Petrel geomodel was maintained in the upscaled reservoir simulation model. As shown in Figures 5.8a-b and 5.9, the qualitative representation (i.e., the shape) of the permeability and porosity distribution remained similar in both the geo and reservoir models. The upscaled reservoir grid was imported from Petrel into CMG Builder, where the model was prepared for dynamic simulations assuming an equivalent porous medium model with flow limited to only the rock matrix. The minimum, maximum, and average porosity and permeabilities in the reservoir model are documented in Table 5.3 alongside the statistics for the geomodel.

Because of the absence of published capillary pressure and relative permeability relationships for the Arbuckle in Kansas, the simulations used the relative permeability function governing multi-phase flow in fractured carbonate-CO_2-brine system as proposed by Bennion and Bachu (2007) (Figure 5.10).

5.4.4 Initial Conditions and Injection Rates

The initial conditions specified in the reservoir model are specified in Table 5.4. The simulations were conducted assuming isothermal conditions. Although isothermal conditions were assumed, a thermal gradient of 0.008 °C/ft was considered for specifying petrophysical properties that vary with layer depth and temperature such as CO_2 relative permeability, CO_2 dissolution in formation water, etc. The original static pressure in the injection zone (at a reference depth of 4,960 ft) was set to 2,093 psi and the Arbuckle pressure gradient of 0.48 psi/ft (discussed in Section 4) was assumed for specifying petrophysical properties. A 140-ft thick perforation zone in well KGS 1-28 was specified between 4,910 and 5,050 ft. A constant brine density of 68.64 lbs/ft^3 (specific gravity of 1.1) was assumed. A total of 40,000 metric tons of CO_2 was injected in the Arbuckle formation over a period of nine months at an average injection rate of 150 tons/day.

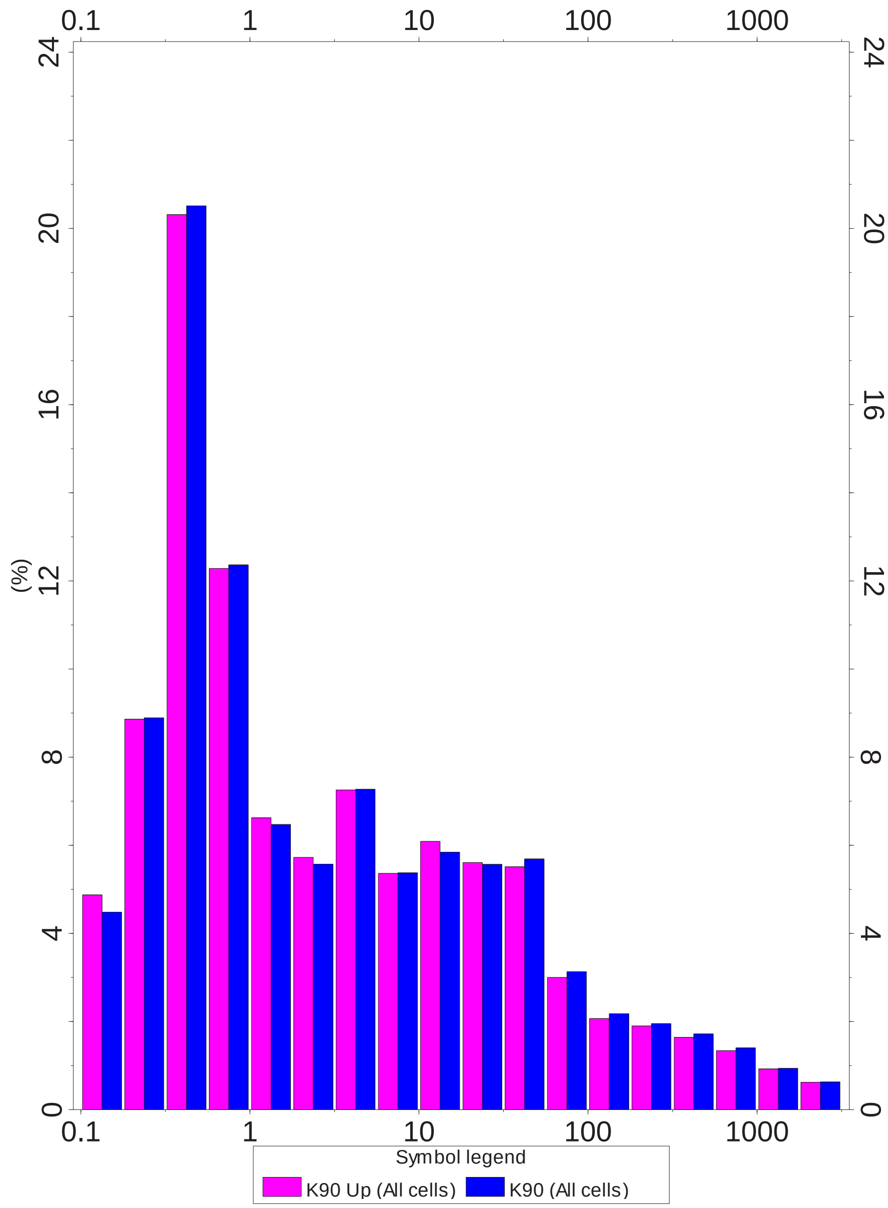


Figure 5.8a—Horizontal permeability distribution histogram comparison for original and upscaled model properties. (Note: x-axis represents permeability in milliDarcy, mD.)

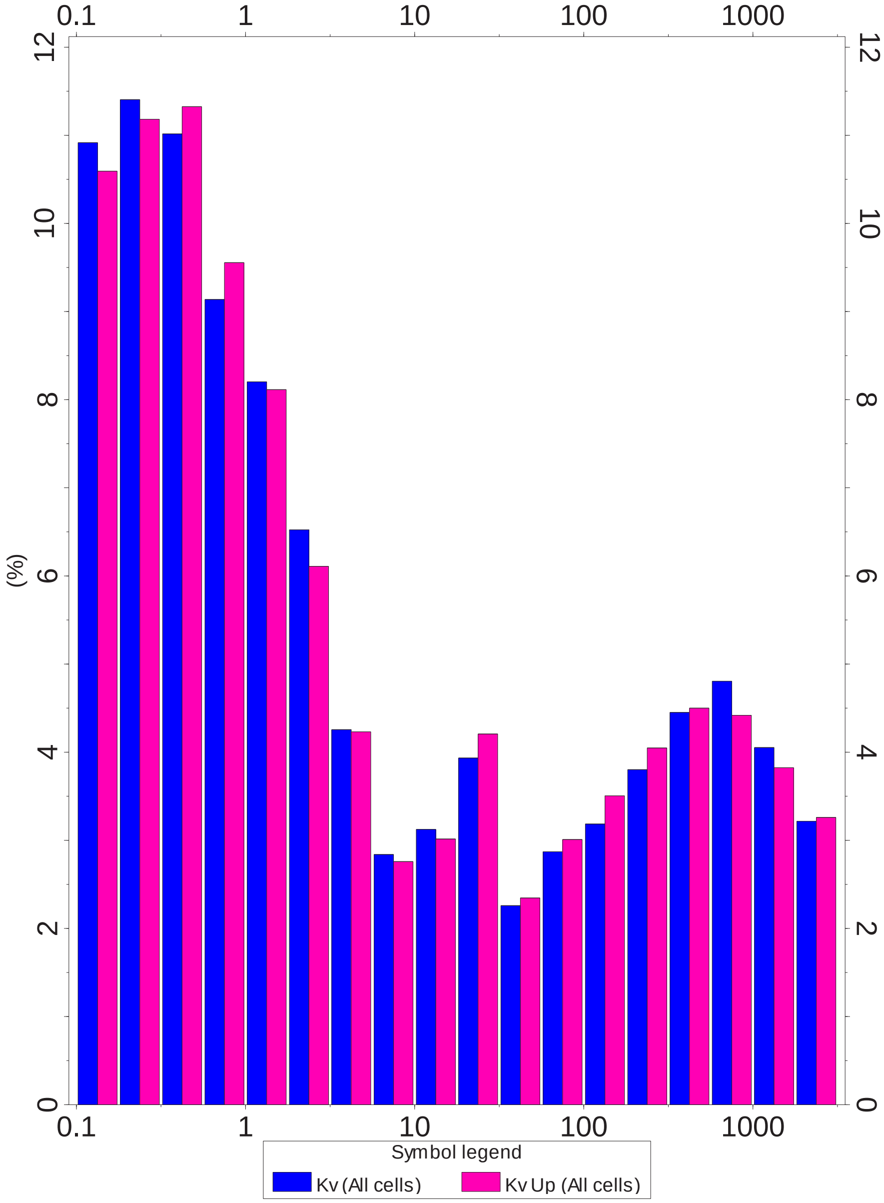


Figure 5.8b—Vertical permeability distribution histogram comparison for original and upscaled model properties. (Note: x-axis represents permeability in milliDarcy, mD.)

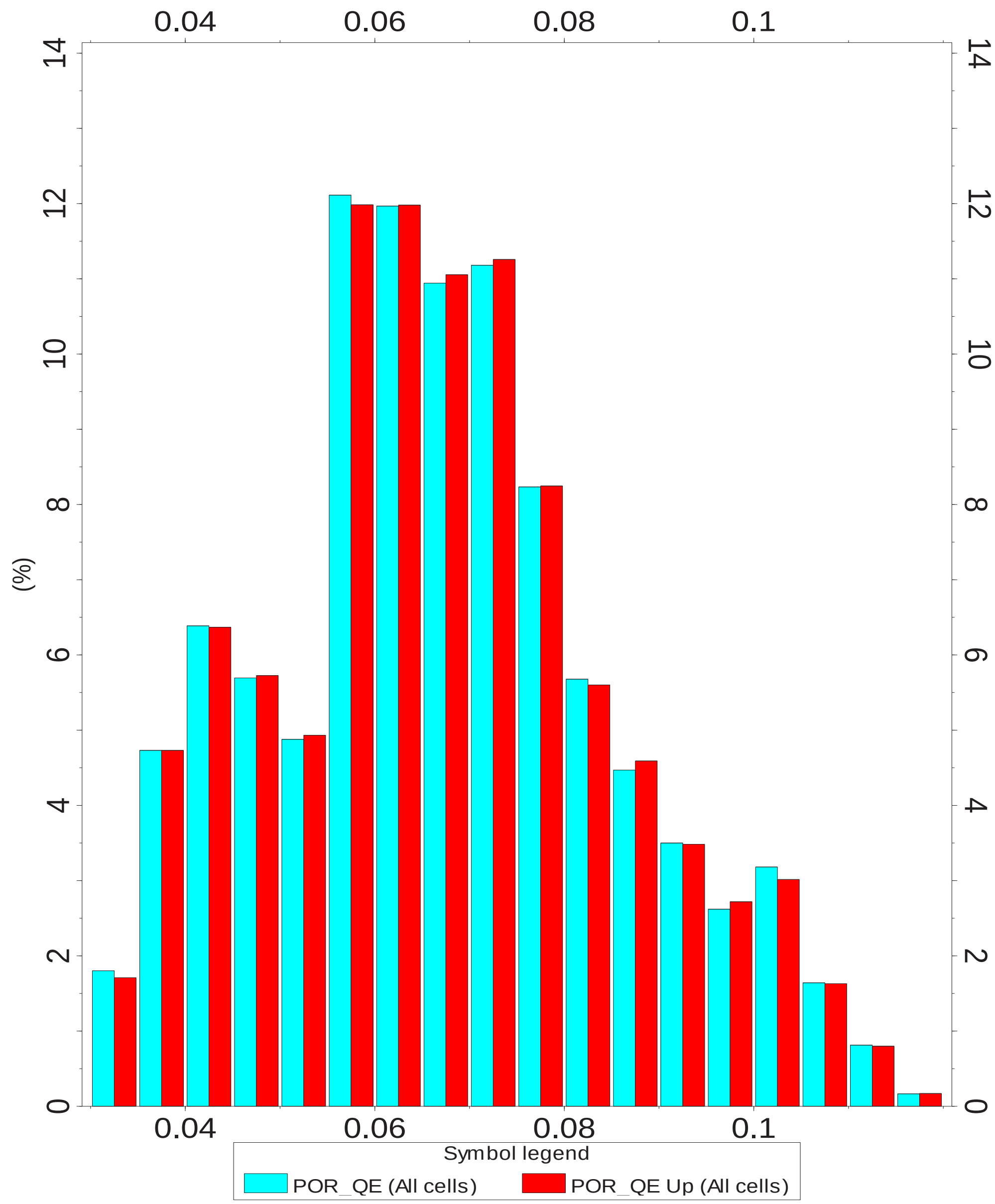
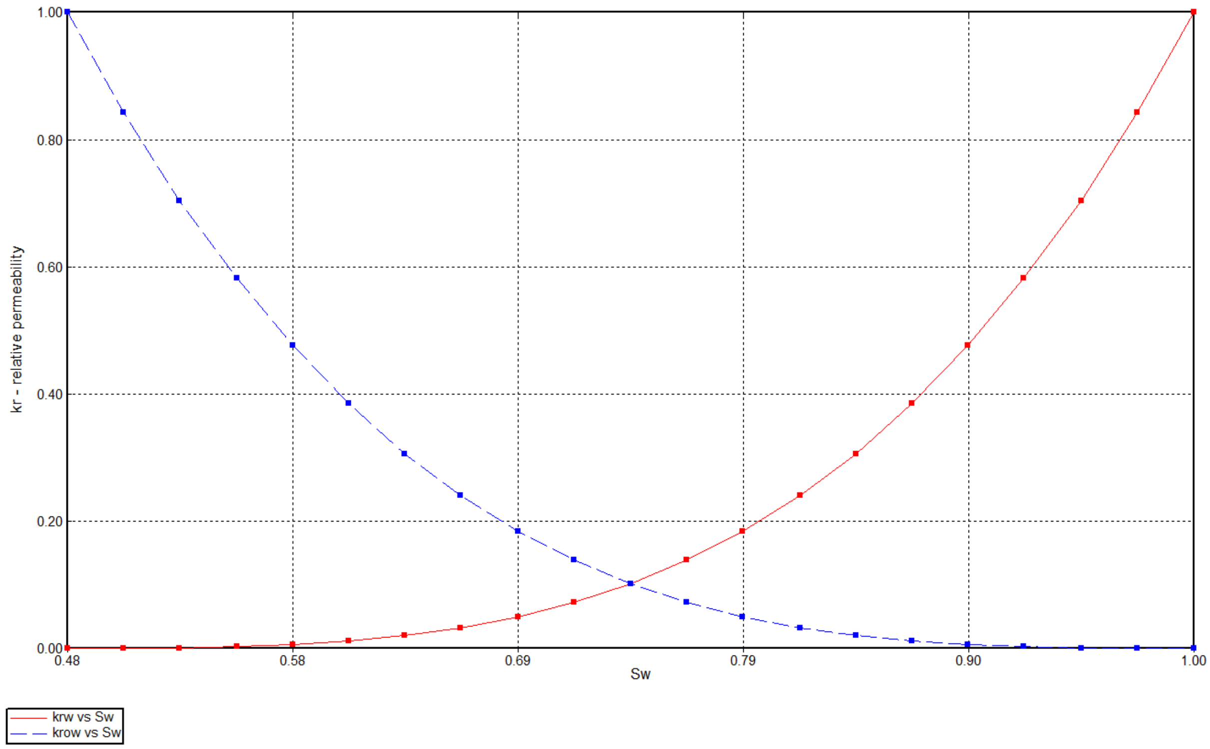


Figure 5.9—Porosity distribution histogram comparison for original and upscaled model properties. (Note: x-axis represents porosity.)



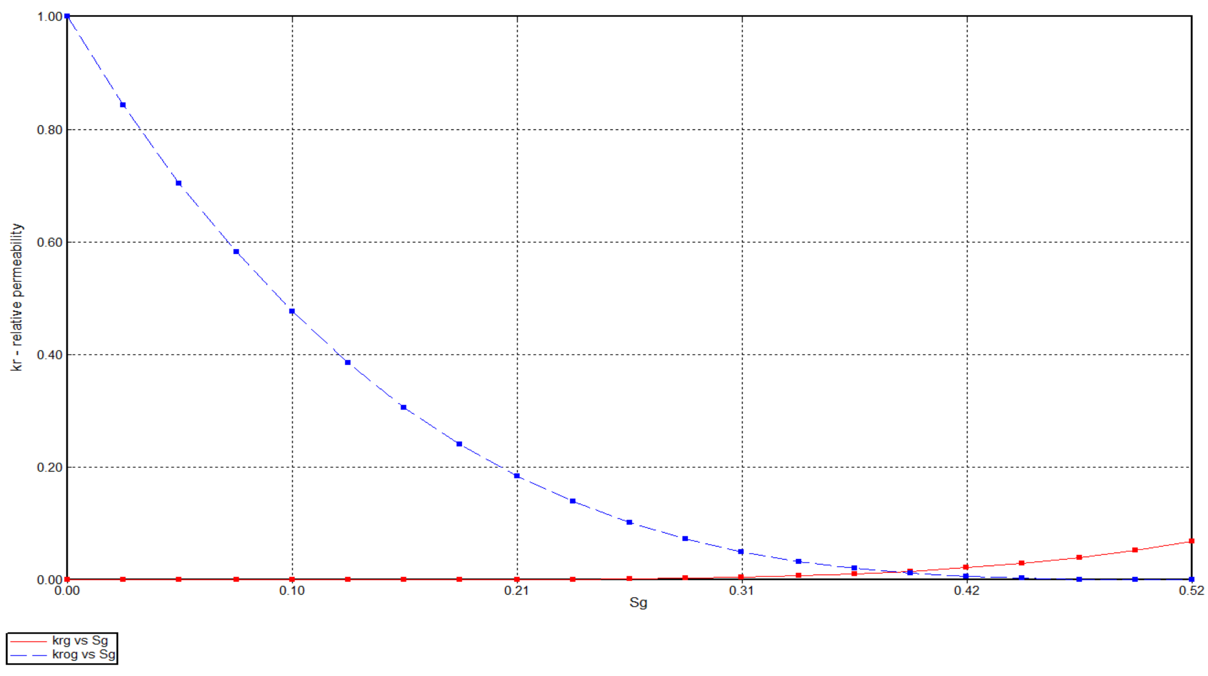


Figure 5.10—Relative permeability as a function of water and gas saturation (source: Bennion and Bachu [2007]).

Table 5.4—Model input specification and CO_2 injection rates.

Temperature	60 °C (140 °F)
Temperature Gradient	0.008 °C/ft
Pressure	2,093 psi (14.43 MPa) @ 4,960 ft RKB
Perforation Zone	4,910-5,050 ft
Perforation Length	140 ft (model layers 54 to 73)
Injection Period	9 months
Injection Rate	150 tons/day
Total CO_2 injected	40,000 MT

5.4.5 Alternative Models

The base-case reservoir model has been carefully constructed using a sophisticated geomodel as discussed in Section 5.3, which honors site-specific hydrogeologic information obtained from laboratory tests and log-based analyses. However, to account for hydrogeologic uncertainties, a set of alternate parametric models were developed by varying the porosity and horizontal hydraulic permeability. Specifically, the porosity and permeability were increased and decreased by 25% following general industry practice (FutureGen Industrial Alliance, 2013). This resulted in nine alternative models, listed in Table 5.5. Simulation results based on all nine models were evaluated to derive the worst-case impacts on pressure and migration of the plume front for purposes of establishing the AoR and ensuring that operational constraints are not exceeded.

Table 5.5—Nine alternative permeability-porosity combination models. (Showing multiplier of base-case permeability and porosity distribution assigned to all model cells.)

Alternative Models	Base Porosity x 0.75	Base Porosity	Base Porosity x 1.25
Base Permeability x 0.75	K-0.75/Phi-0.75	K-0.75/Phi-1.0	K-0.75/Phi-1.25
Base Permeability	K-1.0/Phi-0.75	K-1.0/Phi-1.0	K-1.0/Phi-1.25
Base Permeability x 1.25	K-1.25/Phi-0.75	K-1.25/Phi-1.0	K-1.25/Phi-1.25

5.4.6 Reservoir Simulation Results

For the simulations, 40,000 metric tons (MT) of CO_2 were injected into the KGS 1-28 well at a constant rate of approximately 150 tons per day for a period of nine months. A total of nine models representing three sets of alternate permeability-porosity combinations as specified in Table 5.5 were simulated with the objective of bracketing the range of expected pressures and extent of CO_2 plume migration.

The extent of lateral plume migration depends on the particular combination of permeability-porosity in each of the nine alternative models. These two parameters are independently specified in CMG as they are assumed to be decoupled. A high-permeability value results in farther travel of the plume due to gravity override, bouyancy, and updip migration. Similarly, a low effective porosity for the same value of permeability results in farther travel for the plume as compared to high porosity as the less-connected pore volume results in faster pore velocity. The high-permeability/low-porosity combination (k-1.25/phi-0.75) resulted in the largest horizontal plume dimension. In contrast, the highest induced pressures were obtained for the alternative model with the lowest permeability and the lowest porosity (k-0.75/phi-0.75). The results for these alternative models are discussed below along with the base-case model (k-1.0/phi-1.0).

5.4.6.1 CO_2 Plume Migration

Figure 5.11a–f shows the maximum lateral migration of the CO_2 plume in the injection interval (elevation 5,010 ft) for the largest areal migration case (k-1.25/phi-0.75). The plume grows rapidly during the injection phase (Figure 5.11a–c) and is largely stabilized by the end of the first year (Figure 5.11d). The plume at the end of 100 years (Figure 5.11f) has spread only minimally since cessation of injection and has a maximum lateral spread of approximately 1,750 ft from the injection well. It does not intercept any well other than the proposed Arbuckle monitoring well KGS 2-28, which as documented in Section 10, will be constructed in compliance with Class VI injection well guidelines.

The evolution of the maximum lateral extent of the plume is shown in Figure 5.12 for the maximum plume spread case (k-1.25/phi-0.75) along with the base case (k-1.0/phi-1.0) and the maximum pressure case (k-0.75/phi-0.75). As can be inferred from the plot, the extent of maximum lateral migration is fairly similar for all three cases, and the plume has largely stabilized within three months of cessation of injection for all three cases.

The CO_2 plumes discussed above represent CO_2 in both the dissolved and free phases. The lighter free-phase CO_2, which could potentially rise to the USDW if any hypothetical vertical pathways were present inside the plume boundary, has a slightly smaller footprint, as shown in Figures 5.13a–f, which depicts the evolution of the free-phase plume from commencement of injection to 100 years after injection stops. The free-phase plume grows rapidly during the injection period and then continues growing gradually thereafter. The free-phase plume, however, is always contained within the total CO_2 plume (i.e., CO_2 in the dissolved and free phases). The stabilized free-phase plume at 100 years is shown in Figure 5.13g along with the total CO_2 plume at 100 years. The free-phase plume has a maximum lateral extent of approximately 1,700 ft and is contained within the total CO_2 plume. The plume only intercepts the proposed Arbuckle monitoring well KGS 2-28, which will be built to be in compliance with Class VI design and construction requirements. There are no additional natural or artificial penetrations that will allow CO_2 to escape upward into the USDW.

The extent of vertical plume migration for the fast vertical migration case (k-1.25/phi-0.75) is also shown in Figures 5.11a–g and 5.13 a–g. Both the dissolved and the free-phase plumes remain confined in the injection interval (lower Arbuckle) because of the presence of the low-permeability baffle zones above the injection interval. This same information is shown in Figure 5.14, which shows the maximum extent of vertical migration for the base case and two alternative cases discussed above. For all three cases, the plume remains confined in the injection interval in the lower Arbuckle.

The simulation results discussed above are expected to represent conservative estimates of plume migration. This is because the present CMG simulations neglects mineral sequestration trapping and capillary forces. The effects of capillary forces, however, were studied in preliminary modeling exercises and were found to have a negligible effect on reservoir pore pressure response and extent of CO_2 lateral movement. Additionally, the modeling results presented in this document do not simulate convection cells, which as demonstrated recently by Pau et al. (2010) can greatly

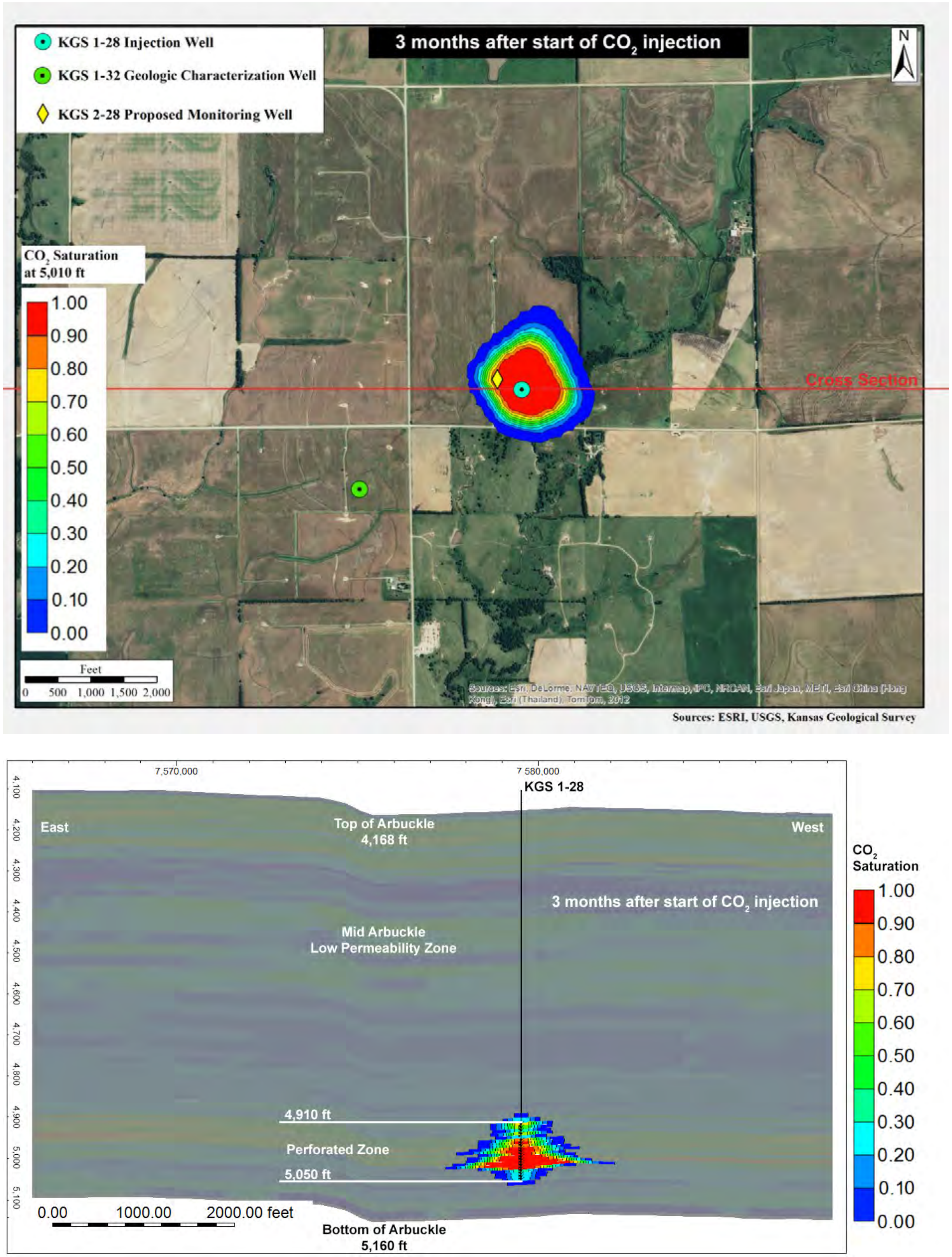
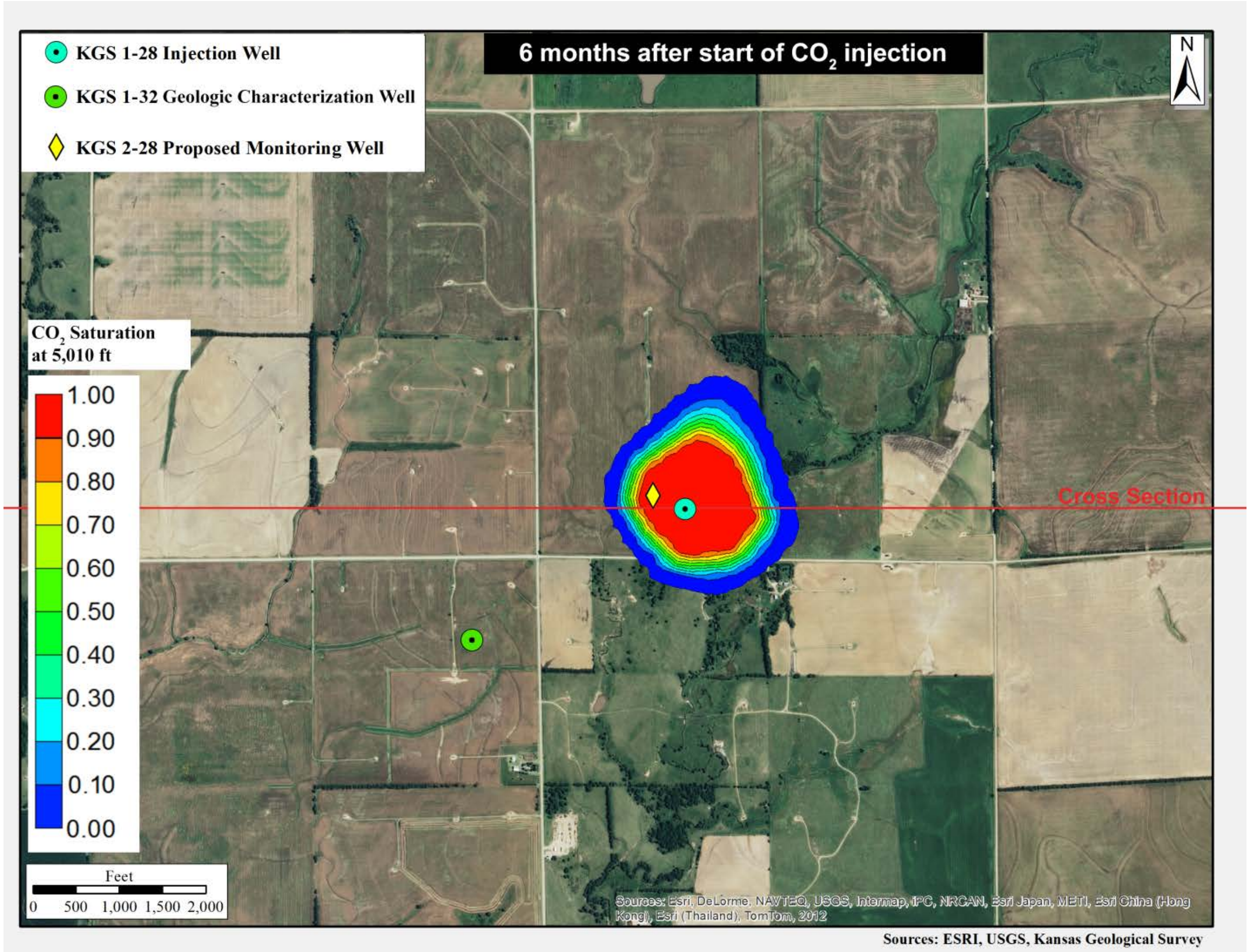


Figure 5.11a—CO_2 plume in aerial and cross-sectional view in the injection interval for the largest plume migration alternative model (k-1.25/phi-0.75) at three months from start of injection. Background represents horizontal permeability distribution.



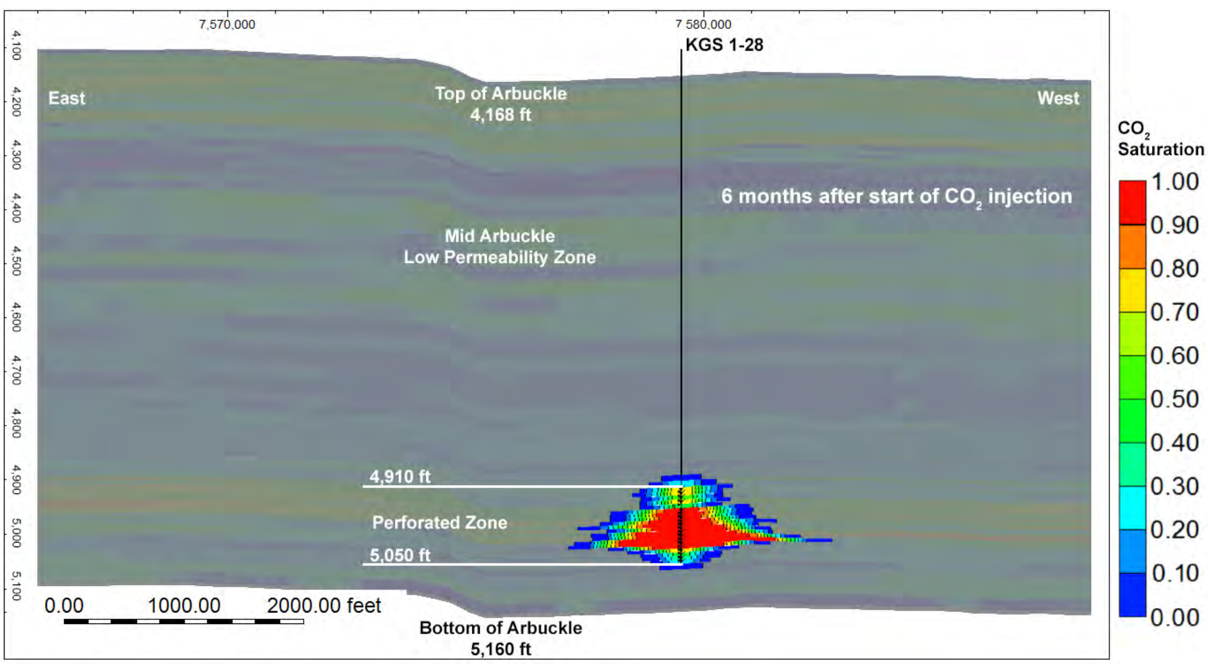
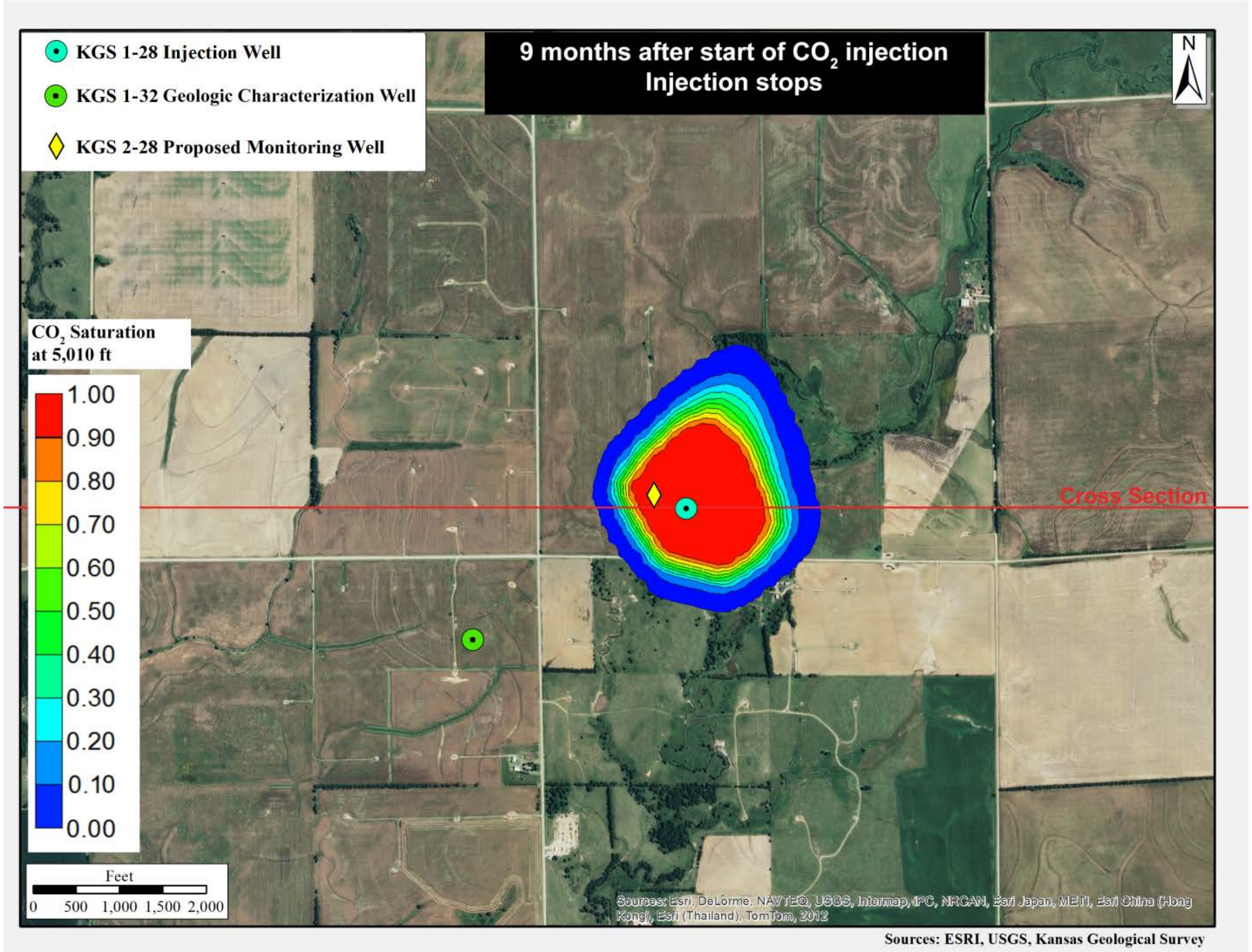


Figure 5.11b—CO_2 plume in aerial and cross-sectional view in the injection interval for the largest plume migration alternative model (k-1.25/phi-0.75) at six months from start of injection.



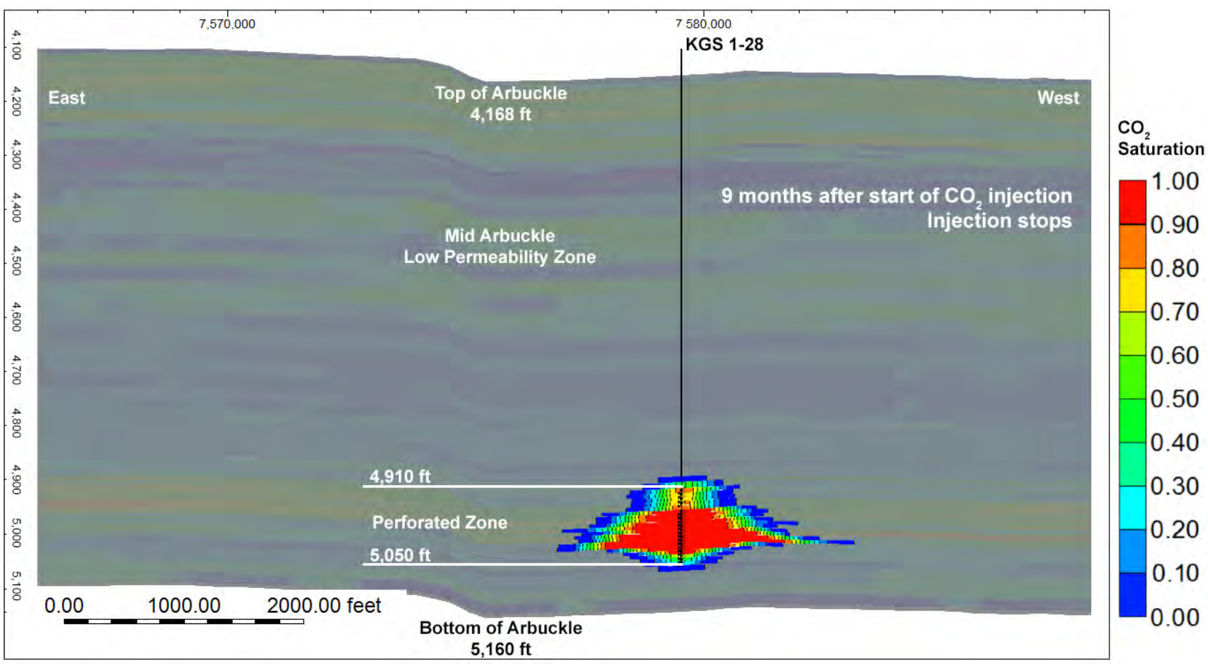
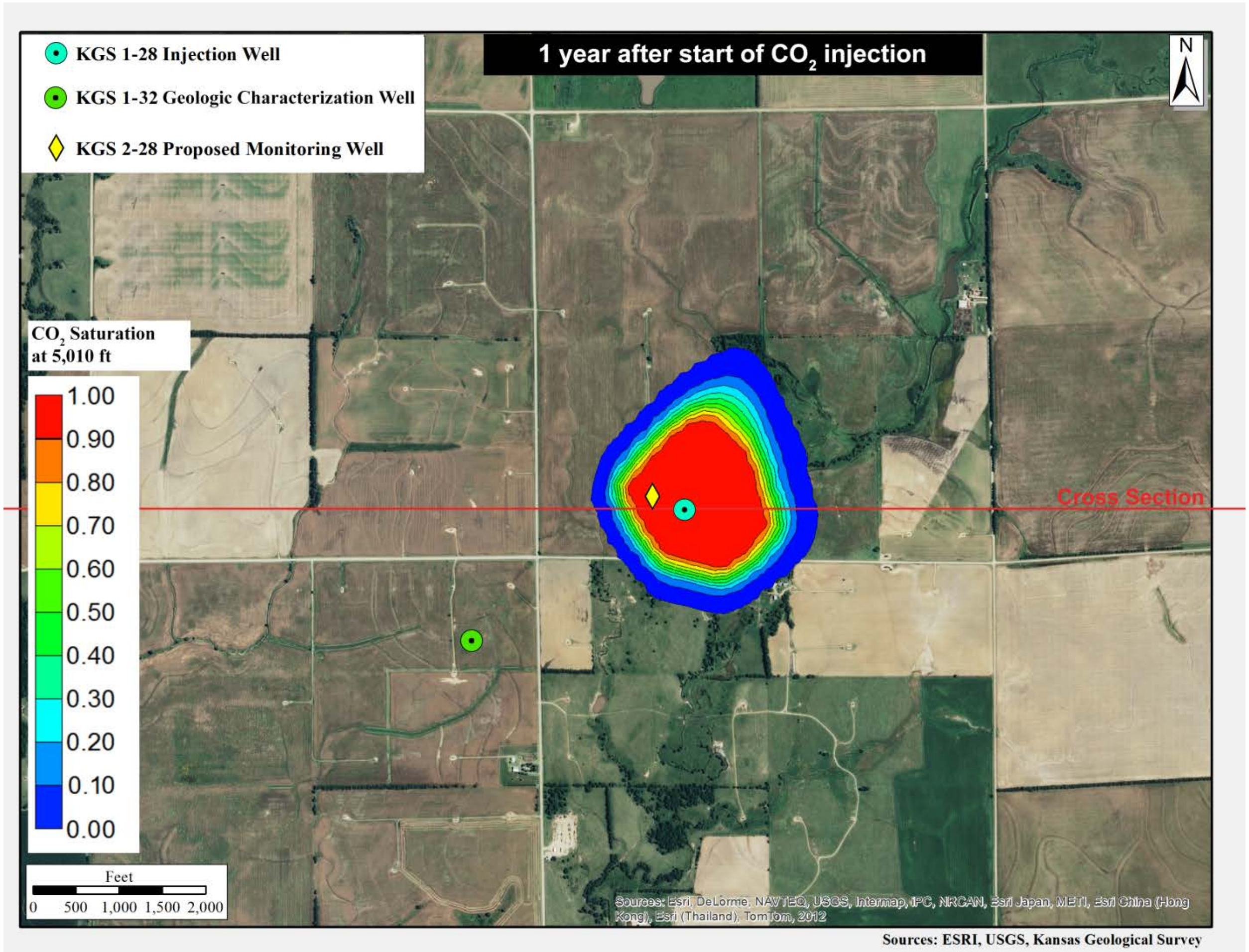


Figure 5.11c—CO_2 plume in aerial and cross-sectional view in the injection interval for the largest plume migration alternative model (k-1.25/phi-0.75) at nine months from start of injection.



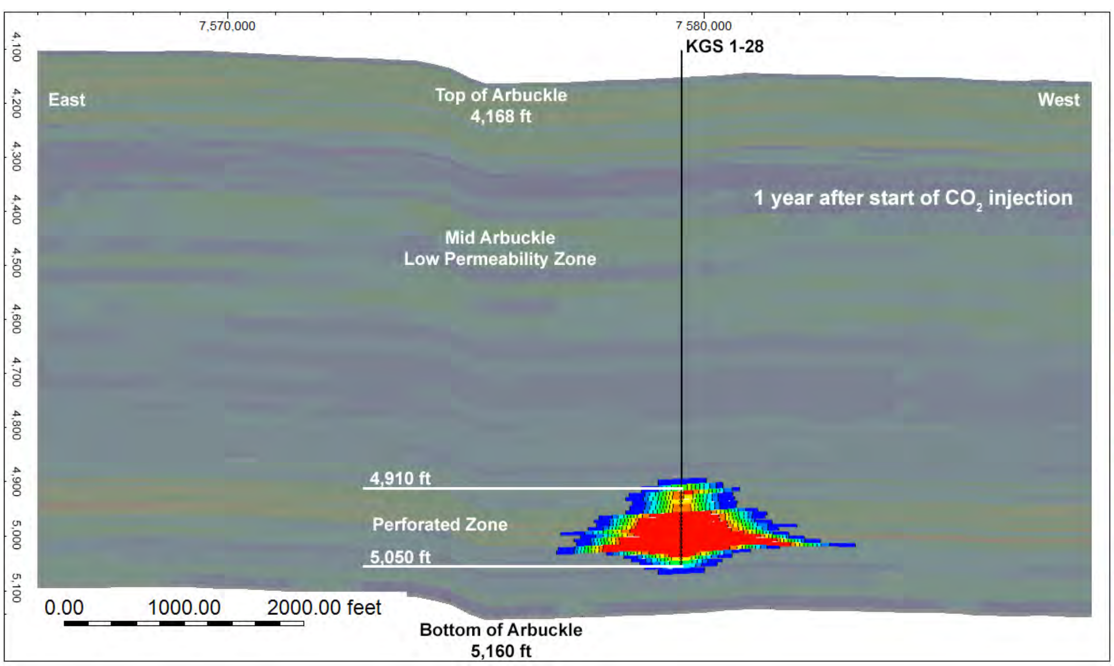


Figure 5.11d—CO_2 plume in aerial and cross-sectional view in the injection interval for the largest plume migration alternative model (k-1.25/phi-0.75) at one year from start of injection.

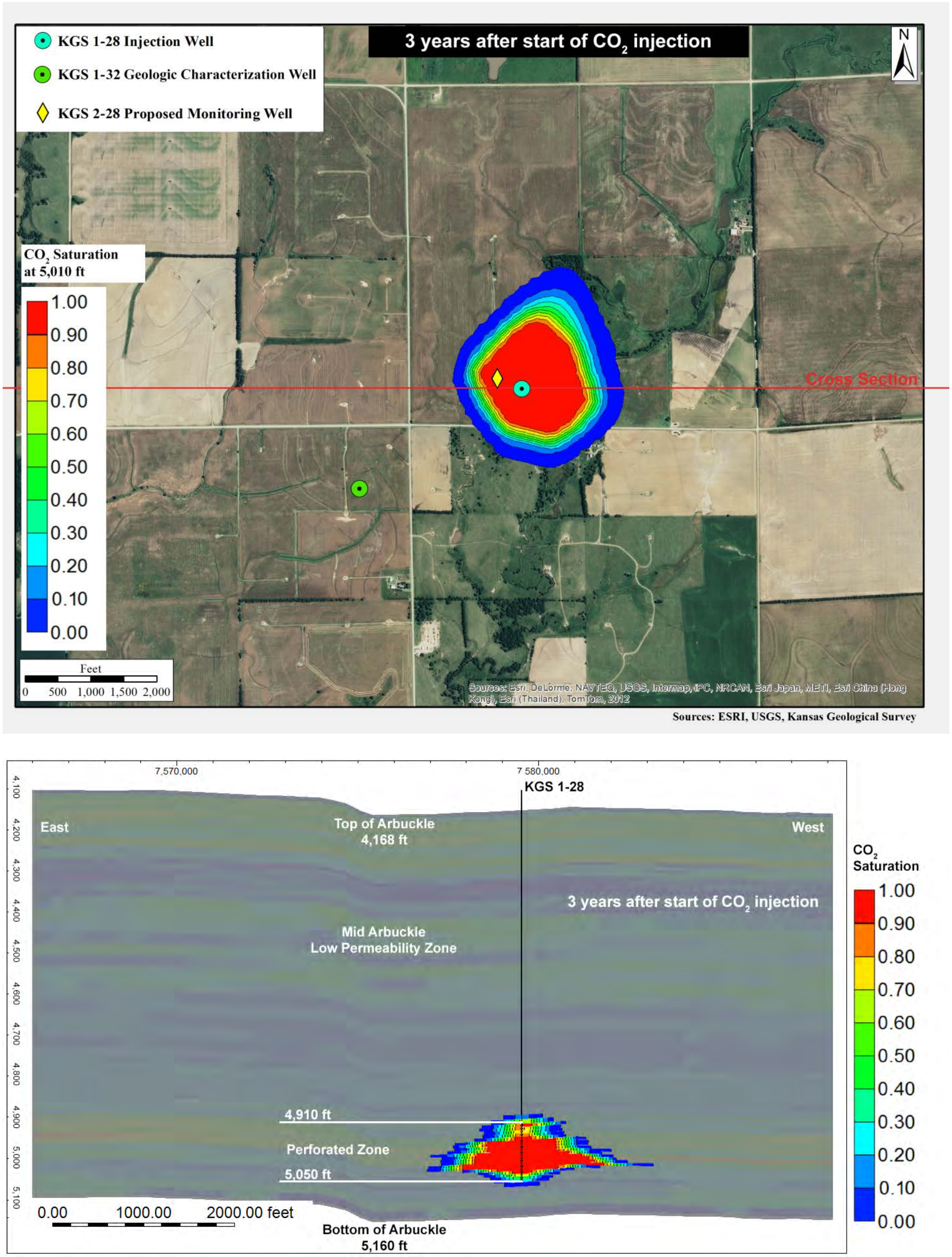


Figure 5.11e—CO_2 plume in aerial and cross-sectional view in the injection interval for the largest plume migration alternative model (k-1.25/phi-0.75) at three years from start of injection.

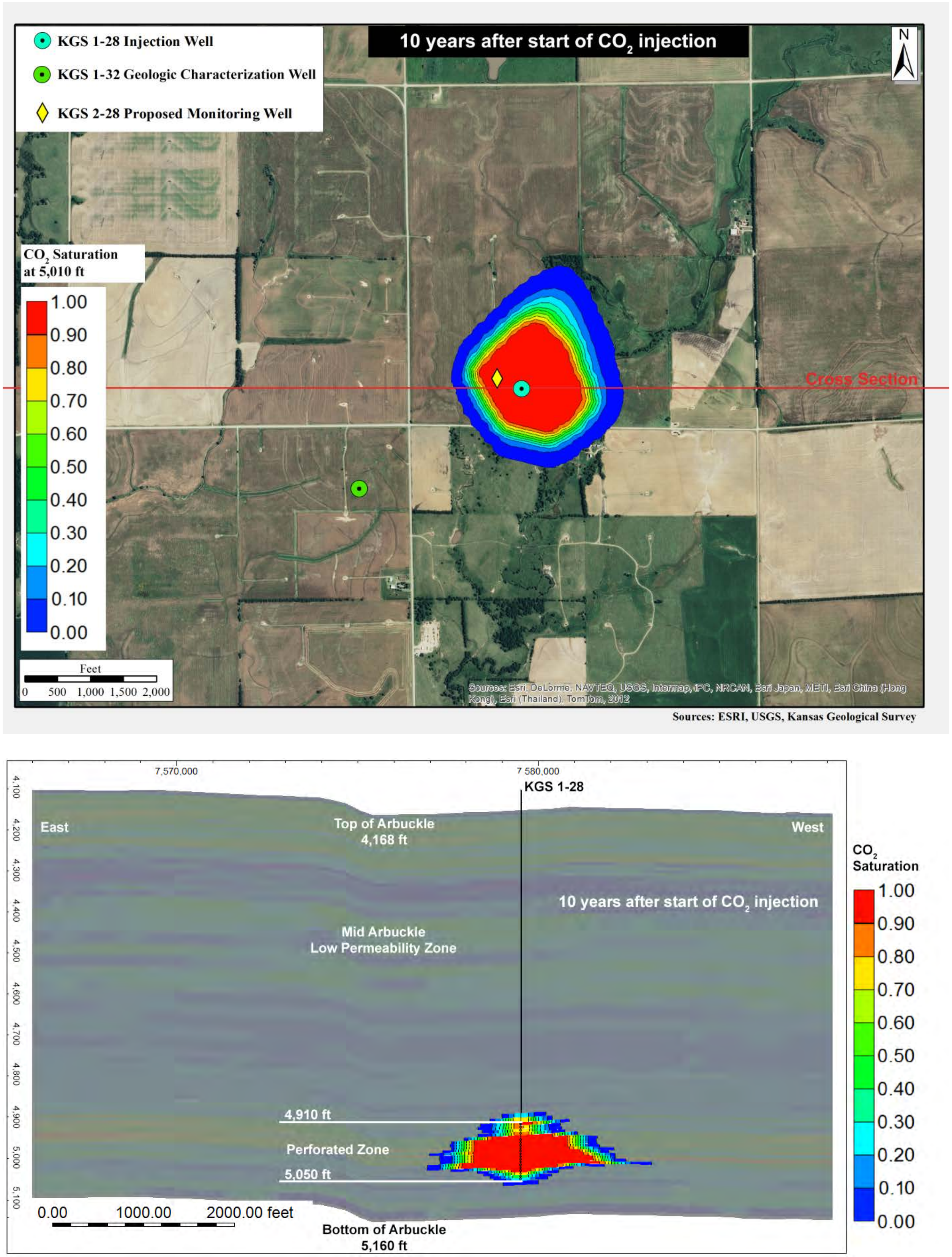


Figure 5.11f—CO_2 plume in aerial and cross-sectional view in the injection interval for the largest plume migration alternative model (k-1.25/phi-0.75) at 10 years from start of injection.

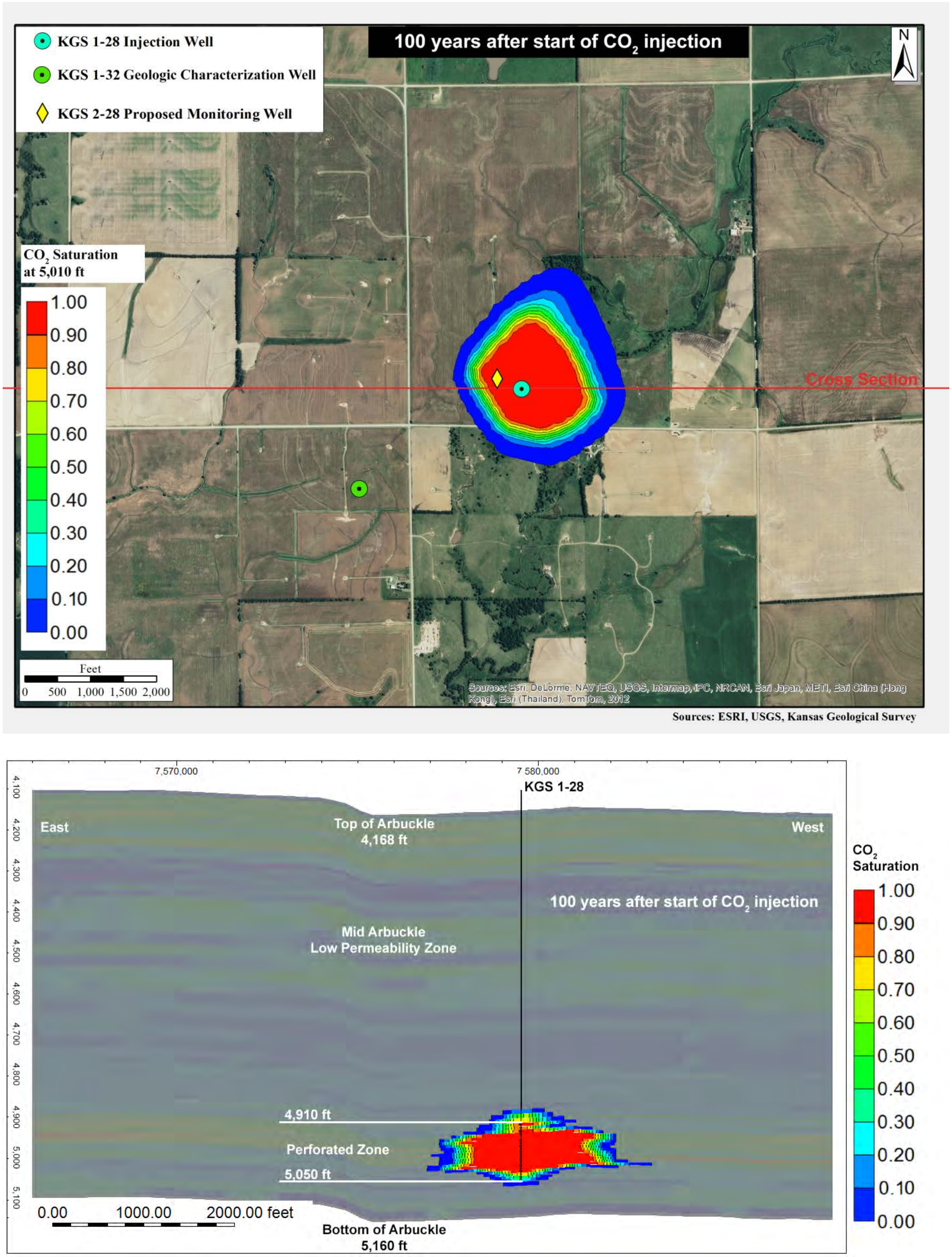


Figure 5.11g—CO_2 plume in aerial and cross-sectional view in the injection interval for the largest plume migration alternative model (k-1.25/phi-0.75) at 100 years from start of injection.

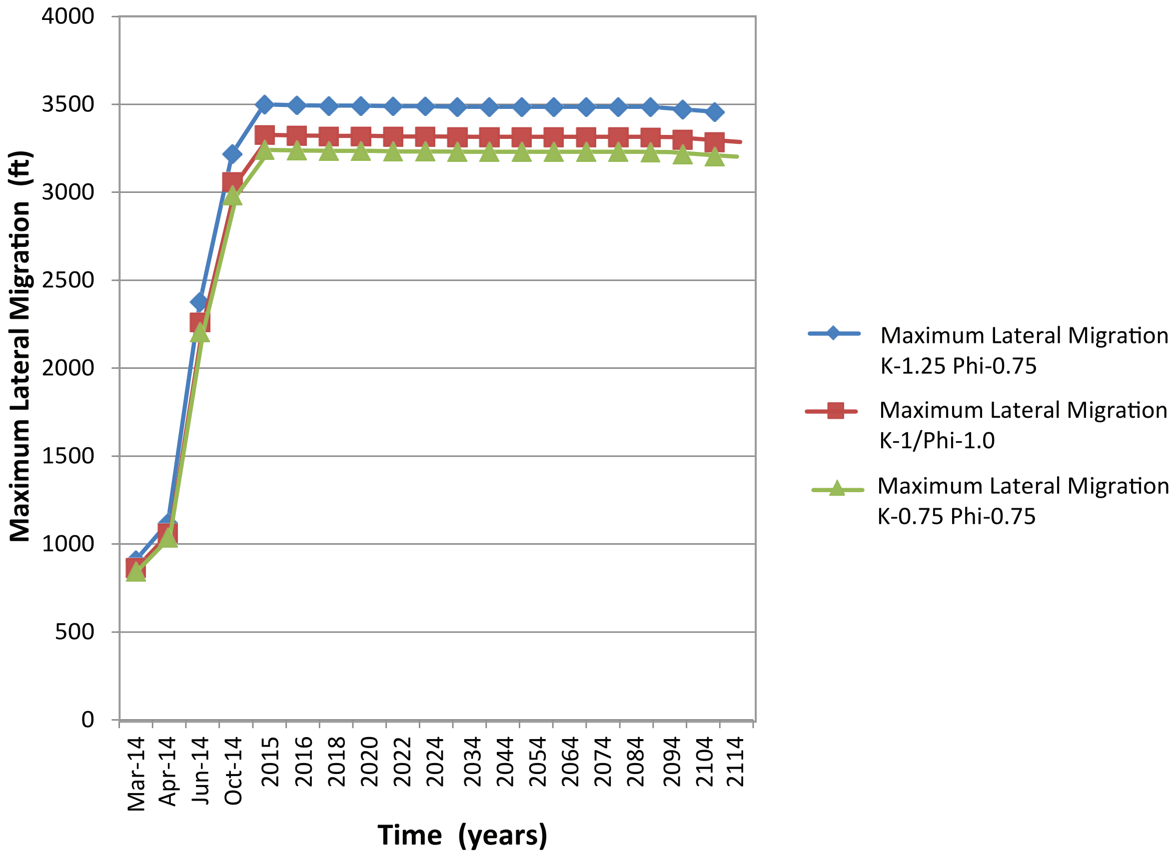


Figure 5.12—Maximum lateral extent of CO_2 plume migration (as defined by the 1% CO_2 saturation isoline) for the base case and for the two alternative models, which represent the maximum extent of plume and pressure-front migration.

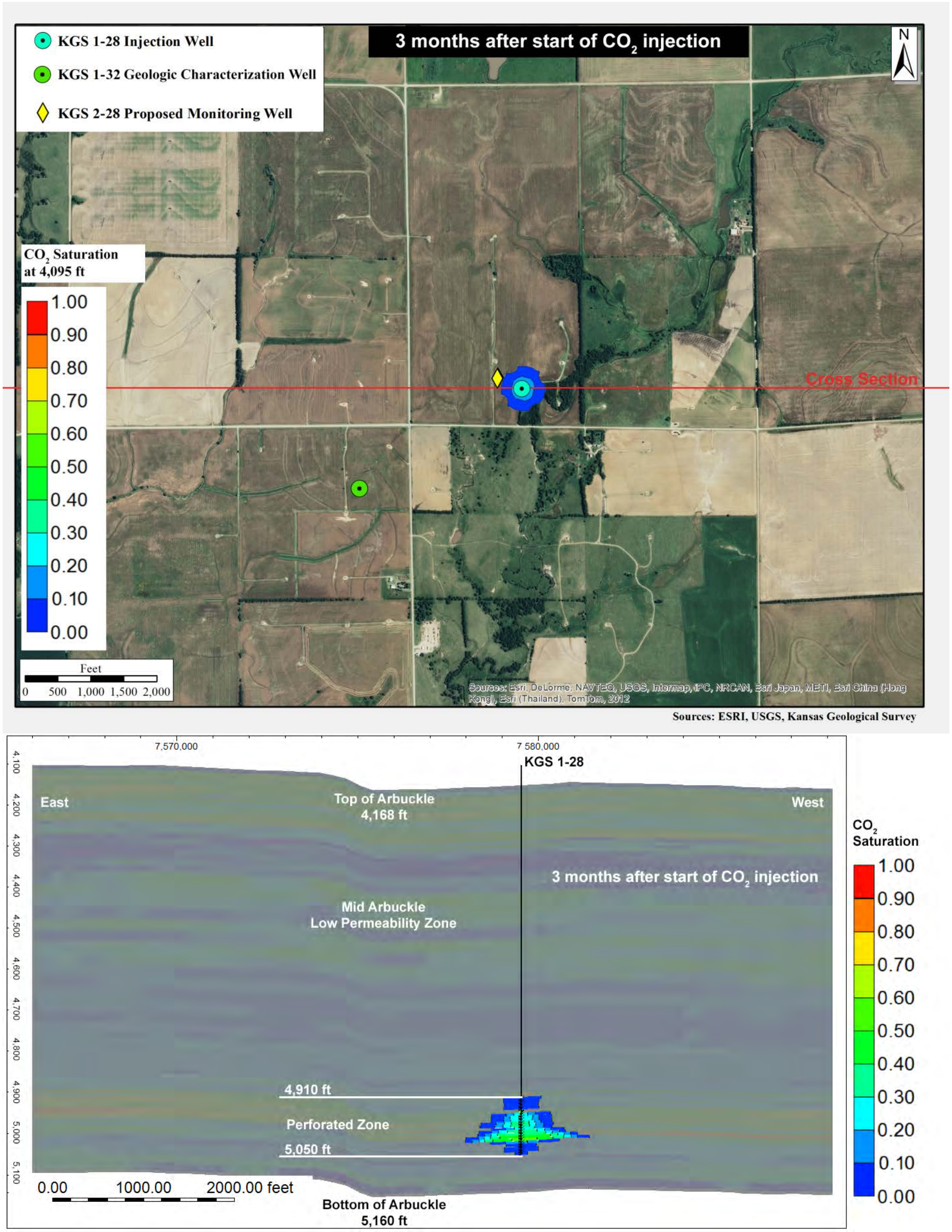


Figure 5.13a—Free-phase CO_2 plume in aerial and cross-sectional view for the largest migration alternative model (k-1.25/phi-0.75) at three months from start of injection.

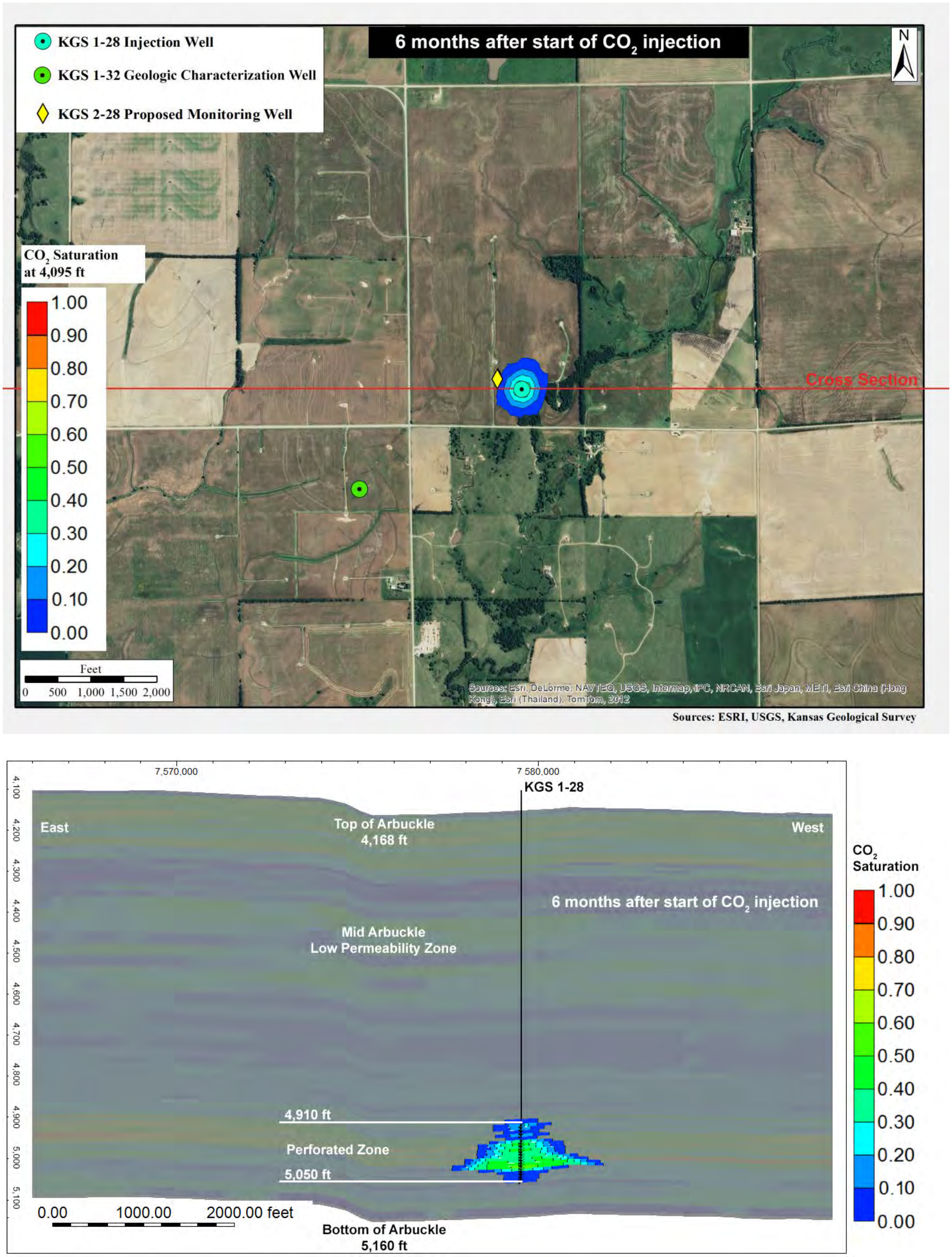
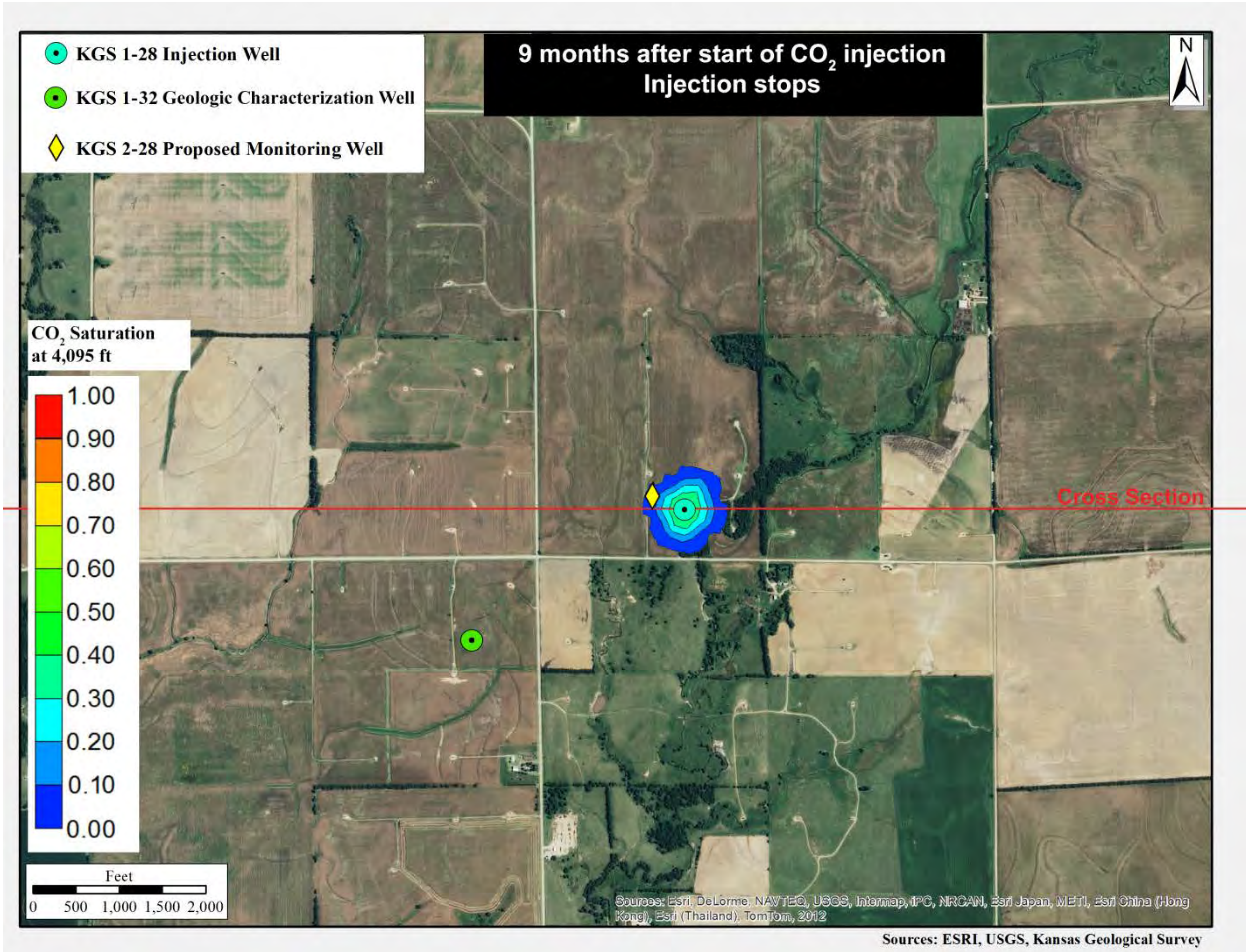


Figure 5.13b—Free-phase CO_2 plume in aerial and cross-sectional view for the largest migration alternative model (k-1.25/phi-0.75) at six months from start of injection.



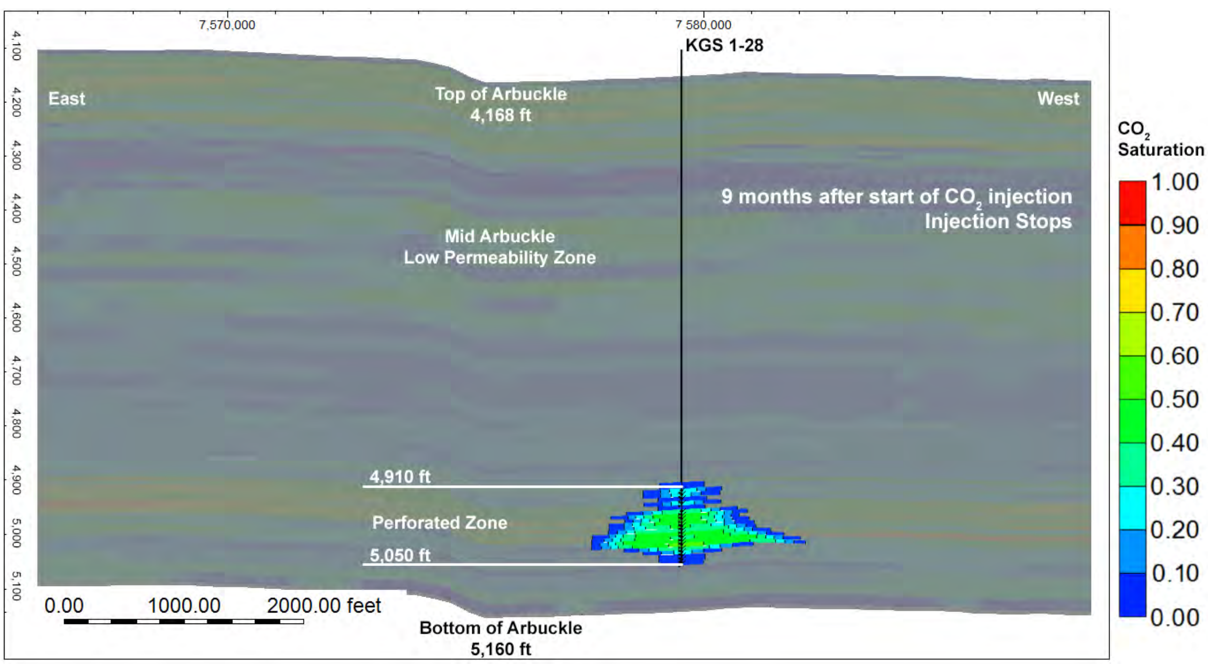
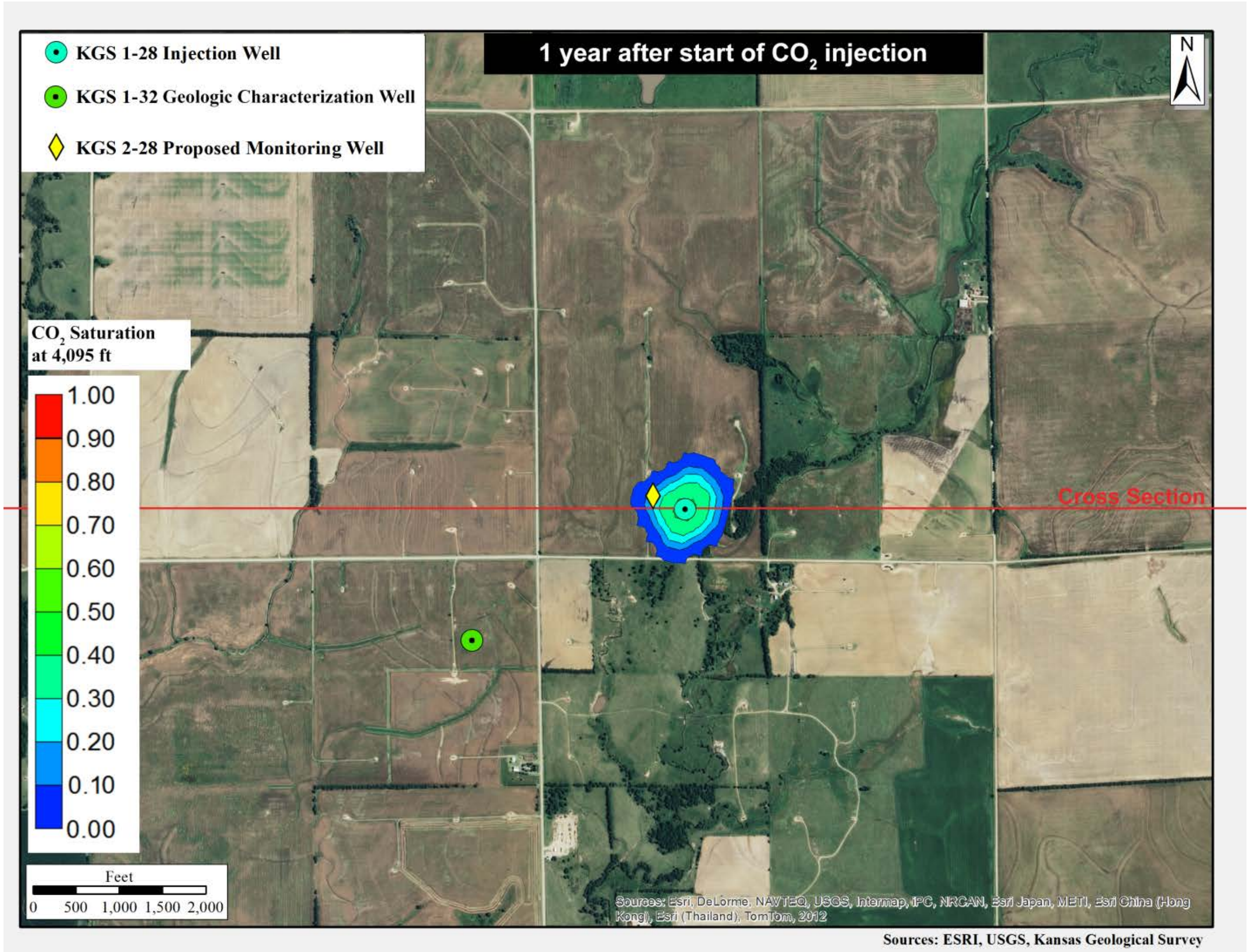


Figure 5.13c—Free-phase CO_2 plume in aerial and cross-sectional view for the largest migration alternative model (k-1.25/phi-0.75) at nine months from start of injection.



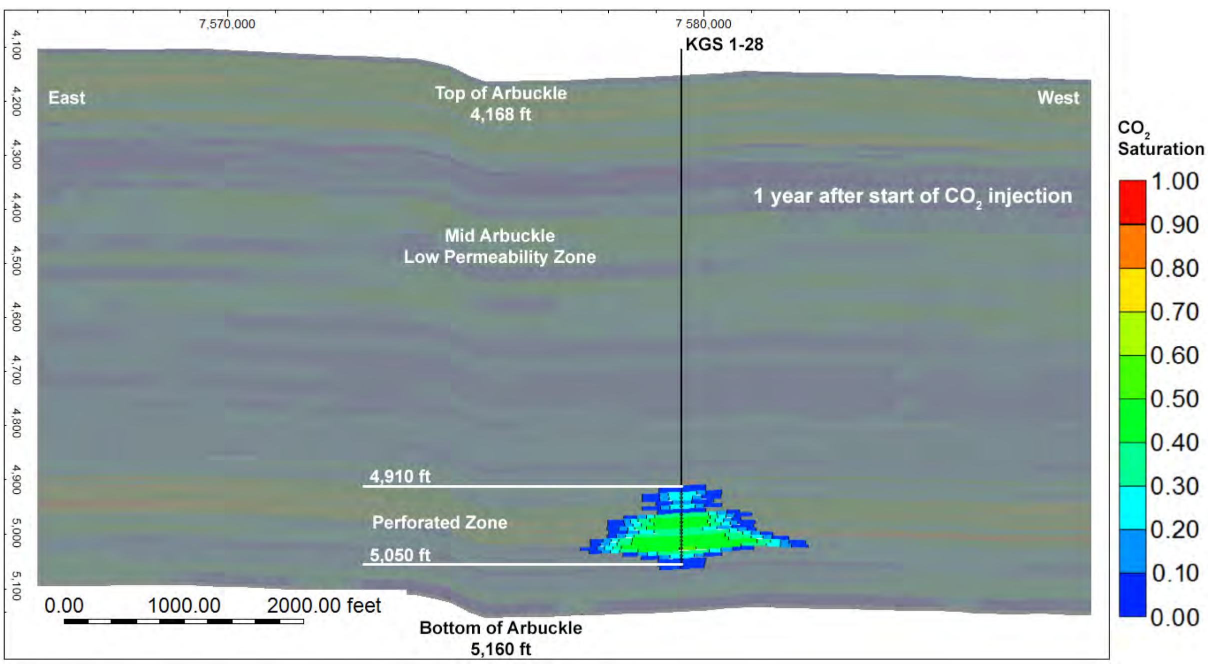


Figure 5.13d—Free-phase CO_2 plume in aerial and cross-sectional view for the largest migration alternative model (k-1.25/phi-0.75) at one year from start of injection.

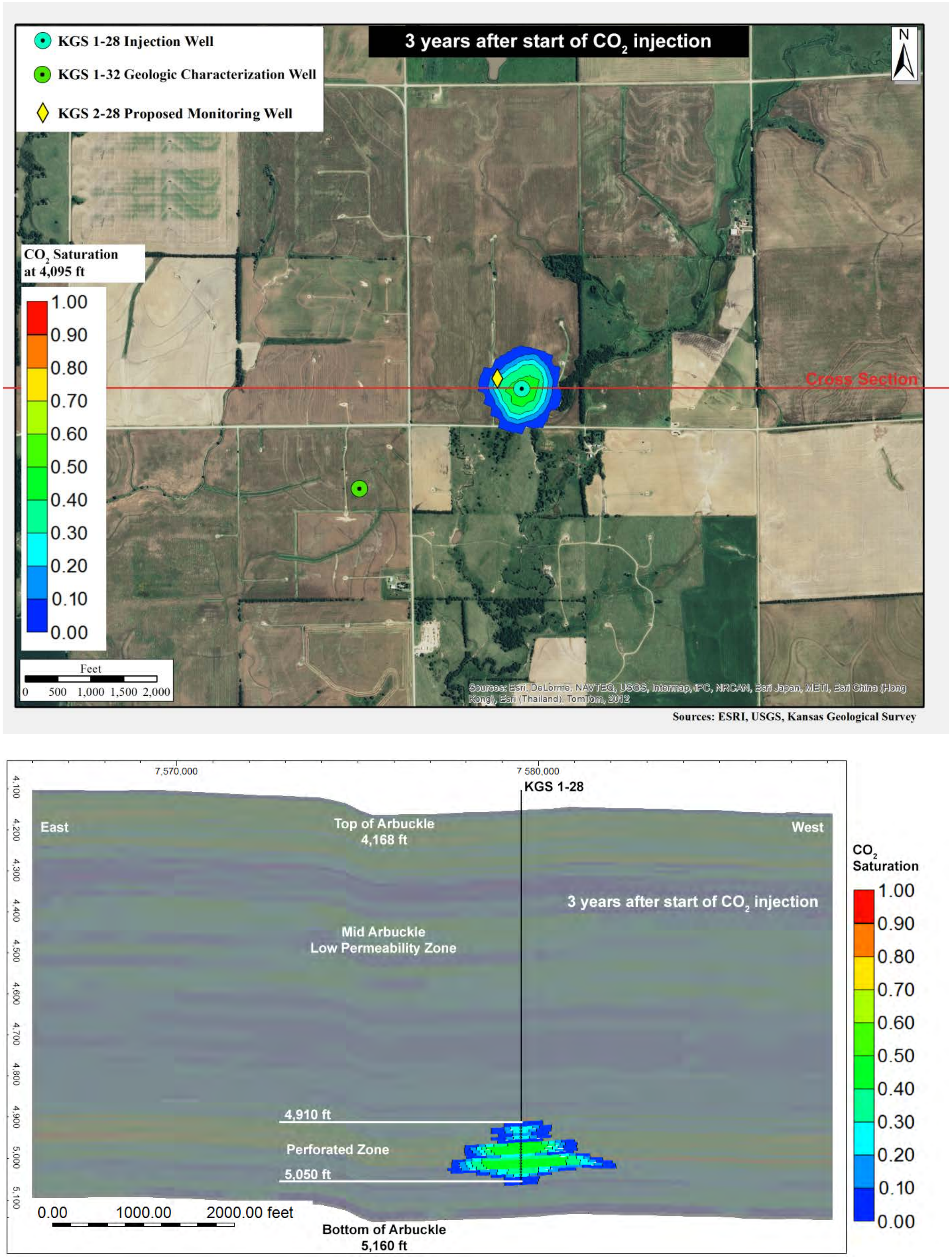
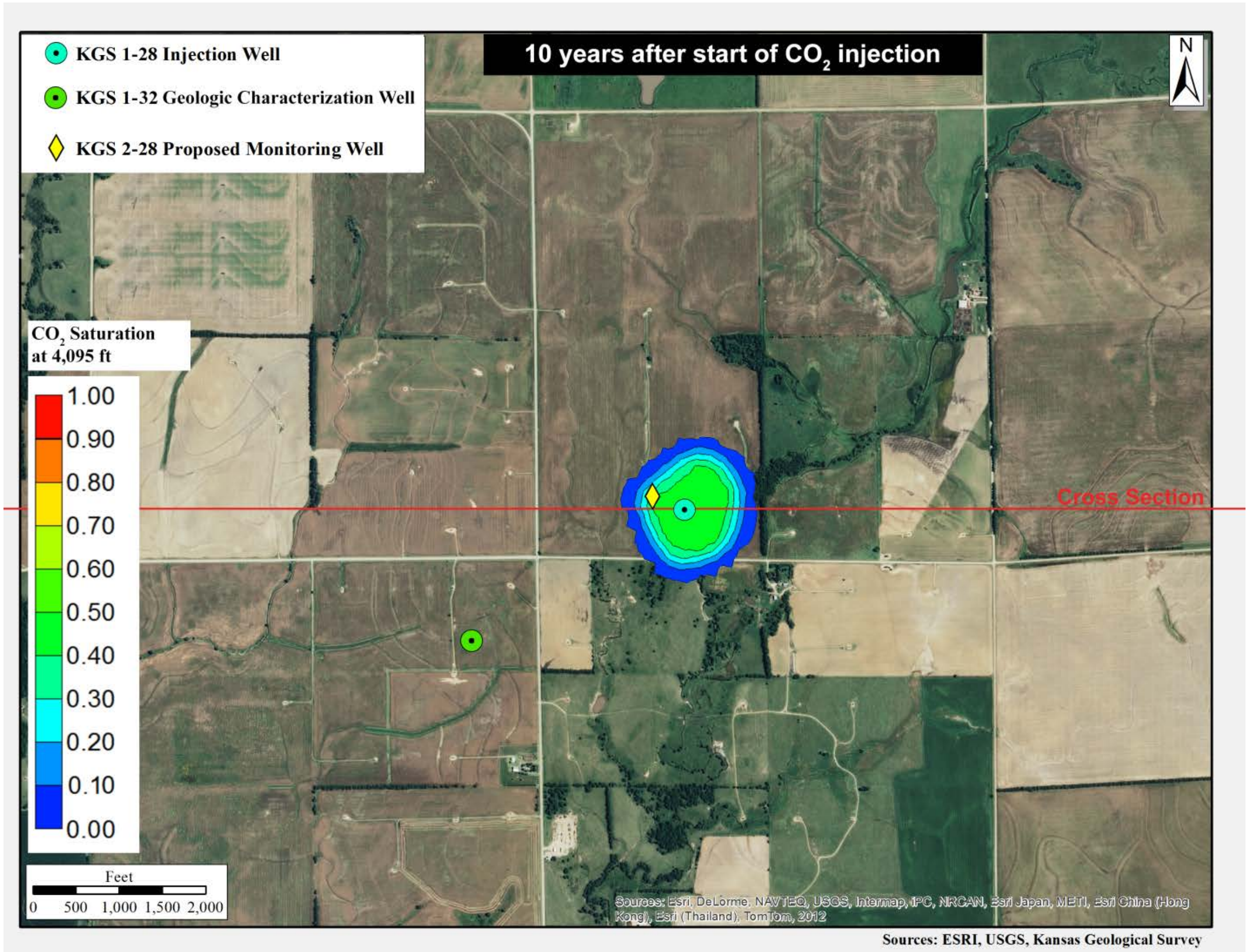


Figure 5.13e—Free-phase CO_2 plume in aerial and cross-sectional view for the largest migration alternative model (k-1.25/phi-0.75) at three years from start of injection.



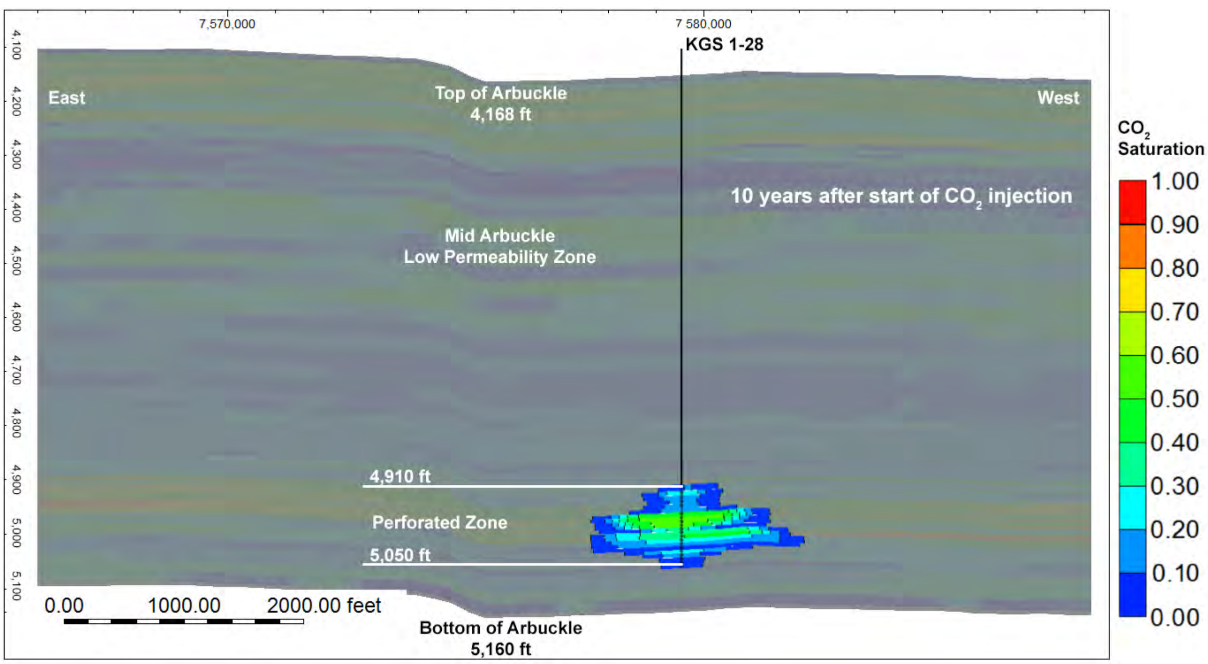


Figure 5.13f—Free-phase CO_2 plume in aerial and cross-sectional view for the largest migration alternative model (k-1.25/phi-0.75) at 10 years from start of injection.

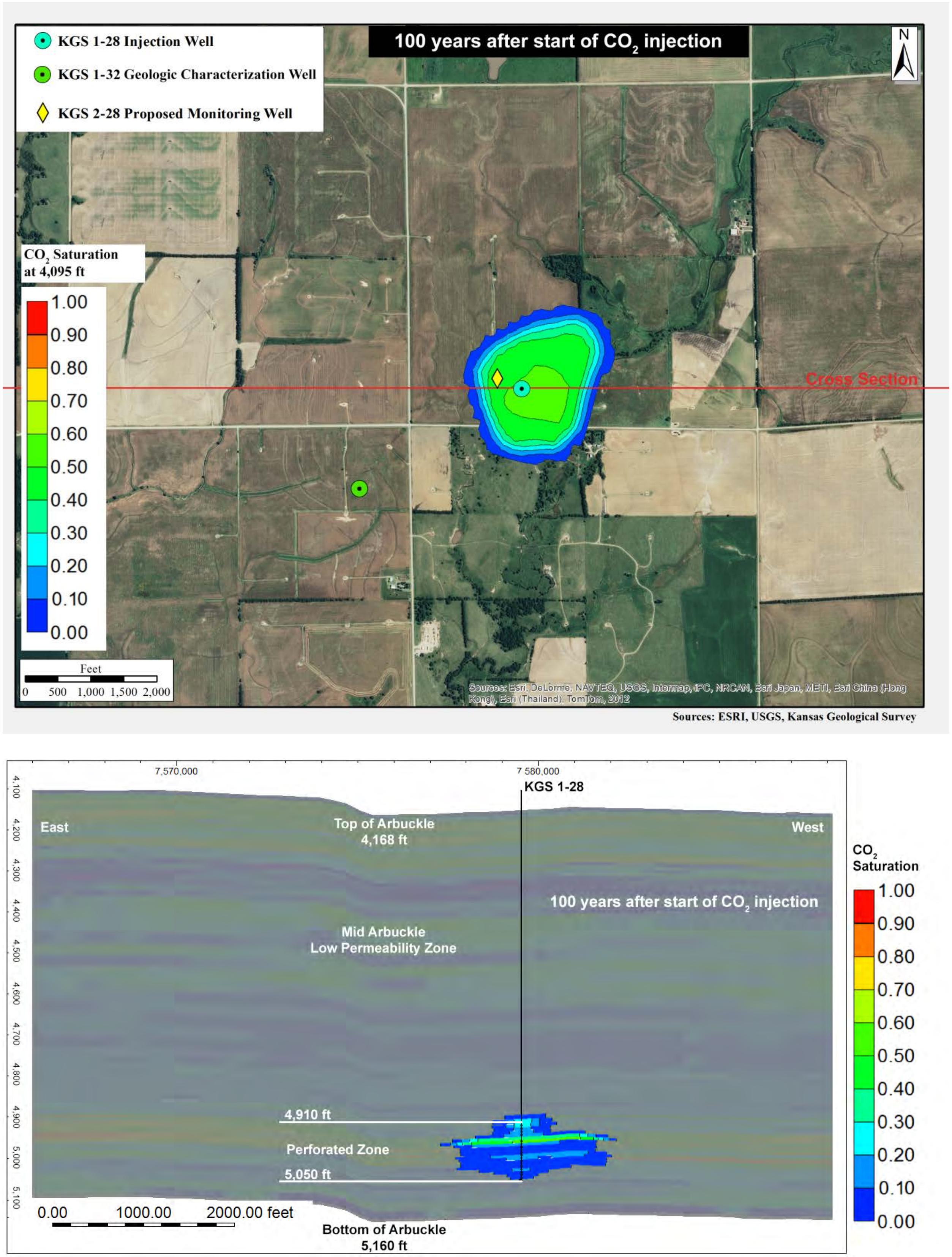


Figure 5.13g—Free-phase CO_2 plume in aerial and cross-sectional view for the largest migration alternative model (k-1.25/phi-0.75) at 100 years from start of injection.

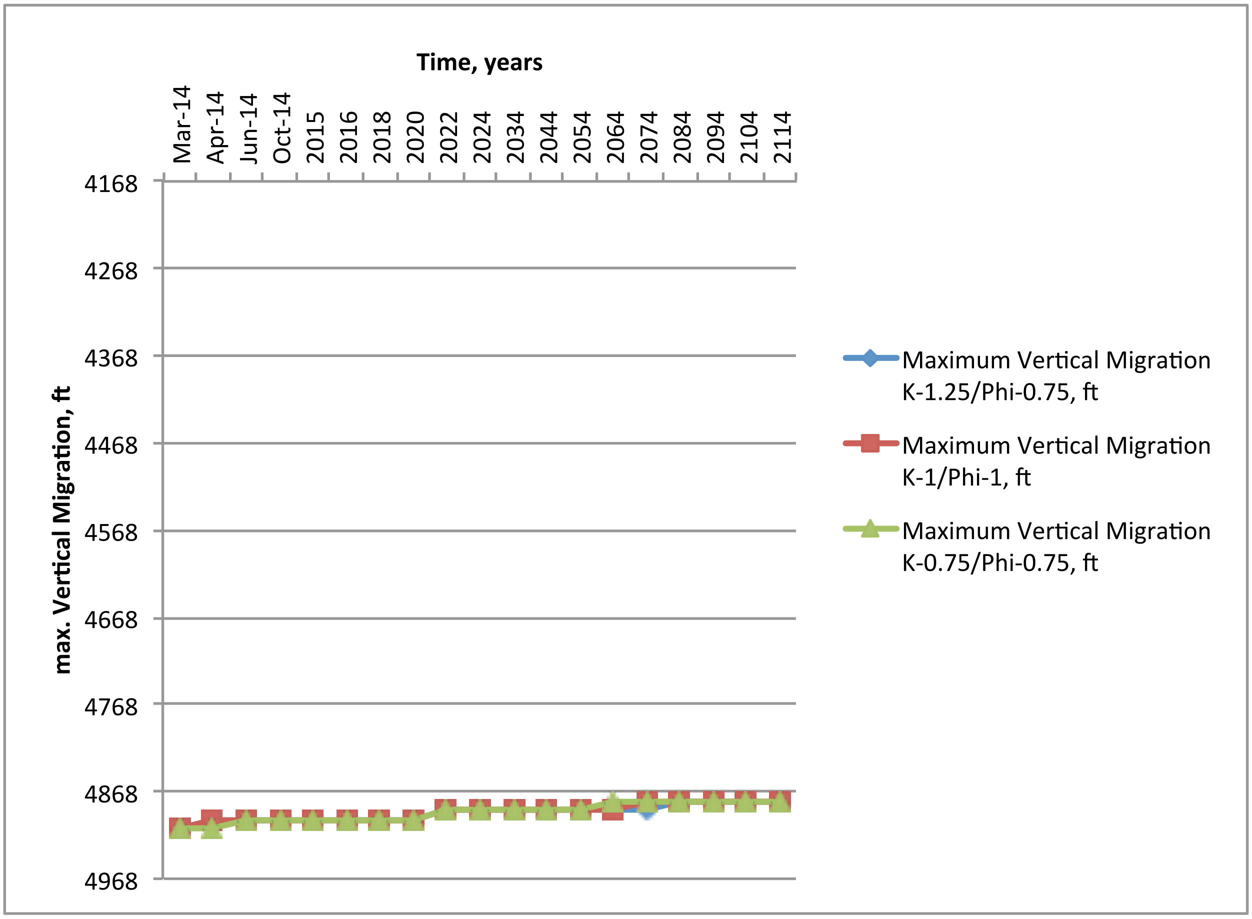


Figure 5.14—Maximum vertical extent of free-phase CO_2 migration for the two alternative cases that result in the maximum plume spread (k-1.25/phi-0.75) and the maximum induced pressure (k-0.75/phi-0.75) along with base case (k-1.0/phi-1.0).

accelerate the dissolution rate. Because of time and computational constraints, these mechanisms were ignored, and therefore the storage rates and quantities are likely to be underestimated, thus ensuring that the projections presented in this application provide a “worst-case” scenario.

5.4.6.2 Simulated Pressure Distribution

Figure 5.15 presents the bottomhole pressure (at a reference depth of 5,050 ft) for the base case and the two cases that resulted in highest pressures and plume migration. The bottom-hole pressures for all nine alternative cases are listed in Table 5.6. For all three cases presented in Figure 5.15, the pressure increases when CO_2 injection operations start and then drops to nearly pre-injection values when injection ceases. The pressure is influenced by permeability and porosi-

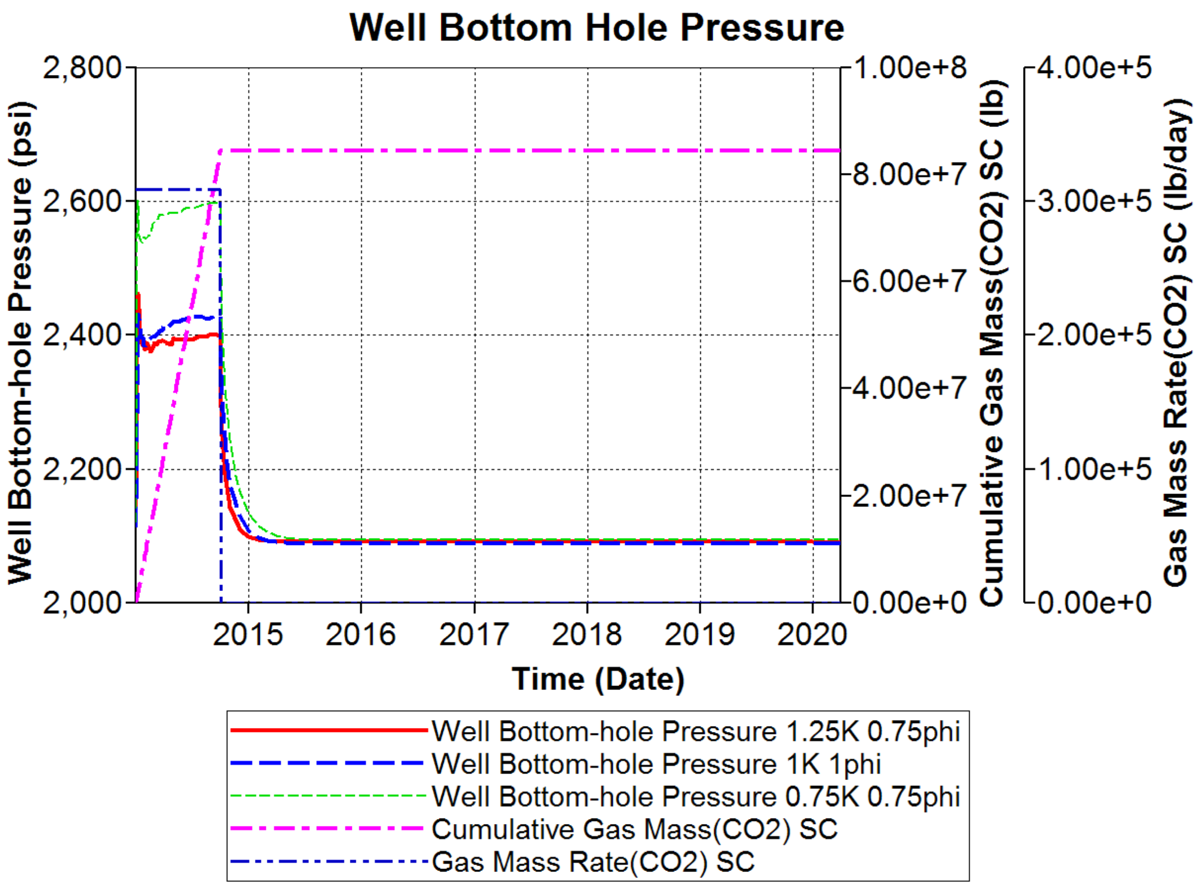


Figure 5.15—Well bottomhole pressure at the depth of 5,050 ft for the two alternative cases that result in the maximum plume spread (k-1.25/phi-0.75) and the maximum induced pressure (k-0.75/phi-0.75) along with base case (k-1.0/phi-1.0).

ty, as these two parameters are independent (decoupled) variables in CMG. Therefore, as expected, the highest bottomhole pressure (BHP) of 2,535 psi at a depth of 5,050 ft is observed for the low permeability–low porosity case. This pressure represents an increase of 442 psi over pre-injection levels and results in a pressure gradient of 0.515 psi/ft, which is less than the maximum allowable pressure gradient of 0.675 psi/ft corresponding to 90% of the fracture gradient (0.75 psi/ft) as documented in Section 4.6.9.

Table 5.6—Maximal CO_2 migration extent and bottom-hole pressure for each of the nine alternative cases

Modeling Case	Case Identifier	CO_2 Maximum Diameter of Areal Extent (ft)	Maximum Bottomhole Pressure, psi (@ 5,050 ft)	Maximum Bottomhole Pressure Increase (psi)
Low Permeability, Low Porosity	K-0.75/Phi-0.75	3,389	2,535	442
Medium Permeability, Low Porosity	K-1.0/Phi-0.75	2,629	2,462	369
High Permeability, Low Porosity	K-1.25/Phi-0.75	3,504	2,418	325
Low Permeability, Medium Porosity	K-0.75/Phi-1.0	2,218	2,512	419
Medium Permeability, Medium Porosity	K-1.0/Phi-1.0	2,433	2,428	335
High Permeability, Medium Porosity	K-1.25/Phi-1.0	3,203	2,415	322
Low Permeability, High Porosity	K-0.75/Phi-1.25	1,952	2,525	432
Medium Permeability, High Porosity	K-1.0/Phi-1.25	2,517	2,459	366
High Permeability, High Porosity	K-1.25/Phi-1.25	2,802	2,410	317

Figure 5.16 presents the change in pore pressure at the base of the confining zone (Simpson Group) for the base case and the two alternative cases that resulted in the highest pressures and plume spread. The maximum pressure increase at the end of the injection period is fairly small and varies between 8.9 psi and 13.1 psi. As observed for pressures at the bottom of the well, the highest pressure is noted for the low permeability/low porosity case (k-0.75/phi-0.75).

Figure 5.17a–d presents the lateral distribution of pressure in the Arbuckle injection interval (at an elevation of 4,960 ft) for the k-0.75/phi-0.75 case, which resulted in the maximum induced pore pressures. The pressures increase from commencement of injection to nine months and then drop significantly by the end of the first year (three months after operations stop). The pressures also drop very rapidly at short distances from the injection well at the end of the nine-month injection period, as shown in Figure 5.18. The pressures at the end of the nine-month injection period drop from about 283 psi a short distance from the injection well to less than 11 psi at the geologic characterization well, KGS 1-32, which is approximately 3,500 ft southwest of the injection well. The maximum induced pressure at the model boundary is only 2–3 psi.

Figure 5.17a–d also shows the vertical pressure distribution for the maximum induced pressure case (k-0.75/phi-0.75). The confining effect of the mid-Arbuckle baffle zones is evident in the plots as the large pressure increases are mostly restricted to the injection interval. The pressures decline rapidly at a short distance from the injection well. The pressures throughout the model subside to nearly pre-injection levels soon after injection stops, as shown in the one-year pressure plot in Figure 5.17d.

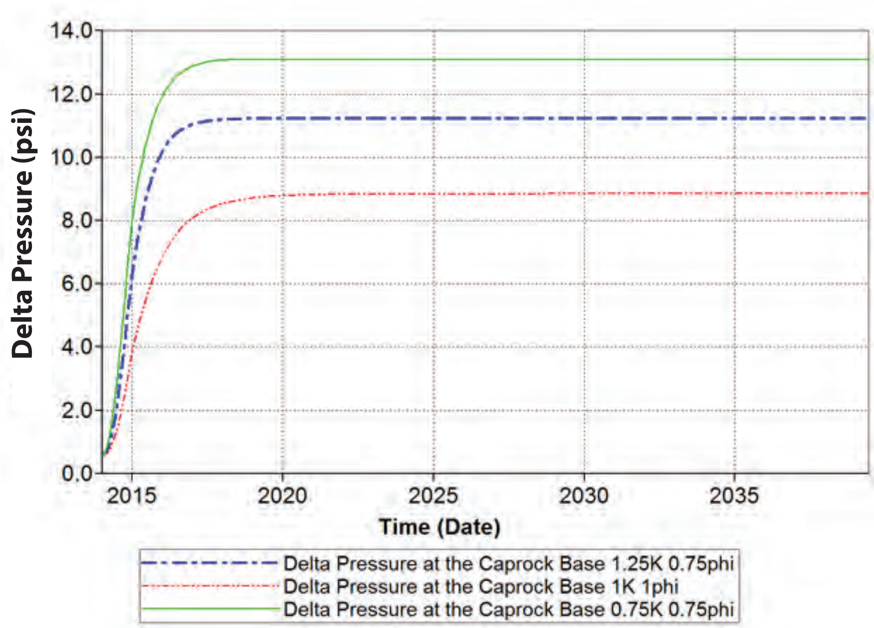


Figure 5.16—Change in pore pressure at the base of the confining zone (i.e., base of Simpson Group) at the injection well site for the two alternative cases that result in the maximum plume spread (k-1.25/phi-0.75) and the maximum induced pressure (k-0.75/phi-0.75) along with base case (k-1.0/phi-1.0).

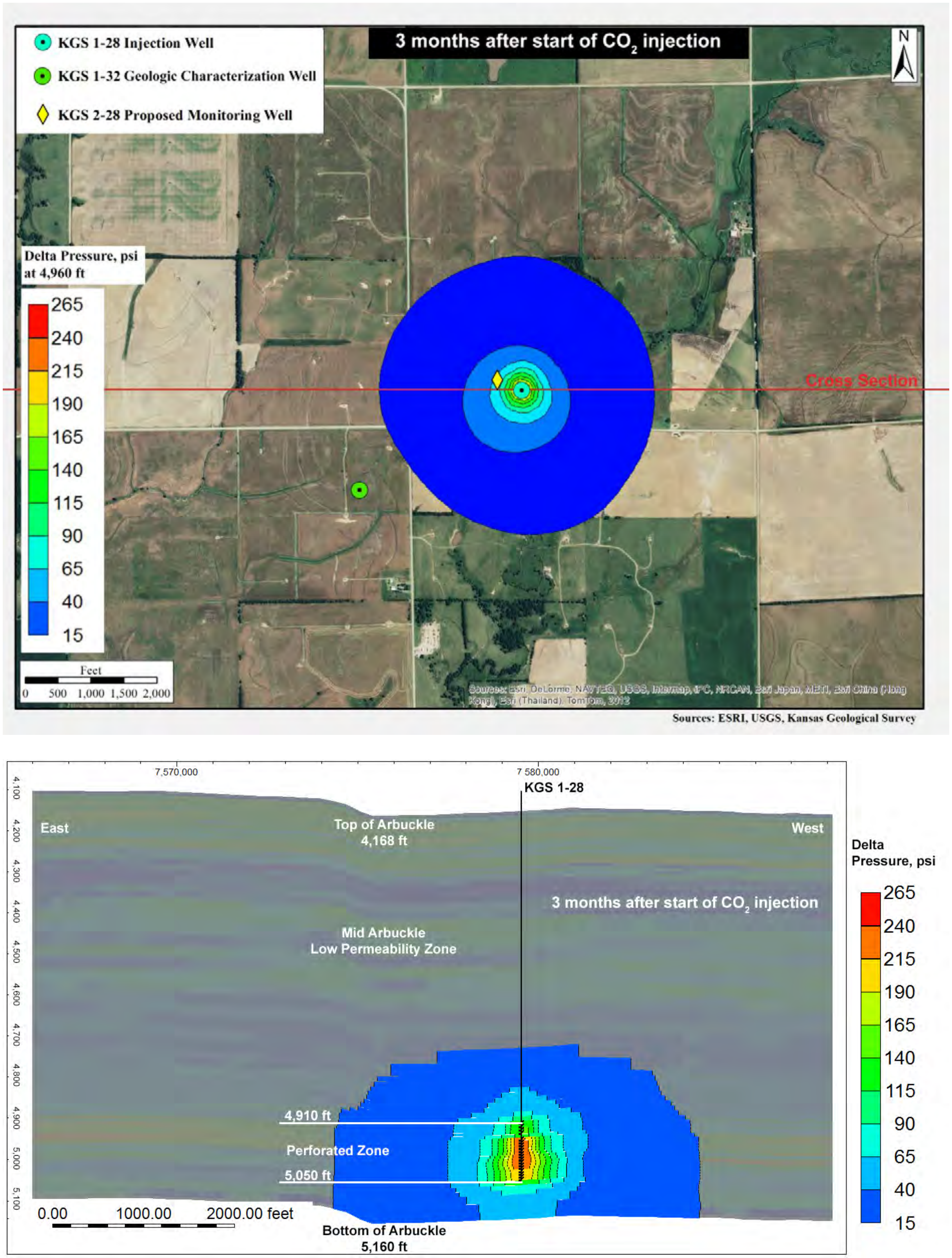


Figure 5.17a—Simulated increase in pressure in plan and cross-sectional view at three months from start of injection for the low permeability–low porosity (k-0.75/phi-0.75) alternative case, which resulted in the largest simulated pressures.

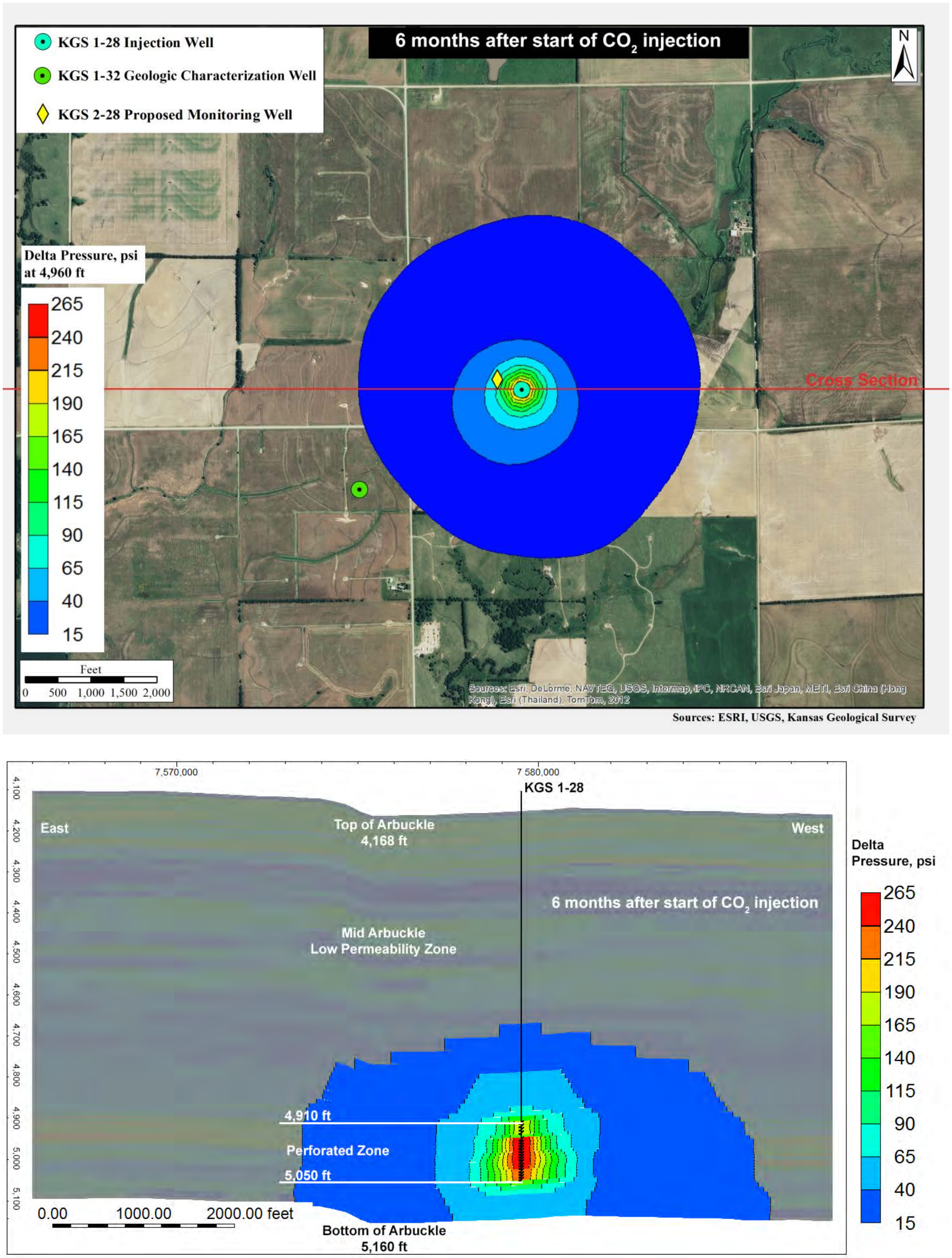


Figure 5.17b—Simulated increase in pressure in plan and cross-sectional view at six months from start of injection for the low permeability–low porosity (k-0.75/phi-0.75) alternative case, which resulted in the largest simulated pressures.

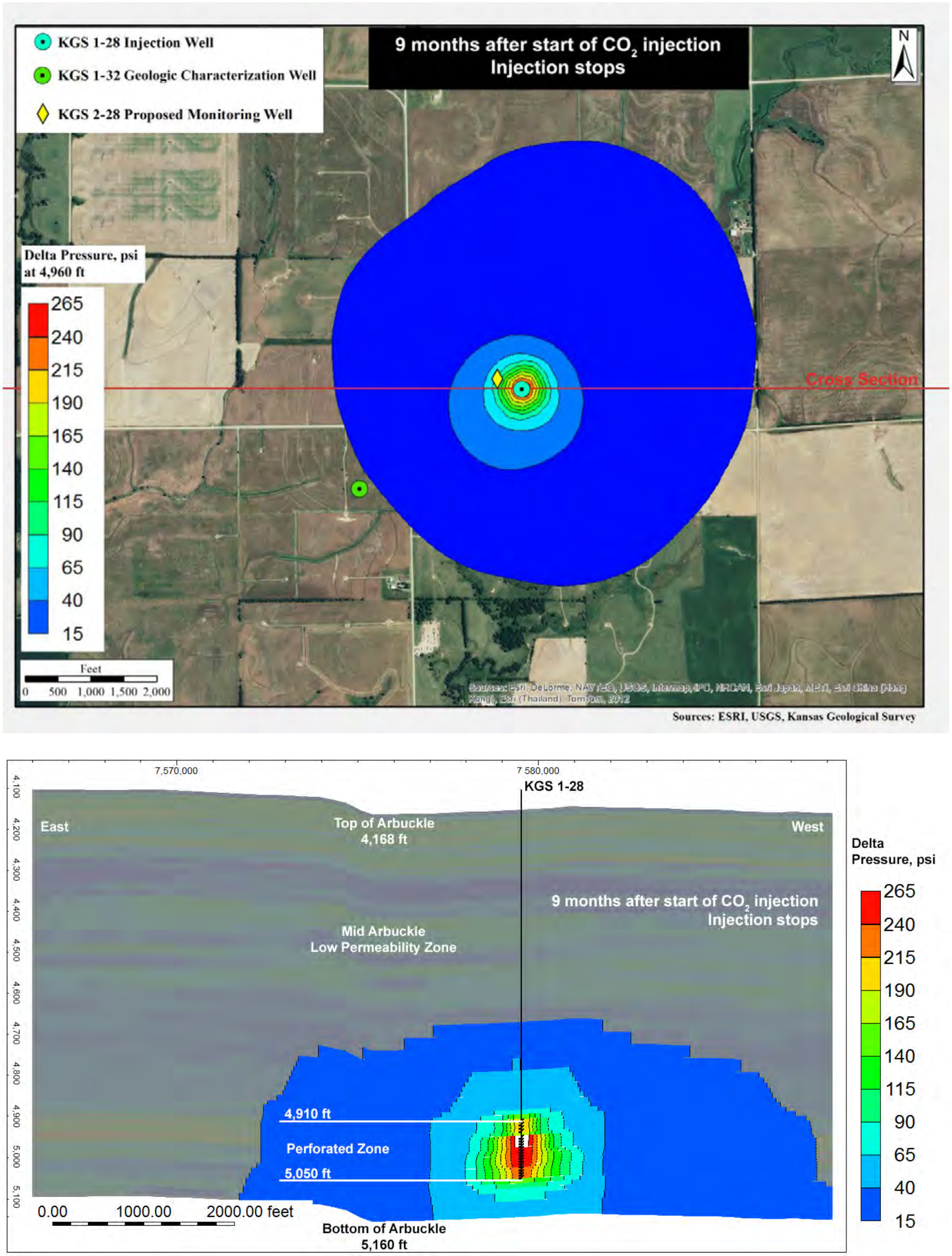


Figure 5.17c—Simulated increase in pressure in plan and cross-sectional view at nine months from start of injection for the low permeability–low porosity (k-0.75/phi-0.75) alternative case, which resulted in the largest simulated pressures.

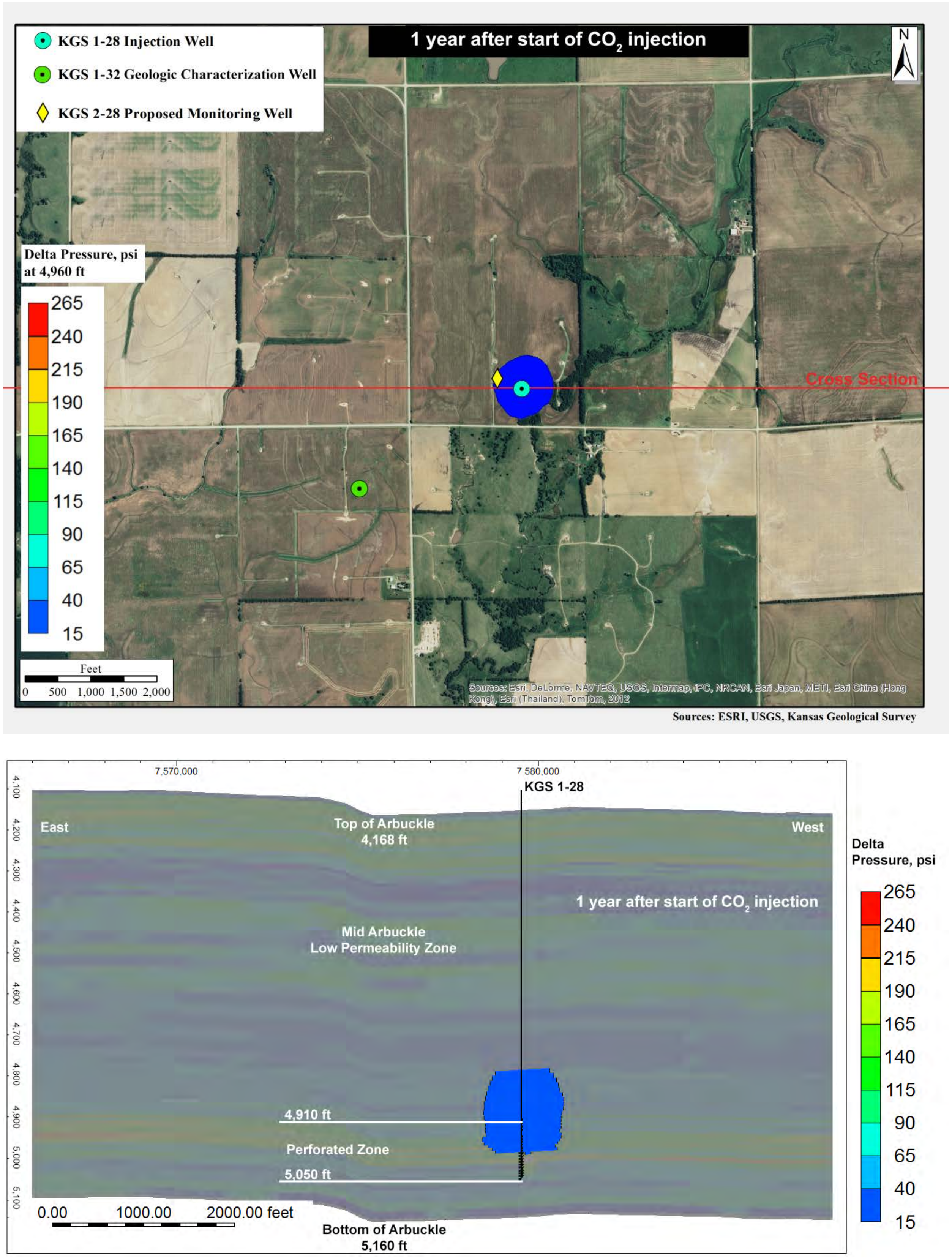


Figure 5.17d—Simulated increase in pressure in plan and cross-sectional view at one year from start of injection for the low permeability–low porosity (k-0.75/phi-0.75) alternative case, which resulted in the largest simulated pressures.

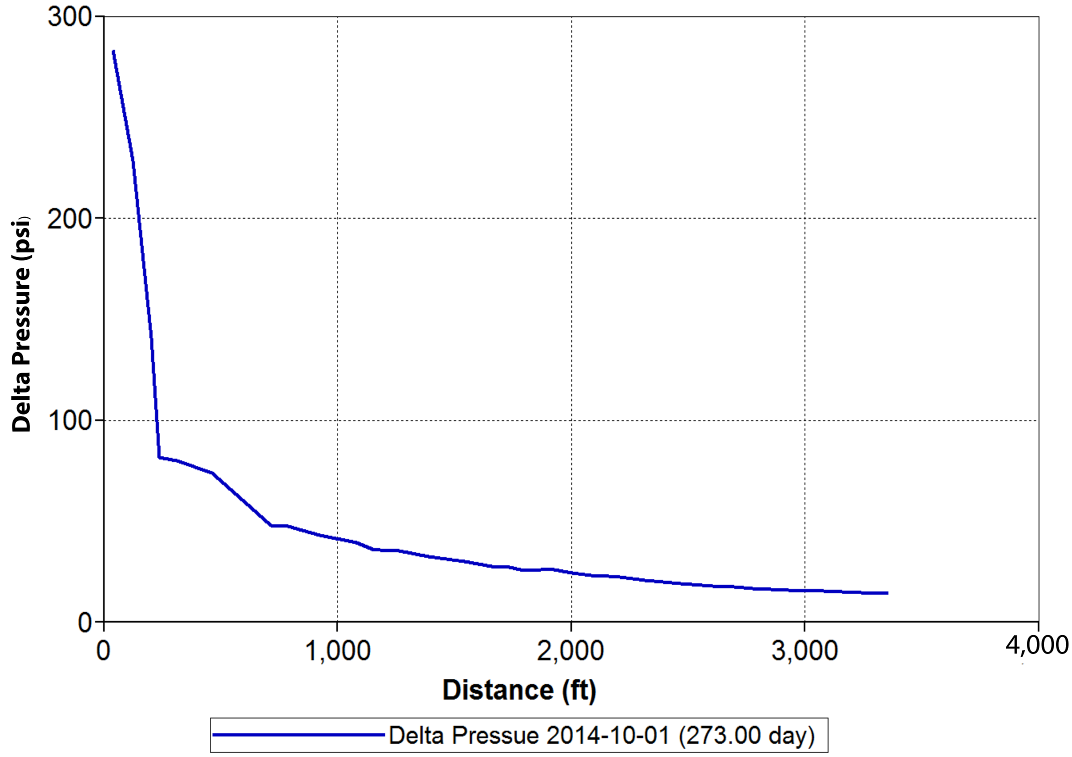


Figure 5.18—Pore pressure as a function of lateral distance from the injection well (KGS 1-28) at the end of the injection period (nine months) for the highest induced pressure case (k-0.75/phi-0.75).

Section 6

Geomechanical Analyses and Seismic Risk Evaluation

6.1 Introduction

The objective of this section is to demonstrate that the pressures induced due to CO_2 injection at KGS 1-28 are insufficient to a) initiate new fractures, b) propagate existing fractures, and c) cause slippage along fault planes.

The information in this section is provided in support of:

- 40 CFR 146.82 (3) Information on the geologic structure and hydrogeologic properties of the proposed storage site and overlying formations, including:

  (ii) The location, orientation, and properties of known or suspected faults and fractures that may transect the confining zone(s) in the area of review and a determination that they would not interfere with containment;

  (iv) Geomechanical information on fractures, stress, ductility, rock strength, and in-situ fluid pressures within the confining zone(s);

  (v) Information on the seismic history, including the presence and depth of seismic sources, and a determination that the seismicity would not interfere with containment.
- 40 CFR 146.83 (a) (2) Confining zone(s) free of transmissive faults or fractures and of sufficient areal extent and integrity to contain the injected carbon dioxide stream and displaced formation fluids and allow injection at proposed maximum pressures and volumes without initiating or propagating fractures in the confining zone(s).
- 40 CFR 146.84 (c) (1) (iii) Consider potential migration through faults, fractures, and artificial penetrations.
- 40 CFR 146.87 (d) At a minimum, the owner or operator must determine or calculate the following information concerning the injection and confining zone(s):

  (1) Fracture pressure.

- 40 CFR 146.88 (a) Except during stimulation, the owner or operator must ensure that injection pressure does not exceed 90 percent of the fracture pressure of the injection zone(s) so as to ensure that the injection does not initiate new fractures or propagate existing fractures in the injection zone(s). In no case may injection pressure initiate fractures in the confining zone(s) or cause the movement of injection or formation fluids that endangers a USDW.

The information in this section is organized as follows:

- Section 6.2 discusses the technical approach for analyzing geomechanical stability and integrity.
- Section 6.3 documents analyses conducted to demonstrate the unlikelihood of initiation of new fractures.
- Section 6.4 documents analyses conducted to demonstrate the unlikelihood of slippage occurring along fault planes.
- Section 6.5 presents analyses conducted to demonstrate the unlikelihood of propagation of existing fractures.
- Section 6.6 documents the location of known faults in the Arbuckle and confining zones and evaluates seismic risk at the Wellington site based on historical earthquake data.

6.2 Technical Background

Injecting CO_2 in the subsurface increases pore pressure, which, at high rates or pressures, can potentially reactivate existing structural features or cause new fractures to be initiated. Geomechanical and confining zone integrity studies are therefore a vital part of subsurface investigations to ensure that the injected CO_2 remains confined deep in the injection zone and does not endanger USDW or escape into the atmosphere. The three possible forms of geomechanical failure—a) initiation of new fractures, b) slippage along existing fault planes, and c) opening of existing fractures—were investigated and are discussed in Section 6.3–6.5. The technical approach implemented for analyzing geomechanical integrity is summarized below.

The Mohr failure envelope for an ideal rock is shown in Figure 6.1. It is represented by a line along which fault slippage initiates as the shear stress approaches a fraction of normal stress acting on the failure plane (the coefficient of friction of the rock material). If the Mohr circle intersects the failure envelope, then slippage may occur along a plane of failure. Fault and geomechanical stability is therefore evaluated in terms of the ratio of shear stress to effective normal stress acting on either a) a fault plane or b) any other plane that is susceptible to failure due to a relatively high shear-to-normal stress ratio. This ratio is termed the *slip tendency*, and for a cohesionless soil, slippage occurs once the shear-to-normal stress ratio exceeds the coefficient of friction, i.e.,

$$\frac{\tau}{\sigma_n} = \mu \qquad \text{(Equation 6.1)}$$

In reality, however, there is a minimum shear stress, *C*, called the cohesion of the material, which must be overcome before the development of a fracture plane or before slippage occurs in an existing fault (Figure 6.1). Stress fields below the failure envelope are stable, while stress fields above the failure envelope will result in rock failure. If the Mohr circle crosses the failure envelope, then the rock will undergo permanent deformation.

The total effective stress in the subsurface is a combination of lithologic stress, pore pres-

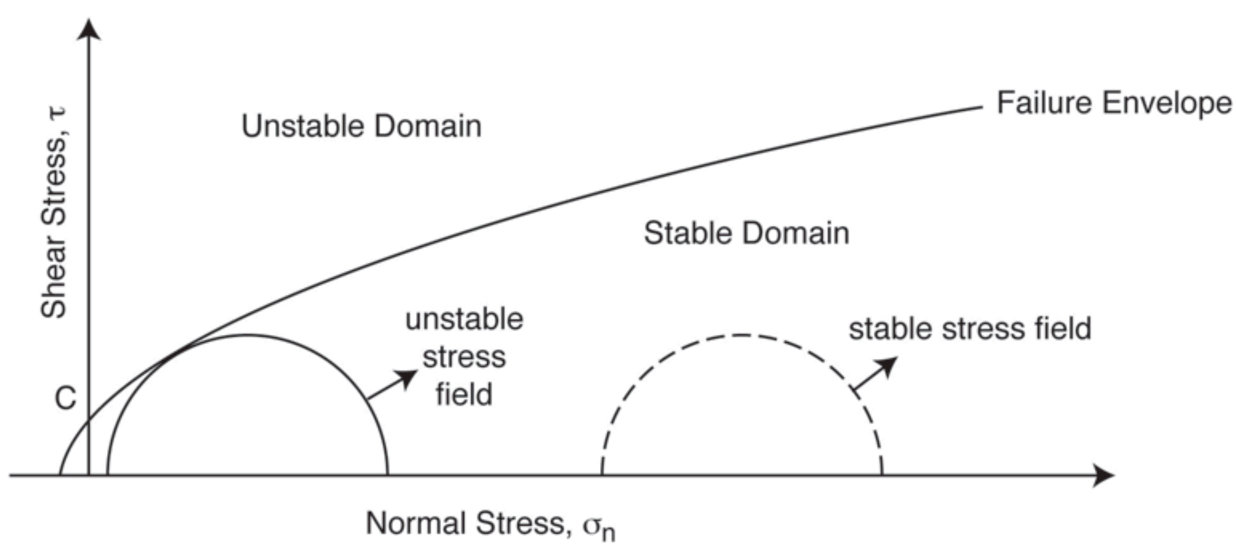


Figure 6.1—Mohr envelope rock showing stable and unstable regions.

sure, and tectonic stresses. At depths exceeding several hundred meters, the dominant principal stresses are usually compressive in nature. If the medium is saturated, then the pore fluid pressure counters a portion of the lithologic and tectonic pressure, resulting in a lower effective stress, σ', which can facilitate fault movement (Streit et al., 2005):

$$\sigma' = \sigma_{litho} - P_{fluid} \pm \sigma_{tectonic} \qquad \text{(Equation 6.2)}$$

The Mohr diagram in Figure 6.2 illustrates the effects of increasing fluid pressure on fault stability. Increasing the fluid pressure reduces effective normal stress and shifts the Mohr circle toward the failure envelope. If the Mohr circle intersects the failure envelope, slippage occurs. As illustrated in Figure 6.2, intact rock has a higher failure envelope than a relatively weak fault. Consequently, increasing fluid pressure is expected to lead to failure at a fault instead of country rock or caprock failure. The failure envelope for a fault may therefore be written in a general form as

$$\tau_{sliding} = C_{fault} + \mu(\sigma_n - P_{fluid}) \qquad \text{(Equation 6.3)}$$

Where $\tau_{sliding}$ is the shear stress that causes sliding and μ is the coefficient of friction,

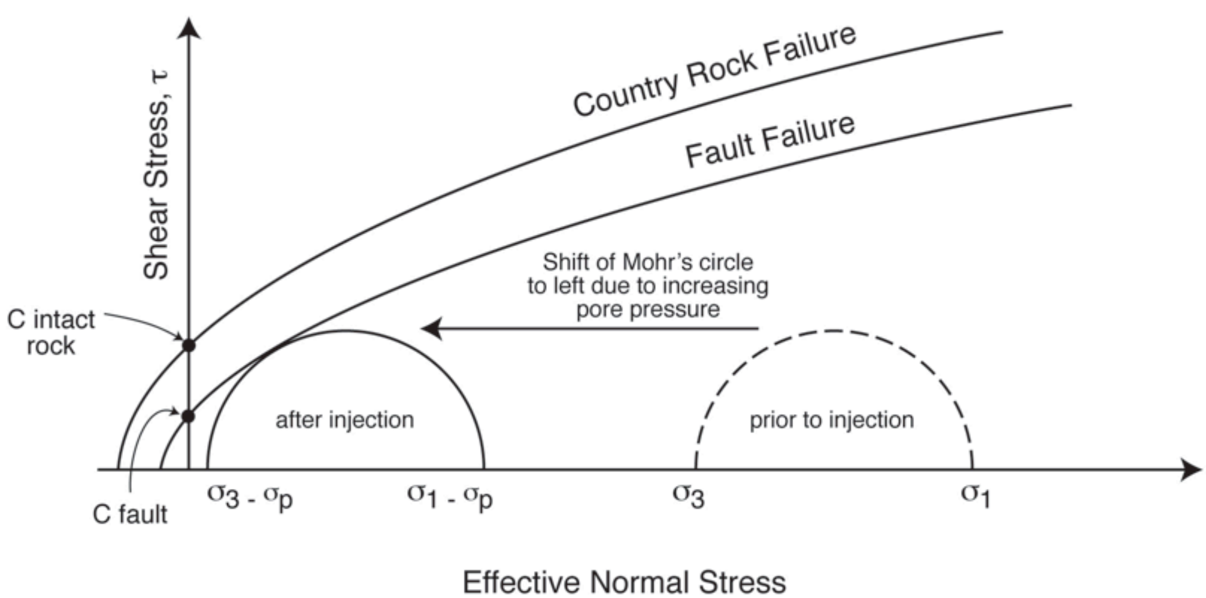


Figure 6.2—Effect of increasing pore pressure on stability of fault/fracture.

C_{fault} denotes a shear or cohesive strength of the fault, which must be overcome even in the absence of zero normal stress.

6.3 Failure Due to Initiation of New Fractures (§146.82[a][3], §146.83[a][2], §146.87[d], §146.88[a])

The maximum pore fluid pressure that can be sustained without inducing any failure can be estimated by considering the fault slip tendency (Equation 6.3) and neglecting the soil cohesion coefficient, *C:*

$$P_{critical} = \sigma_n - \frac{\tau}{\mu} \qquad \text{(Equation 6.4)}$$

Where σ_n and τ are stresses normal and parallel to the fracture plane, and μ is the coefficient of friction. These stresses can be estimated from results of the triaxial tests conducted on core samples obtained within the interval 3,630 ft (Mississippian) to 5,151 ft (base of the Arbuckle) at KGS 1-32 (Table 6.1, Figure 6.3). The triaxial tests were conducted at Weatherford Laboratories in Houston, Texas. Data are presented in Figure 6.3 and Table 6.1. In general, the compressive strength is higher in the Mississippian and Arbuckle carbonates and decreases significantly in the shales (Simpson and Cherokee). The weakest sample in the Simpson Group (the lowest unit in the confining zone) was selected for determining $P_{critical}$. The normal and shear stresses at failure (σ_n and τ) were calculated as follows:

Assume the vertical stress is the largest principal stress, σ_1, and the minimum principal stress, σ_2, is estimated as:

$\sigma_2 = Poisson's\ Ratio\ \ x\ \ \sigma_1$ (Kumar, 1976)

= 17,089 x 0.22 = 3,759 *psi*

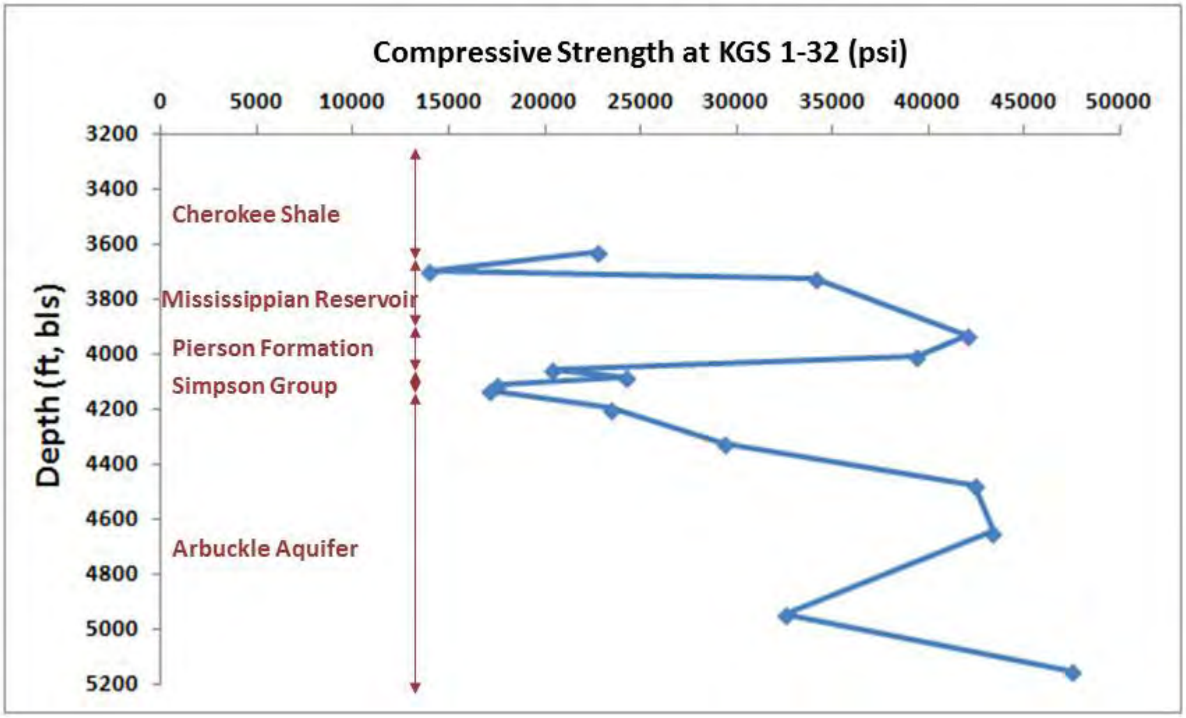


Figure 6.3—Compressive stress at failure for triaxial tests conducted on KGS 1-32 samples.

Conservatively assuming a failure plane (θ) of 30°[1] from the horizontal, the normal and shear stresses along the failure plane can be calculated from Equations 6.1 and 6.2 as:

$$\sigma_n = \frac{\sigma_1+\sigma_2}{2} + \left(\frac{\sigma_1-\sigma_2}{2}\right) cos2\theta \ = \ 13{,}757\, psi$$

$$\tau = \left(\frac{\sigma_1-\sigma_2}{2}\right) sin2\theta \ = \ 5{,}771\, psi$$

The coefficient of friction (μ) typically ranges between 0.6 and 0.85 (Scholz, 2002) and was assumed to be on the low end (0.6) to obtain conservative results. Therefore,

$$P_{critical} = \ \sigma_n - \frac{\tau}{\mu} \ = \ 4{,}138\, psi$$

1 The failure plane for the triaxial tests were not recorded. Therefore, a failure plane of 30° is assumed.

As documented in Table 5.6, the pore pressure at even the bottom of the well due to injection does not exceed 2,535 psi even under the worst-case scenario. Therefore, no new fractures are expected to be initiated at the Wellington test site due to increased pore pressure caused by injection.

Table 6.1—Results of triaxial tests at KGS 1-32.

Sample No.	Depth (ft)	Confining Pressure (psi)	Compressive Strength (psi)	Static Young's Modulus ($x10^6$ psi)	Static Poisson's Ratio
2-31RMV	3,630.46	1,350	22,754	2.40	0.15
4-5RMV	3,696.17	1,700	13,988	2.62	0.25
4-33RMV	3,724.05	1,700	34,131	4.53	0.34
8-4RMV	3,932.76	1,500	41,979	5.71	0.39
9-16RMV	4,005.70	1,500	39,389	4.75	0.31
10-34RMV	4,053.85	1,500	20,350	3.07	0.37
11-6RMV	4,084.94	1,600	24,233	5.19	0.33
11-31RMV	4,109.31	1,600	17,487	2.97	0.12
11-54RMV	4,132.61	1,600	17,089	1.96	0.22
13-14RMV	4,197.65	1,750	23,418	6.62	0.25
16-30RMV	4,323.02	1,750	29,337	7.46	0.30
19-14RMV	4,476.05	1,750	42,375	10.73	0.30
25-22RMV	4,646.40	1,750	43,343	10.53	0.32
30-46RMV	4,945.15	1,750	32,543	10.23	0.29
35-8RMV	5,151.84	1,900	47,455	9.72	0.29

6.4 Failure Due to Slippage along Fault Plane (§146.82[a][3], §146.83[a][2])

As discussed in Section 4.6.3 and shown in Figure 4.29, the Mississippian is significantly under-pressurized as compared with the Arbuckle aquifer at the Wellington site. This supports the hypothesis that the confining zone above the Arbuckle Group provides a high degree of hydraulic confinement. As discussed in Section 7.3.2 and also shown in Figures 7.7–7.8, the entire Mississippian reservoir is under-pressurized in south-central Kansas, with an abnormally low pressure gradient averaging 0.34 psi/ft (as compared to a pressure gradient of 0.42 psi/ft in the Arbuckle). Such a regionwide under-pressurization in the Mississippian is not possible in the presence of communicative faults between the Arbuckle and the Mississippian reservoirs.

As discussed above and illustrated in Figure 6.2, injecting CO_2 will cause the Mohr circle along the fault plane to shift leftward toward the failure envelope. However, there are no documented faults in the area, and the closest known fault zone traversing the Arbuckle is approximately 12.5 mi southeast of the site (Figure 6.4). As discussed in Section 5, the increase in pressure at the model boundary, approximately 6 mi from the injection well, is only 2–3 psi. The increase in pressure at the fault is therefore expected to be negligible (< 1 psi). Therefore, it can be reasonably concluded that injection of CO_2 at KGS 1-28 will not impart enough pressure to cause destabilization or slippage along the mapped fault planes.

6.5 Failure Due to Parting Pressure (§146.82[a][3])

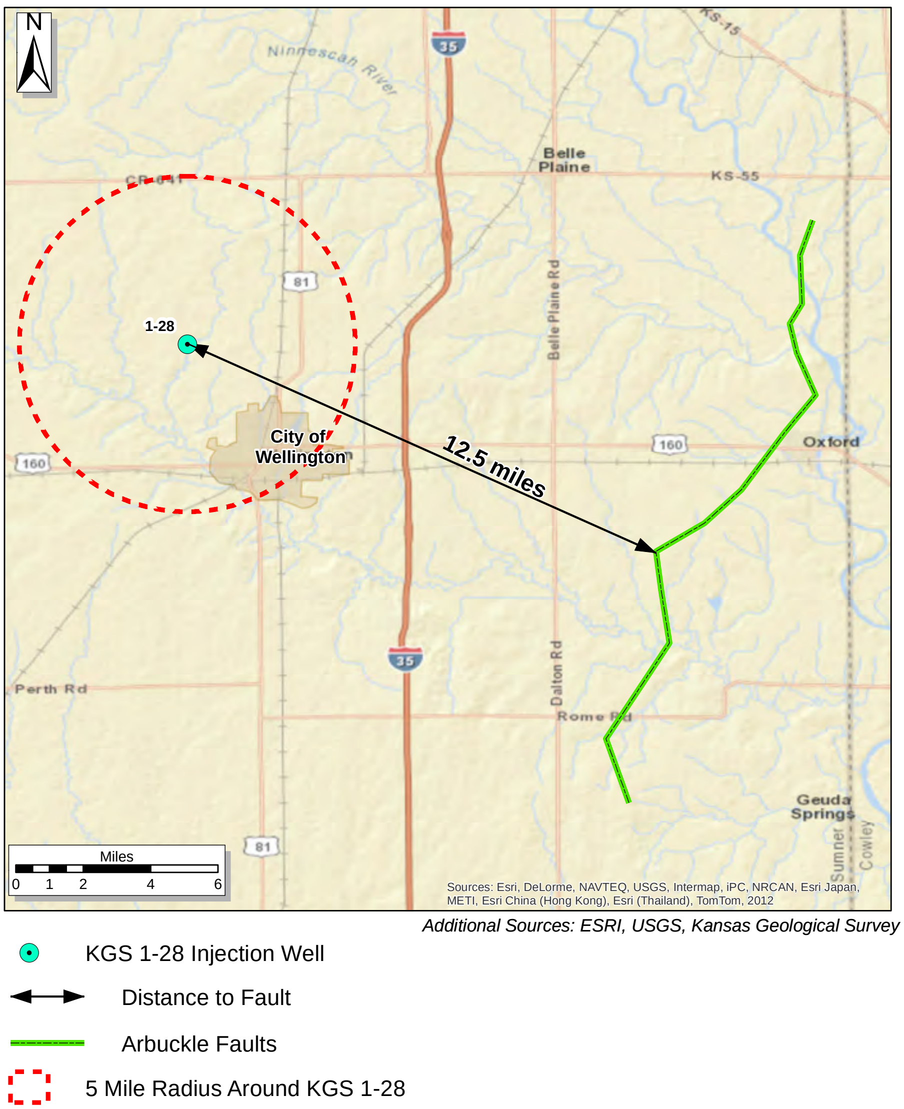


Figure 6.4—Mapped Arbuckle faults in the study area.

As indicated in Section 4.6.9, the fracture gradient at the Wellington site is assumed to be 0.75 psi/ft. This equates to a parting pressure of approximately 3,787 psi at the bottom of the perforation (5,050 ft) in the injection well (KGS 1-28). Based on modeling results presented in Section 5, the maximum bottomhole pressure at 5,050 ft is 2,535 psi for the worst-case scenario (low permeability–low porosity alternative model). This is substantially less than the not-to-exceed maximum of 90% of the estimated parting pressure of 3,409 psi (0.9 * 3,787). Therefore, it can be concluded that CO_2 injection at Wellington will not approach the fracture parting pressure in the Arbuckle.

6.6 Faults and Seismic Risk

The Precambrian basement rocks appear to be faulted primarily along the Nemaha anticline as shown in Figure 6.5. Previous structural studies have investigated deformation associated with Ancestral Rocky Mountains and the Ouchita tectonic events that were active during the early Pennsylvanian (Watney et. al., 2008; Figure 6.6). This tectonism led to the reactivation along the Central Kansas and Nemaha uplifts and smaller structures in the Sedgwick and Salina basins closely related to the reactivation of the underlying Precambrian (Proterozoic) age Midcontinent Rift System (MRS), a zone of the earth's continental crust that was pulled apart, subsided, and filled with basaltic rocks and sediment about 1,100 million years ago. This zone of rifting extended through Kansas northeastward across Nebraska, Iowa, and Minnesota and into the Lake Superior region. Movement along northeast trending faults bounding the east side of the MRS led to for-mation of the Nemaha uplift, a buried granite mountain range that extends from roughly Omaha, Nebraska, to Oklahoma City (Figure 6.7). This uplift, about 50 miles east of the MRS, was formed about 300 million years ago, and the faults that bound it are still slightly active today, especially the Humboldt fault zone that forms the eastern boundary of the Nemaha Ridge. As discussed below, a number of small earthquakes in Kansas are associated with the Nemaha Ridge, while the signif-icant activity has been limited to the Oklahoma portion of the ridge and the adjoining Anadarko and Arkoma basins.

Figure 6.8 shows the mapped faults along the top of the Precambrian, Arbuckle Group, and

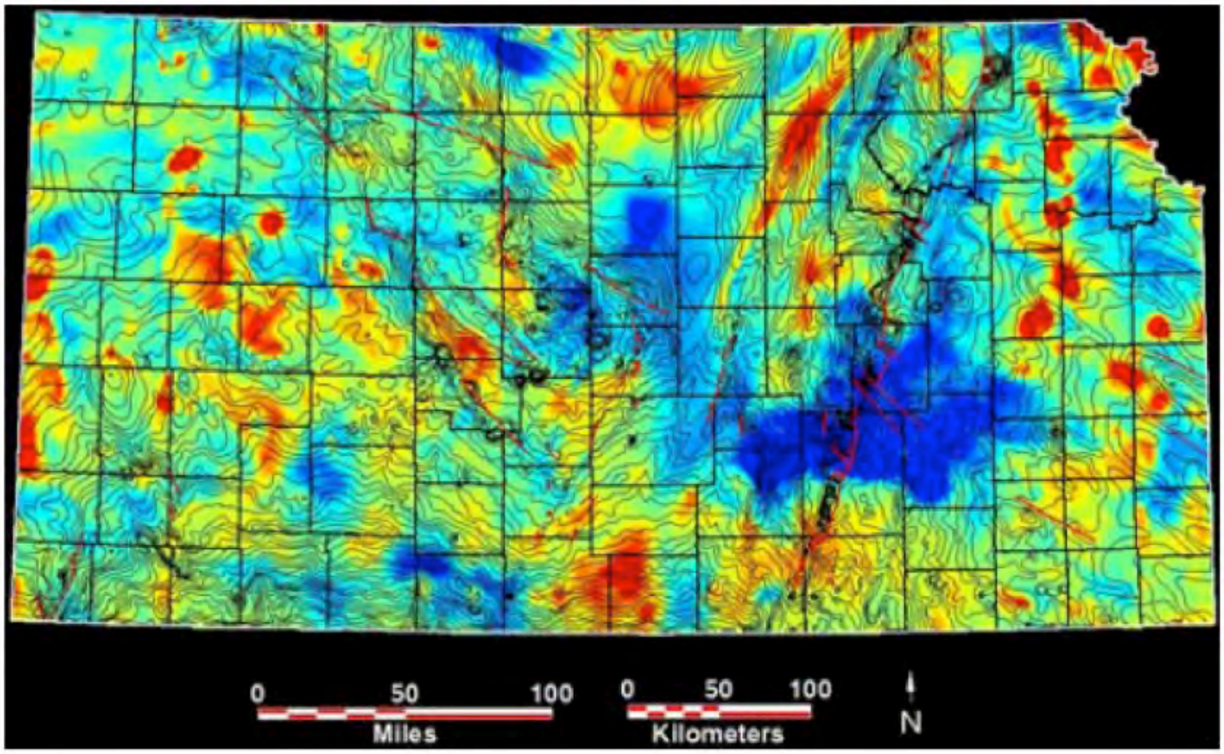


Figure 6.5—Aeromagnetic map of Kansas. Shaded relief with vertical illumination; lowest magnetic values in blue. Steeper gradients are darker shading (Kruger, 1996). Contours are configuration of the Precambrian surface with mapped faults shown by red lines (Cole, 1976).

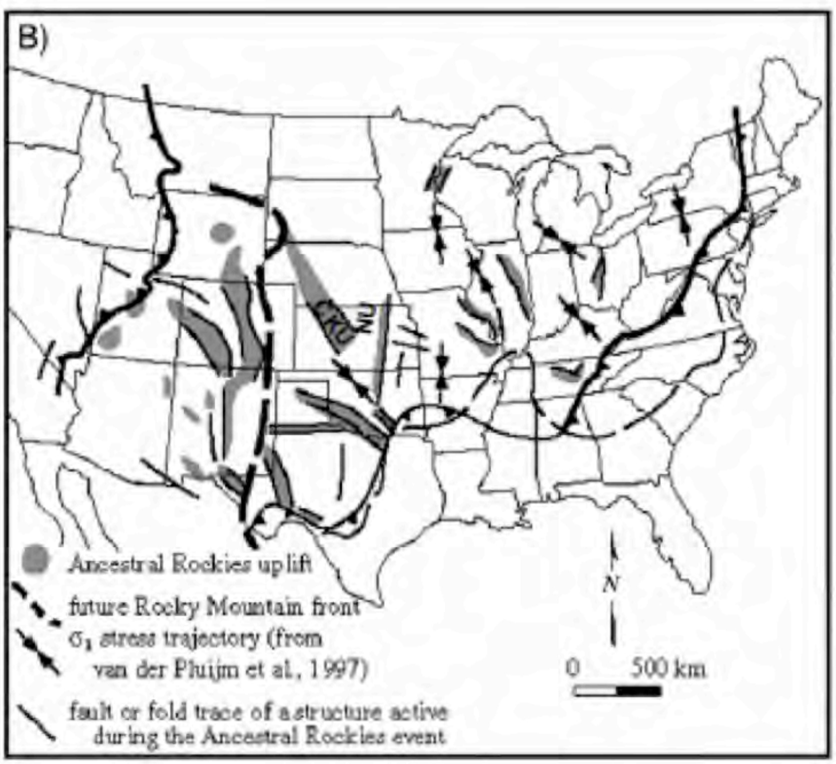


Figure 6.6—Ancestral Rockies structures including northwest trending Central Kansas uplift (CKU) in western Kansas, and the north-northeast trending Nemaha uplift (NU) in eastern Kansas (from Watney et al., 2008).

the Mississippian system. The faults associated with the Nemaha Ridge to the east of the Wellington storage site have the largest extent in the Precambrian basement and the Arbuckle Group but do not extend much above the Mississippian formation, which is more than 3,000 ft below the USDW in the area. The closest fault associated with the Nemaha Ridge traverses in a northeast-southwest direction approximately 12.5 mi east of the Wellington storage site (Figure 6.4), which is much farther than the approximately 1,700-ft radius EPA AoR as discussed in Section 5 and shown in Figure 9.1.

All faults evolve as a dual conduit-barrier system with a low permeability core along the slip plane and a high permeability damage zone on both sides of the core (Figure 6.9). Over time, the damage zone may seal up due to deposition of fine materials and geochemical reactions. Such may be the case at Wellington in particular (and Kansas in general) as the pressure and geochemical data discussed in Sections 4.6 and 4.7 strongly suggest that there are no transmissive faults between the Arbuckle and overlying Mississippian in the vicinity of KGS 1-28 and KGS 1-32 or

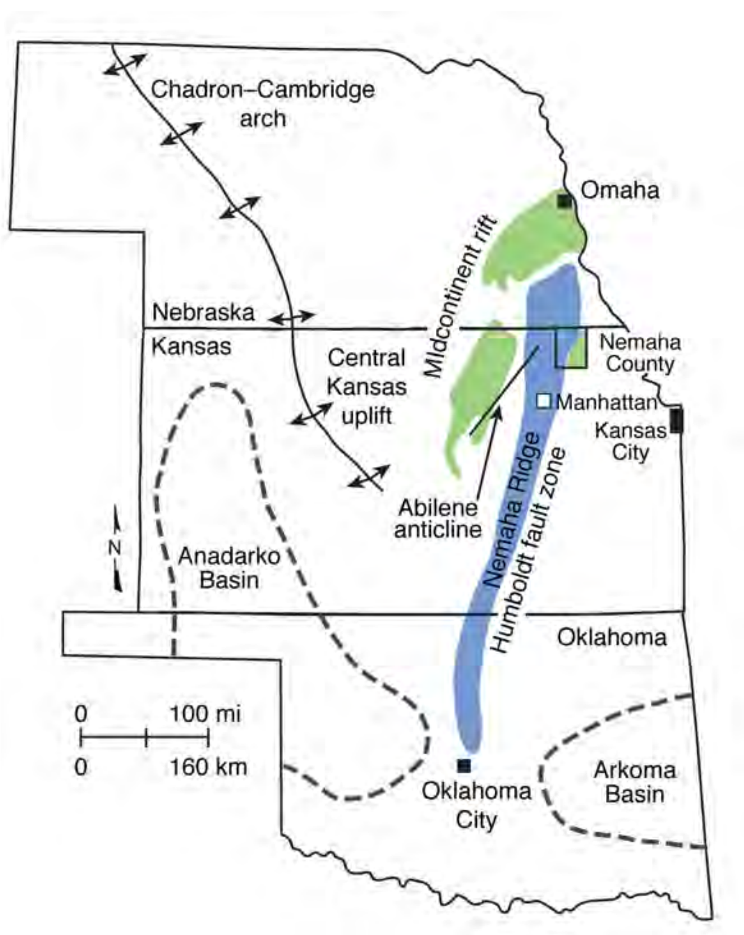
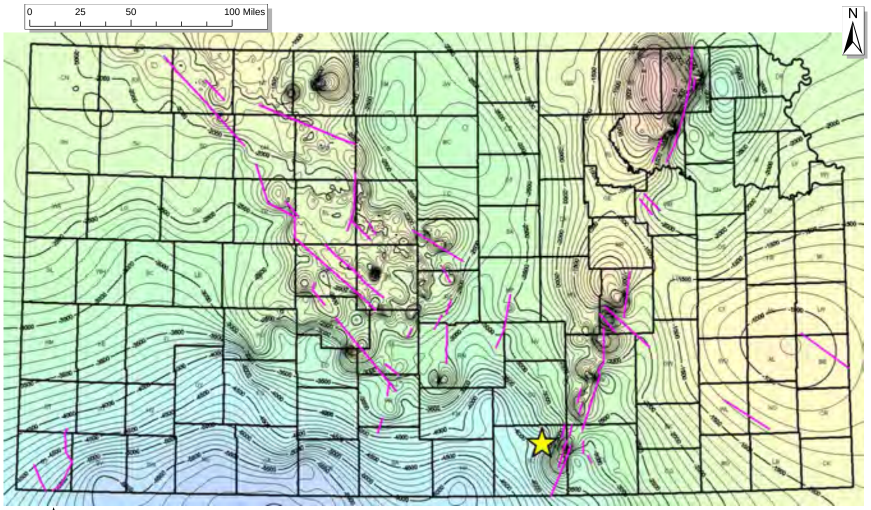
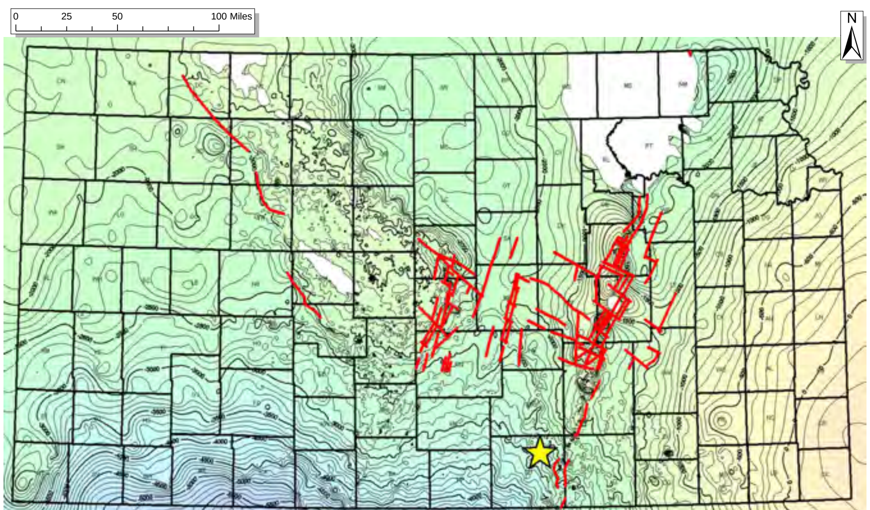


Figure 6.7—Major regional tectonic features that are apparently related to earthquake activity (Source: http://www.kgs.ku.edu/Publications/pic3/pic3_1.html).



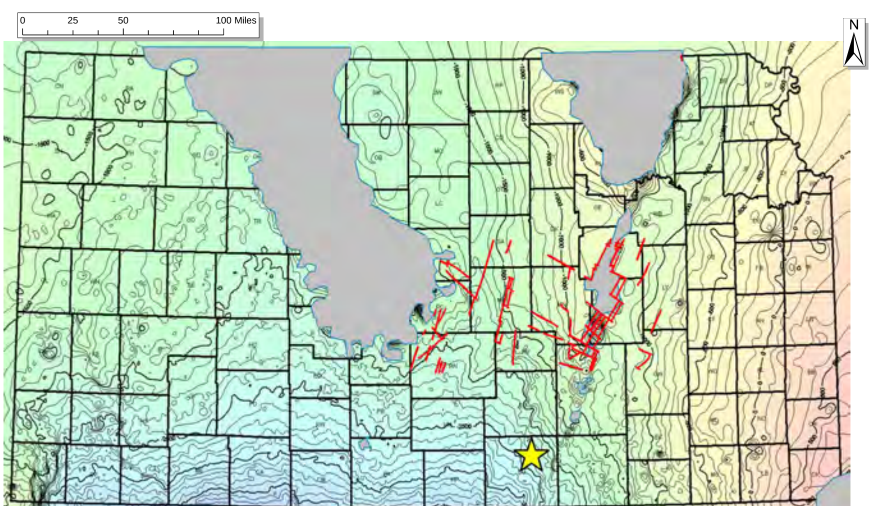
Top of Precambrian Surface

Wellington CO_2 Storage Site



Top of Arbuckle Group

Wellington CO_2 Storage Site



Top of Mississippian Formation

Wellington CO_2 Storage Site

Figure 6.8—Mapped faults (red lines) in Kansas; top—Precambrian surface, middle—Arbuckle Group, and bottom—Mississippian formation (source: Merriam, 1961).

in the immediate area based on comparison of formation pressures. The Mississippian reservoir would not be as highly under-pressurized as observed (Figure 4.29), and neither would the geochemistry be as notably different in the Arbuckle and Mississippian formations as discussed in Section 4.6.7, if the fault(s), if any, were not healed. Therefore, it is reasonable to conclude that there are no vertically conductive faults in the vicinity of the Wellington storage site that would provide a pathway for CO_2 to escape into the USDW or the atmosphere. The structural continuity of the Precambrian, Arbuckle, and Mississippian formations on a regional basis, except along the Nemaha uplift, also suggest the absence of any major faults within the Arbuckle formation in the

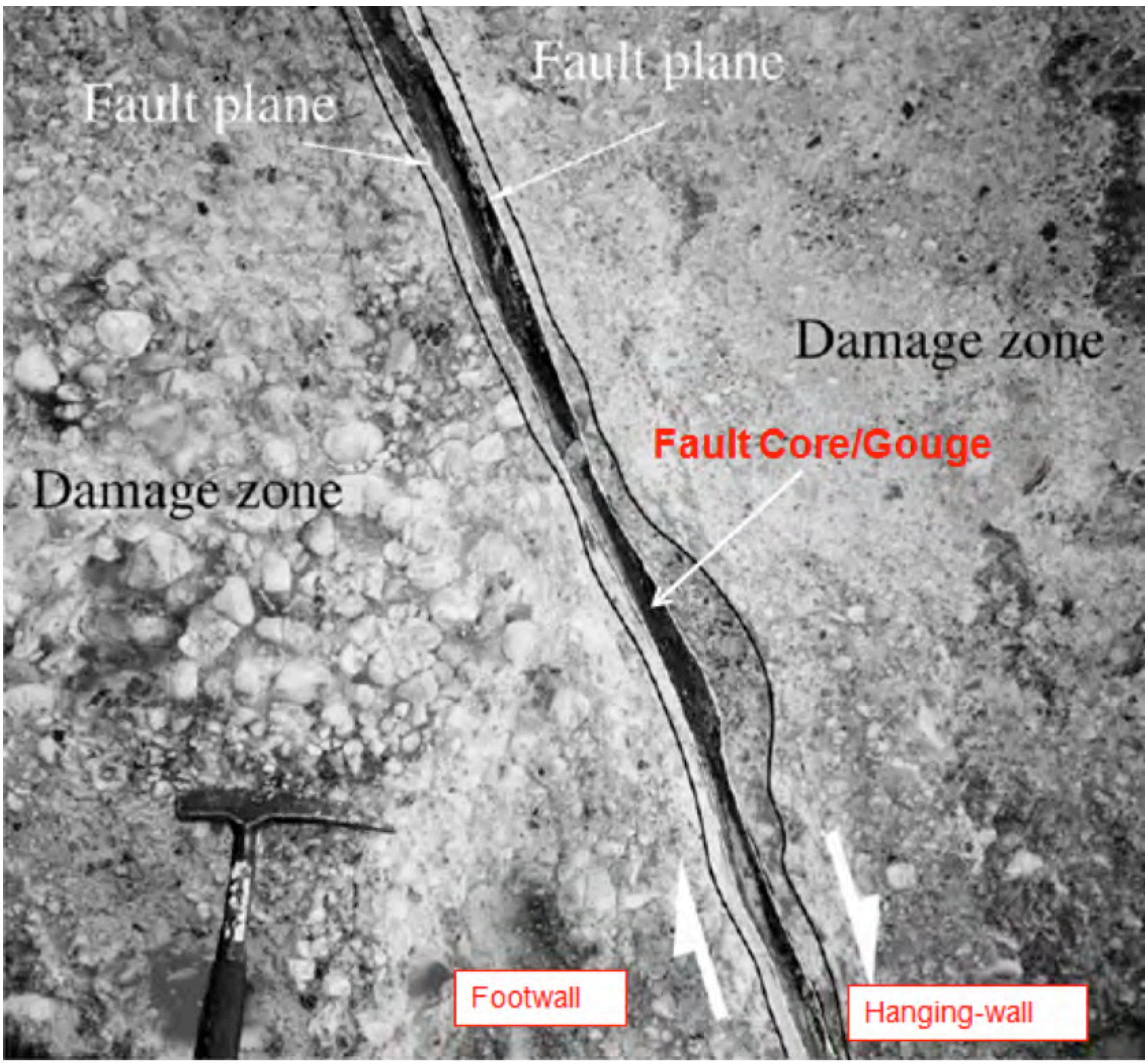


Figure 6.9—Fault zone architecture showing low permeability gouge along fault plane and high permeability damage zone on either side of the fault plane

vicinity of the storage site.

As shown in Figure 6.10, at least 25 earthquakes occurred in Kansas between 1867 and 1976 (Steeples and Brosius, 1996). In 1977, the Kansas Geological Survey installed a highly sensitive seismograph network to study earthquakes from December 1977 to June 1989. During the 12 years of observation, more than 200 small earthquakes were registered in Kansas and Nebraska (Figure 6.11). The largest of these measured about magnitude 4.0 on the Richter scale, and the smallest was magnitude 0.8. Earthquakes of magnitude less than 1.5 on the Richter scale are only detected by sensitive instruments; magnitude 4 earthquakes are “felt by most people; with some breakage of dishes, windows, and plaster may occur; and disturbance of tall objects may occur” (Steeples and Brosius, 1996). In general, most of the earthquake activity in 1867–1989 occurred along the Nemaha Ridge. In the future, Kansas will continue to experience minor non-severe earthquakes, but most of the state is classified as a minor damage zone by the USGS Earthquake Hazard Program as shown in Figure 6.12.

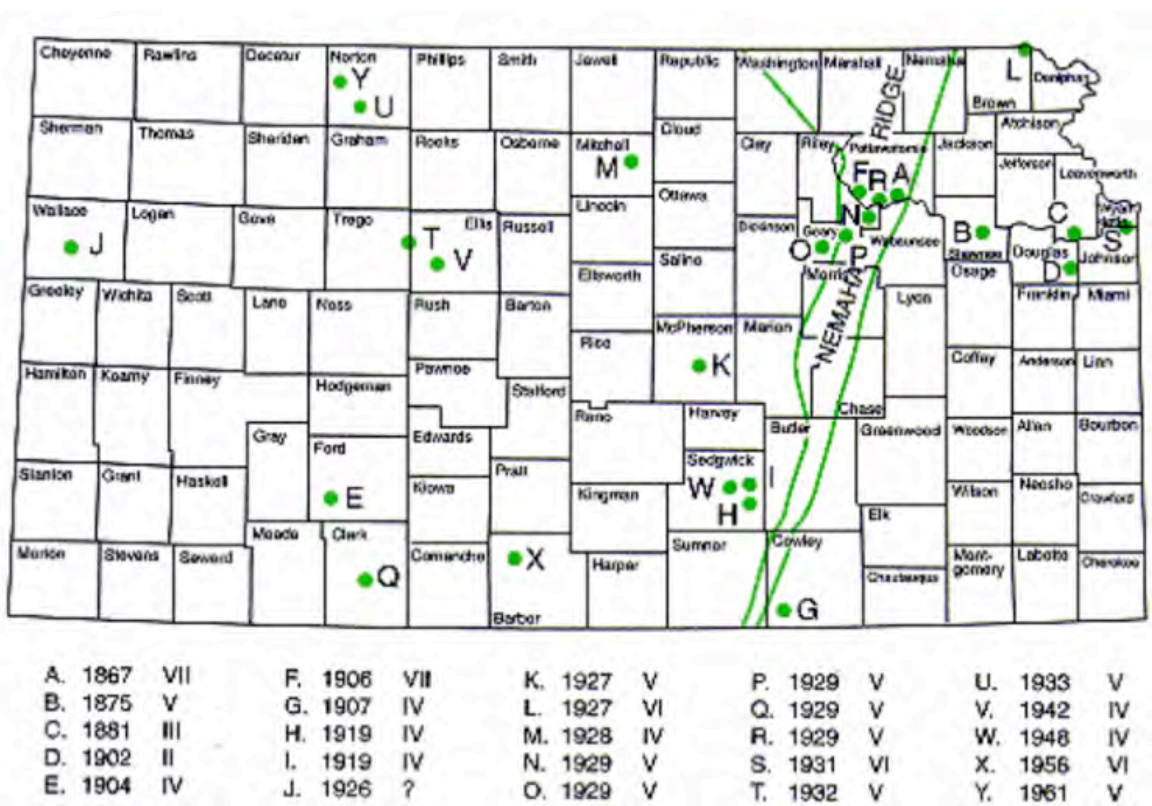


Figure 6.10—Historical earthquakes in Kansas, prior to 1977 (source: Steeples and Brosius, 1996)

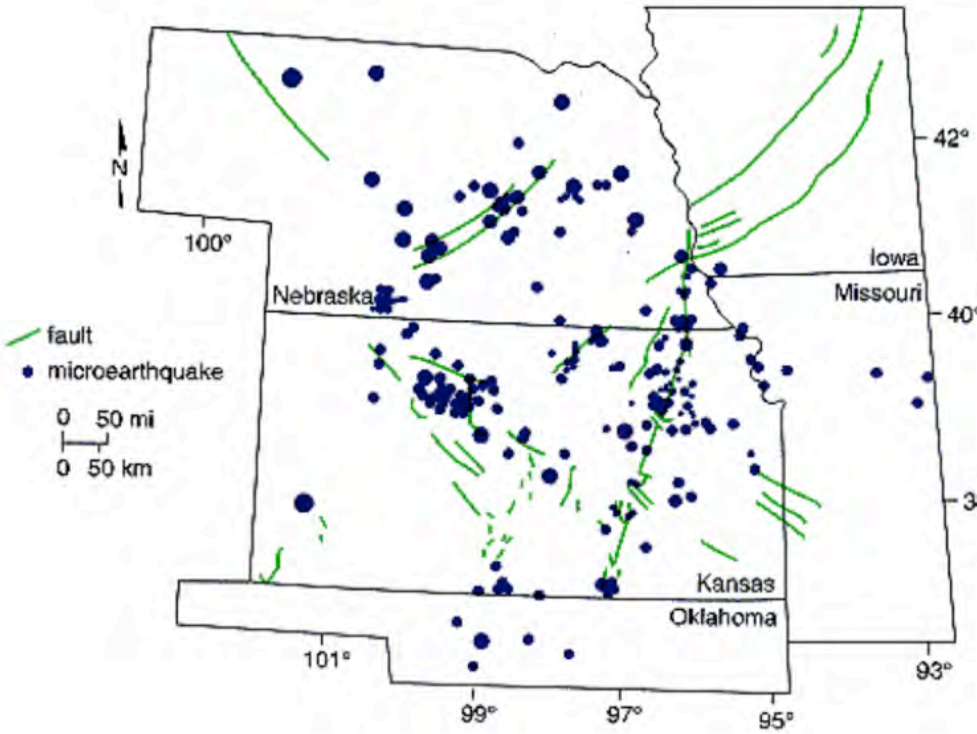


Figure 6.11—Microearthquakes recorded by the Kansas Geological Survey between August 1977 and August 1989 are size-coded by local magnitude. The largest event had a magnitude of 4.0 and the smallest had a magnitude of 0.8 on the Richter scale. (Source: Steeples and Brosius, 1996).

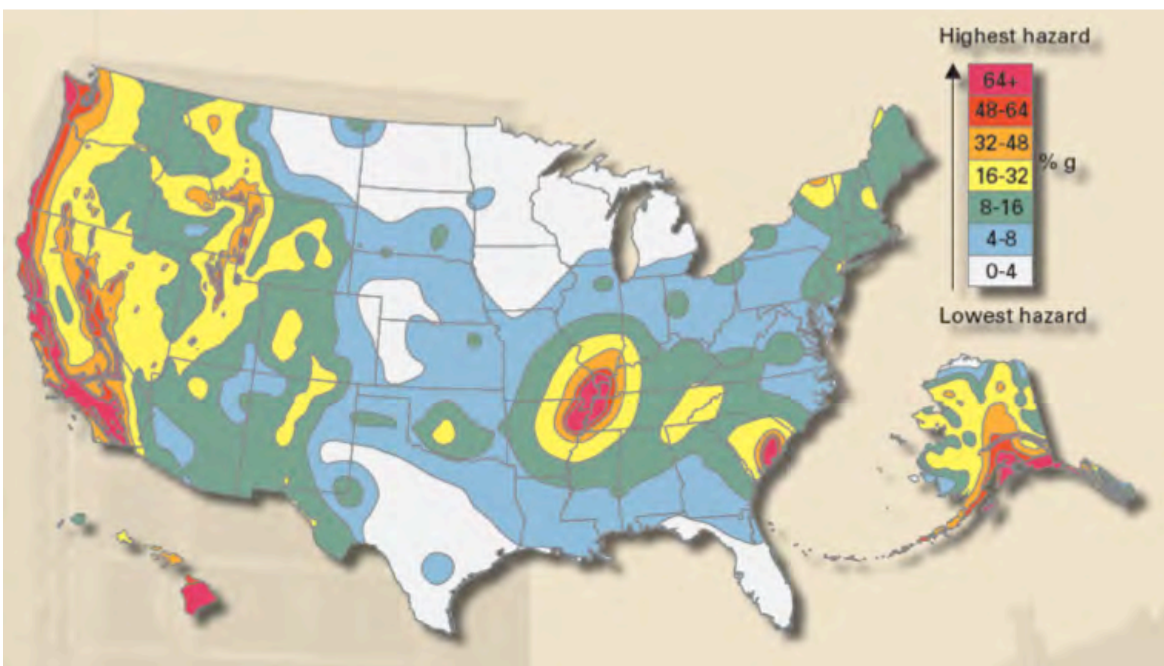


Figure 6.12—U.S. seismic hazard map. Colors on this map show the levels of horizontal shaking that have a 2-in-100 chance of being exceeded in a 50-year period. Shaking is expressed as a percentage of g (g is the acceleration of a falling object due to gravity). (Source: 2008 United States National Seismic Hazard Maps, USGS, Menlo Park, California.)

Section 7

CO_2 Trapping Potential of Mississippian Reservoir

7.1 Introduction

The objective of this section is to highlight the CO_2 trapping potential of the Mississippian reservoir due its under-pressurization. The Mississippian reservoir lies immediately above the confining zone comprising the Simpson Group, Chattanooga Shale, and the Pierson formation as shown in Figure 1.8. The under-pressurization in this reservoir is likely a result of oil and gas production that has occurred in this formation in the area since the early 1900s. As a consequence of this under-pressurization, any CO_2 that may escape from the confining zone, in the unlikely event of fracturing of this zone, will likely remain confined in the Mississippian formation.

The information in this section is not strictly required by Class VI rules and is voluntarily provided in support of 40 CFR 146.83 (b), which states that "The Director may require owners or operators of Class VI wells to identify and characterize additional zones that will impede vertical fluid movement, are free of faults and fractures that may interfere with containment, allow for pressure dissipation, and provide additional opportunities for monitoring, mitigation, and remediation." The information provided in this section is not being relied upon to demonstrate geologic storage potential at the Wellington site. The hydrogeologic analysis and modeling sections (Sections 4 and 5) indicate that the Arbuckle aquifer and the overlying confining zone have adequate hydrogeologic properties to contain the injected CO_2 in the Arbuckle aquifer without danger of leakage into the Mississippian reservoir. The identification and presentation of information pertinent to the Mississippian in this section is provided to address potential questions from the agency as allowed under 40 CFR § 146.83(b).

The information in this section is organized as follows:

Section 7.2 presents the historical development of the Mississippian oil and gas fields in Kansas.

Section 7.3 discusses the geology of this formation and cumulative extracted volumes of oil and gas.

Section 7.3.1 discusses historical production from the Wellington field, which exists at the Wellington storage site.

Section 7.3.2 documents the extent of under-pressurization of the Mississippian reservoir throughout Sumner County.

7.2 Background

Significant quantities of petroleum production in Kansas started with the discovery of the El Dorado and Augusta fields in 1914 in Butler County. Both El Dorado and Augusta are structural traps associated with folding and faulting along the Nemaha uplift (Fath, 1921; Berry and Harper, 1948). Most of the larger fields in eastern Kansas (associated with the Nemaha uplift) were discovered by 1920. Thereafter, exploration activities migrated westward in Kansas (Figure 7.1).

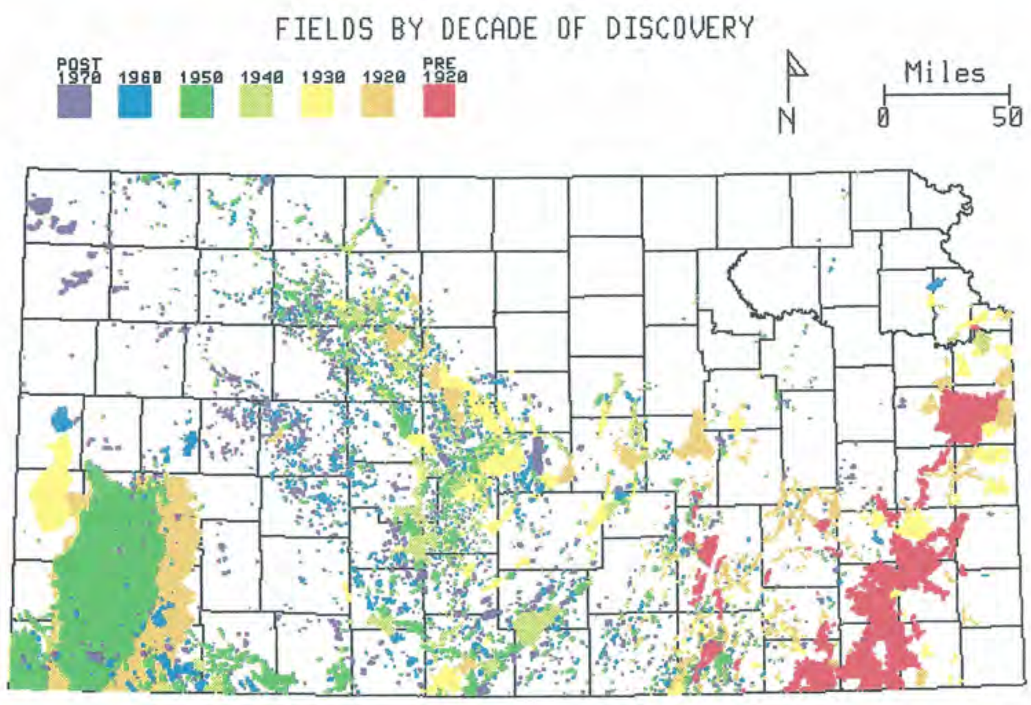


Figure 7.1—Discovery of oil and gas fields in Kansas by decades (Source: Newell et al., 1987)

Kansas petroleum production occurs in several geologic pay horizons (Figure 7.2). In ascending order, these include the Arbuckle; Simpson; Viola and Maquoketa; "Hunton" (Silurian and Devonian limestones); Misener; Mississippian; Morrow and Atoka; Cherokee and Marmaton; Pleasanton, Kansas City and Lansing; Douglas, Shawnee, and Wabaunsee; Admire; Council Grove; Chase; Sumner; and Niobrara. Of these, the Mississippian reservoir is the most productive. Reservoir production statistics, numerical simulation results, and whole core data all indicate that fracturing in this reservoir has resulted in enhanced permeability by as much as an order of magnitude (Watney et. al., 2001). The high permeability in the upper Mississippian has resulted in targeted production from this formation throughout Kansas. By 1992, approximately 43% (about 21 million barrels) of the oil produced in the state was from the Mississippian reservoir (Figure 7.3).

As a consequence of extensive production since the early part of the last century, the Mississippian reservoir is now typically under-pressured significantly (as demonstrated in Section 7.3.2). With its blanket-like

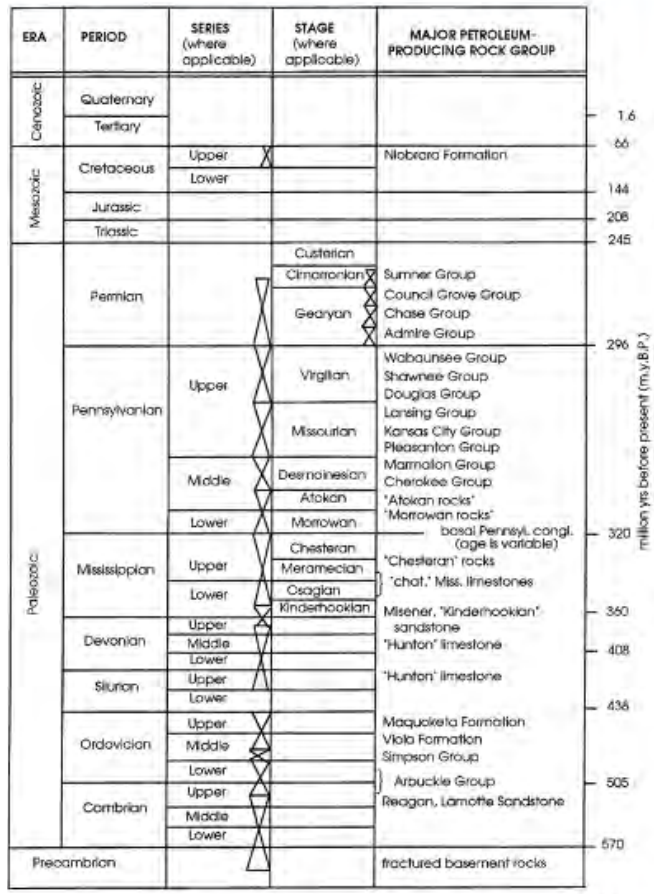


Figure 7.2—Major oil producing rock groups in Kansas (source: Newell et al., 1987).

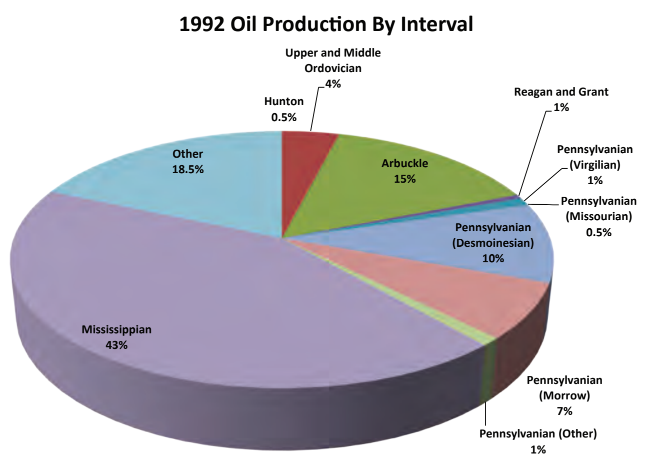


Figure 7.3—Oil production by geologic formation in Kansas by 1992.

distribution in the area as shown in Figures 4.2a-d and 7.4, it could serve as a low-pressure trap to capture CO_2 in the unlikely event that CO_2 escapes from the underlying Arbuckle aquifer. As discussed in Section 5, modeling demonstrates that both the injectate front and pressure impacts will be limited to the Arbuckle, so the productive and under-pressured reservoir rocks within the upper Mississippian will only provide additional zones that will assure protection of the USDW.

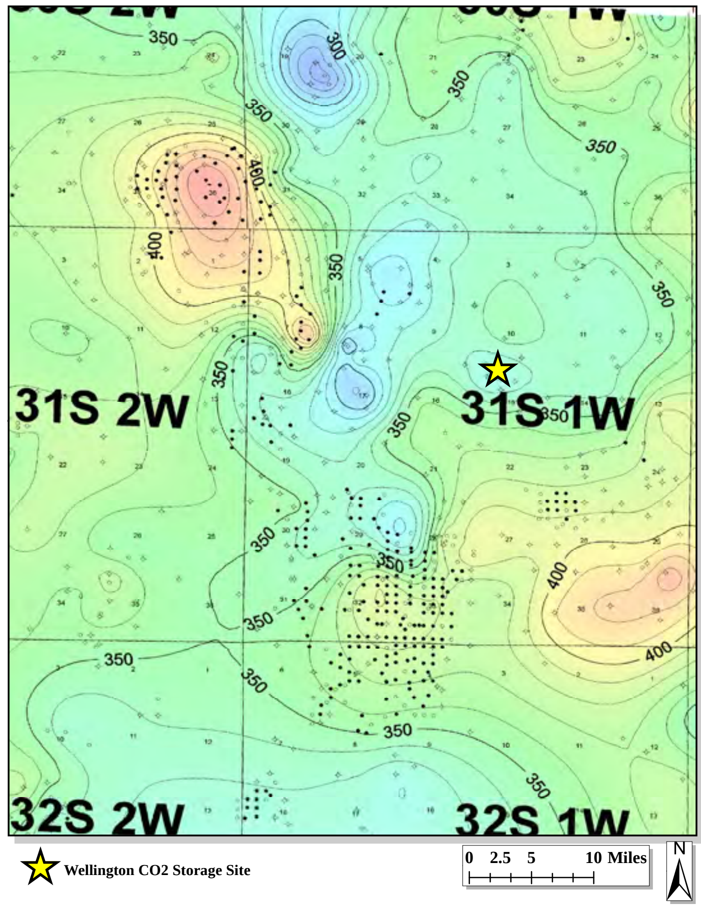


Figure 7.4—Thickness (feet) of Mississippian reservoir in study area (source: KGS database).

7.3 Mississippian Reservoir

Most of the Mississippian production in the midcontinent occurs at or near the top of the Mississippian section just below the sub-Pennsylvanian unconformity (Adler, 1971) because the Mississippian is most permeable at the top. Examination of the porosity distribution at KGS 1-28 and KGS 1-32 found this to be the case at the Wellington site as well. Solution weathering of the Mississippian limestones commonly produces a residual cherty, porous weathered zone just beneath the unconformity that is called the Mississippian “chat” by drillers. The chat is thickest in the vicinity of the Central Kansas uplift and Pratt anticline.

Mississippian rocks produce in several hundred fields in Kansas. Most of the larger fields are combination structural-stratigraphic traps in which porous chat and overlying conglomerates change to nonporous chat or limestone in an updip direction (Adler, 1971). These reservoirs are a major source of Kansas oil production and, as shown in Figure 7.3, accounted for approximately

43% (21 million barrels) of total annual production by 1992. Table 7.1 summarizes total production from chat fields in south-central Kansas. Approximately 1.5 billion barrels of oil and 3.5 billion cubic feet of gas have been produced since commencement of production.

Table 7.1—Oil and gas production from Mississippian chat fields in south-central Kansas as of 2013 (Source: Kansas Geological Survey).

County	Cumulative Oil (bbl)	Cumulative Gas (mcf)	Number of Wells
Barber	131,842,548	2,428,488,185	6,356
Butler	392900351	0	3263
Comanche	533,054	30,094,853	86
Cowley	71,563,423	20,028,686	3,142
Harper	10,442,860	42,816,317	450
Harvey	146,983,233	50,081,447	2,442
Kingman	42,183,326	70,323,209	1,392
Kiowa	32,045,101	700,605,330	1,432
Marion	49801280	51564643	1392
McPherson	234104014	19725910	2825
Reno	136962229	62541790	2218
Rice	49945982	1412064	1692
Sedgwick	87,801,928	161,562	1,576
Sumner	79346056	9945573	1893
Total	**1,466,455,385**	**3,487,789,569**	**30,159**

7.3.1 Mississippian Wellfield in Wellington and Vicinity

The Wellington oil field was discovered in the late 1920s. Production from the Wellington Field is primarily from Mississippian formations. The cumulative production of oil from this wellfield as of 2013 is 20,666,003 barrels (bbls). The large volume of oil produced from the Wellington Field encouraged other operators to expand north and west, which led to the discovery of five other fields of significant oil production (Figure 7.5). The Anson Southeast Field was discovered in the late 1950s and has a cumulative production of 4,255,922 bbls of oil. The Trekell and Bates fields were also discovered in the late 1950s and early 1960s. These two fields have a combined cumulative production of 1,935,117 bbls of oil since their discovery. In the 1970s, the Wellington West Field was discovered, which has a cumulative production of 746,739 bbls of oil to date. The production in all these wellfields is primarily from Mississippian formations. To a large degree,

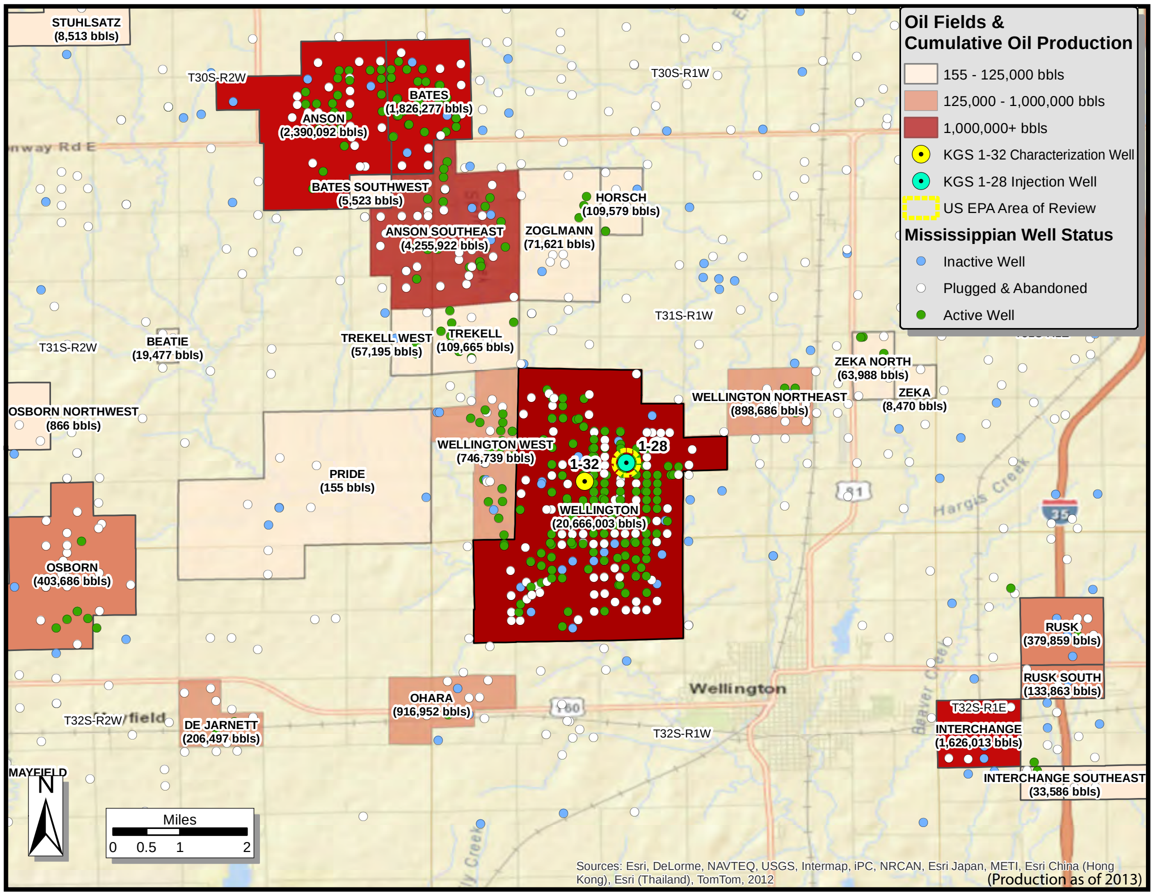


Figure 7.5—Major oil fields in the study area and vicinity showing cumulative production values in barrels (bbls) till 2013.

this production is responsible for the significant under-pressurization now present in the upper Mississippian at the Wellington storage site.

In addition to the favorable reservoir conditions evidenced by the entrapment of oil and gas in the Mississippian Wellington Field, site-specific data support the potential viability of the Mississippian as an additional zone that would capture CO_2 in the unlikely event that upward migration above the top of the Arbuckle at Wellington were to occur, thus impeding further vertical flow and allowing for additional pressure dissipation. The fact that the Mississippian reservoir is significantly under-pressured can be deduced from the DSTs conducted in both KGS 1-28 and KGS 1-32 during well construction at the Wellington site. The test intervals in both these wells are illustrated in Figure 4.28. At KGS 1-28, four DSTs were conducted in the proposed Arbuckle injection zone to obtain permeability estimates in the CO_2 injection zone. At the proposed characterization well, KGS 1-32, three DSTs were conducted in various Arbuckle zones to characterize the Arbuckle Group, and one DST was conducted in the Mississippian to determine the pressure differential between the Arbuckle and Mississippian reservoirs, which also sheds light on the tightness of the intervening confining zone. The pressures recorded during the DSTs in both KGS 1-28 and KGS 1-32 are shown in Figure 7.6. A notable feature of the plot is the under-pressurization observed in the Mississippian formation. The pressure gradient *within* the Arbuckle is 0.48 psi/ft, which is representative of hydrostatic conditions for the brine concentration in the Arbuckle. If the pressure gradient in the Arbuckle were to extend upward into the Mississippian reservoir, then the pressure at the measured depth of 3,664 ft (in the Mississippian) would have been 1,470 psi versus 1,048 psi that was recorded during the test as shown in Figure 7.6 . This represents a significant under-pressurization of the Mississippian in comparison to the Arbuckle and highlights the isolation between the Mississippian and deeper porous units, including the Arbuckle aquifer. The significant pressure decline in the Mississippian due to historic production activities supports the characterization of the Simpson, Chattanooga, and Pierson rocks as providing a relatively low-permeability confining zone between the Arbuckle and the overlying Mississippian as discussed in Section 4.7.

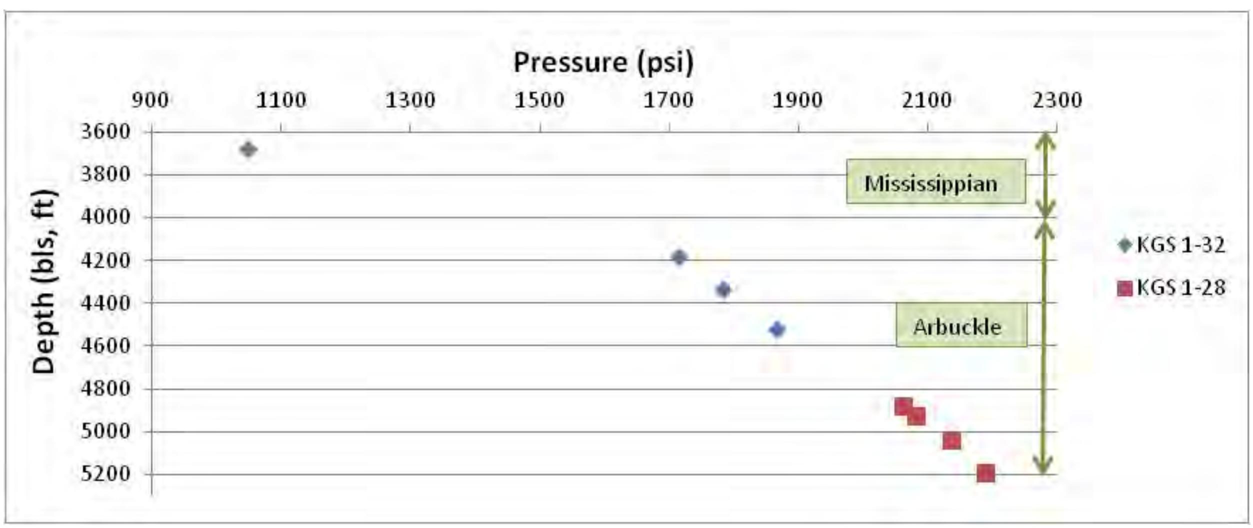


Figure 7.6—Pressures in the Arbuckle and Mississippian formations recorded during drill-stem tests conducted at KGS 1-28 and KGS 1-32.

7.3.2 Under-Pressurization of Mississippian Reservoir in Sumner County

The pressure gradient from land surface (pressure/depth from land surface) at any depth can be used as a measure of the degree of under- (or over-) pressurization at a site. Table 7.2 presents the pressure gradient at the eight DST elevations at KGS 1-28 and KGS 1-32 and clearly shows the significant pressure depletion and current relative under-pressurization in the Mississippian reservoir. The pressure gradient throughout the 1,000-ft thick Arbuckle is within a narrow range of 0.41–0.42 psi/ft, while the pressure gradient in the Mississippian is substantially lower at 0.29 psi/ft.

Table 7.2—DST-derived overall pressure gradient at KGS 1-28 and KGS 1-32.

Well	Average Depth (ft, bls)	Formation	Pressure (psi)	Pressure Gradient (psi/ft)
KGS 1-28	5,178.5	Precambrian	2,189	.422
KGS 1-28	5,023.5	Arbuckle	2,137	.422
KGS 1-28	4,914	Arbuckle	2,082	.423
KGS 1-28	4,862.5	Arbuckle	2,061	.423
KGS 1-32	3,664	Mississippian	1,048	.286
KGS 1-32	4,504.5	Arbuckle	1,867	.414
KGS 1-32	4,322	Arbuckle	1,783	.412
KGS 1-32	4,169.5	Arbuckle	1,716	.411

The under-pressurization caused primarily by hydrocarbon production that is observed in the Mississippian reservoir at the Wellington site is also prevalent throughout Sumner County. Figure 7.7 presents the Sumner County pressure gradient (pressure at measuring elevation/depth of measuring elevation from land surface) derived from DSTs throughout the county. At most well sites, the gradient is within the 0.2–0.4 psi/ft range. Figure 7.8 presents the Sumner County Mississippian pressure gradient histogram, which shows a data tendency towards the low end of the measured range with an average value of 0.34 psi/ft. Very few sites have a freshwater hydrostatic gradient of 0.433 psi/ft or greater.

In summary, the Mississippian formation has been mapped as present throughout Sumner County and has been a productive oil and gas reservoir for decades, implying that the formation offers favorable porosity, permeability, and containment characteristics. Further, regionwide under-pressurization of the Mississippian is very favorable for trapping any CO_2 in the unlikely event

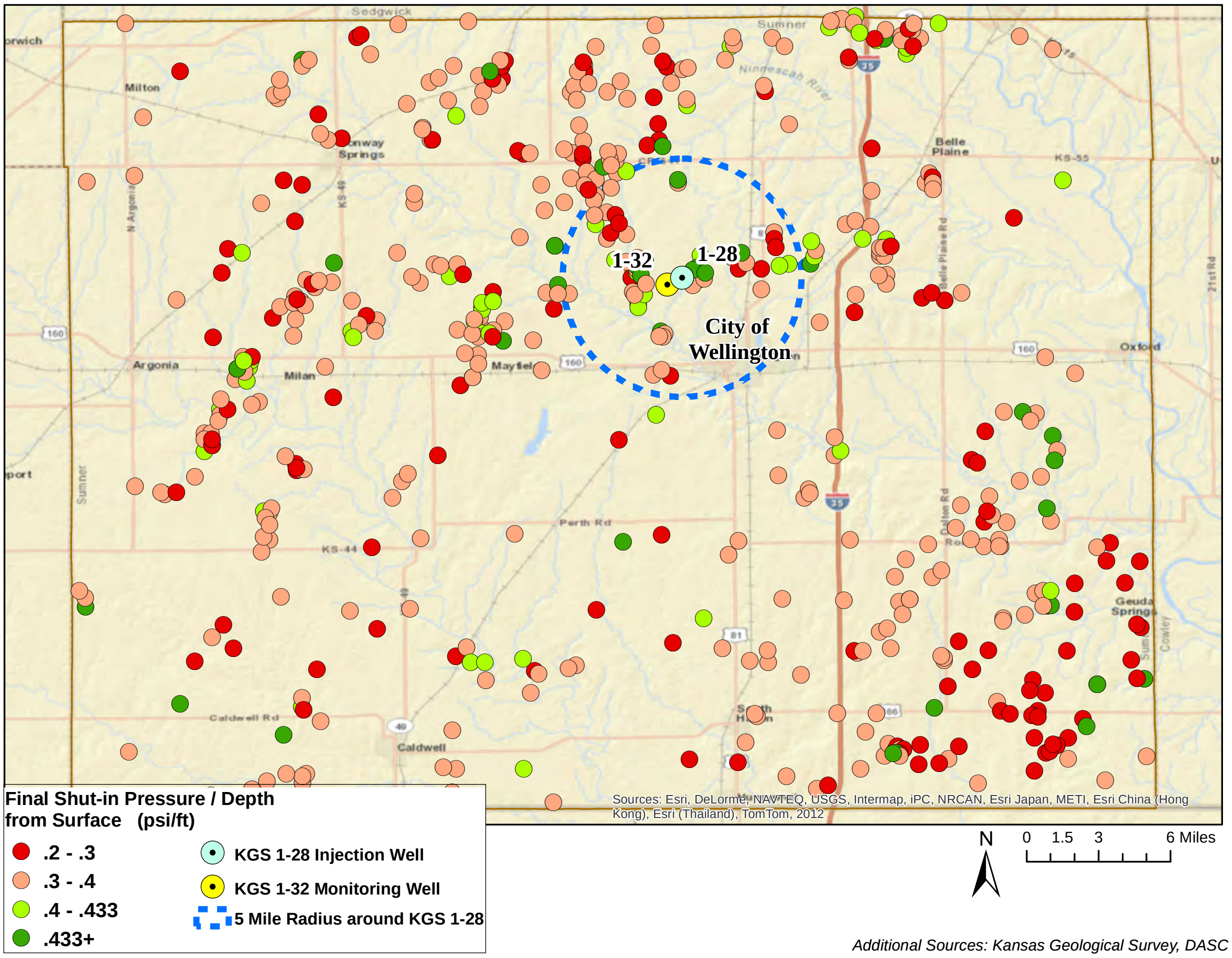


Figure 7.7—Pressure gradient (psi/ft) based on drill-stem tests in the Mississippian reservoir in Sumner County.

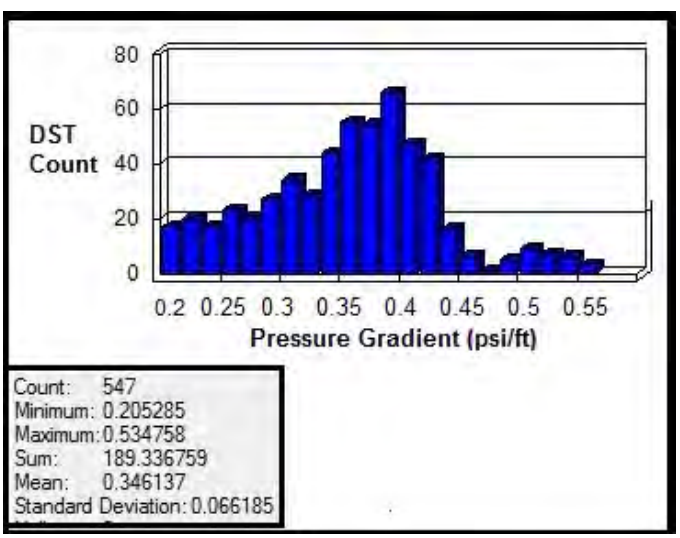


Figure 7.8—Histogram of DST-based pressure gradient (psi/ft) in the Mississippian reservoir in Sumner County.

that CO_2 were to escape from the Arbuckle aquifer and move vertically through the confining zone composed of the Simpson Group, Chattanooga Shale, and the Pierson formation (see Section 4.7 for additional information about confining zones). It is also worth noting that with the very large volume of oil that has been produced from Mississippian sediments, and virtually no oil or gas having been found to exist in Cherokee or younger rocks, one could also conclude that vertical migration above Mississippian rocks has been largely contained due to apparently very low permeability and the spatial continuity of the overlying Cherokee rocks, which are largely shale in this area.

Section 8

System Design, Construction, and Operation

8.1 Introduction

40 CFR § 146.86 (a) requires the owner or operator to ensure that all Class VI wells are constructed and completed to:

1) Prevent the movement of fluid into or between Underground Sources of Drinking Water (USDWs) or into any unauthorized zones,
2) Permit the use of appropriate testing devices and workover tools,
3) Permit continuous monitoring of the annulus space between the injection tubing and long-string casing.

Casing and cement requirements are presented in §146.86 (b) with tubing and packer requirements presented in §146.86(c). Additionally, operational requirements are presented in §146.88 and pre-operational testing is specified in §146.87.

Information in this section is presented to satisfy the above requirements and to ensure that requirements for §146.82(a)(7–12) are satisfied, which require the permit application to include:

(7) Proposed operating data for the proposed small-scale, short-term pilot geologic storage site,

(8) Proposed pre-operational formation testing program to obtain an analysis of the chemical and physical characteristics of the injection zone(s) and confining zone(s) that meets the requirements at § 146.87,

(9) Proposed stimulation program, a description of stimulation fluids to be used, and a determination that stimulation will not interfere with containment,

(10) Proposed procedure to outline steps necessary to conduct pilot-scale injection operation;

(11) Schematics or other appropriate drawings of the surface and subsurface construction details of the well, and

(12) Injection well construction procedures that meet the requirements of § 146.86.

8.2 Background

Well KGS 1-28 is located in central Sumner County (Figure 1.6a) and will be used to inject CO_2 into the Arbuckle Group during a small-scale, short-term pilot project. Construction of the well started on February 20, 2011, and ended on August 24, 2011. Figure 8.1 shows the well design and construction details. The 5,241-ft deep well penetrated the top of the Precambrian basement rock at a depth of approximately 5,165 feet. The well has subsequently been plugged to a depth of 5,155 feet. As shown in Figure 8.1, the well will be perforated between 4,910 and 5,050 ft for injection into a higher permeable interval within the lower portion of the Arbuckle Group. The well penetrated several shale intervals above the Arbuckle as shown in Figure 8.2, most notable among these being the Simpson Group, Chattanooga Shale, and Pierson formation, which together constitute the primary confining zone.

During construction of the well, an extensive suite of geophysical logs, cores, and other geologic data were obtained to better understand the geology and to derive the petrophysical properties documented in Section 4. Well logs and well construction documents are presented in Appendix B. In addition to other discussion within this permit application, additional details about the KGS 1-28 pilot project injector can be found at the KGS website and include DST information, well logs, the Final Geologist's Report, daily drilling reports, maps, and links to other project information (http://www.kgs.ku.edu/PRS/Ozark/well_1_28.html).

8.3 Geologic Formations (§146.86 [a][1] and [b][1][i and vii])

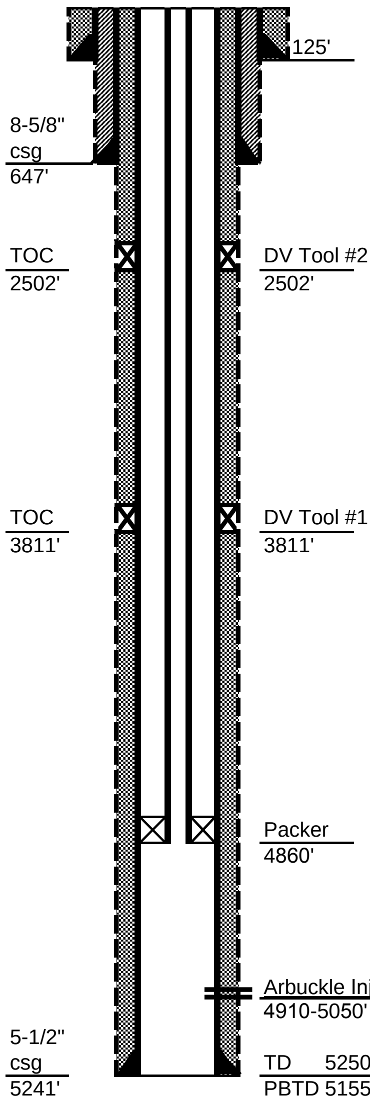
The injection well penetrates the Simpson/Chattanooga/Pierson confining zone, as well as several additional thick shale layers above the confining zone (Figure 8.2). These additional shale layers provide a secondary level of confinement as discussed in Section 4.7.6. The lowermost USDW is the Upper Wellington Formation, which occurs within 250 ft of ground surface at the site, as shown in Figure 8.2.

The dolomitic Arbuckle Formation, which was completely penetrated in KGS 1-28, occurs between the basal Precambrian granite lower confining zone and the upper confining zone com-

Wellbore Diagram

LEASE Wellington KGS #1-28 **API 15-191- 22590**
NE SW SE SW Sec 28 31s - 1w Sumner COUNTY KANSAS

Perforate Arbuckle for CO2 Injection 4910' to 5050'



13-3/8" CONDUCTOR, 48#/FT
Set at: 125' 135 sx cement
Top of Cmt @ Circulated to Surface

8-5/8" SURFACE CASING 24 #/FT
Set at: 647' 325 sx cement
Top of Cmt @ Circulated to Surface

DV Tool #2
Set at: 2502' 610 sx cement
Top of Cmt @ Circulated to Surface

DV Tool #1
Set at: 3811' 260 sx cement
Top of Cmt @ 2502'
Circ cement to surface when DV Tool #2
was opened

2-7/8", J-55 Lined Injection Tubing
Packer at: 4860'

5-1/2" PRODUCTION CASING 15.5#/FT, J55
Set at: 5241' 250 sx cement
Top of Cmt @ 3811'
Circ cement to surface when DV Tool #1
was opened

Wellington KGS #1-28==WellBore Diagram.xls
-bl- Date Printed: 12/8/2011

Figure 8.1—Well design and construction details of KGS 1-28.

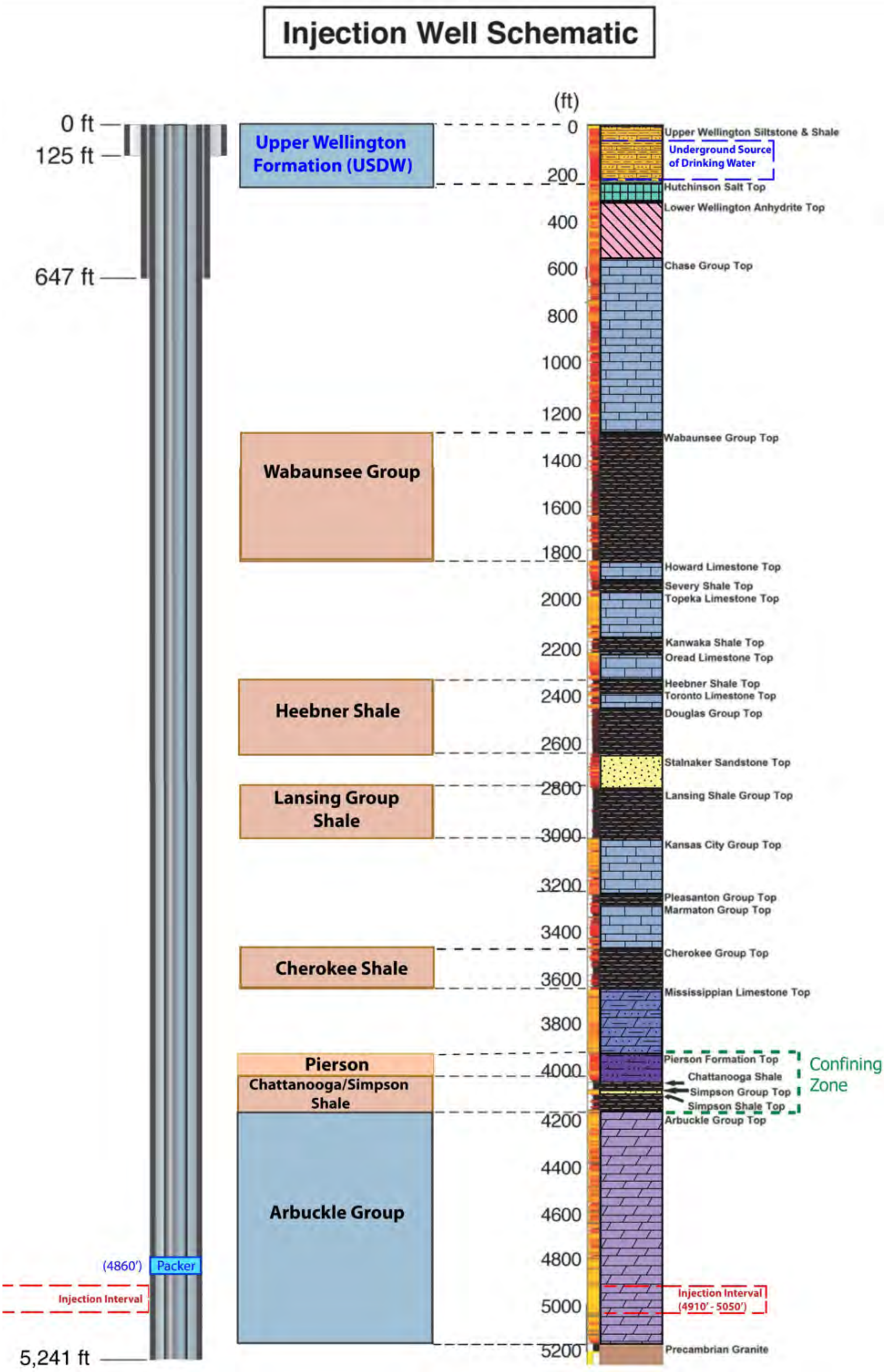


Figure 8.2—Injection well schematic and geologic formations encountered at KGS 1-28.

prising the Simpson Group, Chattanooga Shale, and the Pierson formation. The Arbuckle Group occurs at a depth of approximately 4,168 ft to 5,160 ft below ground surface (Figure 8.2) and injection is planned to take place in the interval 4,910–5,050 ft, which is in the lowermost portion of the Arbuckle Group as shown in Figure 8.2. The injection interval proposed for completion is a dolomite. The lowermost (and only) USDW in the area is the Upper Wellington Formation, which is limited to the top 250 ft of the geologic column at the site. The water resources in this formation are discussed and characterized in Section 4.5. The base of the USDW is approximately 3,900 ft above the top of the injection formation and approximately 250 ft below land surface.

8.4 Operational Information Relevant to Well Construction (§146.86 [b][1][ii and vi])

As discussed in Section 8.16, the surface facilities at the site will consist of a CO_2 storage tank, an injection skid, wellhead, necessary piping and instrumentation, and a programmable logic controller (PLC) or programmable chart recorder for automated injection operation and monitoring. A majority of this equipment is upstream of the well. Information pertaining to the surface equipment and the operational plans are also presented in Section 8.16. Approximately 150 tons of CO_2 will be transported to the well site on a daily basis during the pilot injection test. Delivery will be via trucks operating daily between the Wellington storage site and the CO_2 source selected for project supply. The controller will be programmed to automatically control the injection flow rate based on the operational parameters discussed below, intended pilot-scale research activities, and the operational limits specified in Table 8.1. Critical issues regarding typical operating conditions and limits are presented in the following subsections.

8.4.1 Temperatures

The temperature of the CO_2 during transportation and in the site storage tank is expected to be between approximately -10° and 10° F upon delivery. This temperature may increase depending on ambient conditions and the duration of CO_2 storage in the tanks. As the CO_2 is stored and travels through surface equipment and approximately 4,900 ft down the injection tubing, the temperature

Table 8.1—Probable Operational Conditions at KGS 1-28.

Parameter	Lower Limit	Average	Upper Limit
Injection Rate	0	150 tons/day	300 tons/day (Intermittent)
Surface Temperature	-10°F	+0°F – +20°F	+30°F
Bottomhole Temperature	+10°F	+20° F – +40°F	+70° F
Surface Pressure	0 psi	100 – 800 psi	1,500 psi
Bottomhole Pressure @ 5,050 ft (bottom of perforation)	2,200 psi	2,500 psi	3,408 psi

will rise depending on ambient conditions, the injection rate, and the temperature in the formations surrounding the well. Near the wellbore, formation temperatures will gradually change over time as the cool CO_2 is injected in the well. The bottomhole temperatures cannot be predicted with certainty, but for purposes of selecting appropriate monitoring gauges and estimating CO_2 density with depth, a temperature range of 10° to 70° F at the bottom hole and -10° F to +30° F at the surface is estimated (Table 8.1).

8.4.2 Pressure

To inject CO_2 into the Arbuckle injection interval, the injection pressure at the downhole perforations must be greater than reservoir pressure. The pressure to be applied at the surface (wellhead) will be a function of the bottomhole pressure necessary to inject the desired rate of CO_2 into the Arbuckle, the friction loss generated as the CO_2 is pumped down the tubing and through the perforated completion, and the density of the CO_2 in the tubing. Each of these components that define wellhead pressure will change with time. This short-term small-scale pilot injection may use variable rates, and the specific injection rates sustainable will be, in part, determined by the CO_2 supply and the pilot-scale testing experiments being conducted. The surface pressure will be limited such that the maximum permitted injection pressure is not exceeded. Friction loss will then be highly variable, depending on the experimental injection rates used, the condition of the perforations over time, and the density/viscosity of the CO_2 injected. The density is a function of both pressure and temperature and is expected to range between approximately 46 lb/cu-ft and 59 lb/cu-ft (specific gravity of 0.75 and 0.95) due to temperature and pressure variation in the borehole.

As a final variable, pressure rise will be generated in the injection zone as more CO_2 is displaced into the Arbuckle but this will vary depending on injected volume, conditions, and instantaneous injection rate. At the end of the pilot-scale injection, a maximum bottomhole pressure of less than 2,535 psi at a reference depth of 5,050 ft has been projected at possible pilot flow rates from the simulation results presented in Section 5. This is less than the 3,408 psi pressure at a depth of 5,050 ft conservatively estimated as an allowable bottomhole injection pressure using 90% of pressure calculated at depth with a gradient of 0.75 psi/ft.

Wellhead pressures may be variable but are generally not expected to exceed 800 psi when the effects of variable fluid density along with perforation and tubing friction loss are included in calculations. Bottomhole pressure will be a primary operational issue of concern and will need to be adjusted based on operational data. Because the well is being used for a pilot study, a downhole pressure transducer is planned for monitoring bottomhole pressure. This will be a point of compliance and the PLC or well controller will be programmed to keep bottomhole pressure at 5,050 ft at values of less than a pressure gradient of 0.675 (0.90 x 0.75) psi/ft. The fracture gradient has been estimated as 0.75 psi/ft for this area (see Section 4.6.9).

Without any friction loss included, maximum wellhead pressure could range from 472 to 814 psi, assuming that the maximum bottomhole pressure of 2,535 psi was sustained at the perforations and the average specific gravity of fluid in the wellbore ranges from 0.79 to 0.95. Depending on injection rate and final well completion materials, friction loss may require a larger wellhead pressure to sustain the required downhole injection pressure at the perforations. At higher flow rates, at least several hundred psi of tubing friction loss is likely. Although wellhead pressure may vary from 100 to 1,500 psi depending on flow rate, temperature, fluid density and viscosity, it is anticipated that the system typically will be operated at wellhead pressures of less than 800 psi.

8.4.3 Injection Rate

The planned volume of CO_2 injection is 150 tons per day. However, depending on the formation properties and the need to maintain the CO_2 in liquid state at the pump (which will require a certain minimum pressure based on the temperature), an operating volume of 150–300 tons per day might potentially be injected into the aquifer during batch operations during a 24-hour period to achieve the desired daily injection volume. The PLC or well controller will be programmed to keep a running total of the injected CO_2 and will cease operations if the injection exceeds more than 300 tons within a 24-hour period. The flow rate, however, will also be controlled so as not to exceed the maximum bottomhole pressure of 3,408 psi as specified in Table 8.1.

8.5 Well Casing (§146.86 [b][1–3])

The borehole and casing specifications for the KGS 1-28 well are shown in Table 8.2 and Figure 8.1. The conductor casing has been run from the surface to 125 ft. The surface casing, cemented to surface to provide a cement sheath to fully isolate the USDW from the well, runs from the surface to a depth of 647 ft. This casing shoe is significantly below the lowermost USDW (Upper Wellington Formation) that occurs within 250 ft of ground surface at the site as also shown in Figure 8.1. The production casing was set from the surface to the bottom of the well at 5,241 ft. The well has subsequently been plugged back to a depth of 5,155 ft. The injection tubing (as discussed below in Section 8.7) will be 2.875-in, 6.4 lb/ft J55 tubing with an internal CO_2 resistant plastic liner or coating (Duoline or suitable equivalent). There are approximately 2 inches of annulus spacing between the production casing and the tubing, which is sufficient for conducting the testing and monitoring activities described in Section 10.

Burst pressure, collapse pressure, and tensile strength were obtained from API Bulletin 5C2, Bulletin on Performance Properties of Casing and Tubulars (API, 1999), which states minimum values. Simple calculations are presented to illustrate the maximum scenarios that the well may have been exposed to during drilling conditions or will potentially be subjected to under operating conditions. Definitions of each and equations used are as follows.

Burst pressure: Maximum internal pressure the pipe may withstand before failure caused from hoop stress. Pressure that causes this failure is the pressure differential between internal

Table 8.2—Casing specifications at KGS 1-28.

Casing	Depth Interval (ft)	Borehole Diameter (in)	Size OD/ID (in)	Weight (lb/ft)	Grade	Connection Type	Collapse Pressure (psi)	Burst Pressure (psi)	Tensile Yield (lbs)	Thread Yield
Conductor	surface: 125	17.5	13-3/8 / 12.615	54.5	J-55	ST&C	1,130	2,730	853,000	514,000
Surface	surface: 647	12.25	8-5/8 / 7.972	24	J-55	ST&C	1,370	2,950	381,000	244,000
Production	surface: 5,241 Injection Interval: 4,910–5,050	7.875	5-1/2 / 4.95	15.5	J-55	ST&C	4,040	4,810	248,000	202,000

and external pressure. The only casing string that may experience any pressure events of concern during operations will be the 5.5-in long-string production casing. Maximum internal pressure is calculated at the bottom of the casing string by the following equation:

Internal Pressure = depth x fluid gradient + surface pressure

Collapse Pressure: Maximum external pressure is the pressure exerted on the outside of the pipe that will cause the pipe to be crushed. This is a differential between internal and external pressure. The highest pressure will be at the bottom of the pipe. The worst-case scenario for this well is defined by the following equation:

Collapse Pressure = depth x (pressure gradient of the formation) + (pressure gradient of the cement) - (pressure gradient of water).

Tensile Strength: The amount of pull that can be exerted on the pipe before plastic deformation of the metal occurs. The worst case is to assume the entire string weight is supported by the top joint suspended in air. Under downhole conditions, a large portion of the weight is actually negated due to buoyancy of the pipe in the fluid. The equation in air is as follows:

Tensile weight = weight of the pipe/ft x length

Calculations:

Constants:

Pressure gradient = 2,060 psi at 4,930 ft (depth pressure estimated) = 0.418 psi/ft depth

Freshwater = 0.433 psi/ft depth

Surface Casing Calculations:

14#/gal cement = (14#/gal) x (0.052 psi/ft /#gal) = 0.728 psi/ft

Collapse pressure = 647 ft x (0.418 + 0.728 - 0.433) psi/ft

Collapse pressure = 461 psi

Burst = 647 ft x 0.433 + 500 psi

Burst = 780 psi

Tensile weight = 647 ft x 24 lb/ft

Tensile weight = 15,528 lb

None of the calculated values exceeded minimum standards.

Long-String (injection or production) Casing Calculations:

15#/gal cement = (15#/gal) x (0.052 psi/ft /#gal) = 0.780 psi/ft (from 5,239 ft to 3,811 ft)

14.3#/gal cement = (14.3#/gal) x (0.052 psi/ft /#gal) = 0.743 psi/ft (from 3,811 ft to 2,502 ft)

13#/gal cement = (13#/gal) x (0.052 psi/ft /#gal) = 0.676 psi/ft (from 2,502 ft to surface)

Average cement weight to TD used assuming the unrealistic scenario that no compressive strength developed between cementing stages

Collapse = (5,239 ft-3,811 ft) x (0.418 + 0.780 - 0.433) + (3,811 ft-2,502 ft) x (0.418 + 0.743 - 0.433) + (2,502 ft) x (0.418 + 0.676 - 0.433) psi/ft

Collapse = 3,699 psi

Burst = 1,000 psi + 5,239 ft x 0.433

Burst = 3,268 psi

Tensile strength use weight of entire production string

Tensile weight = 5,239 x 15.5

Tensile weight = 81,205 lbs

None of the calculated values exceeded minimum standards.

8.6 Cement (§146.86 [b][1–4])

The conductor and surface casing cement jobs were each completed in a single stage. The cementing for the production casing was accomplished in three stages using two DV tools (one tool at 2,502 ft and another at 3,811 ft) to promote good cement circulation, placement, bond and annulus isolation (Figure 8.1). The production (long-string) cement was circulated to the surface by pumping the first bottom stage down the casing and circulating up the annulus until the displacement volume had been pumped, at which time the deeper DV tool was opened so that excess cement could be circulated out of the annulus to the surface. After circulation continued through the DV tool for sufficient time for compressive strength to develop in the first stage, the same process was repeated by pumping the middle stage through the DV tool and up the casing annulus. The final top stage was pumped to ground surface in the same way using the upper DV tool. The staged cementing process allowed cement to remain in the annulus of the production (long-string) casing without larger hydrostatic pressures developing that would potentially cause it to drain from the annulus into higher permeability intervals of the injection zone. The lower cement stage covers the entire Arbuckle formation. A total of 27 centralizers were used to properly align the casing and to ensure that it is completely sealed with the borehole.

As shown in Table 8.3, common portland cement was used to seal the annulus of the conductor casing, and a 60/40 Pozzolanic cement was used for the surface casing. For the production casing, CO_2-resistant cement AA-2 was used in the bottom stage, a combination of AA-2 and CO_2-resistant A-Con was used in the middle stage, and A-Con was used in the top stage. The CO_2-resistant cement (with C-44 additive) is engineered to be more resistant to degradation by CO_2 than common portland cement. This is achieved by reducing the lime content and optimizing the particle size distribution, resulting in cement with a very high solid content, which significantly reduces the permeability of the cement and thereby also reduces the degradation rate due to CO_2 reaction, which dissolves the calcite and increases porosity.

To verify the effectiveness of the cementing operations, cement bond and variable density logs are required after setting and cementing the surface casing and long-string casing (40 CFR 146.87[a][2][ii] and 146.87[a][3][ii]). These logs use sonic signals to determine the condition of cement behind the casings and its bonding to the casings. The two cement logs provide complementary information and can be run simultaneously. Interpreted together, the logs indicate the presence or absence of cement behind the casing and the quality of the pipe-cement-formation bonds. Appendix B presents the cement bond and variable density logs for KGS 1-28 obtained on July 27, 2011. The recorded amplitude is indicative of sufficient cement placement and bond for an effective seal between the casing and the subsurface formations (USEPA, 2012b). The temperature log run in the KGS 1-28 well presented in Appendix B also does not show any unusual temperature trends that could be indicative of channels or crossflow in the cement. As discussed in Section 10 (Testing and Monitoring Plan), temperature logs will also be obtained before, during, and after injection to ensure integrity of the cement and casing.

Table 8.3—Casing, borehole, and cement specifications for KGS 1-28.

Purpose of String	Size Hole Drilled (in)	Size Casing Set (in)	Casing Weight (lb/ft)	Setting Depth (ft)	Type of Cement	Number of Sacks Used	Type and Percent Additives
Conductor	17.5	13.375	48	125	Common	135	3%cc, ¼# flake
Surface	12.25	8.625	24	647	60/40 POZ	325	3%cc, ¼# flake
Production	7.875	5.50	15.5	5,241	AA-2	250	10% salt, 6% gils, C-44
1st DV Tool	7.875	5.50	15.5	3,811	A-Con & AA-2	260	10% salt, 6% gils, C-44
2nd DV Tool	7.875	5.50	15.5	2,502	A-Con	610	10% salt, 6% gils, C-44

8.7 Injection Tubing (§146.86 [c][1-3])

The tubing will consist of a 2.875-in 6.4 lb/ft J-55 string lined with a plastic (or suitable equivalent) CO_2-resistant internal liner. It will be set with a packer at approximately 4,860 ft. Total string weight (neglecting buoyancy) will be approximately 31,360 lbs, which is substantially less than the allowable tension load ratings based on joint or pipe body yield (Table 8.4). The tubing prevents contact of the CO_2 with the cemented long-string (production) casing. Collectively, the surface casing and the cement in the surface casing in addition to the tubing, the tubing/casing annulus, and the cemented production casing provide multiple levels of isolation between the injected CO_2 and the geologic formations above the injection zone.

Table 8.4—Tubing specifications.

Name	Depth (ft)	Wall Thickness (in)	Inside Diameter (in)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Thread)	Burst Strength (psi)	Collapse Strength (psi)	Joint Yield strength (lb)	Body Yield Strength (lb)
2-7/8″ J-55 Lined Injection Tubing	surface: 4,900	0.217	2.441	6.4	J55	Non upset	7,260	7,680	72,580	99,661

Note strength-related data values were obtained from the "Halliburton Cementing Tables," 1981.

8.8 Packer (§146.86 [c])

A packer compatible with the CO_2 injection stream will be used to anchor the tubing at a depth of approximately 4,960 ft in the long-string casing. The packer will be lined, coated or constructed of an alloy such that the short-term (less than nine months) pilot project operations can be completed without degradation of the packer performance. The specific packer will be selected based on final details regarding downhole sensors to be deployed through the packer during the scientific investigations planned during the pilot injection. The selection also will take into consideration the temperature range of CO_2 injection likely to be encountered based on the final source and injection rate selected for the study. Before injection, the injection tubing and packer will be tested by applying 500 psi of surface pressure to the annulus and monitoring annulus pressure for a period of 1 hour with less than 5% loss.

8.9 Injection Tubing Stresses (§146.86 [b][1][ii])

The well components will be deployed to withstand the maximum anticipated downhole axial, burst, and collapse stress. The internal loading on the well is determined by the injection pressure and/or the pressure in the annulus between the casing and the tubing. The downhole pressures expected in the tubing and annulus of KGS 1-28 during storage operations are presented in Figure 8.3. As discussed below, the annulus will be filled with corrosion-resistant fluid at hydrostatic pressure. The tubing is expected to experience a surface pressure of approximately 100 to 800 psi to maintain the CO_2 in liquid state and maintain necessary borehole pressure for injection into the Arbuckle. At no time will surface tubing injection pressure exceed 1,500 psi. The non-injection pressures in the tubing are also presented in Figure 8.4 to estimate the “collapse” stresses below.

Figure 8.3—Schematic of stresses on the well bore (source; USEPA, 2012b).

The maximum burst pressure will be experienced during injection at the top of the tubing where the landing joint extends out of the wellhead. This is substantially less than the burst strength of the tubing (7,260 psi) specified in Table 8.4 and also shown in Figure 8.4.

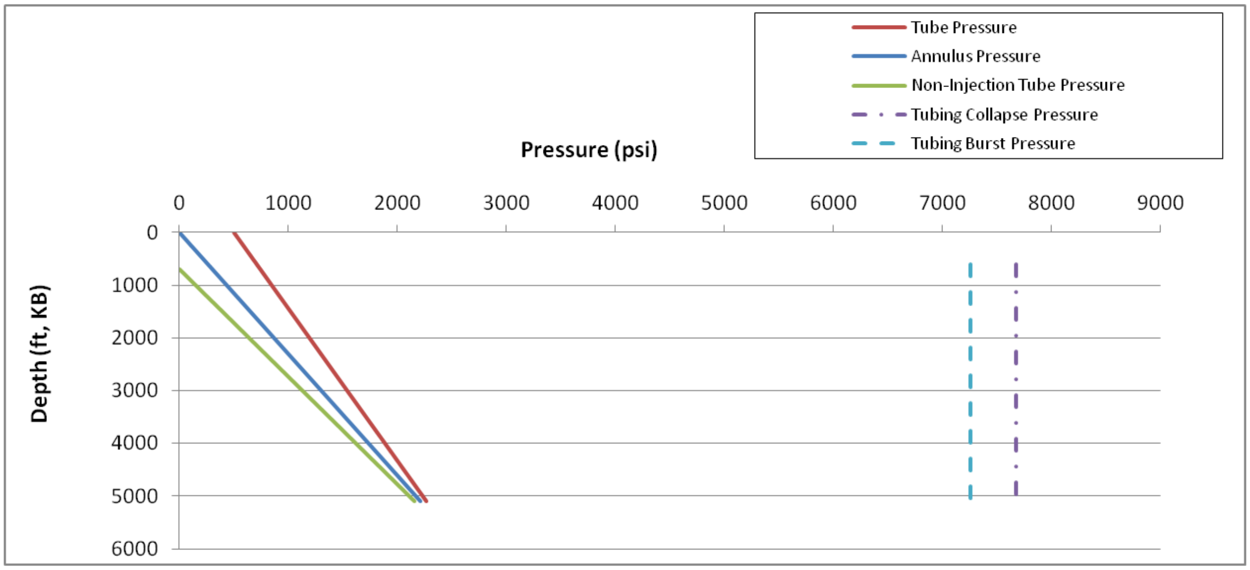


Figure 8.4—Estimated downhole fluid pressures in injection tubing and external casing at KGS 1-28.

8.10 Request for Low-Pressure Annular System

The Class VI rule requires that the annulus be filled with a non-corrosive fluid and that the annular pressure between the tubing and the casing be maintained at a pressure higher than the injection pressure (40 CFR §146.88[c]). The owner or operator must maintain on the annulus a pressure that exceeds the operating injection pressure, unless the director determines that such requirement might harm the integrity of the well or endanger USDWs. Conditions at the small-scale Wellington injection site are such that a casing annulus filled with non-pressurized corrosion-resistant fluid will not jeopardize the integrity of the tubing or casing and will satisfy all objectives for monitoring continuous well integrity.

If a positive pressure annulus (>100 psi above maximum wellhead injection pressure) is required, the high annulus pressures (up to 1,600 psi) resulting at the Wellington site have the potential to threaten well integrity and would not be protective of the USDW. Installation of an annular pressure system, where surface annular pressures are 100 psi greater than surface injection pressures would create the following conditions:

- Annulus pressure of up to 1,600 psi at surface.
- Annulus pressure of 3,735 psi at the packer (this exceeds formation fracturing pressure).
- 1,235 psi differential during operation.

Some of the risks associated with the pressured annulus include:

- High differential pressure across casing and packer could cause casing leaks.
- Annulus pressure is over the fracturing pressure for the entire length of the tubing string.
- High differential across tubing could cause leaks.
- High annular pressure could create a micro-annulus outside or damage cement isolation capacity.
- Cycling of pressures will put additional stresses on the cement.
- High annular pressures at the surface create additional hazards for those working near the surface equipment.
- If the downhole packer system were to fail, then the pressure would potentially fracture the reservoir and the buffering and sealing formations.

It is proposed that the KGS 1-28 well be equipped with a low pressure annular system designed around atmospheric pressure. The annular pressure will be continuously monitored at the surface to detect anomalies or changes. The annular pressure will be monitored to evaluate potential leakage through the injection tubing or casing or around the injection packer. Additionally, a set of operating limits or a minimum and maximum pressure range would be employed within a sensitive enough range to react to identified pressure losses. It is proposed to use annulus pressure monitoring limits set at -5.0 psi to +100 psi. If there is an identified leak in the production casing, fluid would be lost from the annulus and a negative pressure would be observed. If a leak is present in the tubing, a positive pressure deflection would be observed. Anomalies can be suggestive of potential fluid leaks that could develop in either the injection tubing or the production casing or be associated with thermal effects. This operating range is set to reduce false alarms resulting from other variations in operating conditions, such as thermal effects, and to continuously monitor and record values.

If a slowly developing vacuum condition is observed in the annulus, indicating a possible annulus leak, the well annulus could be refilled with fluid. Upon stabilized injection conditions (temperature and rate) being maintained, the continued loss of annulus fluid would indicate a leak from the casing into an under-pressurized formation. Upon development of a continued positive annulus pressure trend, the pressure could be bled from the system and the fluid tested for CO_2. If the positive pressure returned under stable operating conditions (temperature and rate), then a leak would be indicated. The presence of CO_2 gas in the annular fluid would confirm a tubing/packer leak.

8.11 CO_2 Compatibility with Injection Well Components (§146.86[b][v])

The tubing, casing, packer, and cement of the injection well are all designed to withstand CO_2 service. Similar completions have been used in Kansas and other states. The chemical composition of the injectate should cause no adverse reactions or degradation of the well components for the nine-month duration of injection. The low water content (expected to be less than 50 ppm) and the low temperatures will result in only a mildly corrosive environment. Quarterly monitoring for corrosion using coupons as specified in Section 10 will also provide early warning of a deteriorating environment. As proposed in Section 10, the annulus pressure will be monitored daily to detect any leakage from the tubing, casing, or the packer. The annulus fluid will not react negatively with the injected CO_2 should a leak occur in the packer. The CO_2-resistant cement between the injection casing and the borehole reduces the potential for fluid migration into the USDW. The formation water geochemistry data presented in Section 4.6.7 indicate that the formation water also is not corrosive.

8.12 Design and Service Life

Due to the CO_2-resistant properties of the cement and casing, the design life of the well is expected to exceed 10 years. As discussed below, however, the lower segment of the well within the Arbuckle is planned to be plugged at closure within a year of cessation of the injection project. Thereafter, the well will be used in the Mississippian reservoir either as an injection, production, or monitoring well.

8.13 Demonstration of Mechanical Integrity (§146.89)

Before commencing injection, an annulus pressure test will be conducted at the injection well to demonstrate internal mechanical integrity. Testing has already been conducted to provide the information necessary to determine the integrity of the casing and casing-cement bond. The casing, injection tubing, and packer will be further evaluated by means of a pressure test after completion activities are finished and before injection begins. The details of the test are provided in Section 10.3.4.1. Also, discussed in Section 10 are additional tests that are to be conducted to demonstrate mechanical integrity, including daily monitoring of the annular system, and obtaining/analyzing temperature logs during the pre-injection, injection, and post-injection phases.

8.14 Stimulation Plan (§146.82[9], §146.88 [a])

If needed to promote additional injection capacity, standard acid stimulation of the Arbuckle will be completed using standard oilfield practices. Although design parameters may vary depending on conditions encountered, a typical stimulation might involve pumping lease brine as a buffer followed by 1,000 to 2,000 gallons of 15% HCL with iron controls and other additives such as surfactants. This would then be displaced to the perforations by pumping lease brine or with CO_2 as displacement fluid. Due to the cooling effect of CO_2 injection, a short soak time might occur, followed by further displacement of the spending acid into the injection interval using additional lease brine.

8.15 Pre-Injection Testing and Logging (§146.87)

The extensive suite of geophysical log and testing at the injection well site is summarized in this sub-section. Appendix H presents a report on interpretation of the log data by an expert analyst at the Kansas Geological Survey.

8.15.1 Pressure Fall-Off Test

Before commencing injection, a pressure fall-off test will be conducted and the methodology/results submitted to the EPA within 30 days of conducting the test.

8.15.2 Annulus Testing

Before starting injection operations, the annulus and tubing/packer integrity will be tested by applying a minimum pressure of 500 psi at the surface to the annulus for a period of 60 minutes. After stabilization, the pressure will be recorded a minimum of every 10 minutes during isolation. Failure of the pressure to remain within 5% of the starting value would indicate lack of mechanical integrity. At the end of the test, the liquid returned from the annulus will be captured in a container and measured to ensure that the entire length of the annulus was tested. The results of the test will be submitted to the EPA director within 30 days of conducting the test.

8.15.3 Geophysical Logging and Drill-Stem Testing

Table 8.5 presents the geophysical and geological well logs acquired for KGS 1-28. Table 8.6 presents Arbuckle drill-stem test information for well KGS 1-28, and Table 8.7 presents DST recovery information for each Arbuckle DST.

Table 8.5—Geophysical and geological logs acquired at KGS 1-28.

Log Type	Logger/Operator	Log Interval (ft below KB)	Log Date	Comments
Array Compensated True Resistivity	Halliburton/Berexco	648–5,241	March 3, 2011	Gamma Ray log run; BHT 130F
Drilling Time and Sample Log	Geologist's Report/ Berexco	2,650–5,250	March 6, 2011 (final date)	None
Temperature Log	Halliburton/Berexco	50–5,180	March 3, 2011	Gamma Ray log run; BHT 130F
Compensated Spectral Natural Gamma Ray	Halliburton/Berexco	648–5,197	March 3, 2011	Gamma Ray log run
Microlog	Halliburton/Berexco	648–5,241	March 3, 2011	Gamma Ray log run; BHT 130F
Spectral Density Dual Spaced Neutron Log	Halliburton/Berexco	648–5,227	March 3, 2011	Gamma Ray log run; BHT 130F
Annular Hole Volume Plot	Halliburton/Berexco	648–5,241	March 3, 2011	Gamma Ray log run; BHT 130F
Extended Range Micro Imager Correlation Plot	Halliburton/Berexco	648–5,241	March 4, 2011	Gamma Ray log run; SP run, BHT 130F
Radial Cement Bond Log	Halliburton/Berexco	0–5,150	July 27, 2011	Gamma Ray log run, BHT 141F
Composite Plot	Halliburton/Berexco	648-5241	March 4, 2011	Gamma Ray log run
Magnetic Resonance Imaging Log	Halliburton/Berexco	2235-5250	March 4, 2011	Gamma Ray log run; SP run, BHT 130F

Table 8.6—Arbuckle formation drill-stem tests, KGS 1-28.

DST No.	Date/Time	Test Interval (ft KB)	Initial Hydrostatic (1) Pressure and Temperature (psig/°F)	End Shut-In (1) Pressure and Temperature (psig/°F)	Shut-In (2) Pressure and Temperature (psig/°F)	End Shut-In (2) Pressure and Temperature (psig/°F)	Final Hydrostatic Pressure and Temperature (psig/°F)
1	3/5/2011/ 11:46:24	5,133–5,250	2,501.29/129.43	2,189.46/130.04	202.79/129.54	2,186.18/130.50	2,493.29/131.24
2	3/5/2011/ 22:20:17	5,026–5,047	2,428.68/124.88	2,137.71/131.45	1,536.67/132.69	2,137.94/131.94	2,362.88/131.15
3	3/6/2011/ 16:37:17	4,917–4,937	2,411.28/120.02	2,081.64/127.89	598.64/131.52	2,082.44/129.03	2,312.18/127.77
4	3/6/2011/ 00:31:57	4,866–4,885	2,363.19/125.03	2,060.91/128.85	1,699.12/132.12	2,060.91/130.61	2,348.96/129.35

Table 8.7—Recovery table for Arbuckle DSTs conducted at KGS 1-28.

DST	Test Interval	Recovery Length, (ft)	Description	Recovery Volume (bbl)	Total Length (ft)	Total Volume (bbl)	Salinity (ppm)
1	5,133–5,250	185.00	MW33%M 67%W RW .22 ohms@60 degF	0.910			
		185.00	WM50%w 50%m	0.910	370	1.820	39,000
2	5,026–5,047	239.00	MW 28%M 72%W	1.131			
		2480.00	SW	31.909	2,710.00	33.040	34,000
3	4,917–4,937	686.00	Salt Water	4.649			
		186.00	MCW, 30%M 70%W	2.609			
		196.00	WCM 40%W, 60%M	2.749	1,068.00	10.007	31,000
4	4,866–4,885	1543.00	Salt Water	16.670			
		186.00	MCW 10%M 90%W	2.609			
		372.00	WCM 40%W 60%M	5.218	2,101.00	24.497	30,500

8.15.4 Deviation Checks

Deviation measurements were conducted approximately every 1,000 ft during construction of KGS 1-28. Appendix B presents the deviation survey, which indicates that the average hole deviation was less than 1.25 degrees.

8.15.5 Formation Cores

Whole cores were obtained at KGS 1-32 within the interval 3,540 to 5,179 feet (Figure 4.21), which spans from the granitic basement up into the Cherokee Shale. Well KGS 1-32 is approximately 3,500 ft away from the injection well KGS 1-28. However, as discussed in section 4.6.1 and shown in Figure 4.20, the geologic formations and the stratigraphic column at both sites are remarkably similar. Therefore, the information derived from cores at KGS 1-32 is expected to be applicable at the injection well site (KGS 1-28).

The cores were analyzed to characterize the injection and confining zones and to derive hydrogeologic properties. Specifically, as described in Section 4 (Local Hydrogeology), the cores were analyzed for mineralogical composition, subjected to fracture studies, tested in the laboratory to derive hydrogeology properties such as horizontal/vertical permeabilities and porosity, and used for conducting geochemical testing to determine reaction kinetics.

8.15.6 Formation Data

The formation fluid and rock information in the injection and confining zones is documented extensively in Section 4. Specifically, the fluid temperature is discussed in Section 4.6.5, geochemistry in Section 4.6.7, reservoir pressures in Section 4.6.3, estimated static head in Section 4.6.8, fracture gradient in Section 4.6.9, injectivity test in Section 4.6.4, hydrogeologic properties in Section 4.6.6, and confining zone entry pressure analysis in Section 4.7.4.

8.15.7 Future Logging and Testing Activities

An extensive suite of geophysical logs will be acquired and testing conducted for formation characterization during construction of the new Arbuckle monitoring well (KGS 2-28) located 400 ft from the injection well site (KGS 1-28) as shown in Figure 1.6b. Due to the close proximity of the monitoring well to the injection well, the information and data gathered at KGS 2-28 is expected to be fairly representative of conditions at KGS 1-28. The EPA director will be invited to witness the testing and logging activities at KGS 2-28 at least 30 days ahead of the planned activities.

8.16 Description of Surface Facilities and Injection Operations (§146.82[a][11])

8.16.1 Surface Facilities

The CO_2 will be delivered to the site in trucks operating daily between the selected CO_2 supplier/vendor and the Wellington site. Each truck will transport approximately 20 tons of CO_2 in liquid state at a pressure of approximately 250 psi and temperature of approximately -10^{o} F.

The surface facilities at the Wellington injection site will consist of a storage tank, a pump, a programmable logic controller (PLC) or suitable equivalent, and flowlines to the wellhead (Figure 8.5). The injection pump and the controller will be mounted on a skid. The CO_2 will be stored in a pressure vessel adjacent to the injection well (KGS 1-28). The storage tank will be connected to the injection pump skid.

The wellhead assembly will consist of a master valve, a swab valve, and flow line valves. The well annulus will also have connections and valves necessary for access and testing. Wetter surfaces will be coated or lined or made of alloys suitable for short-term CO_2 service as available

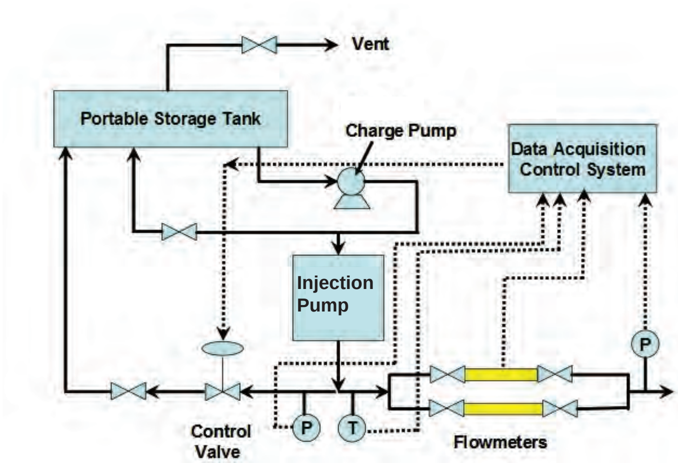


Figure 8.5—Flow schematic of CO_2 injection skid and portable storage tank.

at the time of completion. As discussed in Section 10.3, the bottomhole and wellhead pressures and temperatures will be continuously monitored along with the flow rate at the wellhead, and the data will be fed continuously to the PLC or controller. The controller will manipulate a control valve in the flow line and/or the pump to ensure that the maximum specified flow rate and the bottomhole pressure in the injection well do not exceed the maximum allowable pressure. The CO_2 in the storage tank may experience an increase in pressure as the vessel heats up, which may require occasional venting of the CO_2 to relieve the pressure.

The control system will be programmed to initiate shutdown if emergency events documented in Section 13.3 occur. All operating data (pressure, temperature, and flow rates) will be digitally stored by the control system. Berexco also will store a physical copy of the data in case of a failure of the SCADA system.

8.16.2 Source Fluid (§146.86 [c][3][ii])

8.16.2.1 Source and Chemical Composition

It is expected that the CO_2 source will be acquired from an ethanol production facility in Kansas or a suitable alternative. Regardless of the source, the CO_2 obtained will be analyzed before injection to ensure that it meets the criteria specified in Table 8.9.

Table 8.9—Chemical composition of CO_2 injectate.

Component	Quantity	Comment
$C0_2$	97%	Dry basis
Inert constituents	1%	
Trace constituents	2%	
Oxygen (0_2)	<20 ppm	
Total Sulfur	<25 ppm	
Arsenic	<5 mg/l	Less than RCRA TC standard
Selenium	< 1 mg/l	Less than RCRA TC Standard
Mercury	< 2 ppb	Less than SDWA standard
Hydrogen Sulfide	< 20 ppm	pipeline quality CO_2
Water vapor	< 30 lb/mmscf	

8.16.2.2 Injection Rate and Volume of Injected Fluid

Approximately 150 to 300 metric tons will be injected daily for a maximum of approximately 40,000 metric tons to be stored over a nine-month period.

8.16.3 Shut-Off System

The PLC or control system used to operate and monitor the well will process flow rate, annulus, and injection pressure transducer data. Set points will be programmed to alert operators regarding well conditions of concern.

In the event of an emergency, the system will be shut off. Depending on the event, the system may be either shut off manually or automatically. The lists of events triggering a shutoff are documented in Section 13.3. They include conditions such as high pressure at the wellhead or bottomhole transducer, exceeding the daily injection volume, or annulus pressure that indicates communication to the injection tubing above a set point based on well operating temperature and pressure. Automatic shutoff will occur if the operational parameters that are being continuously monitored exceed permit limits by the controller cutting the run permissive signal and power to the pump on the skid and closing a valve in the flow line. Manual shutoff will occur in the event of failure of well mechanical integrity, detection of CO_2 during MVA activities, surface infrastructure damage, etc. The controller will have commercially available alarm capabilities to notify Berexco of a shutdown over cellular network as specified in Section 13.

Section 9

Area of Review Delineation Re-Evaluation and Corrective Action Plan

Facility Name: Wellington Field Small Scale Carbon Capture and Storage Project

Injection well Location: Latitude 37.319485, Longitude -97.4334588

Township 31S, Range 1W, Section 28 NE SW SE SW

Facility Contact: Dana Wreath, Vice President

Contact Information: 2020 N. Bramblewood Street

Wichita, KS 67206

(316) 265-3311

Fax: (316) 265-8690

9.1 Introduction

Class VI Area of Review and Corrective Action requirements states in § 146.84 (b) that the owner or operator of a Class VI well must prepare, maintain, and comply with a plan to delineate the AoR for a proposed geologic storage project, periodically re-evaluate the delineation, and perform corrective action that meets the requirements of this section and is acceptable to the director. The Area of Review and Corrective Action Plan must include the following:

(1) The method for delineating the AoR, including the model to be used, assumptions that will be made, and the site characterization data on which the model will be based;

(2) A description of

(i) The minimum fixed frequency, not to exceed five years, at which the owner or operator proposes to re-evaluate the AoR;

(ii) The monitoring and operational conditions that would warrant a re-evaluation of the AoR before the next scheduled re-evaluation, as determined by the minimum fixed frequency.

(iii) How monitoring and operational data (e.g., injection rate and pressure) will be used to inform an AoR re-evaluation; and

(iv) How corrective action will be conducted to meet the requirements, including what corrective action will be performed before injection and what, if any, portions of the AoR will have corrective action addressed on a phased basis and how the phasing will be determined; how corrective action will be adjusted if there are changes in the AoR; and how site access will be guaranteed for future corrective action.

Additionally, §146.84 (e) also requires a re-evaluation of the AoR at the minimum fixed frequency, not to exceed five years, as specified in the Area of Review and Corrective Action Plan, or when monitoring and operational conditions warrant. The re-evaluation process must do the following:

(1) Re-evaluate the AoR in the same manner as originally conducted;

(2) Identify all wells in the re-evaluated AoR that require corrective action;

(3) Perform corrective action on wells requiring corrective action in the re-evaluated AoR; and

(4) Submit an amended Area of Review and Corrective Action Plan or demonstrate to the director through monitoring data and modeling results that no amendment to the plan is needed. Any amendments to the Area of Review and Corrective Action Plan must be approved by the director, must be incorporated into the permit, and are subject to the permit modification requirements at §144.39 or §144.41, as appropriate.

Section 5 presents the reservoir modeling conducted in support of the Wellington Arbuckle pilot project AoR. The conceptual model, model domain, modeled processes, geologic structure, hydrogeologic and CO_2 injectate properties, model mesh, initial and boundary conditions, model operational constraints, simulations software description, and simulation results are all documented in Section 5. Therefore, Section 5 is an integral part of the Area of Review and Corrective Action Plan and contents in Section 5 should be reviewed in conjunction with information presented in this section. This section summarizes how modeling information from Section 5 was used to delineate the AoR, how the AoR will be re-evaluated over time, and the overall plan for demonstrating compliance with 40 CFR 146.84 requirements listed above.

9.2 EPA Area of Review (AoR)

The EPA AoR is based on the Maximum Extent of either the Separate-phase Plume or Pressure-front (MESPOP) methodology as explained in the EPA AoR guidance document (USEPA, 2011). The goal is to define the extent of the plume and pressure front within which any artificial or natural penetration (such as improperly plugged wells, transmissive faults or fractures) could have the potential to allow brines within the injection zone to migrate upward into the lowermost USDW. As documented in Sections 4.4 and 4.5, the lowermost USDW at the Wellington geologic storage site is the Upper Wellington Formation within the top 250 ft of the geologic column. Section 9.2.1 discussed the pressure-based AoR, and Section 9.2.2 discusses the plume-based AoR.

9.2.1 Pressure-Based AoR

The pressure-based AoR is defined by the following equation:

$$P_{i,f} = P_u \frac{\rho_i}{\rho_u} + \rho_i \, g \, (z_u - z_i) \qquad \text{(Equation 9.1)}$$

Where,

$P_{i,f}$ = Minimum pressure (MPa) within the injection zone necessary to cause vertical flow from the injection interval into the USDW

P_u = Pressure (MPa) within the lowermost USDW (97 psi = 0.67 MPa),

ρ_u = Fluid density (kg/m^3) within the USDW (1,000 kg/m^3),

ρ_i = Fluid density (kg/m^3) in the injection zone (1,130 kg/m^3),

z_i = Injection depth (m) (5,050 ft = 1,539 m; bottom of injection interval),

z_u = depth of lowermost USDW (m) (250 ft = 76.2m)

g = acceleration due to gravity (9.81 m/sec^2)

The pressure-based AoR is defined by the 327 psi (increase in pore pressure) isoline. It was derived as follows.

Based on water level hydrographs presented in Figure 4.15, the water table in the area is generally 8–12 ft below ground. In one well in western Sumner County, the water table is approximately 25 ft below ground level. To be conservative, it is assumed that the water table is also 25 ft below ground level at the Wellington site within the entire AoR. This equates to a hydraulic freshwater pressure at the base of the USDW (Upper Wellington formation; 250 ft below ground, elevation of approximately 1,000 ft / 305 m, msl) of approximately 0.67 MPa. It is assumed that the density of freshwater in the USDW is 1,000 kg/m^3. Based on the DST at KGS 1-28, the chloride concentration in the injection zone is approximately 112,000 ppm, which results in a specific gravity of 1.13 (density of 1130 kg/m^3) as per the brine density relationship for the Arbuckle Group presented in Figure 4.3.

Substituting the above values in Equation 9.1 above results in a pressure of 16.97 MPa (2,461 psi) at the bottom of the injection interval at 5,050 ft.

$$P_{i,f} = 0.67 \text{ MPa } (1{,}130 \text{ kg/m}^3 / 1{,}000 \text{ kg/m}^3) + 1{,}130 \text{ kg/m}^3 * 9.81\text{x}10^{-6} \text{ m/s}^2 \ (1{,}539.2 \text{ m} - 76.2 \text{ m}) = 16.97 \text{ MPa} = 2{,}461 \text{ psi}$$

Working similarly, the pressure-based AoR at the top of the injection interval (4,910 ft) is derived as 16.502 MPa (2,393 psi) as shown in Table 9.1

Table 9.1—Pressure boundary for Area of Review delineation.

Depth (ft)	Pressure-Based AoR Boundary (psi)	Estimated Ambient Pressure (Section 5.2.4) psi	Delta Pressure (psi)
4,910 (top of injection zone)	2,393	2,066	327
5,050 (bottom of injection zone)	2,461	2,134	327

The ambient (pre-injection) pressure is approximately 2,134 psi at the bottom of the injection interval (5,050 ft) based on the pressure equation derived in Section 5.2.4, which implies that a pressure increase of 327 psi (due to CO_2 injection) is required for the brine from the Arbuckle to migrate vertically to the base of the USDW outside of the CO_2 plume. As shown in Figure 5.18, the pore pressure in the formation drops to less than 300 psi within a few tens of feet from the injection well at the end of the injection period. Therefore, the only well within the pressure-based AoR is KGS 1-28, which has been constructed per Class VI guidelines.

9.2.2 Plume-Based AoR

The plume-based AoR is defined by the boundary that encompasses the injected free-phase CO_2 with a concentration greater than 1%. As discussed in Section 5.4.6.1, the maximum plume spread results for the alternative model with the largest permeability and the lowest porosity (K-1.25/phi-0.75). Figure 9.1 shows the free-phase CO_2 plume in the injection zone at 100 years, by which time the plume has largely stabilized. As shown in Figure 9.1, no existing or abandoned wells, other than the proposed injection well (KGS 1-28) and the proposed monitoring well (KGS 2-28), penetrate the top of the confining zone (Pierson formation)

9.3 Corrective Action Plan

Since both the existing well (KGS 1-28) and the future well (KGS 2-28) located in the AoR will be constructed in accordance with 40 CFR 146.86 (Injection Well Construction Requirements), no corrective action is anticipated for the wells within the AoR. The construction details for well KGS 1-28 and KGS 2-28 are documented in Sections 8 and 10 respectively and are summarized in Table 9.2.

Table 9.2—Existing or abandonment wells/boreholes that penetrate the confining zone within the AoR.

API Well Number	Lease Name	Well Class	Operator Name	Total Depth (ft)	Status	Spud Date	Completion Date	API Number	Elevation (ft, msl)	NAD83 Latitude	NAD83 Longitude
22590	Wellington KGS #1-28	Inactive Well	Berexco LLC	5,250	CO_2 Injection	2/20/11	8/24/11	15-191-22590	1257	37.31951	-97.43378
Future Well	Wellington KGS #2-28	Proposed Well	Berexco LLC	5,250	CO_2 Monitoring	N/A	N/A	N/A	1255 (Est)	37.319965	-97.434739

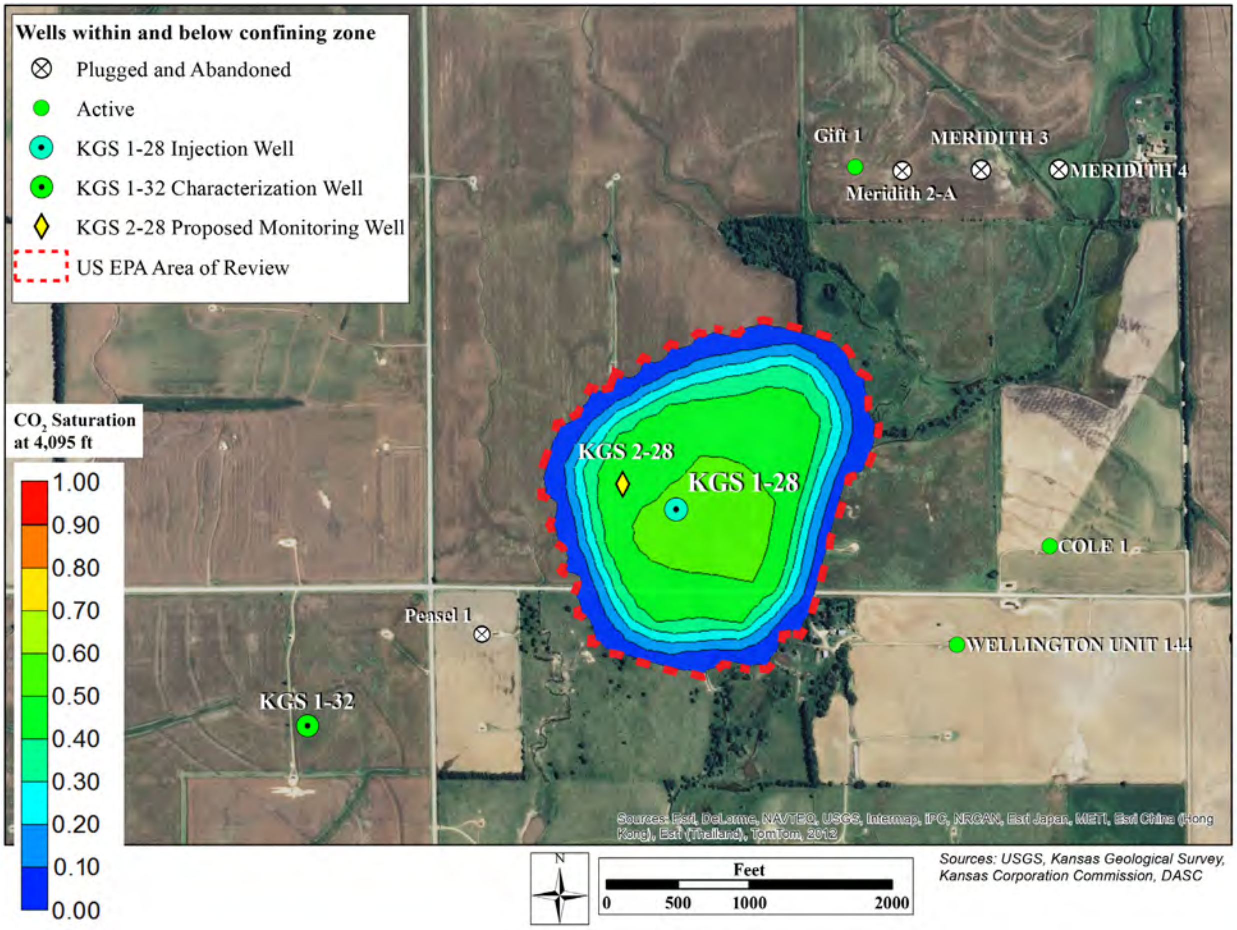


Figure 9.1—The plume-based AoR as defined by the 1% free-phase saturation isoline, which encompasses 99% of the injected CO_2 in free phase for the largest plume migration alternative model (k-1.25/phi-0.75). Also shown are all existing, abandoned, and proposed wells that penetrate the top of the confining zone (Pierson formation) in the AoR and vicinity.

9.3.1 Area of Review Plan and Schedule

The AoR will be re-evaluated for this pilot-scale project according to the criteria presented below, or a demonstration will be made to the Director that an AoR re-evaluation is not required.

a) When the following operational parameters are exceeded:

- Average injection rate exceeds 300 tons/day for more than 1 week.
- The pressure at the top and bottom of the Arbuckle injection interval exceeds 90% of the fracture gradient as specified in the following table:

Depth (ft)	Expected Ambient Pressure* (psi)	90% of Fracture Gradient Based Pressure** (psi)
4,910	2,066	3,314
5,050	2,134	3,408

* based on pressure-depth relationship specified in Section 5.2.4.
** assuming fracture gradient of 0.75 psi/ft as specified in Section 4.6.9.

b) If newly collected characterization data at KGS 2-28 are deemed to significantly alter the hydrogeologic properties specified in the reservoir model,

c) When pressure and plume data recorded at the monitoring well (KGS 2-28) differ significantly from model projections,

d) At the termination of injection,

e) Just before site closure to demonstrate stability of the plume and pressure front, since an early site closure is requested for this short-term small pilot scale project,

f) If the following events occur and re-evaluation is determined to be warranted based on evaluation of the event impact:

- Change in modeled direction of plume movement as detected by means other than the monitoring well (KGS 2-28) (evaluation within one month of detection),
- Initiation of competing Arbuckle injection projects within the same injection formation within a 1-mi radius of the injection well (evaluation within one month of detection),

- A significant deviation of monitored wellhead operational data, or formation pressure and plume migration data
- Significant land use changes that would impact the USDW or site access (evaluation within one month of detection),
- New site characterization data that identify faults within the AoR (within one month of identification),
- Seismic events or other emergency events that trigger an AoR re-evaluation as specified in Section 13,
- Any other activity prompting a model recalibration.

The AoR re-evaluation will ensure that site monitoring data are used to update modeling results and that the AoR delineation reflects any changes in operational conditions. Figure 9.2 illustrates the general relationship between site characterization, modeling, and monitoring activities that is to be followed. At the end of injection and at closure, and if evaluation of the events listed above indicates that the event was significant, then §146.84 (e), which requires a re-evaluation when monitoring and operational conditions change, will be implemented:

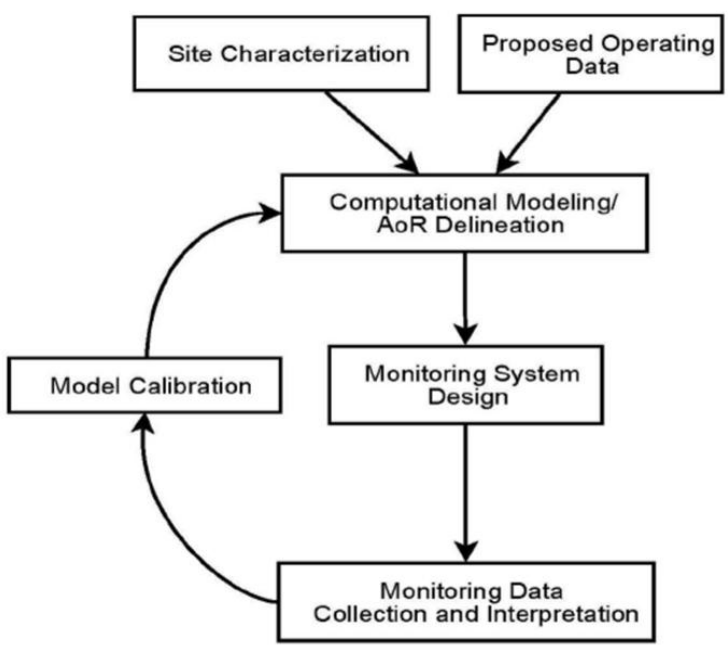


Figure 9.2—Flow chart of monitoring and modeling (source: EPA, 2011).

(1) Re-evaluate the AoR in the same manner specified in paragraph (c) (1) of section 146.84;
(2) Identify all wells in the re-evaluated AoR that require corrective action in the same manner specified in paragraph (c) of §146.84;
(3) Perform corrective action on wells requiring corrective action in the re-evaluated AoR in the same manner specified in paragraph (d) of §146.84; and
(4) Submit an amended Area of Review and Corrective Action Plan or demonstrate to the director through monitoring data and modeling results that no amendment to the plan is needed. Any amendments to the Area of Review and Corrective Action Plan must be approved by the director, must be incorporated into the permit, and are subject to the permit modification requirements at §144.39 or §144.41 as appropriate.

9.3.2 Corrective Action Plan and Schedule Following AoR Re-evaluation (§146.8 [b][2][iv])

As discussed earlier, since both wells within the AoR are either constructed (KGS 1-28) or will be constructed (KGS 2-28) in accordance with 40 CFR 146.86, no corrective action is presently required. Should future modeling indicate that the AoR extends beyond the present AoR boundary and includes wells that penetrate the confining zone other than KGS 1-28 or KGS 2-28, the Corrective Action Plan will be revised to include the well name, well location, planned date of corrective action, planned corrective action method, and any other pertinent information required by the director. If the result of the re-evaluation requires corrective action(s), these will be implemented as expeditiously as possible in consultation with the EPA director.

9.3.3 Site Access (§146.8 [b][2][iv]):

The Wellington site is in close proximity to paved roads in the area, thereby providing easy access. Berexco is the operator of the Wellington oil field and has permission to access all well sites should that be necessary to perform any corrective action.

9.4 Compatibility of CO_2 with Arbuckle Brine and Minerals

No compatibility problems are anticipated in the injection zone. Conclusions from preliminary modeling results indicate that the CO_2 brine formation interactions and reactions from chemical processes will have a negligible effect on reservoir porosity. Additionally, the effects of mineralization and mineral precipitation are not expected to meaningfully reduce the formation permeability. The injection interval is mainly a dolomitic peloidal packstone-wackestone becoming a cherty packstone. Zones of autoclastic breccia have also been identified. Thin-section studies reveal extensive silica micro-porosity that contributes to high porosity values in the lower injection interval and that should facilitate injection. Microporous regions have high surface areas that increase reaction rates, which may lead to rapid dissolution.

9.5 Period of Data Retention

All modeling inputs and data used to support AoR delineation and re-evaluation will be retained for 10 years by Berexco/KGS.

Section 10

Injection Well Testing and Pressure/Plume Front Monitoring Plan

Facility Information

Facility Name: Wellington Field Small Scale Carbon Capture and Storage Project

Injection well Location: Latitude 37.319485, Longitude -97.4334588

Township 31S, Range 1W, Section 28 NE SW SE SW

Facility Contact: Dana Wreath, Vice President

Contact Information: 2020 N. Bramblewood Street

Wichita, KS 67206

(316) 265-3311

Fax: (316) 265-8690

10.1 Introduction

40 CFR Part 146.90 requires the owner/operator to prepare, maintain, and comply with a testing and monitoring plan to verify that geologic injection and storage of CO_2 is operating as permitted and is not endangering USDWs. At a minimum, testing/monitoring must include:

- Analysis of the CO_2 stream,
- Installation and use of continuous recording devices to monitor injection pressure, rate, and volume; the pressure on the annulus between the tubing and the long string casing; and the annulus fluid volume added;
- Corrosion monitoring;
- Periodic monitoring of the groundwater quality and geochemical changes above the confining zone;
- A demonstration of external mechanical integrity pursuant to §146.89(c) at least once per year until the injection well is plugged; and, if required by the director, a casing inspection log pursuant to requirements at §146.89(d) at a frequency established in the testing and monitoring plan;

- A pressure fall-off test at least once every five years;
- Testing and monitoring to track the extent of the CO_2 plume and the presence or absence of elevated pressure using direct and indirect methods;
- Surface air/soil gas monitoring, if required by the director.

The Wellington project is funded by a cooperative agreement between the U.S. DOE and the Kansas Geological Survey and their cost-share partners as an experimental pilot-scale CCS project and, therefore, subject to funding availability, may include monitoring activities not mandated by Class VI regulations. These additional monitoring activities are specified in Appendix G. The mandatory monitoring activities to be conducted to meet Class VI requirements are specified in this section.

In addition to testing and monitoring at the injection well site (KGS 1-28), pressure and plume-front monitoring activities will be conducted at the Arbuckle observation well (KGS 2-28), two existing Mississippian wells above the primary confining zone, and two new Upper Wellington Formation (USDW) wells (Figure 10.1). A schedule of the testing and monitoring activities and frequency before, during, and after injection are listed Table 10.1.

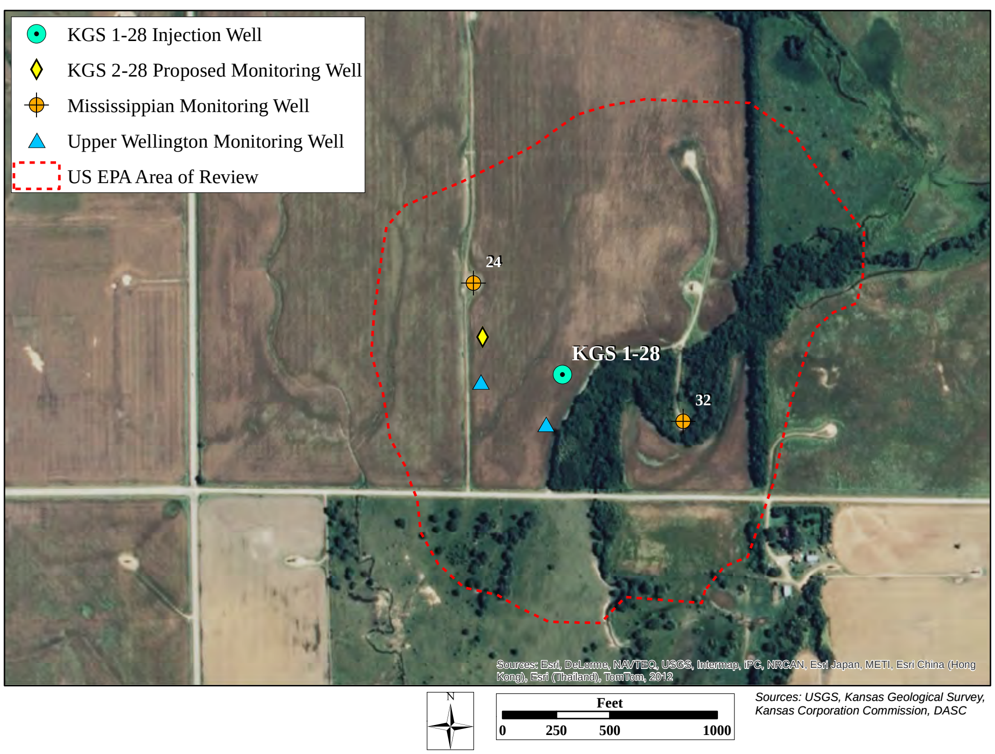


Figure 10.1—Location of monitoring wells in the Arbuckle, Mississippian, and Wellington formations.

The monitoring well construction plans are documented in Section 10.2. The well testing and pressure/plume-front monitoring plans are discussed in sections 10.3–10.5.

Table 10.1—Listing of monitoring activities to be conducted at the Wellington, Kansas, CO_2 storage site.

Monitoring Activity	Pre-Injection	Injection	Post-Injection
CO_2 Fluid Chemical Analysis	x	x	-
CO_2 Injection Rate and Volume[1]	-	x	-
CO_2 Injection Pressure at Wellhead[1]	-	x	-
CO_2 Injection Pressure at Well Bottom[1]	x	x	x
Internal MIT (Anulus Pressure Test)	x	-	-
External MIT (Temperature Log)	x	x	x
Continuous Annular Pressure	-	x	-
Corrosion	-	x	x
Pressure Fall Off Test	x	-	-
Pressure in Arbuckle Monitoring Well (Direct Arbuckle Monitoring)	x	x	x
INSAR (Indirect Arbuckle Pressure Monitoring)	x	x	x
USDW Geochemistry	x	x	x
Mississippian Geochemistry	x	x	x
U-Tube (Direct Arbuckle Geochemistry Monitoring)	x	x	x
CASSM (Indirect Arbuckle Plume-Front Monitoring)	x	x	x[2]
Crosswell Seismic (Indirect Arbuckle Plume-Front Monitoring)	x	x	-
3D Seismic Survey (Indirect Arbuckle Plume-Front Monitoring)	x	-	x

[1] Monitored continuously
[2] If CO_2 plume is detected at KGS 2-28 during the injection phase, then CASSM will not be conducted during the post-injection phase.

10.2 Monitoring Well Construction Information and Justification for Well Placement

A total of five monitoring wells will be used for tracking the CO_2 plume and pressure front. The locations of these monitoring wells and the formations that they will monitor are shown in Figure 10.1. One monitoring well is located in the Arbuckle aquifer. Two existing Mississippian wells will be used to check whether CO_2 has escaped upward from the primary confining zone (base of Simpson Group to top of Pierson formation) at the site. Two shallow wells will monitor water quality in the Upper Wellington Formation (lowermost USDW). The well design and construction plans for the monitoring wells are discussed below.

10.2.1 KGS 2-28 Arbuckle Monitoring Well

As shown in Figure 10.1, one monitoring well (KGS 2-28) is proposed to monitor CO_2 plume movement and pressure-front expansion in the Arbuckle Group. The well will be constructed approximately 400 ft updip of the injection well KGS 1-28 and will be used to facilitate direct and indirect monitoring of both the pressure front and CO_2 plume in the Arbuckle. The well will be constructed in full compliance with Class VI standards to ensure containment of CO_2, and a full suite of geophysical logs will be obtained. Based on modeling results, it is projected that the plume will reach the well in approximately 60–75 days after commencement of injection. Since the injection is to occur for only nine months, data obtained from this well will be sufficient to monitor and evaluate the movement of CO_2 within the Arbuckle Group, ensuring compliance with Class VI standards.

As discussed in Section 4.6.1 and shown in Figure 4.20, there is remarkable similarity in the geologic formations at well sites KGS 1-28 and KGS 1-32, which are located approximately 3,500 feet apart. Therefore, the geologic horizons at KGS 2-28 are also expected to be very similar to that at KGS 1-28. Hence, the proposed design of KGS 2-28 presented in Figure 10.2 is very similar to the injection well, KGS 1-28[1]. The well is expected to be approximately 5,300 feet deep, penetrating the top of the Precambrian granitic basement rock underlying the Arbuckle aquifer. The well will be perforated in the injection zone at approximately the same depth as the injection well (KGS 1-28) shown in Figure 8.1. The final depth and perforation interval will be established on completion of drilling and will be specified in the well completion report. The wellbore trajectory will be monitored every 1,000 ft to ensure that the deviations are minimal.

10.2.1.1 KGS 2-28 Wellbore and casing

The planned borehole and casing specifications at KGS 2-28 are shown in Table 10.2 and Figure 10.2. The conductor casing is expected to run between the surface and 125 ft. The surface casing, designed to provide a continuous cement sheath to fully isolate the USDW from the well,

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1 It is expected that the kelly bushing (KB) reference elevation at the site will be 13 ft above ground, which would be similar to the condition at the existing injection well, KGS 1-28. All elevations in Figure 10.2 are sub-KB.

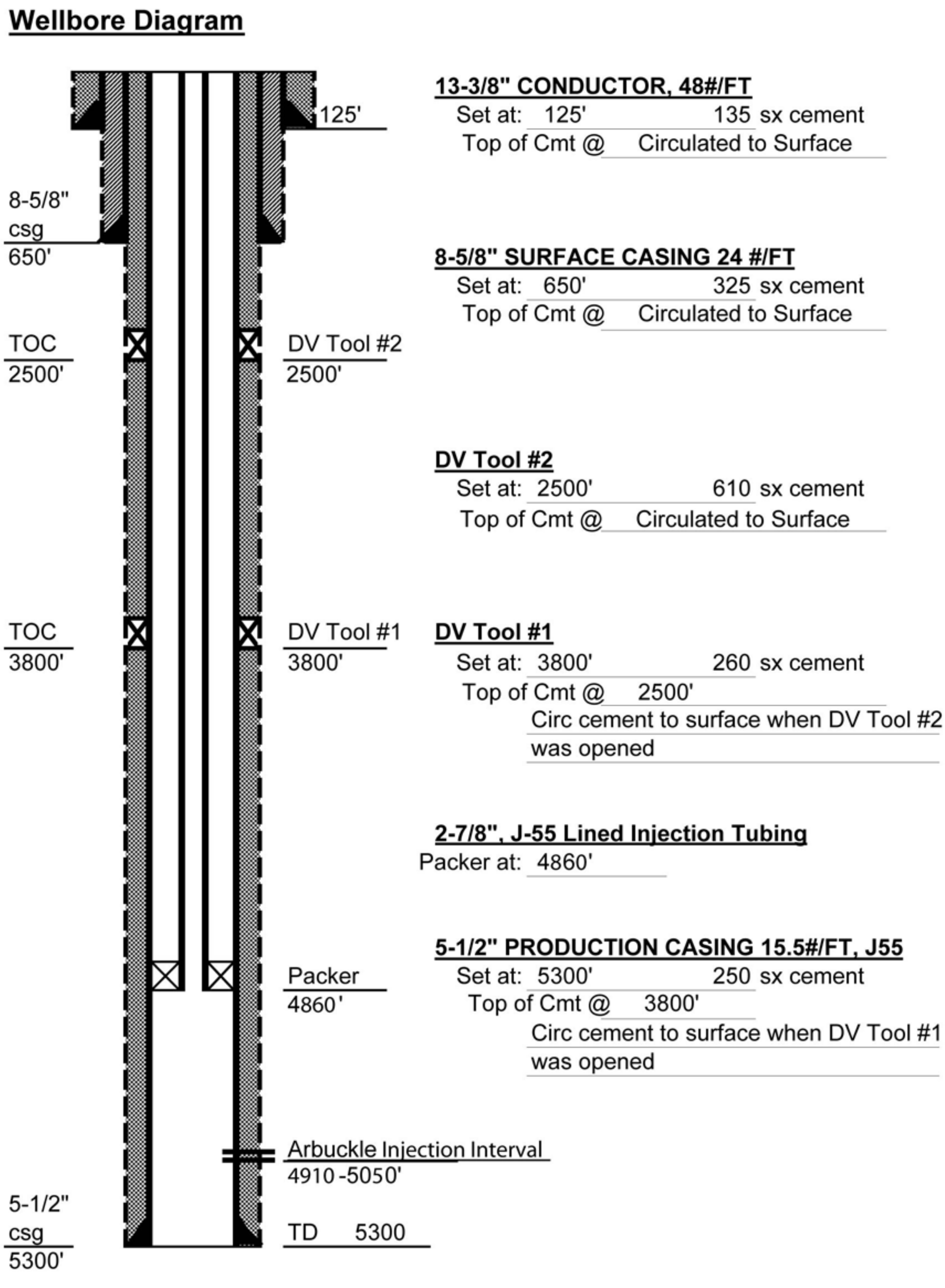

Figure 10.2—Well design schematic of the proposed Arbuckle monitoring well KGS 2-28.

Table 10.2—Projected borehole and casing specifications at KGS 2-28.

Casing	Depth Interval (ft)	Borehole Diameter (inches)	Size OD/ID (in)	Weight (lb/ft)	Grade	Connection Type	Collapse Pressure (psi)	Burst Pressure (psi)	Tensile Yield (lbs)	Thread Yield
Conductor	surface: 125	17.5	13-3/8 / 12.615	54	J55	ST&C	1,130	2,730	853,000	514,000
Surface	surface: approximately 650	12.25	8-5/8 / 7.972	24	J55	ST&C	1,370	2,950	381,000	244,000
Production	surface: approximately 5,300	7.875	5.5 / 4.892	15.5	J55	ST&C	4,040	4,810	248,000	222,000

runs from the surface to a depth of approximately 650 ft, well below the lowermost USDW (Upper Wellington Formation), which is expected to be in the top 250 ft at the site. All casing strings are designed as carbon steel. Corrosion of carbon steel casing is not expected during the life of this well. However, the potential for corrosion of casing material will be addressed by using CO_2-resistant cement as discussed below, and the well will be monitored for signs of corrosion as specified in Section 10.3.3.

10.2.1.2 KGS 2-28 Tubing

The tubing will consist of a 2.875 inch steel. It is expected to be approximately 5,000 ft long and weigh approximately 32,000 lbs, which is substantially less the maximum allowable joint yield strength of approximately 72,580 lbs (Table 10.3). This provides a safety margin at the uppermost joint of slightly more than 40,000 lbs if one assumes the axial load is being carried only by that joint

There will be approximately 2.5 inches of spacing between the production casing and the tubing, which is sufficient for work-over tools and conducting the testing and monitoring activities described in sections 10.4–10.5.

10.2.1.3 KGS 2-28 Cement

The conductor and surface casing cement job will be completed in a single stage. The cementing for the production casing will be accomplished in three stages using two DV tools at approximately 3,800 (DV #1) and 2,500 (DV #2) ft to ensure proper cement adherence (Figure 10.2). The cement will be circulated to the surface by opening DV Tool #1 and DV Tool #2 during cementing of the lowest and middle stages respectively. The lower cement stage covers the entire Arbuckle formations. Centralizers are expected to be used to properly align the casing and to ensure that they are completed sealed.

As shown in Table 10.4, common portland cement will be used to seal the space in the borehole for the conductor casings, and 60/40 Pozzolanic cement is to be used for the surface

Table 10.3 —Tubing specifications at KGS 2-28.

Name	Depth (ft)	Wall Thickness (in)	Inside Diameter (in)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Thread)	Burst Strength (psi)	Collapse Strength (psi)	Joint Yield Strength (lb)	Body Yield Strength (lb)
Injection Tubing	surface: approximately 4,860 ft	0.217	2.441	6.4	J55	Non upset	7,260	7,680	72,580	99,661

casing. For the conductor casing, CO_2-resistant cement AA-2 will be used in the bottom stage, a combination of AA-2 and CO_2-resistant A-Con will be used in the middle stage, and AA-Con will be used in the top stage. Note that the cement quantities specified in Table 10.4 are estimates and may be adjusted as a result of hole conditions, depths, etc.

Table 10.4—Cement specifications for Arbuckle monitoring well KGS 2-28.

Purpose of String	Size Hole Drilled (in)	Size Casing Set (in)	Weight (lb/ft)	Setting Depth (bls, ft)	Type of Cement	Number of Sacks Used	Type and Percent Additives
Conductor	17.5	13.375	48	125	Common	135	3%cc, ¼# flake
Surface	12.25	8.625	24	Approximately 650	60/40 POZ	325	3%cc, ¼# flake
Production	7.875	5.50	15.5	Approximately 5,300	AA-2	250	10% salt, 6 #gils, C-44
1st DV Tool	7.875	5.50	15.5	Approximately 3,800	A-Con & AA-2	260	10% salt, 6 #gils, C-44
2nd DV Tool	7.875	5.50	15.5	Approximately 2,500	A-Con	610	10% salt, 6 #gils, C-44

10.2.1.4 Geophysical Data Acquisition and Analyses

A modern suite of wireline logs such as “triple combo,” full-wave sonic samples will be acquired at the monitoring borehole to obtain necessary petrophysical information (i.e., porosity, saturation, and sonic velocity). The triple combo logs will include neutron density, gamma ray, caliper, SP, photo electric, and resistivity logs. Analysis of wireline logs will involve calibration with core measurements to predict porosity and permeability; estimation of rock mechanical properties from dipole sonic waveforms; and evaluation of formation invasion and resistivity to help in flow unit identification. The wireline data acquired at this site shall be integrated with log and core data from existing Arbuckle wells KGS 1-32 and KGS 1-28 to update the regional geomodel-based porosity and permeability distributions in the Arbuckle aquifer, if necessary. The geophysical data also will be used to establish the stratigraphy at the site and if it appears that the geologic formations at KGS 2-28 are offset with respect to KGS 1-28, then the perforation in the injection interval in the new monitoring well will be offset accordingly.

10.2.1.5 Borehole Testing

Drill-Stem Test

A drill-stem test will be run across the injection interval to estimate formation hydrogeologic properties and to sample formation water.

Swab Tests

The borehole will be perforated in the Arbuckle injection interval for collection of fluid samples. Geochemical analysis (Fe, Ba, Mn, SO_4, K, S, Mg, Sr, Ca, Cl, Na, Br, Si, NO_2, NO_3, Cu, Li and P; as well as pH, TDS) will be conducted on the samples to identify chemistry of formation water (cations, anions, TDS).

10.2.1.6 Demonstration of Mechanical Integrity

Mechanical integrity tests shall be carried out at the monitoring borehole to ensure proper setting of the cement and to minimize the risk of CO_2 leakage around the well bore. A cement bond log will be obtained after setting the long-string casing. A thermal log will be acquired to ensure integrity of the cement and casing. The absence of temperature spikes in the log will indicate the absence of substantial leaks in the cement and/or casing. An annulus pressure test will be conducted to ensure that there are no leaks in the packer, tubing, and casing. As discussed in Section 10.3.2.4, the annulus will be monitored daily for leaks during injection by checking the fluid level in the annulus.

10.2.2 Mississippian Monitoring Wells

10.2.2.1 Well Location and Justification for Site Selection

Several active oil wells around the CO_2 injection well KGS 1-28 are producing from the upper Mississippian formation immediately above the Pierson formation, which is part of the upper confining zone. The location of the two Mississippian wells that will be used as monitoring wells are presented in Figure 10.1. Well construction details of these two wells are presented in Table 10.5. No geophysical logs are available for these wells in the KGS database. Both wells were selected because they are in the updip direction as the Arbuckle generally dips southward. The Wellington Well Unit 24 is also the closest Mississippian well to the injection well (KGS 1-28).

Table 10.5—Well data for Mississippian wells to be used for CO_2 monitoring.

API Number	Lease Name	Well Class	Operator Name	Status	Spud Date	Completion Date	Total Depth (ft)	Elevation (ft, msl)	NAD83 Latitude	NAD83 Longitude
15-191-10045	Wellington Unit 32 (Was Kamas 6)	Producing	Sinclair Prairie Oil Co.	OIL	2/1/36	10/1/36	1246	1246	37.318829	-97.4316
15-191-10055	Wellington Unit 24 (Was Frank Kamas 9)	Producing	Sinclair Prairie Oil Co.	OIL	12/14/36	10/1/37	1264	1264	37.320713	-97.43501

Casing head gas and groundwater sampling of the Mississippian wells will be conducted during the pre-injection phase to establish respective background (baseline) readings. Thereafter, water and casing head gas shall be sampled on a periodic basis during the injection and post-injection phases, analyzed, and compared with the baseline survey data to detect the presence of CO_2 in the Mississippian reservoir. The water-quality monitoring plan and schedule are presented in Table 10.1 and Section 10.4.1.1.

10.2.3 Upper Wellington Formation (Lowermost USDW) Monitoring Wells

The Upper Wellington formation is present from near land surface to approximately 250 ft below ground. Based on the water table map presented in Figure 4.14, groundwater movement at the site is primarily toward Slate Creek south of the site. The general dip of the subsurface formation is also southward. Two monitoring wells will be placed in the Upper Wellington Formation: One well will be placed downstream and due south of KGS 1-28, and the second well will be located west of the injection well along the edge of the paved road as shown in Figure 10.1. These wells are expected to intercept any plume that may potentially move into the USDW. Both monitoring sites are located close to paved roads in the area, thereby providing easy access. The water-quality monitoring plan for the USDW is presented in Section 10.4.1.2.

10.2.3.1 USDW Monitoring Well Design

The two USDW monitoring wells (shown in Figure 10.1) will be screened approximately 120 ft below ground surface (Figure 10.3). Most existing groundwater wells in Sumner County are less than 120 ft deep. The final screen intervals, however, will be established after drilling at the site, with the goal to monitor the deepest zone in the USDW. Each well will be constructed of 2-in (internal diameter) Schedule 40 PVC constructed in a 6-in diameter boring and gravel packed across a 10- to 20-ft interval depending on screen location and lithology, which will be decided after completion of the drilling. The well will be fully grouted above and below the screened interval. Approximately 2–3 feet of bentonite seal will be placed on top of the gravel pack to assure a good seal before grouting. Each well will extend about 1.5 ft above ground surface with a pressure tight cap which will have a cap, with a hole for a 0.25-in tube and 0.5-in hole for access with field monitors (water-level meter, D.O., pH, etc.). The wells will have a steel protective housing and a 3-ft by 3-ft cement pad.

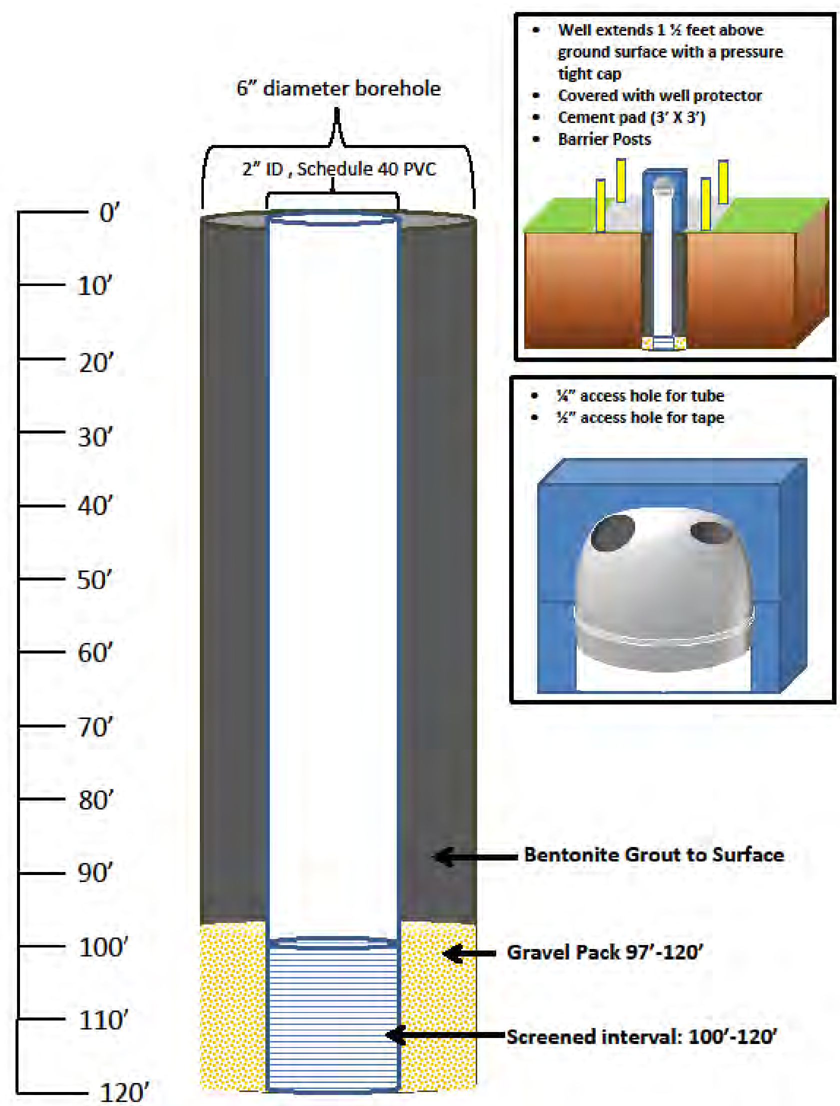

Figure 10.3 —Typical schematic of Upper Wellington Formation monitoring well showing screened interval at 100–200 ft below land surface.

10.2.3.2 Borehole Logs

Samples of soil in the Wellington Formation will be collected and analyzed by X-ray diffraction to obtain major mineralogy.

10.3 Testing and Monitoring at Injection Well Site

10.3.1 Carbon Dioxide Stream Analysis (§ 146.90 [a])

The Class VI rule requires that the injected CO_2 stream be analyzed with sufficient frequency to yield data representative of its chemical and physical characteristics (40 CFR 146.90[a]). Monitoring the chemical composition is accomplished to verify that the injectate does not qualify as hazardous waste with regard to corrosivity or toxicity, as well as to ensure that the delivered CO_2 stream meets the specifications outlined in the UIC permit. As indicated in Section 10.5.2, small quantities of tracer gases SF_6 (sulfur hexafluoride) and Kr (krypton) will be periodically co-injected with the CO_2 to facilitate estimation of the travel time between the injection and monitoring wells/boreholes.

10.3.1.1 Sampling Location and Method

CO_2 will be obtained from an ethanol plant or similar industrial source as described in Section 1. The CO_2 stream is expected to be composed of high purity (99+ %) CO_2. The CO_2 is expected to be water saturated and delivered at near atmospheric pressure. The CO_2 will be dehydrated and compressed to a liquid state at a temperature and pressure of approximately -10^{o}F and 350 psi and transported in trucks to the site for injection. CO_2 injectate samples will be collected immediately upstream of the injection well head in a lined sample bottle and transported to an approved laboratory for analysis.

10.3.1.2 Fluid Analysis

The exact chemical composition of CO_2 will be ascertained pre-injection. The CO_2 stream is expected to have high levels of CO_2 with only trace levels of other constituents or impurities such as nitrogen, oxygen, methanol, acetaldehyde, and hydrogen sulfide. The analytical suite will be established when the first pre-injection sample is collected and at a minimum will include nitrogen, oxygen, methanol, acetaldehyde, and hydrogen sulfide. The samples will be analyzed (by a certified laboratory) using standardized ASTM procedures for gas chromatography, mass spectrometry, detector tubes, and photo ionization. The sample will be tested using ASTM 5954, ASTM 6228, ASTM 5504, or equivalent procedures. For permitting purposes, it is proposed that the CO_2 stream will not exceed the minimum specification shown in Table 10.6.

Table 10.6—Minimum CO_2 Stream Acceptance Specifications (source: FutureGen, 2013).

Component	Quantity
CO_2	97% dry basis
Inert Constituents	1%
Trace Constituents	2%
Oxygen	<20 ppm
Total Sulphur	< 25 ppm
Arsenic	< 5 ppm [a]
Selenium	< 1 ppm [a]
Mercury	< 2 ppb [b]
Hydrogen Sulfide	< 20 ppm
Water Vapor	< 30 lb/mm scf

(a) Resource Conservation and Recovery Act (RCRA) standard

(b) Safe Drinking Water Act standard

CO_2 grab samples will be collected immediately upstream of the well head in a pre-cleaned lined sample bottle and transported to a laboratory for analysis. The bottle will be flushed with inline CO_2 before sample collection, labeled, and transported to the laboratory in accordance with EPA guidelines. A Chain of Custody form will document:

- Sampling date
- Analytical detection limit
- Location of the sample

- Type of container
- Sampler name and signature
- Other comments/notes
- Shipping information (name, address, and point of contact at laboratory, including phone number)
- Name and signature of personnel involved in the chain of custody.

The laboratory report will include the analytical results as well as detection limits established for the method employed to detect each chemical constituent presented in Table 10.6.

10.3.1.3 Sampling Frequency

The CO_2 is expected to have fairly uniform chemical composition throughout the year. Therefore, the CO_2 will be sampled at five periods: before commencement of injection, once each month for the first three months of injection, and again six months after commencement of injection. Injection is to cease at the end of nine months of operation. If there is significant variation in the quarterly sample results, then a final sample will be collected and analyzed at the end of the injection period (nine months).

10.3.1.4 Quality Assurance/Quality Control

The samples will be analyzed (by a certified laboratory) using standardized ASTM procedures for gas chromatography, mass spectrometry, detector tubes, and photo ionization. The sample will be tested using ASTM 5954, ASTM 6228, ASTM 5504, or equivalent procedures. The sample integrity and security will be documented through maintenance of a field sampling record and a Chain of Custody form as described above. The laboratory report will provide documentation of instrument calibration, analytical results, and detection limits established for methods employed. For data validation purposes, the following samples will be analyzed with each batch of collected samples:

- One or two field duplicates

- One equipment rinsate
- One matrix spike (when appropriate for the analytical method)
- One trip blank

10.3.2 Continuous Recording of Operational Parameters (§ 146.90 [b])

10.3.2.1 Continuous Monitoring of Injection Rate/Volume

The Class VI rule requires the installation and use of continuous recording devices to monitor injection rate and volume (40 CFR 146.88[e]). The monthly average, maximum, and minimum values will be reported in semi-annual reports (40 CFR 146.91[a][2]). This information will be used to verify compliance with the operational conditions of the permit and to assist in AoR re-evaluations.

The injection rate will be continuously monitored using the Orifice-Plate differential meter, which uses Bernoulli's equation to determine flow by measuring the pressure drop across a plate with a hole. It is the standard flow measuring device in the oil and gas industry and typically achieves an accuracy of 2–4% of the full-scale reading (EPA, 2012). The mass rate will be calculated using the CO_2 density, which will be calculated using equations of state and pressure and temperature readings. Cumulative injection volume and mass will be continuously calculated and reported in semi-annual reports. Because the CO_2 will be transported to the site via trucks, a direct measurement of the CO_2 mass will be available. Additionally, from a safety/environmental perspective, the maximum amount of CO_2 that can potentially escape into the atmosphere and geologic formation due to a sudden catastrophic well or surface infrastructure failure will be limited to the capacity of the storage tanks at the site, which will be slightly greater than 150 tons.

10.3.2.2 Continuous Monitoring of Injection Pressure

The Class VI rule requires the installation and use of continuous recording devices to monitor injection pressure (40 CFR 146.90[b]). Injection pressure will be measured at both the wellhead and the center of the perforations in the injection zone (bottomhole pressure). Bottomhole pressure is equal to wellhead pressure plus the hydrostatic pressure that exists due to the weight of the fluid column between the wellhead and bottom hole, minus frictional losses. The two sources of pressure data will therefore be used to check the accuracy of the individual pressure measurements. Injection pressure is monitored to ensure that the fracture pressure of the formation and the burst pressure of the well tubing are not exceeded and that the owner or operator is in compliance with the permit. A standard oil-filled pressure gauge will be installed at the wellhead, and a pressure transducer will be placed near the perforation to monitor the bottomhole pressure.

10.3.2.3 Continuous Monitoring of Temperature

Surface and bottomhole temperature will be monitored continuously in the injection well using the same data logger that measures pressure to fulfill injection well operating requirements stated in §146.88 e (1).

10.3.2.4 Continuous Monitoring of Annulus Pressure and Volume

Since a waiver is sought from pressurizing the annulus due to low injection pressures as discussed in Section 8.1, continuous monitoring of the annulus will involve a daily inspection of surface pressure in the annulus of the injection well. The corrosion-resistant fluid in the annulus will initially be filled to the surface. A change in pressure greater (or less) than expected due to temperature changes will be considered a failure of the internal MIT and will trigger a system-wide shut-off (40 CFR 146.88[e][2]), which will halt injection immediately and limit the amount of leakage. The shutoff will be reported to the EPA within 24 hours. The cause(s) of the pressure change will be investigated to identify the location of leakage and repair the well. An annulus pressure test will be conducted after investigation/remediation to ensure well integrity.

10.3.2.5 Operating Range for Key Injection Parameters

The operating range for key injection parameters are:

- CO_2 Injection Flow Rate: 150 metric tons/day (+/- 5%)

- Wellhead Inlet Pressure: < 800 psig
- Bottomhole Pressure: < 3,408 psig at 5,050 ft (90% of fracture gradient of 0.75 psi/ft)
- Annulus Pressure at Surface: 0 psig
- Wellhead CO_2 Temperature: -10^o to +10^o F
- Bottomhole CO_2 Temperature: 20–60^o F at 5,050 ft

10.3.3 Corrosion Monitoring (§ 146.90 [c])

The Class VI rule at 40 CFR §146.90(c) requires quarterly monitoring of well materials for corrosion to detect loss of material in the casing, tubing, and packer that may compromise the mechanical integrity of wells. CO_2, in the presence of water leads to the formation of corrosive carbonic acid, which historically has been the primary cause of well failure in CO_2 injection wells (EPA, 2012). However, due to the short period of injection (nine months) and the construction of the Arbuckle wells in accordance with Class VI guidelines, corrosion is not expected to occur in the Wellington injection or observation wells.

10.3.3.1 Corrosion Detection Method and Sampling

Corrosion coupons will be used for monitoring loss of material in the injection well. Coupons are very simple to use and analyze, and they provide a direct measurement of material lost to corrosion (EPA, 2012). Two pre-weighed, dimensionally measured, and photographed coupons made of representative injection well construction material will be placed in the flow line and the wellhead. These coupons will be removed every quarter, cleaned, and reweighed. The samples will be visually inspected under magnification for loss of mass, thickness, cracking, pitting, or other signs of corrosion.

The average corrosion rate in the well will be calculated from the weight loss of the coupon.

The coupon will be weighed to an accuracy of +/- 0.1 of a milligram. The weight will be used to calculate the corrosion rate in mils/yr, where a mil is equal to a thousandth of an inch.

If the coupons are found to have more than 3 mils/yr of loss, corrective action will be taken in consultation with the EPA Region 7 director, and the coupons will be monitored more frequently. However, as mentioned above, no corrosion of the well material is expected given the short duration of injection.

10.3.3.2 Corrosion Reporting

Dimensional and mass data, along with a calculated corrosion rate (in mils/yr), will be submitted to the EPA program director every six months in semi-annual reports, which will include the following information:

- A description of the corrosion monitoring technique;
- Measurement of mass and thickness loss from corrosion coupons;
- Assessment of additional corrosion, including pitting, in the corrosion coupons and the overall corrosion trends;
- Any necessary changes to the project Testing and Monitoring Plan to continue protection of USDWs.

10.3.4 Mechanical Integrity Testing (§ 146.90 [e])

Internal and external mechanical integrity tests (MITs) will be conducted before, during, and after injection. Internal tests will be conducted to ensure the absence of any leaks in the injection tubing, packer, or casing, and external tests will be conducted to ensure the absence of any leaks through channels adjacent to the wellbore that may result in significant fluid movement into a USDW. The results of the tests, including a description of the methods employed and results of previous tests will be submitted to the EPA for review. The Class VI rule requires that internal mechanical integrity be demonstrated continuously during injection, and external MIT be conducted before injection, at least once per year during the injection phase, and before injection well plugging after the cessation of injection.

10.3.4.1 Internal MIT with Annulus Pressure Test

Before commencing injection, an annulus pressure test will be conducted at the injection well KGS 1-28 in order to demonstrate internal MIT. The test will provide information necessary to determine whether there is a failure of the casing-cement bond, injection tubing, and packers.

The test will consist of pressurizing the corrosion-resistant fluid of the annulus to 500 psi and then isolating the annular space from the source of pressure by a closed valve. Pressure measurements taken during isolation of the annulus will be analyzed for any change in pressure for 30 minutes to detect leakage. Because the annulus exchanges heat with its surroundings, small pressure changes that are not due to leakage may occur during the test.

After the test period, the valve to the annulus will be opened and the amount of returned fluid will be measured in a container. This will be a confirmatory exercise to determine whether the full length of the annulus was tested as the amount of captured liquid should be in conformance with the size of the annulus and the test pressure. The data obtained, including recorded charts from the tests and volume of liquid used, will be submitted to the EPA within 30 days of test completion as required in 40 CFR §146.91(b).

Failure of the pressure to stabilize within a range of 5 percent of the injection pressure will constitute a failure to demonstrate mechanical integrity. If this occurs, the causes of the pressure drop will be investigated and corrective measures implemented as necessary. An annulus pressure test will be conducted after any well remediation activities to confirm well integrity.

10.3.4.2 External MIT Using Temperature Logs

A temperature log will be used to demonstrate external MIT in the injection well (KGS 1-28), and its use is based on the principle that fluid leaking from the well will cause a temperature anomaly adjacent to the wellbore. The log will be obtained from the surface to the bottom of the well using a wireline logging tool.

Temperature logs will be obtained before commencement of injection, after 6 months of injection, and before closure of the site. The pre-injection log, along with the temperature log obtained during well construction, will serve as a baseline for the subsequent monitoring during the injection and post-injection phases.

As suggested in EPA guidance (EPA, 2012), the well will be shut during the injection phase for a period of 36 hours before obtaining the temperature log (EPA, 2012). During the shut-in period, the temperature within the wellbore will typically migrate towards ambient geothermal conditions but will not fully equilibrate to ambient conditions. If there has been a leak of fluid out of the well, the temperature within the wellbore at this location will change to a lesser extent and be measured as an anomaly because the temperature of the surrounding formation will have been modified by the leaking fluid.

Leaks will be identified from injection and post-injection logs by noting relative differences between the collected temperature log and the baseline (and previous) logs. Since lithology and injectate characteristics will be similar, the thermal effects along the wellbore are expected to be very similar. After the temperature effects caused by injection, casing joints, packers, well diameter, casing string differences, and cement have dissipated, the temperature profiles are expected to be similar, although not identical. The log and associated report will be submitted to the EPA within 30 days of test completion as required in 40 CFR §146.91(b). If interpretation of the data indicates a noncompliance, a report will be submitted to EPA within 24 hours of testing as required by § 146.91 (c). If necessary, radioactive tracer, noise, oxygen activation, or other logs approved by the UIC program director may be used to further define the nature of the fluid movement.

10.3.5 Pressure Fall-Off Testing (§146.90[f] and 40 CFR §146.87[e][1])

The Class VI rule requires pressure fall-off testing of the injection well before commencing injection (40 CFR **§**146.87[e][1]) and at least once every five years (40 CFR **§**146.90 [f]). Pressure fall-off tests are used to measure formation properties in the vicinity of the injection well. The objective of periodic testing is to monitor for any changes in the near-wellbore environment that may affect injectivity and pressure increase. Anomalous pressure drops during the test may also be indicative of fluid leakage through the wellbore.

A pressure fall-off test will be conducted before commencement of injection at the Wellington site. However, a pressure fall-off test after commencement of injection is not proposed for this project because a) injection is to occur for a short period of 9 months, b) extensive testing/monitoring to track the carbon dioxide plume will be performed, and c) the site is expected to close within 5 years of commencement of injection.

A steady rate of water flow will be maintained during the injection phase of the pressure fall-off test. This will be followed by a shut-in period, the duration of which will be determined on the site to obtain sufficient transient response for analyzing the data. The bottomhole pressure will be continuously recorded during the entire test by pressure transducers for a sufficient period to make valid observation of a pressure fall-off curve. Pressures will be measured at a frequency that is sufficient to measure the changes in bottomhole pressure throughout the test period, including rapidly changing pressures immediately after cessation of injection. The magnitude of the bottomhole pressure will be adjusted so as to not exceed 90% of the fracture gradient estimated in Section 4.6.9.

A report containing the pressure fall-off data and interpretation of the reservoir ambient pressure will be submitted to the U.S. EPA within 90 days of the test.

10.4 Groundwater Geochemical Monitoring Above the Confining Zone (§146.90 [d])

40 CFR §146.90 requires periodic monitoring of groundwater above the confining zone. Groundwater quality in the USDW (Upper Wellington Formation) and the upper Mississippian System above the confining zone will be directly monitored. Figure 10.1 shows the location of the Mississippian and USDW monitoring wells. Section 10.2 presents information pertaining to construction of the monitoring wells. All monitoring wells shown in Figure 10.1 are located close to paved roads and are fully accessible by truck. Berexco is the operator of the Wellington oil field and has permission to physically monitor all well sites.

Baseline data will be collected from the monitoring wells before injection, and monitoring will be conducted according to the schedule in Table 10.7. An increase in the concentration of dissolved CO_2 will indicate the presence of separate-phase or dissolved-phase CO_2. The concentration of CO_2 will be used to ascertain whether separate-phase CO_2 may be present, based on accepted mass-transfer relations and equilibrium constants.

10.4.1 Monitoring Wells Above the Confining Zone: Sampling Frequency, Analytical Suites, QA/QC, and Reporting Requirements

10.4.1.1 Mississipian Wells

Gas sampling ports shall be installed in the two existing Mississippian wells shown in Figure 10.1 to collect head gas to detect and measure the amount of early breakthrough or off-pattern migration of CO_2. These two wells will be sampled three times before injection to establish baseline CO_2 concentration. Table 10.7 presents the analytical suite to be monitored and the monitoring frequency for monitoring wells within and above the injection zone. Produced water and casing head gas will be sampled, analyzed, and compared with the baseline survey data to determine the presence of CO_2 and other parameters in the Mississippian reservoir. The inorganic indicator parameters are known to be associated with chemical reactions in the presence of CO_2 and therefore are expected to provide information about the presence of the injectate in the hydrogeologic formations. The sampling and testing will continue every 3 months during the post injection phase.

Table 10.7—Geochemical analytical suite to be monitored in the Mississippian and Upper Wellington (USDW) wells at the Wellington site.

Field Parameters	Pre-Injection	During Injection	Post-Injection
pH	Once a week for 3 weeks	Every 3 months	Every 6 months
Specific Conductivity	Once a week for 3 weeks	Every 3 months	Every 6 months
Temperature	Once a week for 3 weeks	Every 3 months	Every 6 months
Dissolved Oxygen	Once a week for 3 weeks	Every 3 months	Every 6 months
Gas-Water Ratio	Once a week for 3 weeks	Every 3 months	Every 6 months
Depth to Water	Once a week for 3 weeks	Every 3 months	Every 6 months
TDS/Salinity	Once a week for 3 weeks	Every 3 months	Every 6 months
Indicator Parameters			
Alkalinity	Once a week for 3 weeks	Every 3 months	Every 6 months
Bromide	Once a week for 3 weeks	Every 3 months	Every 6 months

Calcium, Iron, Magnesium, Potassium, Dissolved Silica	Once a week for 3 weeks	Every 3 months	Every 6 months
Chloride	Once a week for 3 weeks	Every 3 months	Every 6 months
Sodium	Once a week for 3 weeks	Every 3 months	Every 6 months
Total CO_2	Once a week for 3 weeks	Every 3 months	Every 6 months
Total Fe	Once a week for 3 weeks	Every 3 months	Every 6 months
Total Fe (II)	Once a week for 3 weeks	Every 3 months	Every 6 months
Total NH_4+	Once a week for 3 weeks	Every 3 months	Every 6 months
Total NO_3^{2-}	Once a week for 3 weeks	Every 3 months	Every 6 months
Total SO_4^{2-}	Once a week for 3 weeks	Every 3 months	Every 6 months
Total PO_4^{3-}	Once a week for 3 weeks	Every 3 months	Every 6 months
Total HCO_3^-	Once a week for 3 weeks	Every 3 months	Every 6 months
Total CO_2	Once a week for 3 weeks	Every 3 months	Every 6 months
Concentration of Organics			
DOC	Once a week for 3 weeks	Every 3 months	Every 6 months
TOC	Once a week for 3 weeks	Every 3 months	Every 6 months
DIC	Once a week for 3 weeks	Every 3 months	Every 6 months
Stable Isotopes			
δ18O	Once a week for 3 weeks	Every 3 months	Every 6 months
δD	Once a week for 3 weeks	Every 3 months	Every 6 months
δ13C for Carbonates in System	Once a week for 3 weeks	Every 3 months	Every 6 months

10.4.1.2 Upper Wellington Formation (USDW)

Samples will be collected once a week for 3 weeks before injection. This information will constitute baseline data for future comparison during the injection and post-injection phases. Table 10.7 lists the constituents that are to be tested during the injection phase and the testing frequency. Water-quality parameters will be repeatedly checked for any changes with time for ph, conductivity, alkalinity, DO and redox values. During the post-injection period, the same tests described above for the injection period will be conducted every 6 months. The sampling frequency may be increased if the results of monitoring indicate possible fluid leakage or endangerment of USDWs.

10.4.1.3 Sampling and Analysis Procedures and Quality Asssurance/Quality Control (QA/QC)

The following sampling, handling, and analyses QA/QC procedures will be followed to ensure the acquisition of high-quality data:

- Static water levels in the USDW (Upper Wellington) will be determined using an electronic water level indicator before any purging or sampling activities. Dedicated pumps (e.g., bladder pumps) will be installed in each monitoring well to minimize potential cross contamination between wells and minimize the introduction of atmospheric CO_2.
- Each USDW (Upper Wellington) monitoring well will be purged using a submersible pump. At least three well volumes will be purged before obtaining low-flow samples using a pump. Samples will be dispensed into clean new laboratory-supplied containers and field preserved as required by the analytical method.
- The pumps, tubing, and any other downhole accessories will be rinsed with deionized water and placed in remel Anerobags for travel to the field site. During pump deployment and at other times, care will be taken to ensure that equipment to be used inside the monitoring wells remains clean and does not come in contact with potentially contaminating materials.
- All field and downhole equipment will be properly calibrated according to manufacturer specifications.
- Exposure of the samples to ambient air will be minimized.
- Groundwater pH, temperature, specific conductance, and dissolved oxygen will be monitored in the field using hand-held portable probes.
- For data validation purposes, the following samples will be analyzed with each batch of collected samples:
  - One or two field duplicates, sometimes triplicates, depending on the accuracy of instruments provided to analyse the waters
  - One equipment rinsate

    - One matrix spike (when appropriate for the analytical method)
    - One trip blank
- A chain-of-custody record will be completed and will accompany every sample. All sample bottles will be labeled with durable labels and indelible markings. A unique sample identification number, sampling date, and analyte(s) will be recorded on the sample bottles and sampling records will be written for each well. Sampling records (e.g., a field logbook, individual well sampling sheet) will indicate the sampling personnel, date, time, sample location/well, unique sample identification number, collection procedure, measured field parameters, and additional comments as needed.
- Where appropriate, ASTM Method D6911-03 (2003) will be followed for packaging of samples. Immediately upon sample collection, containers will be placed in an insulated cooler and cooled to 4 degrees Celsius. Upon receipt at the Kansas State laboratory for analysis, the samples will be accepted and tracked by the laboratory from arrival through completed analysis.
- All groundwater quality results will be entered into a database or spreadsheet with periodic data review and analysis.

10.4.1.4 Groundwater Quality Data Reporting

The following information will be submitted to the EPA in all semi-annual monitoring reports:

- The most up-to-date historical database of all groundwater monitoring results,
- Interpretation of any changing trends and evaluation of fluid leakage and migration. This may include graphs of relevant trends and interpretative diagrams,
- A map showing all monitoring wells, indicating those wells that are believed to be in the location of the separate-phase CO_2 plume,
- The date, time, location, and depth of all groundwater samples collected and analyzed,
- Copies of laboratory analytical reports,

- A description of sampling equipment,
- Chain of custody records,
- The name and contact information for the laboratory manager at Kansas State University,
- Identification of data gaps,
- Any changes to the project Testing and Monitoring Plan,
- Presentation, synthesis, and interpretation of the entire historical data set,
- Documentation of the monitoring well construction specifications, sampling procedure, laboratory analytical procedure, and QA/QC standards.

10.5 Carbon Dioxide Plume and Pressure-Front Tracking (§ 146.90 [g])

Identification of the position of the injected CO_2 plume and the presence or absence of elevated pressure (i.e., the pressure front) is integral to protection of USDWs for Class VI projects. Monitoring the movement of the CO_2 and the pressure front is necessary to both identify potential risks to USDWs posed by injection activities and to verify predictions of plume movement to ensure that the plume is adequately confined. Monitoring movement of the plume and the pressure front also provides necessary data for comparison to model predictions and inform re-evaluation of the AoR. Arbuckle monitoring well construction information is presented in Section 10.2. Both direct and indirect measurement methods will be used to monitor the movement of the pressure and plume fronts as discussed in the following sections.

10.5.1 Monitoring Pressure Front (§ 146.90 [g])

The Class VI rule requires that fluid pressure be directly monitored within the injection zone (40 CFR 146.90[g][1]). This type of monitoring provides observations of increases in formation pressures and support tracking the migration of the pressure front (40 CFR 146.90[g][1]).

10.5.1.1 Direct Arbuckle Pressure Monitoring (§ 146.90 [g][1])

Pressure transducers in the injection zone will be installed in the Arbuckle monitoring well KGS 2-28 and in injection well KGS 1-28. The transducers will record pressures continuously every 30 seconds in both the injection and monitoring wells.. The system will have a battery backup or alternative power supply to ensure continued collection of data during power failures. The electronic data from the continuous recorder will be stored on multiple data storage media for redundancy. The data will be backed up on an electronic media storage device. As indicated in Section 13.4, a separate alarm system will monitor surface and bottomhole pressures every 30 seconds in the injection well and trigger a system shutoff and notification to Berexco if a violation of the injection pressure limits specified in Table 13.1 occurs.

Pressure time series at the Arbuckle monitoring and injection wells will be constructed and used to monitor the growth of the pressure front. The pressure data will be compared with a model-based prediction of the pressure front, and if necessary, the simulation model will be recalibrated to conform to field data. The UIC program director will be kept updated of pressure observations via quarterly reporting of the pressure time series and will be consulted during model reevaluation if warranted by the data. Based on modeling results, the pressure in the Arbuckle is expected to stabilize to nearly pre-injection levels within 3 months of cessation of injection. Therefore, the frequency for pressure monitoring will be successively reduced during the post-injection phase based on the observed field conditions. If field conditions warrant a revision of the proposed post-injection monitoring frequency, a revised pressure monitoring plan will be submitted to the EPA for review and comment.

10.5.1.2 Indirect Monitoring of Pressure Front by Surface Displacement (§ 146.90 [g][2])

In addition to direct monitoring, the pressure front will also be tracked by monitoring surface deformation as a result of CO_2 injection using the InSAR approach (Interferometric Synthetic Aperture Radar). This technique will provide an independent means to corroborate the pressure front constructed from direct monitoring of pressures in the Arbuckle injection and monitoring wells. InSAR is a radar technique that measures the phase difference between successive satellite orbits. Tropospheric effects between satellite orbits will be removed using data acquired by the MODIS satellite. Once tropospheric effects are removed, any phase differences between the images will be proportional to small differences in distance between the satellite antenna positions and the ground, which could indicate surface deformation associated with elevated pressures due to CO_2 injection at depth.

Archives of InSAR data will be downloaded before injection to establish a range of baseline surface deformation at the Wellington Field related to seasonal effects (e.g., freeze-thaw cycles and dry vs. wet seasons). During the 9-month injection period and 60 days following injection, InSAR measurements shall be collected approximately every 20 days. After the injection period, data collection and analysis will continue but will decrease incrementally to eventually every 12 months until project closure. The InSAR data can provide a time-series of deformation and subsequent relaxation of the ground surface. The InSAR time-series will establish incremental deformation of the land surface due to CO_2 injection and will be compared with plume dimensions obtained from simulation studies and other direct/indirect monitoring data discussed below.

In addition to InSAR data, Continuous GPS (CGPS) data will also be acquired at cemented platforms for purposes of calibration and verification of the vertical component of the surface displacement field using InSAR. The CGPS data will provide three components of the surface displacement (i.e., northing, easting and vertical) to add tighter constraints to the deformation field detected using InSAR. CGPS data will be downloaded via a laptop on a monthly basis. All data files (24-hour periods) will be recovered for archiving and analysis to enable detection of surface accelerations related to subsurface deformation.

10.5.2 Monitoring the Plume Front

Various direct and indirect MVA tools and techniques will be used to monitor, verify, and account for injected CO_2 in the Arbuckle saline aquifer. The crosswell tomography, U-tube, 3-D seismic, and continuous active source seismic monitoring (CASSM) technology will be used to monitor and visualize the movement of the CO_2 plume. The monitored data will also be used to revise the simulation model, update site characterization, and potentially refine the monitoring plan, if necessary. Each of the plume-monitoring techniques mentioned above, along with the monitoring plan, is discussed below.

10.5.2.1 Direct Geochemical Monitoring of the Plume Front: U-Tube Sampling , (146.90 [g], [i])

Understanding the geochemistry of reservoir gases is critical to understanding how carbon is sequestered in geological formations. The U-tube sampler (Freifeld et al., 2005) is able to collect continuous samples of reservoir fluids near in-situ temperatures and pressures. This innovative apparatus has greatly enhanced the success of CO_2 injection pilot studies at the Frio Brine Pilot, Dayton, Texas; the SECARB Cranfield Test, Cranfield, Mississippi; and the CO2CRC Otway Project, Victoria, Australia (Doughty et. al., 2008; Freifeld, 2009) by significantly improving the quality and quantity of samples that can be collected from deep storage reservoirs during supercritical CO_2 injections. Such sampling is difficult because dissolved gasses and supercritical fluids, which exist at high pressures and temperatures in the reservoir, quickly exsolve or flash to gas as they are brought to the surface for analysis (Freifeld, 2009). The U-tube sampler will be installed in monitoring well KGS 2-28.

Figure10.4—Schematic of the U-tube sampling device (source: JGR, Freifeld et al, 2005).

The U-tube (Figure 10.4), which is constructed of stainless steel tubing and fixed within the borehole with tubing strings that reach to the surface, will be installed in the Arbuckle observation borehole (KGS 2-28). The perforated interval will be isolated using a packer with feed throughs to accommodate the U-tube sampling system and other permanent instruments. The drive leg of the U-tube is connected to a source of compressed nitrogen and the other attached to a sampling manifold contained in a trailer on site. After first flushing the loop of tubing with N_2 gas, the sample and drive legs will be vented and pressure in the U-tube will decrease, allowing subsurface fluids to enter the sampling inlet due to the pressure differential between the U-tube (atmospheric) and the reservoir. To recover the sample, N_2 gas will again be used on the drive leg to increase the pressure in the tubing, closing the check valve and forcing fluid up to a high pressure sampling cylinder. Inside the cylinder, brine, dissolved gases, and supercritical fluids will be collected at near in-situ conditions, allowing accurate quantification of the relative concentrations of each component.

The U-tube surface sampling instrumentation will consists of a supply of N_2, a high pressure gas booster, and a valve panel to facilitate collection of mixed phase and separate phase subsamples. Samples will be collected on a weekly basis until breakthrough to identify the arrival of the CO_2 plume and co-injected tracers (e.g., sulfur hexafluoride). After breakthrough, samples will be collected initially on an increased sampling frequency and then gradually decreased as geochemical changes slow. Subsamples will be collected and sent to laboratories for analysis of constituents such as pH, EC, alkalinity, cation and anion chemistry, dissolved gases, and isotopic composition as presented in Table 10.7. If hydrocarbons are present in the subsurface, they will be analyzed and may be used in equilibrium thermodynamic models to aid in the estimation of the rate of CO_2 dissolution into the formation brines. Tracer gases including SF_6 (sulfur hexafluoride) and Kr (krypton) shall be periodically co-injected with the CO_2 to facilitate estimation of the travel time between the injection and monitoring wells/boreholes. Approximately 55 kg of SF_6 and 230 ft^3 of Kr 230 will be injected every eight weeks at KGS 1-28.

Table 10.8—Geochemical analytical suite to be monitored in the Arbuckle monitoring well (KGS 2-28) at the Wellington site.

Field Parameters	Pre-Injection	During injection	Post-Injection
pH	Once a week for 3 weeks	Every 45 days	Every 6 months
Specific Conductivity	Once a week for 3 weeks	Every 45 days	Every 6 months
Temperature	Once a week for 3 weeks	Every 45 days	Every 6 months
Dissolved Oxygen	Once a week for 3 weeks	Every 45 days	Every 6 months
Gas-Water Ratio	Once a week for 3 weeks	Every 45 days	Every 6 months
Depth to Water	Once a week for 3 weeks	Every 45 days	Every 6 months
TDS/Salinity	Once a week for 3 weeks	Every 45 days	Every 6 months
Indicator Parameters			
Alkalinity	Once a week for 3 weeks	Every 45 days	Every 6 months
Bromide	Once a week for 3 weeks	Every 45 days	Every 6 months
Calcium, Iron, Magnesium, Potassium, Dissolved Silica	Once a week for 3 weeks	Every 45 days	Every 6 months
Chloride	Once a week for 3 weeks	Every 45 days	Every 6 months
Sodium	Once a week for 3 weeks	Every 45 days	Every 6 months
Total CO_2	Once a week for 3 weeks	Every 45 days	Every 6 months
Total Fe	Once a week for 3 weeks	Every 45 days	Every 6 months
Total Fe (II)	Once a week for 3 weeks	Every 45 days	Every 6 months
Total NH_4+	Once a week for 3 weeks	Every 45 days	Every 6 months
Total NO_{2-3}	Once a week for 3 weeks	Every 45 days	Every 6 months
Total SO_{2-4}	Once a week for 3 weeks	Every 45 days	Every 6 months
Total PO_{3-4}	Once a week for 3 weeks	Every 45 days	Every 6 months
Total HCO_3^-	Once a week for 3 weeks	Every 45 days	Every 6 months
Total CO_2	Once a week for 3 weeks	Every 45 days	Every 6 months
		Every 45 days	
Concentration of Organics		Every 45 days	
DOC	Once a week for 3 weeks	Every 45 days	Every 6 months
TOC	Once a week for 3 weeks	Every 45 days	Every 6 months
DIC	Once a week for 3 weeks	Every 45 days	Every 6 months
Stable Isotopes			
δ18O	Once a week for 3 weeks	Every 45 days	Every 6 months
δD	Once a week for 3 weeks	Every 45 days	Every 6 months
δ13C for Carbonates in System	Once a week for 3 weeks	Every 45 days	Every 6 months

10.5.2.2 Indirect Geochemical Monitoring of the Plume Front: Seismic Surveys (146.90 [g], [i])

Both borehole and surface seismic methods will be used to track the CO_2 plume. Surface seismic data has the advantage of being laterally extensive, but borehole seismic methods (especially crosswell, which will be used at Wellington) produce higher resolution images but at less penetration (distance from transmitting and receiving equipment relative to target) than surface seismic methods because seismic waves pass through weathered surface horizons only once (for surface to borehole) or not at all (for cross well), minimizing attenuation and distortion. The higher resolution provided by the borehole seismic may be useful where the CO_2 plume is predicted to be thin or complex in shape. The seismic plume-tracking techniques and monitoring plans to be employed on the Wellington project are discussed below.

10.5.2.2.1 High Resolution Seismic Survey

A 3D seismic survey has already been acquired and processed as discussed in Section 4.8. This information will provide a baseline to compare with a final 3D seismic acquisition before site closure. The 3D data will be interpreted and compared with the baseline survey to map the final extent of the CO_2 plume to demonstrate containment in support of site closure.

10.5.2.2.2 Cross-Well Seismic Methods

Cross-well seismic methods deploy sources and receivers in several different wells, producing a survey that images the plane between the wells. The equipment is generally deployed in wells not more than 1,500 ft apart (Hoversten et al., 2002). A seismic source is deployed down one well and seismic sensors are deployed down additional wells. Cross-well surveys using several wells are able to generate three-dimensional cross-well surveys (Washbourne and Bube, 1998). The crosswell seismic technique measures velocity and attenuation characteristics to model CO_2 saturations and/or pressure changes during CO_2 injection. As illustrated in Figure 10.5, in continuous monitoring mode, this technique can provide information about how the CO_2 is migrating in the subsurface.

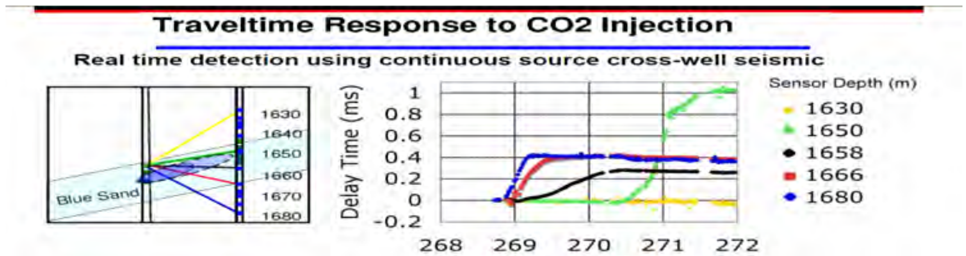

Figure 10.5—Schematic of continuous active-source seismic monitoring (CASSM) Frio-II experiment with conceptual CO_2 plume after one day (inner short dash) and after two days (outer long dash), with measured delay times at three sensor depths over three and a half days of CO_2 injection (right). (Courtesy of Freifeld et al., 2009)

By measuring changes in travel-time and signal amplitude between the wells, tomographic techniques are also used to map velocity and attenuation variations in the section between the wells. These can be used to model CO_2 saturations and/or pressure changes. In addition, cross-hole data can be useful for assessing how effectively the pore space in the storage reservoir is being exploited, which is useful for storage prediction modeling. Because cross-hole seismic uses much higher frequencies than surface seismic (up to 1,000 Hz or more), it interrogates rock and fluid properties at a much finer scale but with much shorter interrogation distances, thereby limiting well separation. Therefore, the method provides valuable ancillary information for the quantitative assessment of surface seismic in proximity to appropriately spaced wells. The technology has been successfully used to capture the CO_2 plume at the Frio experimental storage site in Texas (Figure 10.6). Additional details about the method and its application at the Frio site are documented by Daley et al. (2007) and Freifeld et al. (2009).

The Arbuckle injection well (KGS 1-28) will be fitted with the continuous active-source seismic monitoring (CASSM) sources that in combination with the CASSM receivers placed in the Arbuckle observation borehole, KGS 2-28, will enable a real-time

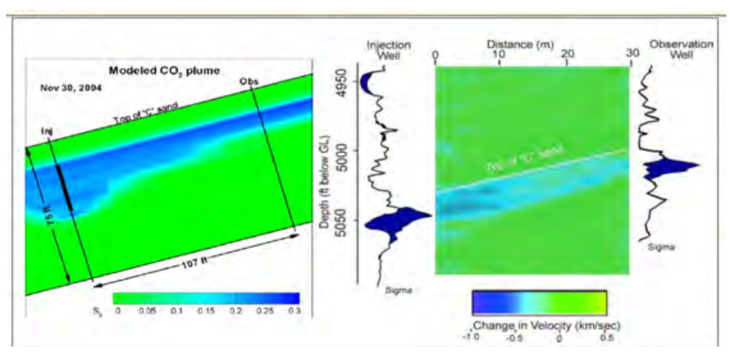

Figure 10.6—Cross-hole seismic imaging at the Frio experimental site in Texas. Velocity tomography (right) compared with reservoir flow simulation (left); (Images courtesy of Tom Daley (Lawrence Berkley National Laboratory); Christine Doughty, LBNL; and Susan Hovorka, University of Texas.

monitoring of the CO_2 plume front from the injector well. The Piezotube CASSM source, a hollow cylinder, will be installed on production tubing in the annulus of the injection well either above or below the packer (or both). A specially designed source carrier shall be used, acting as a "pup" joint of tubing. The installation will include attaching the cable to power the CASSM source, which will run to the surface. The CASSM receivers will be installed on production tubing in the monitoring borehole (KGS 2-28), along with other monitoring instrumentation (pressure/temperature gauge, U-tube, etc). The CASSM receivers will be an array of hydrophones or similar sensors, with spatial distribution such that the expected vertical extent of the plume is monitored. The CASSM system will provide monitoring along specific source-sensor ray paths, complimenting the full cross-well tomography survey to be acquired separately.

A pre-injection cross-well tomography survey will be carried out before the subsurface seismic velocity field is perturbed by the CO_2 injection and will thus be a baseline for the later surveys and for calculating time-lapse changes. The second cross-well tomography survey will be conducted approximately halfway through the injection to estimate the plume location between the Arbuckle injector and observation boreholes.

The CASSM surveys will be acquired at a temporal resolution on the order of 10-30 minutes, allowing estimation of plume growth in real time, until the instruments are removed for the full cross-well survey. The cross-well survey(s) will be useful as bookends to the CASSM survey, providing a detailed spatial description of the CO_2 distribution and the seismic wave field. This plan will alleviate the shortcoming of the relatively sparse spatial sampling of the CASSM, which leaves uncertainty in some aspects of the interpretation of the seismic waveform and the CO_2 distribution (CASSM focuses on the first arrival only, while cross-well allows understanding of later arriving phases and provides imaging in the entire 2D plane between wells).

10.6 Reporting of Monitoring Results to EPA (§ 146.91)

Results of monitoring activities will be submitted to the EPA according to the schedule defined below. Data will be submitted in electronic form directly to the EPA's geologic storage database, where they can then be accessed by the UIC program director.

Prior-to-Injection Report

- CO_2 stream analyses
- Descriptive report of initial MIT as per 40 CFR 146.91(e)
- Baseline InSAR data
- Groundwater geochemistry analyses of USDW
- Groundwater geochemistry analyses of Mississippian formation
- Background U-tube geochemistry

Semi-Annual Report

- Quarterly CO_2 stream characteristics (physical, chemical, other) detailing the list of chemicals analyzed, a description of the sampling methodology and the name of the certified laboratory performing analysis, sample dates and times, and interpretation of the results with respect to regulatory requirements and past results. Any changes to the physical, chemical, and other relevant characteristics of the carbon dioxide stream from the proposed operating data also will be documented
- Description of any event(s) that exceeded operating parameters for annular pressure or injection pressure and corresponding action
- Description of any event(s) that triggered a shut-off device and the corresponding response undertaken
- Monthly volume and/or mass of CO_2 injected over the reporting period;
- Cumulative volume of CO_2 injected over the project life
- Monthly annulus fluid volume added to the injection well

- If pressure or flow rate exceeded permit limits during the reporting period, an explanation of the event(s), including the cause of the excursion, the length of the excursion, and response to the excursion
- Identification of data gaps, if any
- Any necessary changes to the project Testing and Monitoring Plan to continue protection of USDWs
- Continuous measurement of flow rate and pressure in injection well, including the following:
  - Tabular data of all flow-rate measurements
  - Monthly average, maximum, and minimum value for flow rate and volume, injection pressure, and annular pressure
  - Total volume (mass) injected each month
  - Cumulative volume (mass) for the project
  - Demonstration of gauge calibration according to manufacturer specifications
- MIT results
- Corrosion monitoring information, including a description of the techniques used for corrosion monitoring, measurement of mass and thickness loss from corrosion coupons, and a calculated corrosion rate
- Bottomhole pressure results in all monitoring wells, including a synthesis and interpretation of the entire historical data set
- InSAR data
- Groundwater geochemistry sampling results and analyses of USDW
- Groundwater geochemistry sampling results and analyses of Mississippian Formation
- U-tube geochemistry results and analyses
- CASSM results
- Seismic results and analyses

Results to be reported within 30 days of event occurrence

- Results of periodic external MITs as per 40 CFR 146.91(b)
- Any well work performed
- Any test of the injection well as required by the EPA
- If conducted, pressure fall-off test results, including raw data collected during the fall-off test in a tabular format, measured injection rates and pressures, demonstration of gauge calibration according to manufacturer specifications, diagnostic curves of test results, noting any flow regimes, description of quantitative analysis of pressure-test results, calculated parameter values from analysis, including transmissivity and skin factor.

Information to be reported within 24 hours of occurrence

- Any evidence that the CO_2 stream or associated pressure front has or may cause endangerment to a USDW
- Any non-compliance with permit condition(s), or malfunction of the injection system, that may cause fluid migration to a USDW
- Any triggering of a shut-off system, either downhole or on the surface
- Any failure to maintain mechanical integrity
- Any release of CO_2 to the atmosphere
- A description of any event that exceeds operating parameters for annulus pressure or injection pressure

30 Days Notification

- Any well workover, or testing in compliance with EPA directives
- Any well stimulation activities, other than stimulation for formation testing at the injection well as described in Section 8.13
- Any other injection well testing

10.7 Periodic Review of Monitoring Plan (§ 146.90 [j])

The testing and monitoring plan will be periodically reviewed to incorporate a) monitoring data, b) operational data, and c) the most recent AoR re-evaluation. Specifically, a review will be conducted if there is:

- model revision that affects the predicted movement of the plume and pressure fronts (ie, size and shape of AoR)
- evidence of leaching/mobilization of metals or organic constituents in the subsurface that may indicate a need to modify groundwater monitoring parameters or analyses
- operational parameters outside the range specified in Section 10.3.2.5
- AoR re-evaluation
- well construction, mechanical integrity, and corrosion testing data indicating a need to modify the well testing regime, e.g., by revising MITs or corrosion monitoring activities.
- five years elapsed since commencement of injection and site closure has not occurred,

The outcome of the review may be an amended testing and monitoring plan, which will be submitted to the EPA director for approval. If an amended plan is not required, then a justification for the same in the form of a report will be submitted to the EPA director for approval. The amended plans or demonstrations that no amendment is required shall be submitted to the director for approval as follows:

(1) Within one year of an AoR re-evaluation;

(2) After any significant changes to the facility, such as addition of monitoring wells or newly permitted injection wells within the AoR, on a schedule determined by the EPA director; or

(3) When required by the director.

10.8 Period of Data Retention (§ 146.91 [f])

<u>All data</u> collected in support of this Class VI application (including background geologic/hydrogeologic data and analyses, geophysical logs, modeling results, well design and plugging in-

formation/reports) as well as all operating information (including all testing/monitoring activities documented in Sections 10.2–10.7, AoR re-evaluation, corrective action records, post-injection data, well plugging report, and site closure records including data and information used in support of the alternative site care time frame) will be retained for at least 10 years after site closure.

Berexco understands that the EPA director has authority to require that all project records described above (and any additional requetsted information) be retained for longer than 10 years after site closure. Additionally, upon request, Berexco will deliver all project records to the EPA program director.

10.9 Quality Assurance Plan [§ 146.90 (k)]

All Quality Assurance and Quality Control (QA/QC) measures will be documented in semi-annual MVA reports and all intermediate reports that contain field data will be submitted to the EPA.

Data obtained from externally contracted laboratories—such as for CO_2 stream analyses, water-quality testing, temperature/geophysical logs, and corrosion data—will be accompanied with the QA/QC protocol and results followed by the respective laboratories.

Section 10.3.1.4 documents the Quality Assurance/Quality Control procedures to be followed for obtaining and handling CO_2 source samples. QA/QC procedures to be followed during acquisition of groundwater quality data above the injection zone are documented in Sections 10.4.1.3. As discussed in Section 10.5.1.2, the continuous GPS station will be used to calibrate and verify the InSAR satellite data. Instruments installed locally, such as pressure transducers and flow meters, will be calibrated according to the manufacturer's recommendations, and the procedure and results will be documented in reports submitted to the EPA.

Section 11
Injection Well and Arbuckle Monitoring Well Plugging and Abandonment Plan

11.1

Facility name:	Wellington Field Small Scale Carbon Capture and Storage Project
Injection well location:	Latitude 37.319485, Longitude -97.4334588 Township 31S, Range 1W, Section 28 NE SW SE SW
Facility contact:	Dana Wreath, Vice President
Contact information:	2020 N. Bramblewood Street Wichita, KS 67206 (316) 265-3311 Fax: (316) 265-8690

11.2 Introduction

As stated in §146.89, owners of Class VI injection wells are required to appropriately plug and abandon permitted injection well(s). Permittees are required to prepare a Plugging and Abandonment Plan that must specify the following information:

(1) Appropriate tests or measures for determining bottomhole reservoir pressure;

(2) Appropriate testing methods to ensure external mechanical integrity as specified in §146.89;

(3) The type and number of plugs to be used;

(4) The placement of each plug, including the elevation of the top and bottom of each plug;

(5) The type, grade, and quantity of material to be used in plugging. The material must be compatible with the CO_2 stream; and

(6) The method of placement of the plugs.

Further, Section (c) requires the permittee to notify the director in writing pursuant to §146.91(e) at least 60 days before plugging a well and to modify the plugging and abandonment plan at that time, if necessary. Within 60 days after plugging, the owner or operator must submit, pursuant to §146.91(e), a plugging report to the director.

To fulfill the above requirements, the Wellington injection well KGS 1-28 will be plugged and abandoned prior to site closure to prevent any brine and CO_2 from entering the USDW. The well-plugging plan is presented below and lists steps for testing bottomhole reservoir pressure and external mechanical integrity, the type/number/method and placement of plugs, and type/grade/quantity of CO_2-resistant material to be used. In the event that the CO_2 plume reaches the Arbuckle monitoring well (KGS 2-28) as predicted by the model simulations in Section 5, then this well will also be plugged in accordance with Class VI requirements specified in §146.92. Therefore, the information provided in this plan applies to both KGS 1-28 and KGS 2-28. As discussed in Section 10.2, the design and construction of KGS 2-28 is expected to be almost identical to KGS 1-28 (injection well) as the geologic formations are expected to be similar at the two sites. Therefore, the plugging details specified below are applicable to both Arbuckle wells. This will be confirmed after construction of KGS 2-28, and if the design of KGS 2-28 is different from KGS 1-28, the well-plugging plan will be revised and resubmitted to the EPA.

11.3 Planned Tests/Measures to Determine Bottomhole Pressure (146.92[a], [b][1])

The bottomhole pressure and temperatures are to be continuously monitored in the injection and Arbuckle monitoring wells throughout the injection and post-injection periods as specified in Section 10.3.2. The bottomhole reservoir pressure at the time of well abandonment will therefore be obtained as part of these operational activities and will be readily available for reporting.

11.4 Planned External Mechanical Integrity Tests (146.92[a],[b][2])

Before abandonment, a temperature log will be compared with the baseline log of temperature as well as temperature logs acquired during and after injection to demonstrate external mechanical integrity. (See Section 10.3.4 for additional information about mechanical integrity testing.)

11.5 Well Plugging (146.92[b])

The injection well (KGS 1-28), and potentially the Arbuckle monitoring well (KGS 2-28), will be plugged to the top of the Pierson formation, which corresponds to the top of the confining zone at the Wellington site as illustrated in Figure 8.2. Both wells may be used in the future for other oilfield operations in the locally producing Mississippian formation, so plugging will occur from the bottom of the injection well (5,155 ft at KGS 1-28) to the base of the intended oil recovery zone (top of Pierson formation) at 3,930 ft. Should this secondary use of the well occur, the well will be re-permitted to the appropriate status with the Kansas Corporation Commission. If it is determined that the well should be abandoned at the end of the EPA permitted CO_2 disposal project with no future use, a revised well-plugging plan will be submitted to the EPA for review and approval.

The well-plugging plan will be submitted to the EPA 60 days before field operations commence to allow the agency time to witness the plugging operations. Any amendments to the well-plugging plan described below will be incorporated in the latest well-plugging plan.

The wells will first be flushed with brine to force the CO_2 injectate into the formation. A minimum of two wellbore volumes (tubing and casing below packer) will be injected without exceeding 90% of the fracture gradient of 0.75 psi/ft (or 3,408 psi at the bottom of the injection interval at 5,050 ft). The bottomhole pressure will be recorded and the well temperature will be logged to ensure external mechanical integrity as indicated in Section 11.3. If a loss of mechanical integrity is discovered, the well may be repaired if the integrity issue has the potential to yield a problem with plugging operations (or future plug effectiveness) in consultation with the EPA program director before proceeding with the plugging operations.

Attempts will be made to remove the packer before cementing operations begin. However, if the packer cannot be released or removed from the cased hole, initial stages of the plugging operation may take place through the injection tubing before using a wire line tubing cutter to cut off the tubing above the injection packer or to cut the tubing above the packer with the packer left in the wellbore casing.

After the packer has been removed, plugging will commence at the bottom of the well (5,155 ft) by squeezing cement into the perforations and spotting balanced cement plugs. If the injection tubing has been removed, a cement retainer will be set approximately 25 ft above the packer cut-off or 25 ft above the highest perforation, stinging into the retainer with work string tubing. Thirty sacks of CO_2-compatible cement plug will be placed through the retainer, cementing the hole from the bottom up to the cement retainer. This will be followed by 100 sacks of CO_2-compatible cement plug from the top of the retainer to at least the top of the Pierson formation at a depth of approximately 3,930 ft. Assuming a density of 15 ppg slurry with a yield of approximately 1.3 cf/sack, approximately 130 sacks of AA-2 cement will be required for the entire plugging operation. Field conditions encountered at the time of plugging will be used to verify quantities. Both wet and dry samples will be collected for each plug spotted to ensure the quality of the plug. Table 11.1 summarizes plugging information for plugging KGS 1-28 (and KGS 2-28).

Table 11.1—Plugging information KGS 1-28 and KGS 2-28

Zone of Interest	Depth	Formation	Plugging Method	Plug Description	
Description	Cemented Interval	Name	Description	Type	Quantity
TD-Base of plug, including 4,910–5,050 perforated interval	4,910–5,155	Arbuckle	Retainer/work string	AA-2, CO_2-compatible cement	30 sacks
Retainer plug	3,930–4,910	Simpson to top of Pierson	Balanced plug	AA-2 cement plug	100 sacks

11.6 Notice of Intent to Plug (146.92 [c])

The director shall be notified in writing at least 60 days before the well is plugged. At that time, if any changes have been made to the original well-plugging plan, the revised plugging plan will be sent to the EPA for review and approval.

11.7 Injection Well Plugging Report (146.92 [d])

The well-plugging report will be submitted to the EPA within 60 days of completion of plugging activities. The plugging report shall be certified as accurate by the operator. The report will document the bottomhole pressure and temperature log, the details of the plugging operation, and the quantity and specifications of the CO_2-resistant cement. Complete plugging forms and all laboratory information will be submitted to the EPA. The report will be retained by Berexco for a period of 10 years after site closure.

Section 12

Post-Injection Site Care and Site Closure Plan

Facility Name:	Wellington Field Small Scale Carbon Capture and Storage Project
Injection well Location:	Latitude 37.319485, Longitude -97.4334588 Township 31S, Range 1W, Section 28 NE SW SE SW
Facility Contact:	Dana Wreath, Vice President
Contact Information:	2020 N. Bramblewood Street Wichita, KS 67206 (316) 265-3311 Fax: (316) 265-8690

12.1 Introduction

40 CFR §146.93(a) requires that the owner or operator of a Class VI well prepare, maintain, and comply with a plan for post-injection site care and site closure. 40 CFR §146.93(a)(2) requires this plan to include the following information:

(i) The pressure differential between pre-injection and predicted post-injection pressures in the injection zone(s);

(ii) The predicted position of the carbon dioxide plume and associated pressure front at site closure as demonstrated in the area of review evaluation required under §146.84(c)(1);

(iii) A description of post-injection monitoring location, methods, and proposed frequency;

(iv) A proposed schedule for submitting post-injection site care monitoring results to the director pursuant to §146.91(e); and,

(v) The duration of the post-injection site care timeframe and, if approved by the director, the demonstration of the alternative post-injection site care timeframe that ensures non-endangerment of USDWs.

The monitoring activities presented in the Testing and Monitoring Plan (Section 10) will continue during the post-injection phase to meet the post-injection site care (PISC) requirements of 40 CFR §146.93. Both direct and indirect data will be acquired during the post-injection period. Direct data will be acquired in the injection well and the monitoring wells in the Arbuckle Group, Mississippian System, and Wellington Formation at locations shown in Figure 10.1. A detailed description of the planned monitoring activities is documented in Section 10. A summary of the post-injection monitoring frequency is provided in Section 12.2.

Upon cessation of injection, the most recently acquired data and modeling results will be reviewed with respect to the most recent PISC plan. Depending on the rate and extent of plume movement observed during the injection phase, the frequency and spatial extent of the monitoring activities may be modified, and the PISC plan may be resubmitted to the EPA director for review and approval. If the preliminary plans do not need to be altered, there will be no modification to the monitoring plan and the well and sampling locations/frequencies will be maintained.

If significant differences between observed and model-simulated plume and pressure front are noted during the post-injection period, and if these differences are deemed to have the potential to alter the basis for the permit, the model will be recalibrated, and revised plume and pressure projections will be obtained. The existing post-injection monitoring plan will be reviewed along with the latest model projections, and the testing/monitoring plan will be adjusted and provided to the EPA for review to ensure accurate tracking of the plume/pressure front in support of eventual site closure. If necessary, this process of data acquisition and model refinement/projections may continue to determine whether or not the injected CO_2 poses any threat to the USDW. Once a determination of no negative impacts to the USDW is made, an application for site closure will be filed with the EPA director as outlined in Section 12.6.

12.2 PISC Monitoring Activities and Schedule for Submitting PISC Results and Re-evaluation (40 CFR §146.93 [a][2][iv]) (40 CFR §146.93 [a][2][iii] and [b])

Various tools will be used to monitor, verify, and account for the injected CO_2, and the techniques will extend into the post-injection site care timeframe. Table 12.1 presents a summary of the monitoring techniques to be employed and the monitoring schedule. Section 10 (Testing and Monitoring Plan) provides a detailed explanation of each testing and monitoring method.

Table 12.1—Schedule of monitoring activities to be conducted during the PISC phase.

Monitoring Activity	Monitoring Frequency
External MIT (temperature log)	Before closure
Corrosion	Quarterly
Pressure in Arbuckle injection and monitoring wells	Daily
InSAR	Three measurements every 20 days after cessation of injection, and decreasing incrementally to 12 months interval until closure, should closure last beyond 1 year.
USDW geochemistry	Every 6 months as specified in Table 10.7
Mississippian geochemistry	Every 6 months as specified in Table 10.7
Arbuckle geochemistry	Every 6 months as specified in Table 10.7
3-D seismic survey	Before closure

The PISC monitoring data along with any updated reservoir modeling results and any updated PISC and Site Closure Plan will be submitted bi-annually to the EPA. The contents of the these reports are specified in Section 10 (Testing and Monitoring Reporting to EPA). In the event that the monitored data deviate substantially from projections, an analysis will be conducted to explain the deviation. If necessary, the reservoir model may be recalibrated to obtain fresh projection of the future plume trajectory and pore pressures. The findings of the re-evaluation (including a potentially revised PISC and Site Closure Plan) will be submitted to the EPA within 30 days of completion of the re-evaluation. Before authorization for site closure, a demonstration will be made to the EPA director, based on monitoring and other site-specific data, that no additional monitoring is needed to ensure that the geologic storage project does not pose an endangerment to USDWs.

12.3 Alternative Post-Injection Site Care and Site Closure Timeframe (40 CFR §146.93[c])

The default timeframe for post-injection site care is 50 years. However, due to the small extent of the CO_2 plume in the subsurface for this pilot-scale project, which will result in pressures in the injection zone reverting close to pre-injection levels within three months of cessation of injection, Berexco is requesting to close the site at the end of a one-year post-injection period. This proposed post-injection site care timeframe will, however, be re-evaluated and justified to the EPA based on site-specific data obtained during the injection and post-injection phases.

The site-specific conditions that support a request for early closure are provided below in support of 40 CFR §146.93(c) (1):

- (§146.93[c][1][i])—The results of computational modeling of the project indicate that the stored CO_2 will not migrate above the primary confining zone and not spread laterally within the injection zone (Arbuckle aquifer) to any natural or artificial penetration that extends into the confining zone other than KGS 1-28 and 2-28, both of which will be constructed to Class VI (injection well) specifications. These conclusions are documented in Section 9.
- (§146.93[c][1][ii])—The results of computational modeling (Section 5.4.6) indicate that formation pressures are generally not adequate to force the CO_2-brine mixture within the Arbuckle to penetrate into the USDW. As noted from Table 9.1, a pressure increase of approximately 327 psi is required for brines in the injection interval to migrate into the USDW. As shown in Figure 5.18, the pressure drops to less than 327 psi within 100 ft of the injection well, which has been constructed per Class VI guidelines as documented in Section 8. Therefore, there are no existing or abandoned wells through which the Arbuckle brines can be expected to migrate into the USDW. As shown in Figure 6.4, there are no known or mapped faults within the AoR at the Wellington site through which the brines in the Arbuckle could migrate upward either.
- (§146.93[c][1][iii])—The predicted rate of CO_2 plume migration is minimal with a

maximum spread of approximately 1,700 ft from the injection well (Figure 9.1). Also, the plume is expected to remain confined in the injection interval within the lower Arbuckle as shown in Figures 5.11 and 5.13 and not migrate even into the middle or upper Arbuckle.

- (§146.93[c][iv, v, and vi])—The storage processes that were simulated include structural, hydrodynamic, solubility, and residual trapping. The model ignores storage due to capillary entrapment and mineralization, and therefore the results are expected to be on the conservative side.

  The hydrogeologic properties of the Arbuckle aquifer were derived by means of sophisticated analyses involving the construction of a geomodel using Schlumberger's Petrel modeling software. The data in the geomodel were anchored in core and log data for porosity and permeability derived at the injection well site (KGS 1-28) and the geologic characterization well (KGS 1-32). Therefore, the reservoir model is expected to realistically represent the hydrogeologic properties of the Arbuckle aquifer. However, to account for uncertainties, and to obtain conservative results, a set of nine alternative models were derived and used in the simulations by increasing and decreasing the key hydrogeologic properties by 25%. As discussed in Section 5.4, the model-based limits on maximum induced pressure and maximum extent of plume migration are based on these alternative models, which ensures some conservatism built into the projections.

- (§146.93[c][vii])—Section 4 documents in detail all of the site-specific geologic and hydrogeologic data used to develop the conceptual reservoir model of the injection zone (Arbuckle) and the confining zone (Simpson Group, Chattanooga Shale, and Pierson formation). The confining potential of the primary confining zone is extensively documented in Section 4.7.

  There are no known faults within the AoR as shown in Figure 6.4. The lack of hydraulic connection between the injection zone (Arbuckle) and the overlying formations is also documented and confirmed by the geochemical data (Section 4.6.7), which indicates vastly different geochemistry in the injection zone and overlying Arbuckle and Mississippian reservoir formations. The drill-stem test (DST) data (Section 4.6.3) also indicate substantial under-pressurization in the Mississippian Formation that overlies the confining zone (Simpson/Chattanooga/Pierson), suggesting lack of transmissive features in the primary confining zone. Furthermore, the regionwide under-pressurization of the Mississippian Formation with respect to the injection zone (Arbuckle aquifer) could only exist in the absence of hydraulic conduits in the confining zone as documented in Section 7. Even if the CO_2 were to escape from the confining zone, it would be hydraulically trapped in the under-pressurized Mississippian oil reservoir above the confining zone.

- (§146.93[c][viii and ix])—No abandoned wells penetrate the primary confining zone within the AoR as shown in Figure 1.10 and Table 1.2. The only existing well within the AoR that penetrates the confining zone is the injection well (KGS 1-28), which as documented in Section 8 was constructed per Class VI specifications. The Arbuckle monitoring well (KGS 2-28), to be located approximately 300 ft northwest of KGS 1-28 and within the AoR, will also be in compliance with Class VI construction requirements as documented in Section 10. The CO_2 plume is expected to reach this well in approximately two months time.
- (§146.93[c][x])—The distance between the injection zone and the base of the USDW is in excess of 4,500 ft, as shown in Figure 1.8. There are multiple confining (shale) zones between the injection zone and the USDW as documented in Section 4.3 and Figure 1.8.

12.4 Reservoir Simulation Results Pressure Differential and Predicted Plume Position (40 CFR §146.93[a][2][i and ii])

Section 5.4.6 presents and discusses the preliminary reservoir simulation results. At the end of the nine-month injection period, the bottomhole (5,050 ft) pressure at the injection well completion is expected to increase by 442 psi (Table 5.6) but decrease rapidly with distance from the well as shown in Figure 5.18. As discussed in Section 9.2.1, an increase in pore pressure of approximately 327 psi is necessary for the brines in the injection zone to migrate vertically into the USDW through a natural or artificial penetration. As shown in Figure 5.18, the pressure drops to less than 327 psi within less than 100 ft of the injection well, which has been constructed per Class VI guidelines as documented in Section 8. Therefore, there are no existing or abandoned wells through which the Arbuckle brines can be expected to migrate into the USDW. Furthermore, as discussed in Section 7, the Mississippian System above the confining zone is significantly under-pressurized and therefore would act as buffer and bleed-off zones in the unlikely event that a pathway is present between the Arbuckle and the USDW. The projected pressure increase at the top of the Arbuckle (under the primary confining zone) after nine months of injection is expected to be only slightly more than 13 psi at the injection well site under the worst-case scenario (Figure 5.16). This pressure increase would be insufficient to cause migration into the USDW due to the large head differential between the Arbuckle Group and the Wellington Formation (USDW). Additionally, the pressure increase at the top of the Arbuckle is also significantly less than the entry pressure in the Chattanooga Shale of 956 psi as documented in Section 4.7.4. Therefore, the primary confining zone (Simpson/Chattanooga/Pierson) is expected to function as a competent caprock because of its lateral extent and low permeability (at the nano-Darcy level as documented in Section 4.7.3) combined with insufficient pressure build-up at the top of the Arbuckle to overcome capillary forces. The pore pressures in the injection interval are also expected to dissipate to near pre-injection levels in less than three months after cessation of injection as shown in Figure 5.17. Therefore, the aqueous phase CO_2 is not expected to penetrate into the USDW during the post-injection phase due to the large head difference between the Arbuckle and the USDW and confinement offered by the confining zone.

Modeling was also used to predict the movement of the free-phase CO_2 plume. The simulation results (Figure 5.13a–g) indicate that the free-phase CO_2 barely penetrates into the mid-Arbuckle baffle zones and does not reach the base of the confining zone. The configuration of the CO_2 plume in the injection interval at the end of one year after injection (time of proposed site closure) is shown in Figure 12.1, which suggest that the plume (at its widest extent) will have migrated about 1,700 ft from the injection well. Although in the presence of a hypothetical pathway, CO_2 in free phase could theoretically escape into the USDW and the atmosphere through faults or artificial penetrations, there are no wells within the AoR that penetrate the confining zone except KGS 1-28 and KGS 2-28, both of which will be constructed to meet Class VI (injection well) specifications as documented in Sections 8 and 10.

With respect to escape of CO_2 via structural features, not only are there no known faults in the AoR as shown in Figure 6.4, but the pressure increase projected to occur in the injection zone will not initiate new fractures or mobilize any existing faults as documented in Sections 6.3–6.5. Furthermore, the geochemical and DST data presented in Sections 4.6.3 and 4.6.7 suggest a high level of confinement provided by the confining zone, which precludes the presence of any transmissive

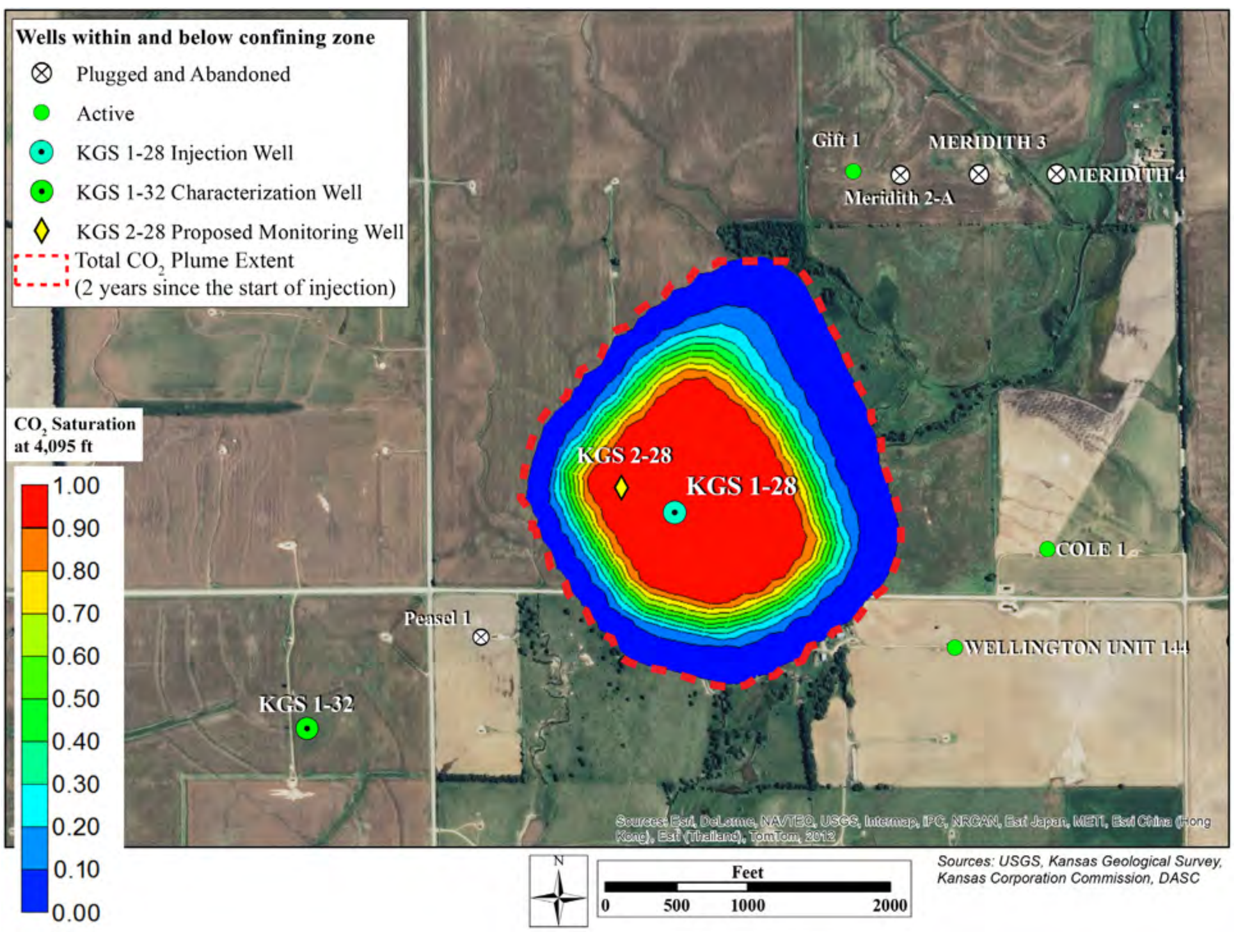

Figure 12.1—Extent of plume migration at the end of one year after cessation of injection for the alternative model resulting in the largest extent of plume migration (k-1.25/phi-0.75).

fractures in the primary confining zone. An analysis of fractures in the confining zones, documented in Section 4.7.5, suggests the absence of communicative fractures in the confining zone.

12.5 Criteria for Demonstration of Alternative Post-Injection Site Care Timeframe. (40 CFR § 146.93 [a][2][v] and [c][2])

Care has been taken to ensure acquisition of quality data and to promote careful processing of the acquired data. The geophysical logs were acquired and analyzed by reputable vendors, such as Weatherford and Schlumberger. Laboratory tests to estimate formation properties, such as permeability/porosity and rock elasticity/strength, were conducted by certified laboratories, such as Weatherford Laboratories. Data synthesis and interpretation were conducted by professional staff at KGS who are experts in their field and by professionally certified external consultants. All technical analyses have been checked and documented and are available for review and reproduction by the EPA.

The geo and reservoir models developed for the project are based on the carefully processed core and geophysical data. The reservoir model is also based on available field data, such as injection tests. However, a set of alternative conceptual models were also developed in order to incorporate conservatism in the simulation results. QA/QC measures to be implemented while conducting testing and monitoring activities during the pre-injection, injection, and post-injection phases are documented extensively in Section 10. All analyses and QA/QC for project data meet and will continue to meet the following required standards:

(i) All analyses and tests performed to support the demonstration will be accurate, reproducible, and performed in accordance with the established quality-assurance standards;

(ii) Estimation techniques will be appropriate and EPA-certified test protocols will be used where available;

(iii) Reservoir model will be appropriate and tailored to the site conditions, composition of the carbon dioxide stream, and injection and site conditions over the life of the geologic storage project;

(iv) Reservoir model will be reviewed to ensure that it is in conformance with newly acquired monitoring and geophysical data;

(v) Reasonably conservative values and modeling assumptions will be used and disclosed to the director whenever values are estimated on the basis of known, historical information instead of site-specific measurements;

(vi) An analysis will be performed to identify and assess aspects of the alternative post-injection site care timeframe demonstration that contribute significantly to uncertainty. Sensitivity analyses will be conducted to determine the effect that significant uncertainty may contribute to the modeling demonstration.

(vii) The quality-assurance and quality-control measures specified in Section 10 will address all aspects of the demonstration; and,

(viii) Any additional criteria required by the director.

12.6 Site Closure Activities (40 CFR §146.93 [d-g])

Prior to authorization of site closure, Berexco will submit to the director for review and approval a demonstration, based on monitoring and other site-specific data, that no additional monitoring is needed to ensure that the geologic storage project does not pose a danger to USDWs. If the demonstration cannot be made (i.e., additional monitoring is needed to ensure that the geologic storage project does not pose a danger to USDWs), an updated PISC plan will be submitted to the director to continue post-injection site care until a demonstration can be made and approved by the director.

The following activities will be carried out before requesting site closure:

- A 3-D seismic survey will be acquired over the area of approximately one square mile. The new 3-D data will be interpreted and compared with the baseline survey (that has already been acquired and discussed in Section 4.8) to detect the presence of CO_2 outside the expected plume containment area as modeled by reservoir simulation studies.
- The non-seismic MVA data and its analyses conducted during the post-injection phase

will be integrated with the newly acquired 3-D seismic data to validate the absence of CO_2 outside the containment strata, thus confirming that future leakage risks are minimal to non-existent.

- All monitoring data and other site-specific data will be accounted for and used in the simulation model to demonstrate to the EPA in the form of a report that the pressures have abated, that the plume growth has slowed, and that no additional monitoring is needed to ensure that the storage project does not pose a danger to USDWs. If the EPA does not approve the demonstration, an amended plan will be submitted to the director for continuing PISC until a demonstration of safe site closure is made and approved by the director.

Berexco will notify the EPA Region 7 director of its intent to close the site at least 120 days before the closure date. Any revisions to the PISC and Site Closure Plan will accompany the notice. Once the EPA has approved closure of the site, all monitoring wells included in the permit application may be plugged. The Arbuckle injection well (KGS 1-28) and potentially the Arbuckle monitoring well (KGS 2-28) will be abandoned in accordance with the plan described in Section 11. The Wellington shallow USDW monitoring wells will be plugged following standard industry practices. The Arbuckle geologic characterization well (KGS 1-32) will be plugged in accordance with procedures used for KGS 2-28. A site closure report will be prepared within 90 days of closure and submitted to the EPA director, documenting the following:

- plugging of the injection and USDW monitoring wells,
- location of the sealed injection well on a plat of survey that has been submitted to the local zoning authority. A copy of the plat also will be submitted to the EPA regional office,
- notifications of closure to state and local authorities,
- records documenting the nature, composition, and volume of the injected CO_2,
- all pre-injection, during injection, and post-injection monitoring records,
- certifications to the Region 7 program director that all geologic injection and storage

activities have been completed in accordance with the Post-Injection Site Care and Site Closure Plan.

Berexco will record the following information in a notation to the property deed on which the injection well (KGS 1-28) was located:

- that the property was used for CO_2 storage,
- the name of the agency with which the survey plat was filed as well as the address of the EPA Region 7 office that received a copy of the plat survey,
- the volume of fluid injected,
- the formation into which the fluid was injected,
- the period over which the injection occurred.

All PISC records will be retained by Berexco for a period of 10 years, after which the records will be delivered to the EPA director for retention.

Section 13
Emergency Remedial Response Plan

Facility Name: Wellington Field Small Scale Carbon Capture and Storage Project

Injection Well Location: Latitude 37.319485, Longitude -97.4334588
Township 31S, Range 1W, Section 28 NE SW SE SW

Facility Contact: Dana Wreath, Vice President

Contact Information: 2020 N. Bramblewood Street
Wichita, KS 67206
(316) 265-3311
Fax: (316) 265-8690

13.1 Introduction and Plan Overview (§146.94 [a-c])

40 CFR **§**146.94, Emergency and Remedial Response, requires the permittee to develop an emergency and remedial response plan that describes the actions that must be taken to address movement of injection or formation fluids that may endanger a USDW. The plan must address movement during construction, operation, and post-injection care time periods. The plan herein addresses actions that will be taken in the event of endangerment of a USDW due to movement of injectate or fluid attributed to injection-related activities. This plan ensures that if Berexco obtains evidence that the injected CO_2 stream and/or associated pressure front endangers the USDW, Berexco will take the following action:

1. Immediately shut down the injection well,
2. Identify and characterize the release,
3. Notify the EPA UIC program director of the event within 24 hours,
4. Implement the ERRP presented below.

The EPA may allow injection to resume before remediation if Berexco demonstrates that the injection operation will not endanger the USDW.

<u>Emergency Contact Information</u>

Contact information of Berexco site personnel and project manager as well as county emergency responders and stakeholders are listed below:

Personnel/Organization	Name	Phone Number	Email
Site supervisor	Evan Mayhew	(316) 265-3311	emayhew@berexco.com
Berexco project manager	Dana Wreath	(316) 265-3511	dwreath@berexco.com
Sumner County Sheriff	Darren Chambers	(620) 326-8943	dchambers@co.sumner.ks.us
Sumner County Emergency Management	James Fair	(620) 326-7376	jfair@co.sumner.ks.us

As described in the preceding sections, all proper steps for siting, construction, and operation of the injection and monitoring wells have been or will be undertaken. An extensive set of MVA activities is also proposed to detect movement of CO_2 above the confining zone. In the event that MVA activities show that endangerment of a USDW has occurred due to movement of formation fluid or injectate based on monitoring/testing results, or if there is a well mechanical failure or natural disaster, the emergency and remedial response plan (ERRP) described below will be implemented to prevent negative impacts to the USDW during pre-injection, injection, and post-injection phases.

13.2 Area Resources and Infrastructure (§146.94)

The facility occurs in a sparsely populated area where there are no major buildings, infrastructures, homes, or water wells. As shown in Figure 4.16, there are no potable water wells within the AoR. The injection well is located in a rural area with some non-irrigated crop cultivation (Figure 1.7). Additionally, there are no buildings or infrastructure near the site that would potentially be affected as a result of CO_2 emissions at the surface. Also, there are no municipal water supplies in the immediate area. The closest surface water feature is Slate Creek, which is approximately 3 mi south of the site (Figure 1.6a).

The key resources/infrastructure in the area that may be impacted by escape of CO_2 from the confining zone include:

- Surface injection facility equipment: CO_2 storage tank, pump, and communication device,
- Injection well KGS 1-28 and monitoring well KGS 2-28 and related equipment,
- USDW within Upper Wellington Formation (ground surface to approximately 250 ft below ground).

13.3 Potential Risk Scenarios (§146.94 [a,b])

The classification of an emergency scenario is related to degree of USDW endangerment posed by the scenario. A list of potential failure/risk scenarios are presented below. Each scenario will constitute an emergency and trigger the ERRP, although response activities related to each scenario will depend on the nature of the failure and the severity of the event. Emergency events will result in:

1. Immediate notification of the Berexco project manager or designated subordinate by on-site staff and automatically over a cellular network;
2. Immediate cessation of CO_2 injection;
3. Evaluation of the nature of the emergency and characterization of any release;
4. Implementation of corrective action as described below for each emergency scenario.

As required in 40 CFR §146.94(b) if, upon evaluation, the owner/operator obtains evidence that the injected CO_2 stream and associated pressure front may cause an endangerment to a USDW, the following additional step will be taken:

5. Notify the director within 24 hours of determination.

All emergencies will require implementation of steps 1–4; those identified as indicating that the injected CO_2 stream and associated pressure front endangers a USDW will trigger step 5.

Emergency scenarios may be defined as major, serious, or minor in terms of anticipated impacts to life and property as indicated below:

- Major Emergency—Immediate risk to human health, resources, or infrastructure.

Area-wide evacuation with the assistance of emergency agencies is to be initiated.

- Serious Emergency—Potential risk to human health, resources, or infrastructure if no response is undertaken or if conditions deteriorate.
- Minor Emergency—No immediate risk to human health, resources, or infrastructure.

Because of the limited extent of the plume and pressure front, and the uninhabitated location of the injection well, all potential emergencies listed below will fall in the Minor Emergency category, posing no risk to human health and safety.

Table 13.1 specifies operating parameters. Should operating parameters be exceeded or violated, Berexco will implement steps 1–4 above, evaluate the circumstances, and determine whether this violation resulted in the injected CO_2 stream and associated pressure front posing a danger to a USDW. If endangerment is determined, Berexco will implement step 5 above.

Table 13.1—Operating range for key injection parameters.

CO_2 Injection Flow Rate	150 metric tons/day (+/- 5%)
Wellhead Inlet Pressure	< 800 psig
Bottomhole Pressure	< 3,408 psig @ 5,050 ft (90% of fracture gradient of 0.75 psi/ft)
Annulus Pressure at Surface	0 psig
Wellhead CO_2 Temperature	-10° to +10° F
Bottomhole CO_2 Temperature	20 - 60° F @ 5,050 ft

13.3.1 Mechanical Integrity Failure

Annulus Pressure Failure

Potential adverse event: Release of injectate through annulus, potential to impact USDW

Timing of event: Operational

Avoidance measures: Well maintenance

Risk level: Low

Potential response action: Cease injection, evaluate cause of violation, and mitigate, if necessary. If evaluation shows that violation resulted in potential release

	of injectate or fluid to impact the USDW, report per §146.94(b), including notification to the EPA director within 24 hours after the determination is made. Cease operations until the issue is resolved.
Response personnel:	Berexco/KGS representative
Discussion:	As discussed in Section 10.3.2.4, the annular pressure is to be monitored manually daily for internal mechanical integrity of the well. A sufficient anomalous pressure or fluid-level change in the annulus will require an investigation of the tubing/borehole, and the appropriate corrective action will be implemented. An annulus pressure test will be conducted after remediation to confirm well integrity. Results will be provided to the EPA Region VII director, and permission will be sought to resume injection.

Mechanical Integrity Test Failure

Potential adverse event:	Monitoring violation
Timing of event:	Operational
Avoidance measures:	Well maintenance
Risk level:	Low
Potential response action:	Evaluate cause of violation and mitigate, if necessary. If evaluation shows that violation resulted in potential release of injectate or fluid to impact the USDW, report per §146.94(b), including notification to the EPA director within 24 hours after the determination is made. Cease operations until the issue is resolved.
Response personnel:	Berexco/KGS representative
Discussion:	If the annular pressure test fails (internal MIT) or an analysis of the temperature log indicates external MIT failure, appropriate steps

will be taken to address the loss of mechanical or wellbore integrity and determine whether the loss is due to the packer system or the tubing. An annulus pressure test will be conducted along with acquisition of temperature log after remediation to confirm integrity.

13.3.2 Equipment Failure

Damage to Wellhead

Potential adverse event:	Monitoring violation
Timing of event:	Operational
Avoidance measures:	Well maintenance and facility safety measures
Risk level:	Low
Potential response action:	Evaluate cause of violation and mitigate, if necessary. If evaluation shows that violation resulted in potential release of injectate or fluid to impact the USDW, report per §146.94(b), including notification to the EPA director within 24 hours after the determination is made. Cease operations until the issue is resolved.
Response personnel:	Berexco/KGS representative
Discussion:	In the event of damage to wellhead, the nearby area will be isolated, if needed. Safe distance and perimeter will be established using a hand-held air-quality monitor. Steps may be taken to log well to detect CO_2 movement outside of casing. Appropriate steps will be implemented to repair the damage and a survey will be conducted to ensure wellhead leakage has ceased.

Well Blowout Due to Equipment Failure

Potential adverse event:	Monitoring violation
Timing of event:	Operational
Avoidance measures:	Well maintenance
Risk level:	Low
Potential response action:	Evaluate cause of violation and mitigate, if necessary. If evaluation shows that violation resulted in potential release of injectate or fluid to impact the USDW, report per §146.94(b), including notification to the EPA director within 24 hours after the determination is made. Cease operations until the issue is resolved.
Response personnel:	Berexco/KGS representative
Discussion:	In the event of a well blowout, the well will be "killed" by pumping fluid to stop the well from flowing.

13.3.3 Release to Ground Surface

Seismic Detection of CO_2 Escape

Potential adverse event:	Monitoring violation
Timing of event:	Operational and post-closure
Avoidance measures:	Injection following approved operational parameters
Risk level:	Low
Potential response action:	Evaluate cause of violation and mitigate, if necessary. If evaluation shows that violation resulted in potential release of injectate or fluid to impact the USDW, report per §146.94(b), including notification to the EPA director within 24 hours after the determination is made. Cease operations until the issue is resolved.
Response personnel:	Berexco/KGS representative

Discussion:	If any monitoring technique detects escape of anthropogenic CO_2 into formations above the primary confining zone, then appropriate investigative and remediation actions will be immediately deployed. If the release is along the wellbore and above the primary confining zone, then a suite of wireline logs will be used to identify the location of failure in the well, and repairs will be made. If the leakage is farther away, or through the primary confining zone, then a plan will be developed in consultation with the EPA to identify the extent of the problem and to develop remedial measures.

13.3.4 Release to USDW

Water-Quality Changes

Potential adverse event:	Detection of anthropogenic CO_2 in groundwater monitoring wells in statistically significant excess over background levels
Timing of event:	Operational and post-closure
Avoidance measures:	Well maintenance and injection in accordance with approved operational parameters
Risk level:	Low
Potential response action:	Evaluate cause of violation, including review of equipment and determination of alternative sources or origin of CO_2. If the source is determined to originate from injection fluid, resulting in the potential release of injectate or fluid that could impact the USDW, report per §146.94(b), including notification to the director within 24 hours after the determination is made and cessation of operations until the issue is resolved. With the recent classification of CO_2 as a non-hazardous waste by the EPA, any necessary remedial activity plan will be developed in consultation with the EPA director.

Response personnel:	Berexco/KGS representative
Discussion:	Water quality will be monitored in a network of observation wells in the shallow USDW and the Mississippian reservoir above the primary confining zone. Water samples from these wells will be collected periodically as described in Section 10.4. If the monitoring network shows a statistically significant change in groundwater quality as a result of CO_2 injection, then additional monitoring and remedial activities will be initiated as follows.

If poor-quality water is determined to be a consequence of well failure, then an attempt will be made to identify the source location in the wellbore. This will involve obtaining a suite of wireline logs to pinpoint the source location. On completion of the remedial work, a new set of logs will be acquired in conjunction with a pressure test to validate well integrity.

If the CO_2 migration is determined to be due to confining zone failure or flow along structural features, then a plan will be developed in consultation with the EPA to identify the extent of the problem and to develop remedial measures. This may involve installing additional wells near the affected groundwater well(s) to delineate the extent of contamination, and conducting additional modeling to predict the fate of the CO_2 and/or brine. If CO_2 is found in the USDW, then the modeling will involve predicting the impacts to any surrounding wells and water resources. The shallow monitoring wells may also be used to vent gas that has reached the USDW. Groundwater monitoring would continue during and after the remedial measures to demonstrate that the concentration levels are below minimum tolerance levels.

If CO_2 is detected in the under-pressured Mississippian reservoir, the Mississippian monitoring wells may be used to release any CO_2 that has leaked into the reservoir. A 2-D seismic survey may also be conducted to identify the extent of plume migration.

13.4 Remote Communication and Shutdown System (§146.94 [a,b])

An alarm and shutdown system that will be activated in the event of deviation of essential operating parameters specified in Table 13.1. The gages measuring flow rate at the wellhead, wellhead pressure, bottomhole pressure, surface temperature, and bottomhole temperature will be connected to the PLC, which will be programmed to cease operations and inform the project manager via cellular communication if the operating ranges are exceeded. The PLC will also be programmed to control injection rates to prevent exceeding the maximum bottomhole pressure and flow rates specified in Table 13.1. As indicated in Section 10.5.1.1, the pressure will be recorded continuously every 30 seconds.

The PLC will have a battery backup to supply power for at least 24 hours in the event of primary power failure. If the PLC malfunctions, the system will automatically shut down. Activation of the automatic shutdown system does not in itself constitute an emergency event. If the shut off is triggered by mechanical or electrical malfunctions, without endangering the USDW, then faulty components will be repaired and the system will be restarted.

13.5 Emergency Communications Plan (§146.94 [a,b])

Because the extent of the plume is very small and in a rural area with no potable wells or inhabitants, the consequences of CO_2 detection in the USDW would not pose any immediate endangerment to life and property. Therefore, upon detection of the plume, or an automatic shutdown that is caused by a compliance trigger with the potential to endanger the USDW, the Berexco project manager will cease injection and inform the EPA Region VII program director within 24 hours. The next step would be to identify the causes of the failure and implement any remedial action.

Due to the limited risk of any immediate harm to humans, Berexco does not believe that any emergency management agency or the media needs to be contacted in the event of implementation of an ERRP. However, Berexco is open to expanding the list of those who receive information when the ERRP is activated at the discretion of the EPA.

13.6 Emergency Remedial Response Plan Reevaluation (§146.94 [d])

This ERRP shall be reviewed and revised a) five years after commencement of injection, should the project extend for such a long duration; b) within one year of an area of review re-evaluation; c) after any significant changes to the facility, such as the addition of injection or monitoring wells; and d) whenever required by the director.

If no changes to the ERRP are required after the review, then all documents in support of this determination will be provided to the EPA for approval. If amendments to the ERRP are prepared, the revised ERRP will be submitted to the EPA for review and approval.

Section 14
Financial Responsibility

14.1 Introduction

Due to its extensive experience in subsurface oil and gas operations and strong financial position, the operator of the Wellington oil field, Berexco, is opting for the self-insurance option to demonstrate financial responsibility for the project. Headquartered in Wichita, Kansas, Berexco is an independent oil and gas exploration company prior to 1980 and operates actively in eight midcontinent states. It has also been a lead industry participant in the U.S. Department of Energy South-Central Kansas CO_2 Project (http://www.kgs.ku.edu/PRS/Ozark/index.html) that is engaged in research and field activities for characterizing hydrocarbon resources, developing innovative oil and gas extraction technologies, and developing climate mitigation initiatives. Berexco is a member of the Kansas Independent Oil and Gas Association (KIOGA) and has 10 active workover rigs supporting its operations. Company personnel serve on the KIOGA Board of Directors, KIOGA Executive Committee, KIOGA Natural Gas Committee, Tertiary Oil Recovery Project Advisory Board, Ad Valorem Gas Price Committee, and Wichita Petroleum Landman Association.

Berexco's financial standing, documented below, demonstrates that it has the resources to carry out CO_2 injection and storage activities related to operating, closing, and potentially remediating the Wellington site without endangering the Underground Sources of Drinking Water (USDW). Berexco is profitable, not overly leveraged, and has sufficient liquidity to successfully execute the project. In addition, all project activities are financed through a cooperative agreement between the U.S. Department of Energy, the Kansas Geological Survey, and other cost-share partners, thereby minimizing financial risks to Berexco (one of the cost-share partners). As discussed in Section 5, there is limited risk of CO_2 and subsurface fluids escaping from the injection zone and causing a risk to human health or the environment.

14.2 Project Activities and Cost Estimates

Rule 40 CFR §146.85 requires that the financial responsibility instrument(s) be sufficient to successfully accomplish the tasks associated with performing well corrective action, injection well plugging, post-injection site care, and site closure and with implementing an emergency/remedial plan. Table 14.1 presents the frequency of each of these activities and refers to the relevant section of the project master plan.

Table 14.1—Project activities that require demonstration of financial responsibility.

Activity	Rule Reference	Frequency	Activity Plan
Performing corrective action	40 CFR §146.84	None expected	The corrective action plan will be re-evaluated periodically as specified in Section 9.3.1
Plugging injection well	40 CFR §146.92	One time	Injection and monitoring well plugging plan (Section 11.5)
Post-injection site care	40 CFR §146.93	Throughout post-injection phase	Post-Injection Site Care Plan (Section 12)
Site closure	40 CFR §146.93	One time	Site Closure Plan (Section 12)
Emergency/remedial response	40 CFR §146.94	As needed	Emergency/Remedial Response Plan (Section 13)

The costs estimated to perform the activities highlighted in Table 14.1 is estimated to be \$192,000 as documented in Table 14.2. Most activities in Table 14.2 are primarily funded by the DOE, with Berexco's contribution not exceeding \$50,000.

Table 14.2—Estimated costs to complete project activities that require demonstration of financial responsibility.

Project Task	Cost Estimate (2016)	DOE Contribution	Berexco and other Project Participant Contribution
Performing Corrective Actions on Deficient Well(s) in AoR			
No activity anticipated	$0	$0	$0
Subtotal: Corrective Actions Cost	**$0**	$0	$0
Plugging Injection Well			
Remove Surface Equipment	$2,000	$2,000	$0
Run temperature log	$3,000	$3,000	$0
Flush injection well with buffer fluid	$1,000	$1,000	$0
Plug injection well	$25,000	$25,000	$0
Plugging report	$1,000	$1,000	$0
Subtotal: Injection Well Plugging Cost	**$30,000**	$30,000	$0
Post-Injection Site Care			
Injection well pressure monitoring	$2,000	$2,000	$0
InSAR	$6,000	$6,000	$0
Geochemistry (Monitoring wells)	$4,000	$4,000	$0
U-Tube monitoring	$11,000	$11,000	$0
Corrosion monitoring	$2,000	$2,000	$0
Data Analyses/Modeling	$7,000	$7,000	$0
Seisimic Survey	$50,000	$50,000	$0
PISC Monitoring Reports to EPA	$6,000	$6,000	$0
Subtotal: Post-Injection Site Care Cost	**$88,000**	$88,000	$0
Site Closure			
Plug USDW Monitoring Wells (2)	$2,000	$2,000	$0
Plug Arbuckle Monitoring Well (1)	$30,000	$12,000	$18,000
Remove Surface Equipment	$5,000	$5,000	$0
Site Closure Report	$5,000	$5,000	$0
Subtotal: Site Closure Cost	**$42,000**	$24,000	$18,000
Emergency and Remedial Response			
Implement shutdown	$2,000	$0	$2,000
Conduct site review	$2,000	$0	$2,000
Well blowout or other emergency remedial implementations	$20,000	$0	$20,000
MIT	$5,000	$0	$5,000
Report Corrective Action to EPA	$3,000	$0	$3,000
Subtotal: ERP Cost	**$32,000**	$0	$32,000
Total Amount Needed to Show Financial Responsibility	**$192,000**	**$142,000**	**$50,000**

14.3 Financial Requirements for Self-Insurance

14.3 Financial Tests

To qualify for self-insurance, minimum financial coverage criteria must be met, pursuant to 40 CFR §146.85. Table 14.3 presents the required/recommended thresholds for net working capital (NWC), total assets, and tangible net worth (TNW) along with the recently audited value of the relevant financial metric for Berexco.

Table 14.3—EPA financial coverage criteria.

Financial Indicator	Berexco	Description	Requirement at 40 CFR §146.85(a)(6)(v)
Net working capital (NWC)	> $10m	Short-term financial health (Current assets minus current liabilities)	NWC must be at least six times the sum of the current cost estimates for all required GS activities.
Total assets	> $10m	Combined value of economic resources and all items of monetary value owned by a firm	Assets in the United States must either a) amount to at least 90 percent of total assets or b) amount to at least six times the sum of the current cost estimates for all required GS activities.
Tangible net worth (TNW)	> $9m	The value of a company that is liquefiable, i.e., total assets (not including intangible assets) minus liabilities	Although the rule doesn't require a minimum TNW amount for GS projects, based on recent evaluation, the EPA recommends a TNW of at least $100 million and at least six times the sum of the current cost estimates for all required GS activities.

Berexco's net working capital of $10 million is approximately 200 times Berexco's estimated cost of $50,000 for geologic storage activities that require demonstration of financial responsibility. This surpasses the EPA minimum threshold for net working capital specified in Table 14.3. Berexco's total assets of greater than $10 million also satisfy the EPA criteria of being greater than six times the cost of injection and storage activities. The final Class VI rule allows for the UIC program director to specify the minimum TNW value for the operator, and we look forward to the director's determination of this metric for the Wellington project, keeping in mind that the bulk of the financial expenditures is to be borne by the DOE.

In addition to financial coverage criteria listed in Table 14.3, the financial ratio tests documented in Table 14.4 must be satisfied. Table 14.4 presents Berexco's financial ratios and shows that the company's financial metrics exceed EPA thresholds.

Table 14.4—EPA financial ratio test for purposes of self-insurance.

Type of Ratio	Financial Ratios	Threshold	Berexco Ratio
Debt-Equity	Total Liabilities/Net Worth	< 2.0	✓
Assets-Liabilities	Current Assets/Current Liabilities	> 1.5	✓
Cash Return on Liabilities	(Net Income + Depreciation + Depletion + Amortization)/ Total Liabilities	> 0.10	✓
Liquidity	(Current Assets - Current Liabilities)/Total Assets	> -0.10	✓
Net profit	Net Profit	> 0	✓

Attached in Exhibit 14.1 is a letter from Berexco's CFO, Donna Stucky, attesting to the veracity of the company's financial metrics presented in Tables 14.2 to 14.4 to meet the EPA's financial tests for self-insurance.

Exhibit 14.1—Letter from Berexco CFO attesting to the veracity of the company's financial metrics.

May 15, 2014

Kurt Hildebrandt
Drinking Water Management Branch
US-EPA Region 7
901 North 5th Street
Kansas City, KS 66101

Subject Berexco's use of financial test to demonstrate Financial Responsibility for CO_2 sequestration at Wellington, Kansas

Dear Kurt,

I am the chief financial officer of Berexco LLC. This letter is in support of Berexco's use of the financial test to demonstrate financial strength to successfully carry out sequestration, monitoring, abandonment, and emergency remedial activities. I hereby attest to the following:

1. Berexco is the owner or operator of the following injection well for which financial assurance for injection well plugging, post injection site care and site closure, and emergency remedial response is demonstrated through the financial test. The current cost estimate for injection well plugging, post injection site care and site closure, and emergency remedial response is provided below:

Injection Well Name: KGS 1-28

Address: Latitude 37.319485, Longitude -97.4334588

Township 31S, Range 1W, Section 28 NE SW SE SW

Berexco's share of the cost of injection well plugging, post injection site care and site closure, and emergency remedial response is estimated to be $50,000:

2. Berexco guarantees, through the corporate guarantee, the corrective action, injection well plugging, post injection site care and site closure, and/or emergency and remedial response of no Class VI injection wells owned or operated by any subsidiaries of this firm.

3. In states where EPA is not administering the financial requirements, Berexco, as owner or operator or guarantor, is demonstrating financial assurance for no Class VI injection wells through the use of a test equivalent or substantially equivalent to the financial test.

4. Berexco is the owner or operator of no Class VI injection wells for which financial assurance for corrective action, injection well plugging, post injection site care and site closure, and/or emergency and remedial response is not demonstrated either to EPA or a state through the financial test or any other financial assurance instrument.

Berexco is not required to file a Form 10K with the Securities and Exchange Commission (SEC) for the latest fiscal year.

The fiscal year of Berexco ends on December 31st. The figures for the following items marked with an asterisk are derived from this firm's independently audited, year-end financial statements for the latest completed fiscal year, ended December 31st 2011.

Financial Coverage Criteria		
1. (a) Berexco's share of the cost in current dollars for injection well plugging, post injection site care and site closure, and emergency and remedial response	$ 50,000	
(b) Sum of the company's financial responsibilities currently met using the financial test or corporate guarantee, including CERCLA and RCRA	$ 0	
(c) Total of lines a and b	$ 50,000	
2. Tangible net worth	> $ 10 M	
3. Current assets	> $ 10 M	
4. Current liabilities	< $ 1 M	
5. Net working capital (line 3 minus line 4)	> $ 9 M	
6. Total assets	> $ 10 M	
7. Total assets in U.S.	> $ 10 M	
	Yes	No
8. Is line 2 at least $100 million?		x
9. Is line 2 at least 6 times line 1(c)?	x	
10. Is line 5 at least 6 times line(c)?	x	
11. Is line 7 at least 90% of Line 6? If not, complete line 12.	x	
12. Is line 7 at least 6 times line 1(c)?	x	

Financial Ratio Test		
1. Total liabilities	< $ 1 M	
2. Net worth	>$ 10 M	
3. Current assets	>$ 10 M	
4. Current liabilities	<$ 1 M	
5. Net working capital (line 3 minus line 4)	>$ 9 M	
6. The sum of net income plus depreciation, depletion, and amortization	>$ 1 M	
7. Total assets	>$ 10 M	
	Yes	No
8. Is line 1 divided by line 2 less than 2.0?	X	
9. Is line 3 divided by line 4 greater than 1.5?	X	
10. Is line 6 divided by line 1 greater than 0.1?	X	
11. Is line 5 divided by line 7 greater than -0.1?	X	
12. Is net profit greater than 0?	X	

I hereby certify to the veracity of the financial information provided above as of the date shown immediately below.

Signature: Donna M. Stucky, CPA

Name: Donna M. Stucky, CPA

Title: Chief Financial Officer

Date: May 15, 2014

14.4 Future Financial Obligations

A requirement of 40 CFR §146.85(c) for self-insurance is that financial information and estimated costs must be updated and submitted annually for the UIC program director's review to ensure continued adequacy of financial demonstration due to inflation, relative price changes, or changes in technology. Updated cost estimates are also due after any amendments to the Area of Review and Corrective Action Plan, the Injection Well Plugging Plan, the Post-Injection Site Care and Site Closure Plan, or the Emergency and Remedial Response Plan. Table 14.5 presents the conditions under which cost updates and financial responsibility documents will be revised and submitted to the Region 7 UIC program director.

Table 14.5—Future financial cost and financial requirements submission plans.

Timeframe/Condition	Berexco/KGS Submission Plans
Annually	Submit updated financial responsibility demonstration
Annually	Submit an updated detailed written estimate of the cost of performing corrective action on wells in the AoR, plugging the injection well, post-injection site care and site closure, and emergency and remedial response. Adjust cost estimate for inflation
Within 60 days of any amendments to required project plans	Submit written updates of adjustments to cost estimate
During the active life of the project, and 60 days after director has approved a request to modify required project plans	If change in plans increases cost, revise cost estimate, which will be adjusted for inflation as specified at 40 CFR §146.85(c)(1)
Within 60 days after the current cost estimate increases to an amount greater than the face amount of self-insurance	Increase face amount of coverage up to an amount at least equal to the current cost estimate and submit evidence of such increase to the UIC program director, or obtain other financial responsibility instruments to cover the increase
In the event of adverse financial conditions such as bankruptcy; within 10 days of commencement of Title 11 filing	Notify director by certified mail that adverse financial conditions may affect ability to carry out injection well plugging and post-injection site care and site closure
Within 60 days of director notification that original demonstration is no longer adequate for required project phases	The owner or operator must provide adjustment of the cost estimate to the UIC program director

14.5 Adverse Conditions

Berexco will notify the EPA director by certified mail of any adverse financial conditions such as bankruptcy that may affect the ability to carry out any of the proposed post-injection site care, injection well plugging, and site closure activities listed in Table 14.2.

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Appendices

Appendix List of Figures and Tables

Appendix A

A-1 Entry Pressure Analyses to demonstrate caprock integrity

Entry pressure in the Chattanooga shale was calculated in well 1-32 and 1-28 using the Techlog wellbore software platform by Schlumberger. Techlog first converts pore size (T2 distribution) to estimate the pore throat radius (as a function capillary pressure) using a proportionally constant Kappa (K) according to the following relationship proposed by Volokin and others (2001):

$$\frac{c}{T_2^{-1}} \quad \frac{\sigma \cos\theta R_{pore}}{\rho r_{neck}}$$

Where,

K=Kappa

ρ=NMR surface relaxivity

σ Interfacial tension

θ Contact angle

r_{neck}= pore throat radius

R_{pore} pore body radius

Based on calibration at the Spivey-Grab field (Watney et al., 2001) and the Wellington West field (Bhattacharya et al., 2003), a Kappa value of 9 and 15 was used in the confining zone. Capillary pressure and pore throat radius relationship is expressed by the following relationship for mercury-air phase:

$$c \quad \frac{2\sigma cos\theta}{r_{neck}}$$

Where,

$_c$ = Capillary pressure,

σ = Interfacial tension of Mercury-air,

r_{neck} = pore radius.

The mercury entry pressure for the Simpson shale varies between 7 to 2,260 psi at KGS 1-32 and between 7 to 9,245 psi at KGS 1-28. The following equation was used to convert entry pressure from mercury-air system to CO_2-brine system:

$$Pe_{CO_2/brine} = P_{eHg/air} \frac{\gamma_{CO2}/_{brine} . COS\theta_{CO2/brine}}{\gamma Hg/air . COS\theta_{Hg/air}}$$

where,

$Pe_{CO_2/brine}$ is entry pressure in the $CO_2/brine$ system,

$_{eHg/air}$ is entry pressure in mercury-air system,

$\gamma_{CO2}/_{brine}$ and $\gamma\ Hg/air$ are interfacial tension of CO_2-brine brine and Hg-air systems respectively,

$COS\theta_{CO2/brine}$ and $COS\theta_{Hg/air}$ are contact angles of reservoir CO_2/brine/solid and Hg/air/solid systems.

Interfacial tension of 30 dyne/cm and 485 dyne/cm were used for CO_2-brine and Mercury air systems respectively (Chalbaud et al. 2006). Also, contact angle of 0^o and 140^o were used for CO_2-brine and Mercury-air systems.

Using the above relationship, the maximum entry pressure of approximately 2260 psi (at KGS 1-32) for the mercury-air system is equivalent to 182 psi in the CO_2-brine system. Similarly, the maximum value of approximately 9,245 psi for the mercury-air system at KGS 1-28 is equivalent to 746 psi in the CO_2-brine system. Entry pressure is higher at KGS 1-28 due to the presence of smaller pores at this site as compared to KGS 1-32.

The Chattanooga Shale is expected to provide much more confinement than the Simpson Group underneath it. The maximum entry pressure in the Chattanooga Shale at KGS 1-28 is 11,840 psi in the mercury-air system and 956 psi in the CO_2-brine system. As discussed in the modeling section (Section 5), the maximum induced CO_2 pressure at the top of the Arbuckle/base of the Simpson Shale is approximately 13 psi. Therefore, the primary confining zone is expected to confine the injected CO_2 in the Arbuckle aquifer.

Appendix B

Geophysical logs and Well Completion Information - KGS 1-28

The following files attached as electronic documents

- Well Completion Report
- Cement Bond Log
- XRMI Log
- ACT Resistivity Log
- AHV Casing Log
- CSN Gamma Log
- Micro Log
- MRI Log
- Spectral Density Neutron Log
- Temperature Log
- Wave Sonic Log
- Mud Log
- Fracture Studies
- Daily Log of Well Construction
- Drilling and Well Completion Report

Appendix C

Geophysical logs and Well Completion Information - KGS 1-32

The following files attached as electronic documents

- Well Completion Report
- Cement Bond Log
- XRMI Log
- ACT Resistivity Log
- AHV Casing Log
- CSN Gamma Log
- Micro Log
- MRI Log
- Spectral Density Neutron Log
- Temperature Log
- Wave Sonic Log
- Mud Log
- Fracture Statistics
- Drilling and Completion Report

Appendix D

Well Testing Data

- Drill Stem Tests at KGS 1-28 and KGS 1-32 (attached as electronic document)

- Estimation of Arbuckle permeability at Cutter #1 (attached as electronic document)

Appendix E

Geochemical Evidence for Stratification of Arbuckle Aquifer System and Presence of Competent Upper Confining Zone

E.1 Geochemistry Based Evidence of Competent Upper Confining Zone

E.1.1 Ion Composition

Due to their conservative nature, bromine and chlorine are especially useful in differentiating salinity sources and establishing the basis of brine mixture in the subsurface (Whittemore, 1995). Bromine, chlorine, and sulfate concentrations of brine from nine depths in the Arbuckle and three depths in the Mississippian formations were evaluated. The Br^-/Cl^- and SO_4^{2-}/Cl^- weight ratios versus chloride concentration for the Arbuckle saline aquifer and Mississippian reservoir at Wellington are presented in Figure E.1 from which it is clear that the geochemical composition of the Mississippian waters is markedly different than that of the Arbuckle. The salinity within the Mississippian varies between approximately 120,000 mg/l and 135,000 mg/l versus approximately 30,500 mg/l in the underlying upper Arbuckle. Similarly, the SO_4^{2-}/Cl^- ratio of approximately 0.002 in the Mississippian formation is significantly different than the range of this ratio of 0.002-0.0055 in the upper Arbuckle. Collectively, the chloride and SO_4^{2-}/Cl^- data suggest a hydraulic separation between the Mississippian and the Arbuckle systems, which supports the conceptualization of a tight upper confining zone.

E.1.2 Isotopic Characterization

Oxygen and hydrogen isotope distributions present another opportunity to assess hydraulic connectivity between the Arbuckle Group and the Mississippian System. Figure E.2 shows the δD vs $\delta^{18}O$, reported as the difference between the $^{18}O/^{16}O$ and $^{2}H/^{1}H$ abundance ratios of the samples vs. the Vienna Standard Mean Ocean Water (VSMOW) in per mil notation ($^{o}/_{oo}$) for the Arbuckle and Mississippian samples. Best fit regression lines for each formation, compared with the global meteoric water line (GMWL) and modern seawater is also presented which suggests different water isotopic composition in the Arbuckle and Mississippian systems

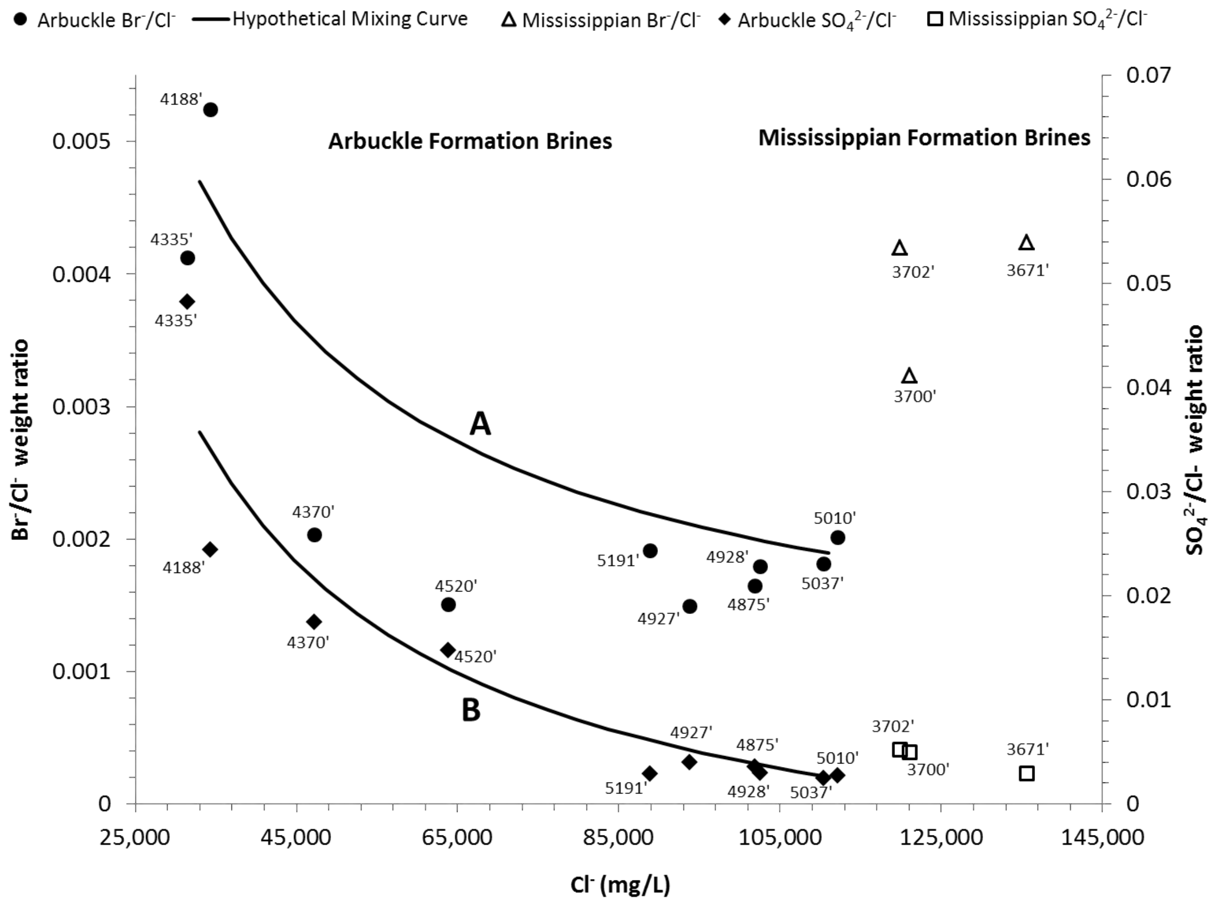


Figure E.1 Br^-/Cl^- and SO_4^{2-}/Cl^- weight ratios versus chloride concentration for the Arbuckle saline aquifer and Mississippian oil producing brines at Wellington, Kansas. Also shown are the hypothetical mixing curves for Br^-/Cl^- (A) and SO_4^{2-}/Cl^- (B). Source: Scheffer, 2012.

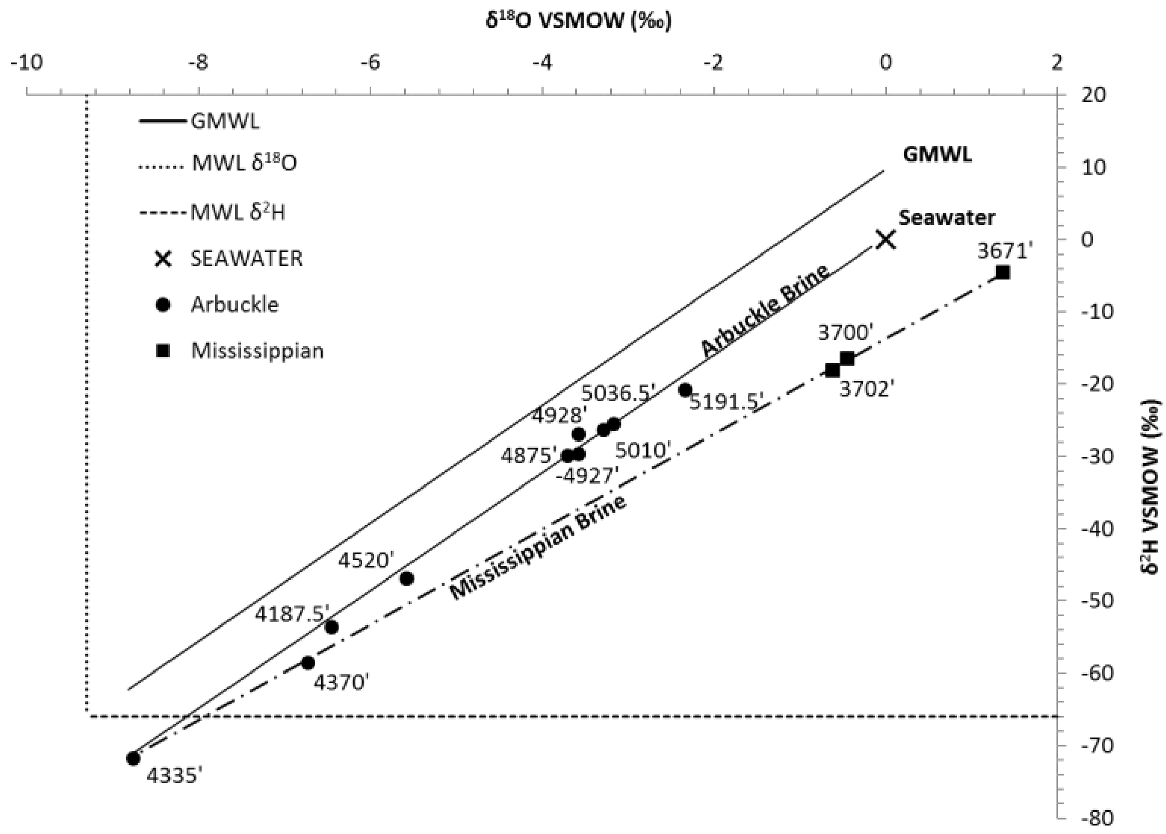


Figure E.2 δD vs $\delta^{18}O$ ($^{o}/_{oo}$, VSMOW) for the Arbuckle and Mississippian reservoirs (from Scheffer, 2012).

E.1.3 Chloride Distribution

The chloride distribution in Arbuckle and Mississippian systems at KGS 1-28 and KGS 1-32, obtained from data collected during Drill Stem Testing (DST) and swabbing, is presented in Figure E.3. The chloride gradient in the Arbuckle approximates a linear trend with chloride concentration increasing from approximately 30,500 mg/l in the Upper Arbuckle to as much as 118,000 mg/l in the injection zone. Chloride concentration in the Mississippian formation at 119,000 mg/l is substantially higher than in the upper Arbuckle. The large difference in chloride concentrations between the Mississippian and upper Arbuckle supports the conceptualization that the confining zone separating the Arbuckle aquifer from the Mississippian reservoir is tight, and that there are no conductive faults in the vicinity of the Wellington site that hydraulic link the two systems.

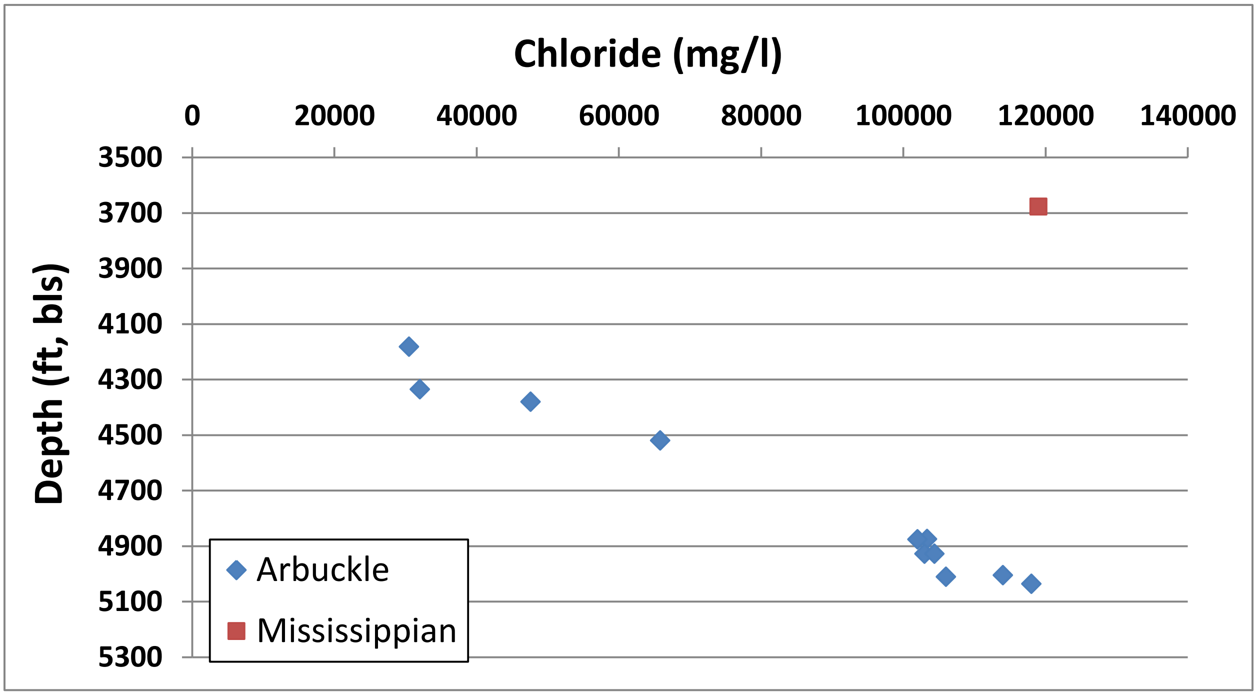


Figure E.3 Chloride distribution within the Arbuckle aquifer and Mississippian reservoir at KGS 1-28 and KGS 1-32.

E.2 Geochemical Evidence for Stratification of Arbuckle Group

E.2.1 Molar Ratios

Figure E.4 shows Ca/Sr molar ratios plotted against Ca/Mg molar ratios of Arbuckle data with trends for dolomitization and calcite recrystallization as described in McIntosh (2004). This plot clearly shows two groupings within the Arbuckle samples. The upper Arbuckle shows a calcite recrystallization signature while the lower Arbuckle shows the influence of dolomitization on brine chemistry. This presents evidence that the upper and lower Arbuckle have different hydrochemical regimes (Barker et al., 2012).

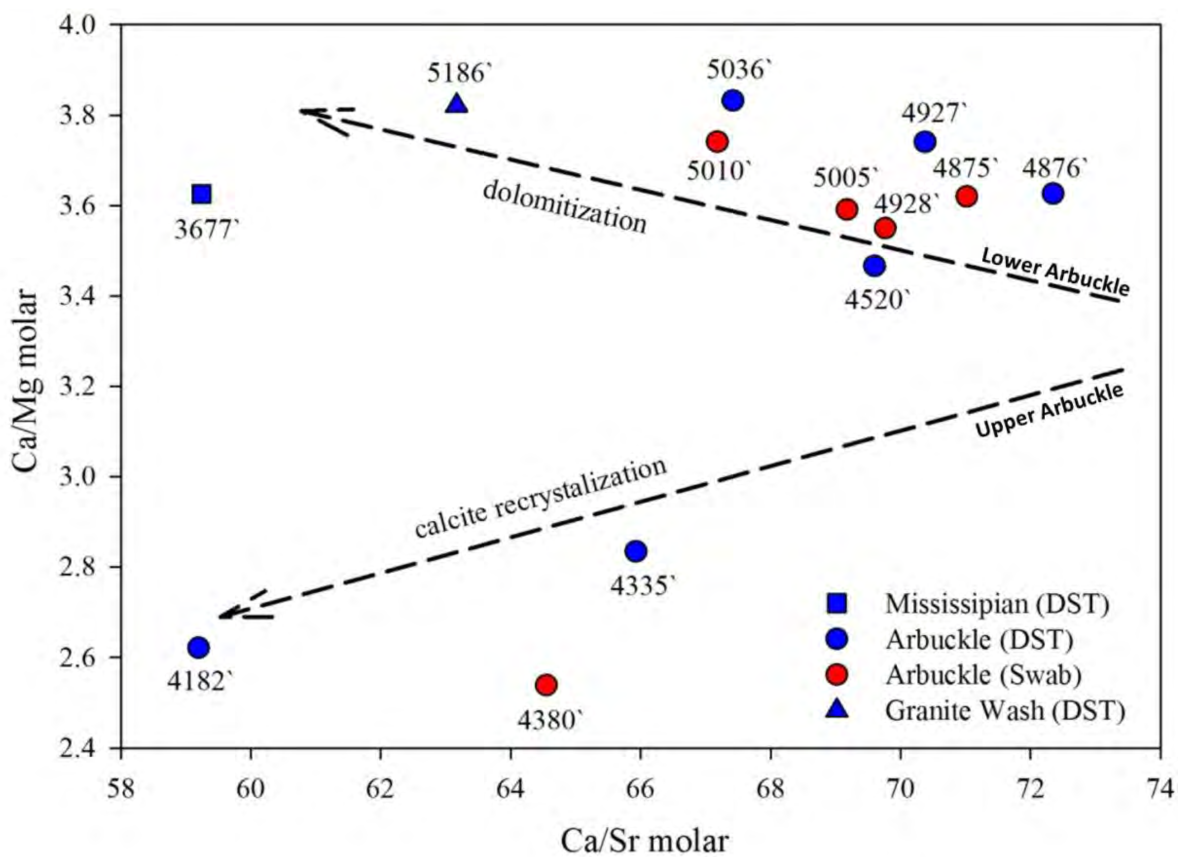


Figure E.4 Ca/Sr vs Ca/Mg molar ratios showing trends of dolomitization and calcite recrystallization (from Barker et al., 2012).

E.2.2 Ion Composition

Figure E.1 shows Ca/Sr molar ratios plotted against Ca/Mg molar ratios of Arbuckle data with trends for dolomitization and calcite recrystallization as described in McIntosh (2004). This plot clearly shows two groupings within the Arbuckle samples. The upper Arbuckle shows a calcite recrystallization signature while the lower Arbuckle shows the influence of dolomitization on brine chemistry. The data therefore suggests that the upper and lower Arbuckle have different hydrochemical regimes (Barker et al., 2012).

The Br^-/Cl^- ratio provides further evidence of the separation of the upper and lower high permeability zones in the Arbuckle. As can be inferred from Figure E.1, the Br^-/Cl^- values of the lower Arbuckle varies over a narrow range in the neighborhood of 0.002, while the variation is much larger (between 0.002 and 0.0055) in the upper Arbuckle. A hypothetical Br-/Cl- mixing curve (Curve A, Figure E.1) was calculated using averaged end-member values from the two deepest samples in the Arbuckle (5010 ft and 5036 ft) and the two shallowest samples in the Arbuckle (4182 ft and 4335 ft) to examine mixing of reservoir fluids for purposes of evaluating connectivity throughout the reservoir. In the lower Arbuckle samples, Br^-/Cl^- concentrations remained relatively consistent, but increased sharply in the upper Arbuckle. This suggests possible different brine origins for the lower and upper regions of the Arbuckle. Regardless of the origin, the data suggests that the brines in the upper and lower Arbuckle are distinctly different and there does not appear to be any mixing between the two zones; supporting the hypothesis of the presence of low permeability baffle zone between the upper Arbuckle and the lower injection interval which was also inferred from the permeability data.

The SO_4^{2-}/Cl^- ratio also supports the suggestion of weak hydraulic connection of the upper and lower intervals of the Arbuckle. The SO_4^{2-}/Cl^- values of the lower Arbuckle show a similar trend as the Br^-/Cl^- in that it spans a very narrow interval in the lower Arbuckle, but varies over a larger range in the upper Arbuckle. A hypothetical SO_4^2/Cl- mixing curve (Curve B, Figure E.1) was calculated using end-member values to examine mixing of reservoir fluids and evaluate connectivity throughout the reservoir. As with the bromine data, a substantially different ratio and a poor fit in the upper Arbuckle provides additional support to the hypothesis that the upper and lower Arbuckle zones are not in hydraulic communication (Scheffer, 2012).

E.2.3 Isotopic Characterization

Oxygen and hydrogen isotope distributions also point to absence of a strong hydraulic connection between the upper and lower parts of the Arbuckle Group. This can be inferred from Figure E.2, which shows δD vs $\delta^{18}O$, reported as the difference between the $^{18}O/^{16}O$ and $^{2}H/^{1}H$ abundance ratios. The brines from the lower Arbuckle (4875-5036 ft) cluster tightly together and have values distinct from those of the upper Arbuckle (4186-4521 ft). The similarity of the brine from the lower Arbuckle strongly suggests active communication within the lower Arbuckle. In contrast, brines of the upper Arbuckle (4182 and 4335 ft) show more variability suggesting a less vigorous flow system. The upper Arbuckle brines also have distinctly different δD and $\delta^{18}O$ values the lower Arbuckle. This suggests that the lower Arbuckle may not be hydraulically well connected to the upper Arbuckle.

E.2.4 Biogeochemistry

The concentration of the redox reactive ions ferrous iron, sulfate, nitrate, and methane (Fe^{2+}, SO_4^{2-}, NO_3^-, CH_4) can be used as evidence of biological activity in the subsurface (Scheffer, 2012). In oxygen restricted sediments that are rich in organic carbon such as the Arbuckle, stratification would follow the redox ladder with aerobes at shallower depths where oxygen is available, followed by nitrate, iron, and sulfate reducers (in this order), and methanogens at the deepest level based on availability of terminal electron acceptors. Because there is a paucity of oxygen in the Arbuckle, typical stratification of microbial metabolisms would involve dissimilar iron reducing bacteria (DIRB) above sulfate reducing bacteria (SRB) above methanogens. This biogenic stratification would be manifested by a zone with increased reduced iron over decreasing sulfate (or increasing sulfide) over increasing methane. However, as shown in Figure E.5 there appears to be two separate trends observed in the Arbuckle aquifer; one trend 4.40, for samples above the suspected baffle (1277 m; 4190 ft to 1321 m; 4334 ft) in the upper Arbuckle, and one trend below the suspected baffle (1378 m; 4521 ft to 1582 m; 5190 ft) in the lower Arbuckle. This suggests a reset of the biogeochemistry due to lack of hydraulic communication between the Upper and Lower Arbuckle.

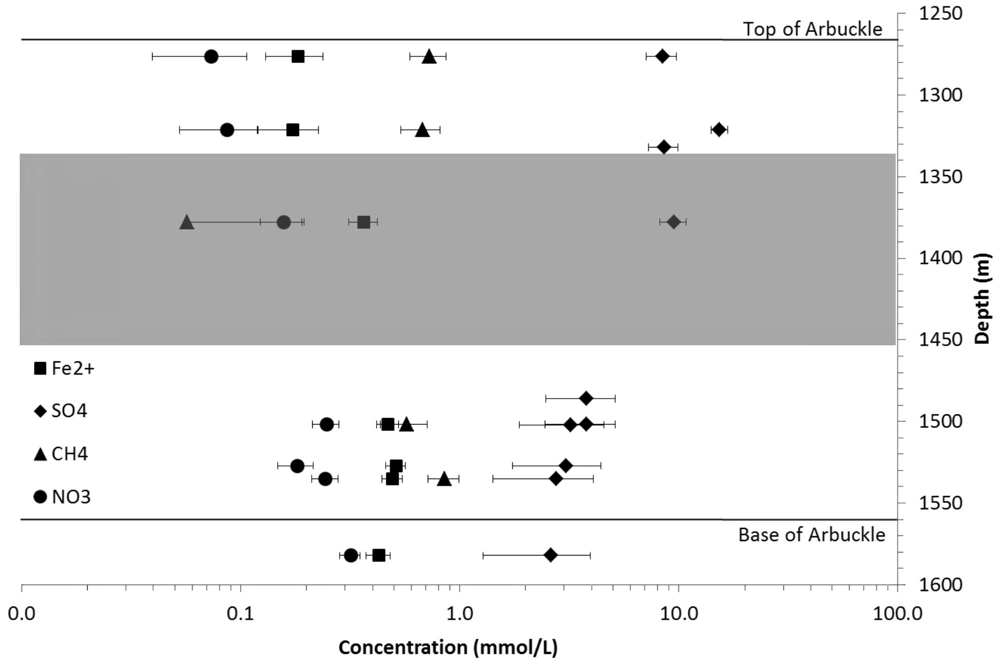


Figure E.5 Concentrations of redox reactive ions; ferrous iron, sulfate, methane, and nitrate (Fe2+, SO42-, CH4, NO3-) in the Arbuckle reservoir (from Scheffer, 2012).

E.2.4 Microbial Diversity

Biomass concentrations of 2.1 x10^6 , 1.9 x 10^7 and 2.6 x 10^{-3} cells/ ml were determined using the quantitative polymerase chain reaction (qPCR) procedures at depths of 1277m (4190ft), 1321m (4334ft), and 1378m (4520ft) respectively (Figure E.6). The lowest biomass coincides with the low permeability baffle zone in the mid Arbuckle (1378 m; 4520 ft). Decreased flow through the baffle zone could decrease nutrient recharge and lead to nutrient depletion (Scheffer, 2012). The highest biomass and most unique sequences occurred in the upper Arbuckle at 1321 m (4334 ft) as shown in Figure E.6.

The free-living microbial community was also examined in the Arbuckle aquifer. Results show 43% diversity at a depth of 1277 m (4190 ft), 62% diversity at 1321 m (4334 ft), and 39% diversity at 1378 m (4520 ft), which follows the same trend as biomass shown in Figure E.6b. Notably, the microbial communities from 1277 m (4190 ft) and 1321 m (4334 ft) are very similar to one another and vary distinctly from the community detected at 1378 m (4520 ft). Nine genera of bacteria were detected at 1277 m (4190 ft) and 1321 m (4334 ft). Seven genera of bacteria were detected at 1378 m (4520 ft). *Alkalibacter, Bacillus and Erysipelthrix* were found at the two shallower depths but not at 1378 m (4520 ft). *Dethiobacter* was detected only at the deeper depth of 1378 m (4520 ft).

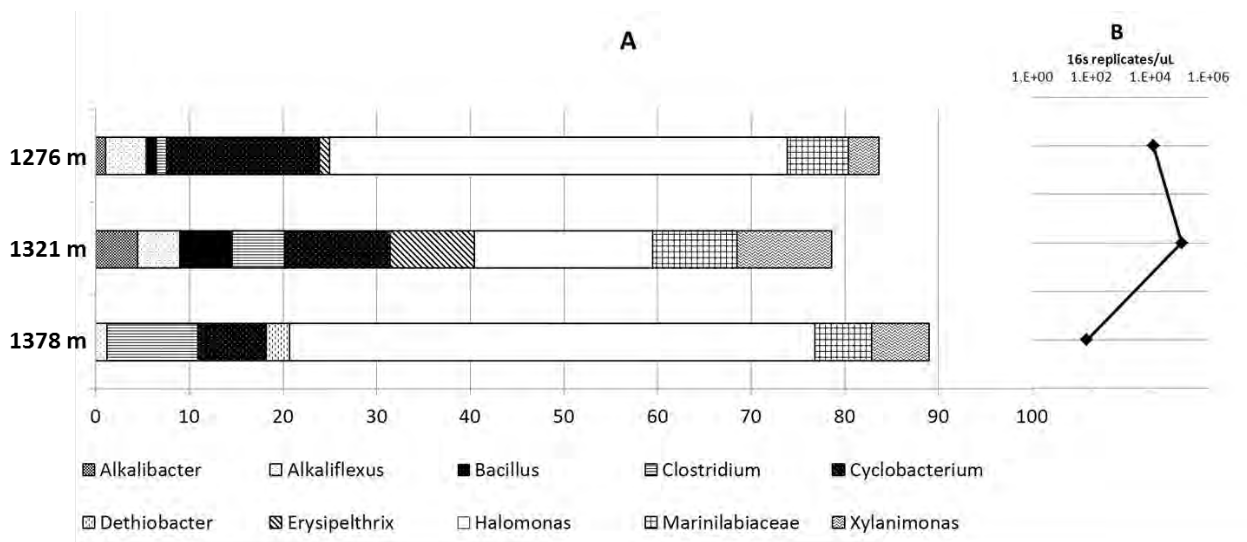


Figure E.6 Arbuckle aquifer microbial profile showing the distribution of bacteria in the Arbuckle (A), and the DNA concentration (B) (from Scheffer, 2012).

Appendix F

X-Ray Diffraction and Spectral Gamma Ray Analyses for Mineralogical Characterization of Confining Zone

The Pierson Formation in the upper parts of the confining zone was shown in Section 4.7.3 to possess extremely low permeability in the nano-Darcy range (nD; 1.0^{-09} Darcy). The results of the X-Ray and photoelectric analyses presented in this appendix suggest that the low permeabilities in the Pierson is due to the abundance of tightly packed quartz content in the dolomitic rock. This conclusion is in agreement with core based observations discussed in Section 4.7.2. The X-Ray Diffraction and Spectral Gamma Ray analyses are presented in section F.1 and F.2 respectively.

F.1 X-Ray Diffraction Analyses

Soil minerals have crystallographic characteristics that strongly influence its physical/chemical properties, and by extension the hydraulic sealing potential of caprock. X-Ray Diffraction (XRD) is the technique most heavily relied in soil analysis for identification of minerals in rocks and soils. The bulk of the clay fraction of many soils is crystalline, but clay particles are too small for optical crystallographic methods to be applied. Therefore, XRD is becoming increasingly popular for identification of clay-sized minerals in soils. X-ray diffraction occurs when X-rays are scattered by atoms arranged in an orderly array in crystals. The atoms serve as scattering centers, reemitting X-rays at the same wavelength as the incident radiation in all directions (coherent scattering). The orderly arrangement of atoms results in the scattered X-rays within the crystal being (i) in phase in specific directions dictated by symmetry and atomic spacings and (ii) out of phase in all other directions (Figure F.1). The X-rays that are in phase constructively interfere and emerge as intense beams (diffracted beams) from the crystal, while those that are out of phase destructively interfere and hence have minimal emergence. This systematic combination of constructive and destructive interference arising from the periodicity of atoms in crystals is X-ray diffraction. Detailed information about the mineralogical composition can be gained from XRD (Harris, 2007).

A simple way to intuitively comprehend the relatively complex phenomenon of XRD is to envision regularly spaced planes of atoms in mineral structures (Figure F.2). The distance between a given set of planes is termed d-spacing. The d-spacing, although on a scale of Angstroms, can be determined quite accurately using XRD. The principles underlying this determination are expressed by the Bragg equation:

$$N \lambda = 2d \sin \theta$$

Where, n is an integer, λ is wavelength of the radiation, d is the spacing between crystal planes, and θ is the angle between the planes and the incident X-ray beam. The factor in the Bragg equation of interest to mineralogist is d-spacing, which can be determined in XRD analysis by fixing λ and measuring the θ angle where a peak in X-ray intensity occurs. Mineral identification

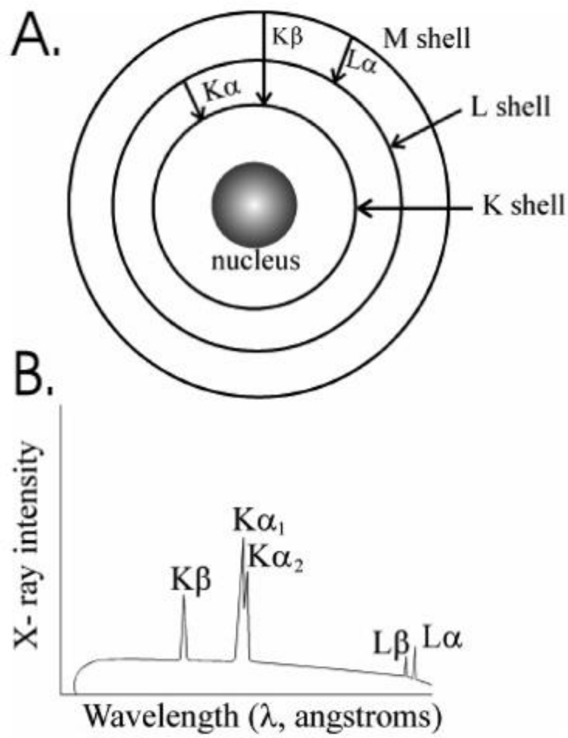


Figure F.1 (A) Schematic of an atom, depicting electron shells and the energy transitions for Kα, Kβ, and Lα characteristic radiation. Kα arises from the replacement of K-shell electrons by electrons from the L shell; Kβ, by replacement of K-shell electrons by M-shell electrons, and Lα, by replacement of L-shell electrons by M-shell electrons. (B) Generalized depiction of an X-ray spectrum, showing peaks in intensity at wave - lengths (energy levels) corresponding to characteristic radiation. The highest-energy (shortest wavelength) characteristic radiation shown is Kβ. Peaks marked Kα and Kα2, which are seldom resolved in XRD data, arise from contribution of electrons from two sublevels in the L shell (from Harris, 2007)

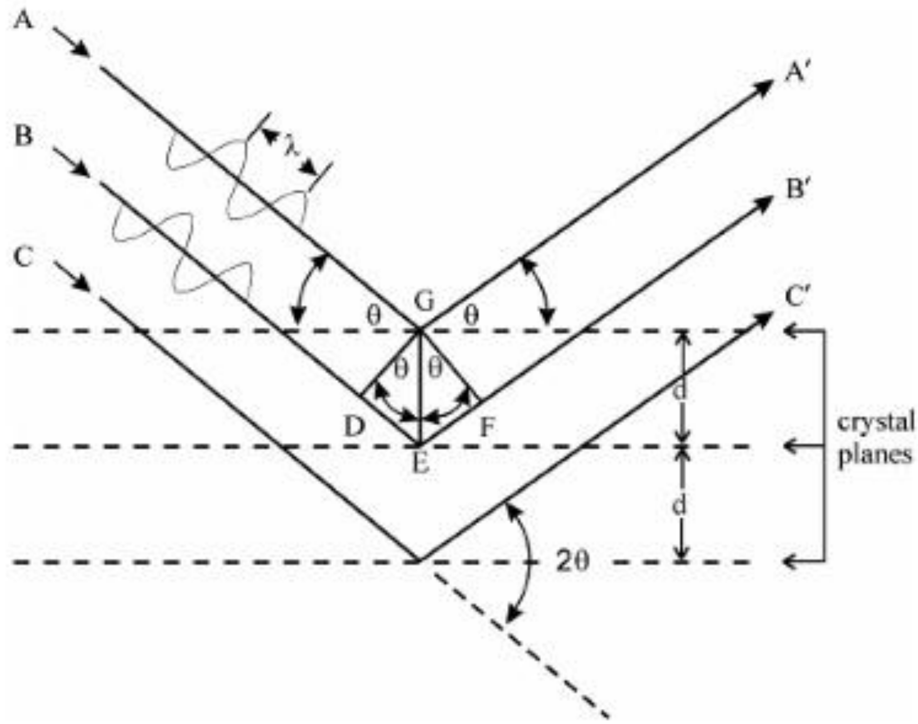


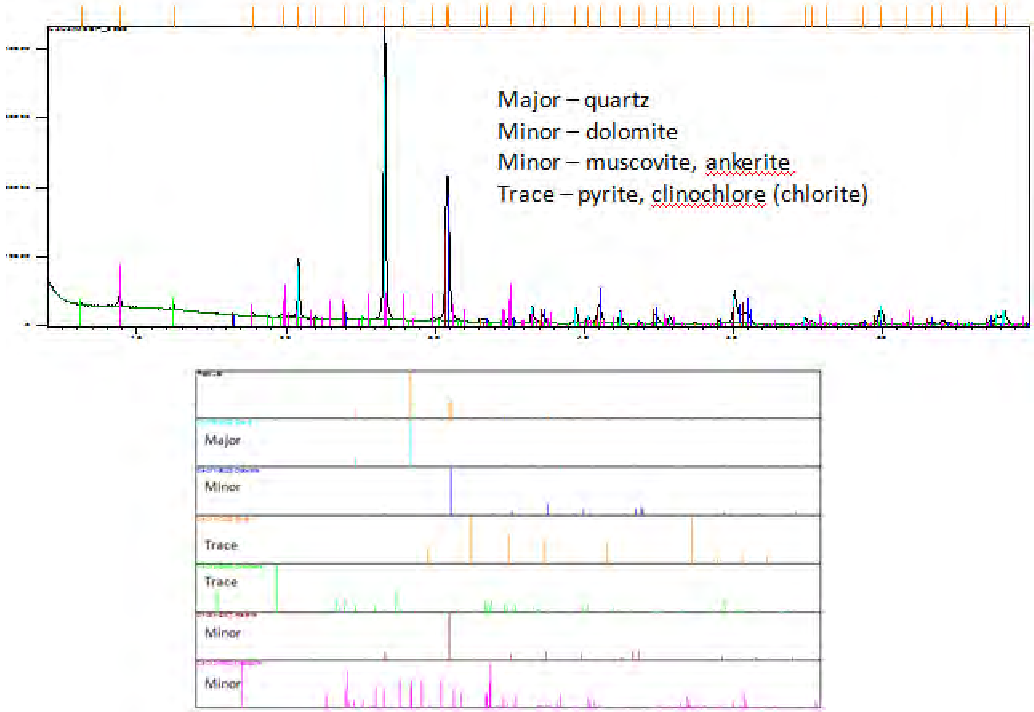
Figure F.2 Schematic representation of XRD by regularly spaced planes of atoms in a crystal. Theta (θ) is the angle that the beam makes with the atomic planes; 2θ is the angle that the diffracted beam deviates from the primary beam; d is the distance between equivalent atomic planes in the crystal (d-spacing); and λ is wave length of the radiation. The Bragg equation can be used to calculate d-spacing from the 2θ angle at which the diffraction peak occurs (from Harris, 2007).

is therefore based on d-spacings and relative peak intensities. The d-spacing for minerals that commonly occur in soils is presented in Table F.1.

Mineral groups	Minerals	Major d-spacings
		Å
Amphiboles	hornblende	8.52, 3.16, 2.73
	riebeckite	8.40, 3.12, 2.73
	tremolite	8.38, 3.12, 2.71
Carbonates	aragonite	3.40, 1.98, 3.27
	calcite	3.03, 1.87, 3.85
	dolomite	2.88, 2.19, 1.80
Chlorites	chamosite	7.05, 3.53, 2.52, 14.1
	clinochlore	3.54, 7.07, 4.72, 14.1
Expansible phyllosilicates	montmorillonite	18.0, 9.0, 4.49
	vermiculite	14.4, 7.18, 4.79, 3.60
Feldspars	albite	3.19, 4.03, 3.21
	anorthite	3.20, 3.18, 4.04
	microcline	3.24, 3.29, 4.22
	orthoclase	3.31, 3.77, 4.22
Kaolins	halloysite	10.7–10.0 (hydrated), 7.6, 4.4, 3.4
	kaolinite	7.17, 3.58,
Micas	biotite	10.1, 3.37, 2.06
	muscovite	10.1, 3.36, 5.04
Oxides, hydroxides	anatase	3.51, 1.89, 2.38
	gibbsite	4.85, 4.37, 2.39
	goethite	4.18, 2.45, 2.70
	hematite	2.69, 2.59, 1.69
	ilmenite	2.74, 2.52, 1.72
	quartz	3.34, 4.26, 1.82
	rutile	3.26, 1.69, 2.49
Phosphates	fluorapatite	2.80, 2.70, 2.77
	strengite	4.38, 5.50, 3.11
	variscite	4.29, 5.39, 4.83
	wavellite	8.67, 8.42, 3.22
Pyroxenes	augite	2.99, 3.23, 2.95
	enstatite	3.18, 2.88, 2.54
Serpentines	antigorite	7.29, 2.53, 3.61
	chrysotile	7.31, 3.65, 4.57
Sulfates	epsomite	4.21, 5.35, 2.68
	gypsum	7.56, 3.06, 4.27
	jarosite	3.08, 3.11, 5.09
Sulfides	marcasite	2.69, 3.43, 1.75
	pyrite	1.63, 2.71, 2.43
Zeolites and related minerals	analcime	3.43, 5.60, 2.93
	clinoptilolite	3.97, 8.99, 3.91
	heulandite	3.92, 2.96, 8.85
	palygorskite	10.4, 4.47, 4.26
	sepiolite	12.1, 2.56, 4.31

Table F.1. Major d-spacings for some minerals that occur in soils, listed for each mineral in the commonly observed order of decreasing XRD peak intensity.

The x-ray diffraction count and phase angle for two lower Pierson samples (3998 and 4001 ft; sub-KB) is presented in Figure F.3. Interestingly, in the sample at 3998 ft (sub-KB), there was a noticeable doublet on the primary dolomite peak that likely means that there is a significant amount of iron substituted dolomite (ankerite). The dominant clay is chlorite while rock is mainly fine silt-sized quartz with scattered dolomite crystals. Much of the dolomite is poorly ordered containing iron, thus an ankerite XRD peak is also noted. Thin section microscroscopy of the dolomite indicates that it is an early formed diagenetic dolomite of uniform fine euhedral crystals that are often nucleated on organic material that is common to other tight siltstones and shales such as the Mississippian Barnett Shale (an oil producing shale in Texas).



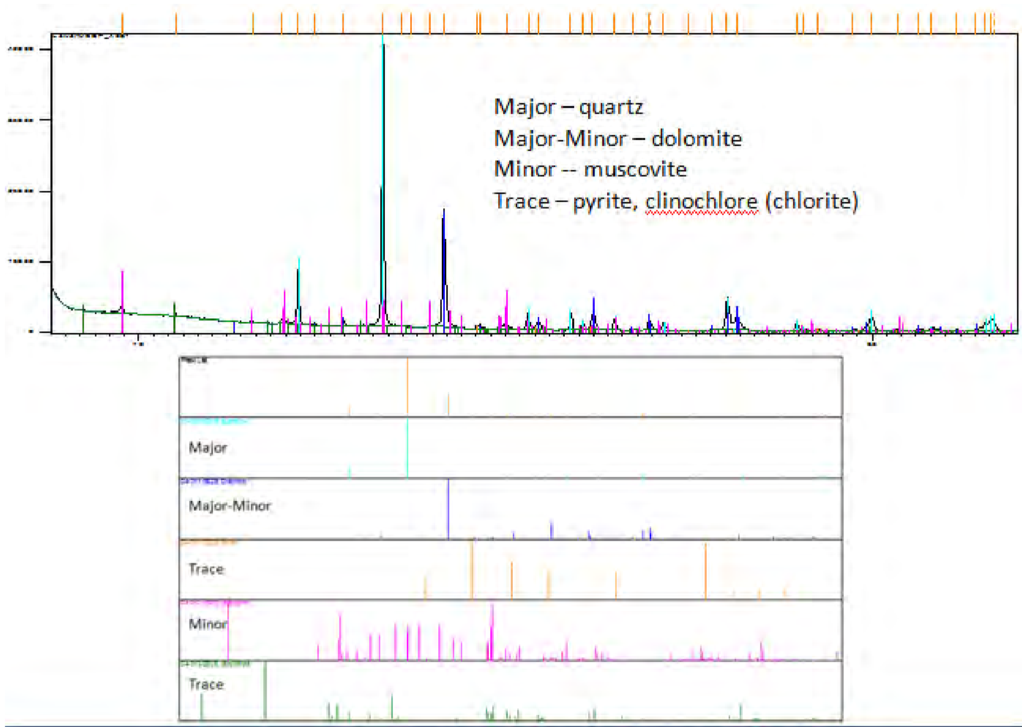


Figure F.3 X-ray Diffraction plots in the Pierson Group at elevation of 3998 ft (top) , and 4001 ft (bottom).

F.2 Spectral Gamma-Ray Analysis

Natural gamma radiation in rocks is almost entirely attributable to the radioactive isotopes of the Potassium (K), Uranium (U) and Thorium (Th) families. A conventional gamma ray log records a pooled summation of counts mainly of these three radioactive sources. A spectral gamma-ray on the other hand isolates the contribution of each of the three isotopes. The various combinations of the isotopes can be useful for diagnostic and soil characterization purposes. For example, the Th/U ratio is often strongly linked with depositional environment, based on their laboratory analysis of many samples of differing lithologies and supports other analyses that have been applied to this site under the general name of “Petrofacies,” the use of core and log analysis to define and quantify the lithologically distinct strata (Doveton; 1991; Doveton et al., 2000; Watney et al., 1999c; Doveton, 1989)

While the spectral gamma ray log analysis generally helpful for soil characterization, the similarity of potassium and thorium levels in some clay minerals and the multi-clay character of most shales often results in ambiguous interpretation. Therefore, combining data from other logs that complement the photoelectric information in spectral logs can be useful for detailed clay mineral identification and facies recognition. In recent years, supplementing conventional neutron and density logs with photoelectric information has substantially improved the log based mineral identification. Specifically, the Rhomaa–Umaa crossplot is being increasingly used for matrix mineral characterization utilizing measurements of the photoelectric index, neutron porosity, and bulk density (Macfarlane and others, 1988). RHOMAA is the hypothetical density of the rock matrix computed as the projection of the rock's bulk density which eliminates the effect of the fluids in the pore space. UMAA is the theoretical volumetric photoelectric absorption index of the matrix, calculated from the photoelectric factor using similar considerations.

The two dimensions of the Rhomaa – Umaa crossplot require the three log variables to be condensed. This is accomplished by first converting the photoelectric index, Pe, to a volumetric measure, U. This is possible because Pe is measured in barns per electron, rather than barns per cc. The conversion is made assuming:

$U = P_e . \rho_b$

Where, the bulk density, ρ_b, and the volumetric photoelectric absorption, U, are the properties of the combined matrix and pore fluid. The elimination of the contribution of the pore fluid to these quantities will yield estimates of the apparent density (RHOmaa) and the volumetric photoelectric absorption (Umaa) of the matrix.

Each mineral in its pure form has a specific Rhomaa-Umma. For the interval 3910 – 4070 ft (sub-KB) within the lower Pierson, the combined Rhomaa-Umaa values fall along the Quartz-Dolomite line (Figure G.1), which is consistent with the observation of the core and X-Ray Diffraction analysis presented above.

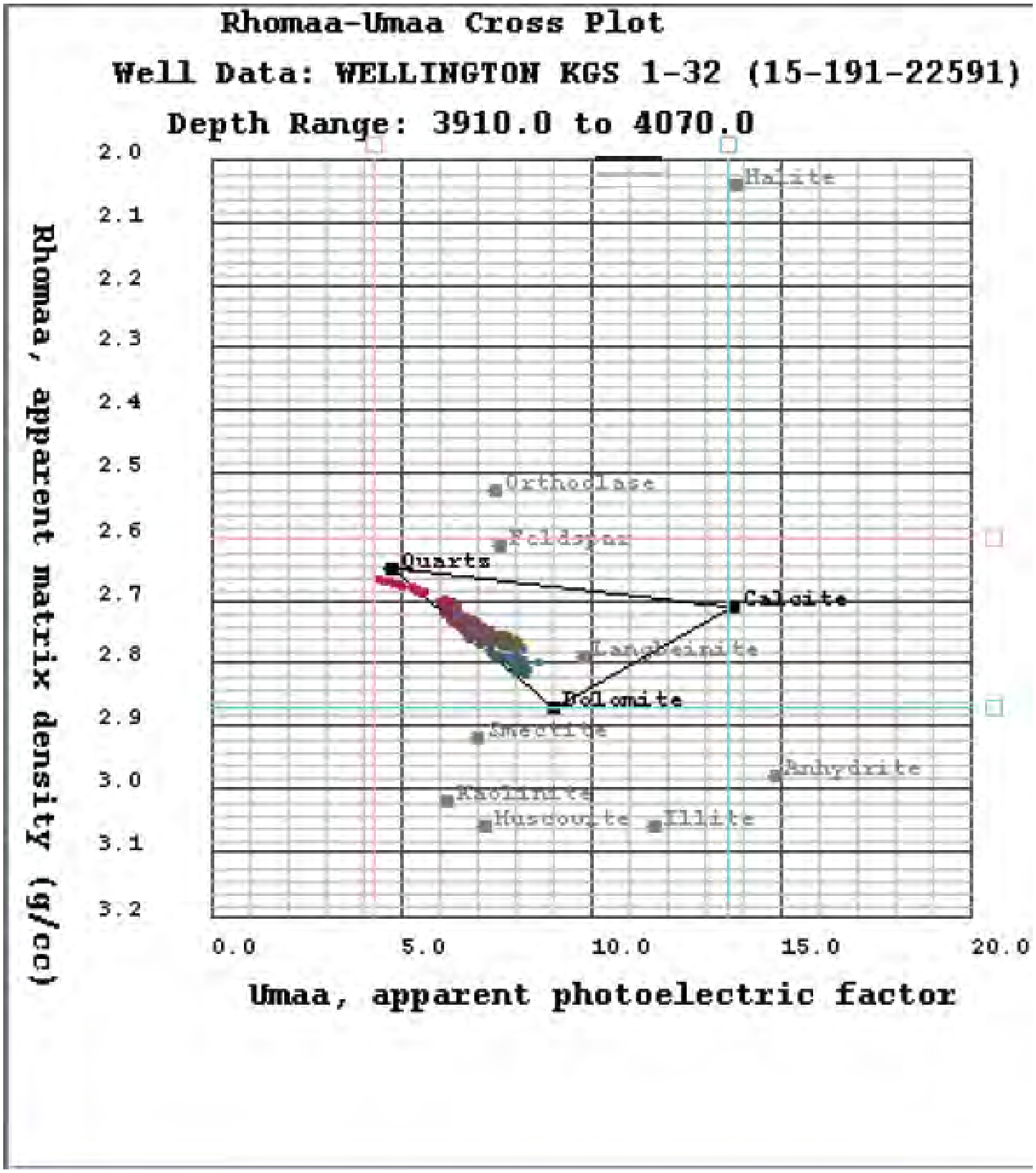


Figure F.4 Rhomaa-Umaa crossplot of sample in the Pierson Formation highlighting the Quartz-Dolomite fabric of the confining strata.

Appendix G

Supplemental Plume and Pressure Front Monitoring

G.1 Introduction and Well Locations

A total of five wells are proposed in the Testing and Monitoring Plan as shown in Figure 10.1 and discussed in Section 10. These five wells meet EPA Class VI requirement for tracking the plume and the pressure front. In the event that additional funds are available for the Wellington project, then the scope of monitoring may be potentially be expanded to test new monitoring technologies and provide additional data for tracking the plume and pressure fronts. It should be emphasized however, that there is no guarantee that the funds will be available, and therefore for purposes of obtaining the Class VI injection permit, EPA should consider the Testing and Monitoring plan presented in Section 10. The information in this appendix is provided to EPA for informational (and not permitting) purposes.

Subject to additional funding, the number of monitoring wells may be increased to twenty one (Figure G.1). Three monitoring wells may be located in the Arbuckle aquifer (Figure G.1). Four existing Mississippian wells may be used to check if CO_2 has escaped upward from the primary confining zone at the site. Two well clusters, each consisting of 6 new wells, will monitor water quality in the Upper Wellington Formation (lowermost USDW). Additionally, one new well in the Chase Group underlying the Wellington Formation may also be drilled to monitor water quality.

In the event that additional monitoring wells are utilized on the project, the groundwater quality plan outlined in Section 10.4 will be followed to monitor geochemistry in the injection zone and formations above the confining zone. The supplemental monitoring technologies that may be deployed at Wellington subject to funding are discussed below.

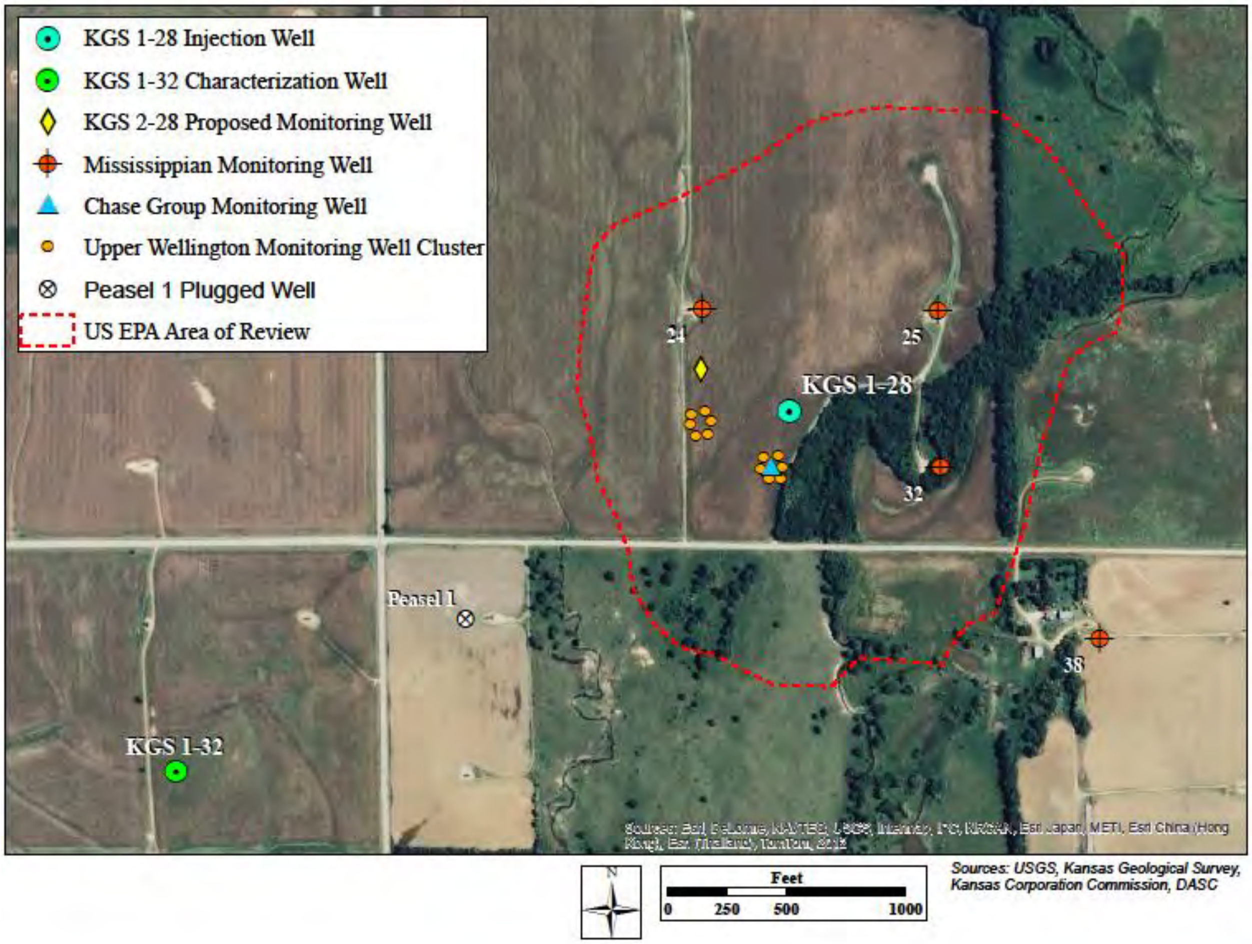


Figure G.1 Location of proposed and supplemental (optional) monitoring wells.

G.2 Soil Gas Chemical and CO2 Flux Monitoring

{This MVA activity (in support of § 146.90 (h)) is not mandatory for a Class VI permit application unless specified by the EPA Director}

Soil gas and CO2 flux monitoring can serve as a warning that carbon dioxide has migrated vertically out of the injection formation and may have endangered the USDW. Although not required by the Class VI Rule, soil gas and CO_2 flux monitoring may be conducted as a complementary/confirmatory activity for containment assurance subject to availability of DOE funds. A description of the soil gas and CO_2 flux monitoring techniques along with the monitoring plan is discussed below.

G.2.1 Soil CO_2 Flux Monitoring Background

The accumulation chamber method is a well-established approach to measure soil CO_2 flux from a relatively small area. Using this approach, an open-bottomed chamber is placed on the soil surface and the rate of change of CO_2 concentration in the chamber measured by an infrared gas analyzer. The CO_2 flux is proportional to the rate of change of CO_2 concentration. The portable accumulation chamber instrument can take measurement of numerous CO_2 fluxes over large study areas. The accumulation chamber method has been applied in a broad range of ecosystem, volcano, geothermal, and geologic carbon sequestration-related studies (e.g., Norman et al., 1992; Chiodini et al., 1998; Lewicki et al., 2003; Lewicki et al., 2007a and b; Pumpanen et al., 2000, Lewicki et al., 2010).

Using geostatistical methods (e.g., interpolation, sequential Gaussian simulation), maps of soil CO_2 flux will be created and the total CO_2 emission rates estimated. Based on the magnitude and spatial distribution of mapped soil CO_2 fluxes and their temporal variation, leakage signals will be identified and quantified (refer to Figure G.2 for an example). Soil gas geochemistry (discussed below) will further help to pinpoint the CO_2 source.

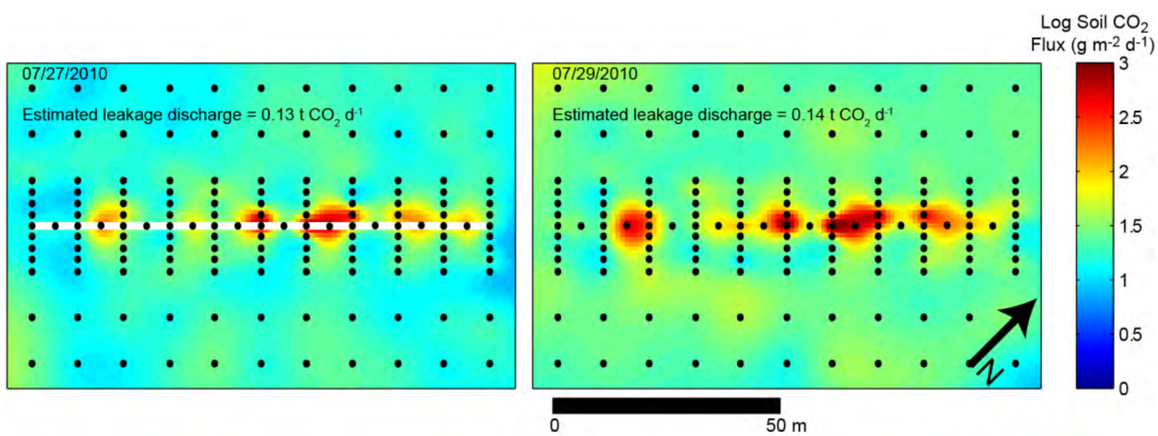


Figure G.2 Maps of soil CO_2 flux, interpolated based on accumulation chamber measurements at the black dots at the Zero Emissions Research and Technology (ZERT) CO_2 release facility in Bozeman, MT (Lewicki, 2012). White line on left map shows surface trace of shallow subsurface CO_2 release well, from which 0.15 t d^{-1} of CO_2 was released over one month in 2010. Surface CO_2 leakage rates estimated based on soil CO_2 flux measurements on 07/27/2010 and 07/29/2010 were 0.13 and 0.14 t d^{-1}, respectively.

G.2.2 Soil Gas Geochemistry Monitoring Background

The characterization of soil gas bulk chemical (CO_2, O_2, N_2, CH_4), natural isotopic tracer (e.g., ^{13}C-CO_2, ^{14}C-CO_2) and artificial tracer (sulfur hexafluoride, SF_6) compositions may be undertaken to detect potential CO_2 leakage near the surface. The relative concentrations of CO_2 in soil gases can provide information on CO_2 source. Background biogenic activity can generate up to 10% CO_2 in soil gas; thus, concentrations above this threshold may be indicative of a deep leakage source. Carbon isotopic compositions (e.g., ^{13}C, ^{14}C) of soil CO_2 are potentially powerful tools to fingerprint CO_2 source. Injected CO_2 derived from natural geologic CO_2 reservoirs have a highly distinctive ^{13}C and ^{14}C signatures from near-surface biogenic CO_2 sources; carbon isotopes will be a valuable method to trace potential leakage in this case. Injected CO_2 derived from fossil fuel sources will have a distinct ^{14}C signature from background biogenic sources, while its ^{13}C signature may be similar to (e.g., coal-derived CO_2) or distinct from (e.g., natural gas-derived CO_2) soil-derived sources. Injected CO_2 derived from ethanol production will have similar carbon isotopic compositions to background biogenic sources; in this case, carbon isotopes will be of limited use as leakage tracers in the soil.

Sulfur hexafluoride (SF_6) will be injected in the CO_2 stream as a tracer. It is an inorganic, colorless, odorless, non-flammable gas, with relatively low toxicity, and is commonly used in tracer gas testing. SF_6 is man-made and therefore environmental background levels are essentially non-existent (~7.5 ppt in northern hemisphere). There are many instruments available that can detect SF6 concentrations in the parts per billion (ppb) range, and some laboratories have capabilities in the parts per trillion (ppt) range. Because it can be detected at very low levels, tracer gas applications do not need large quantities of SF_6 at the source. SF_6 tracer concentration will be measured in soil gases. Since essentially no (or extremely low) concentrations of the tracer should be present in soil gas prior to CO_2 injection, the presence of anomalously high concentrations following injection will indicate leakage. A protocol will be established to determine if a measurement with high concentration of SF6 detected in soil gas is indicative of a leak, or as has occurred in one instance at another site, is an analytical error as shown through repeat analysis and resampling.

G.2.3 Surface CO_2 Flux and Soil Gas Monitoring Method and Frequency

Soil gases will be sampled using a direct push method (Schacht et al., 2010). A steel sampling probe with a retractable drive point may be driven into the ground with a slide hammer to about 3 feet depth to reduce CO_2 contribution from background soil respiration sources. The probe will be jacked up by ~1 cm, exposing a screened section above the drive point that will allow soil gas to enter the probe. The probe will then be purged of atmospheric air, sealed, and allowed to equilibrate for approximately one hour. Soil gas will then be extracted by syringe from the probe and stored in pre-evacuated sample bags for laboratory analysis. Bulk soil gas chemical and SF6 concentrations will be measured by laboratory gas chromatography. ^{13}C-CO_2 and ^{14}C-CO_2 compositions will be measured by laboratory mass spectrometry and accelerator mass spectrometry, respectively. Soil CO_2 flux surveys shall be conducted using an accumulation chamber on established grid to characterize variations.

Soil gases will be sampled contemporaneously with soil CO_2 flux measurements for close data comparison and fingerprinting of the source of potentially anomalous CO_2 fluxes. Because soil gas sampling and analysis is significantly more labor intensive and costly than soil CO_2 flux measurements, soil gas surveys will be conducted less frequently than soil CO_2 flux surveys. Based on modeling results documented in Section 5, the soil gas sampling grid for the pre-injection and the injection/post-injection phases is presented in Figure G.3. Sample density is approximately 400 ft spacing for pre-injection baseline surveys and 200 ft for the injection/post-injection phases. A dense grid of semi-permanent sampling points with tubing may be installed at approximately 3 ft depth around the CO_2 injection well (KGS 1-28) using a PRT (or similar) probe for repeat sampling and analysis of soil gas geochemistry.

Up to four baseline (pre-injection) soil CO_2 flux surveys shall be carried out using the accumulation chamber. Soil gas samples shall be collected contemporaneously with CO_2 flux measurements during two surveys using the sampling probe and tedlar sample bags. Soil CO_2 flux data shall be processed and soil gas samples analyzed in the laboratory for bulk chemical (CO_2, CH_4, O_2, N_2) composition. Selected samples shall be analyzed in the laboratory for sulphur hexafluoride (SF_6) and, if warranted by the source of injected CO_2, carbon isotopic (^{13}C and ^{14}C) compositions. Geostatistical analysis shall be applied to characterize baseline spatio-temporal variations in flux and geochemical data sets to produce maps.

Multiple soil CO_2 flux surveys may be conducted on the established grid to characterize spatial and temporal variations in flux during the CO_2 injection phase. The sample grid may be updated if the CO_2 plume migration is noted to be along a trajectory different than the baseline (pre-injection) projections. Soil gas samples shall be collected contemporaneously with CO_2 flux measurements during every other flux surveys. Soil CO_2 flux data shall be processed and soil gas samples shall be analyzed in the laboratory for bulk chemical and SF_6 compositions. Geostatistical analysis shall be applied to determine spatio-temporal variations in flux and geochemical data sets and compared with baseline analysis. If these variations are suggestive of leakage, (1) additional carbon isotopic (^{13}C and ^{14}C) analyses shall be carried out to determine CO_2 source and (2) detailed soil CO_2 flux measurements shall be made to map and quantify potential leakage.

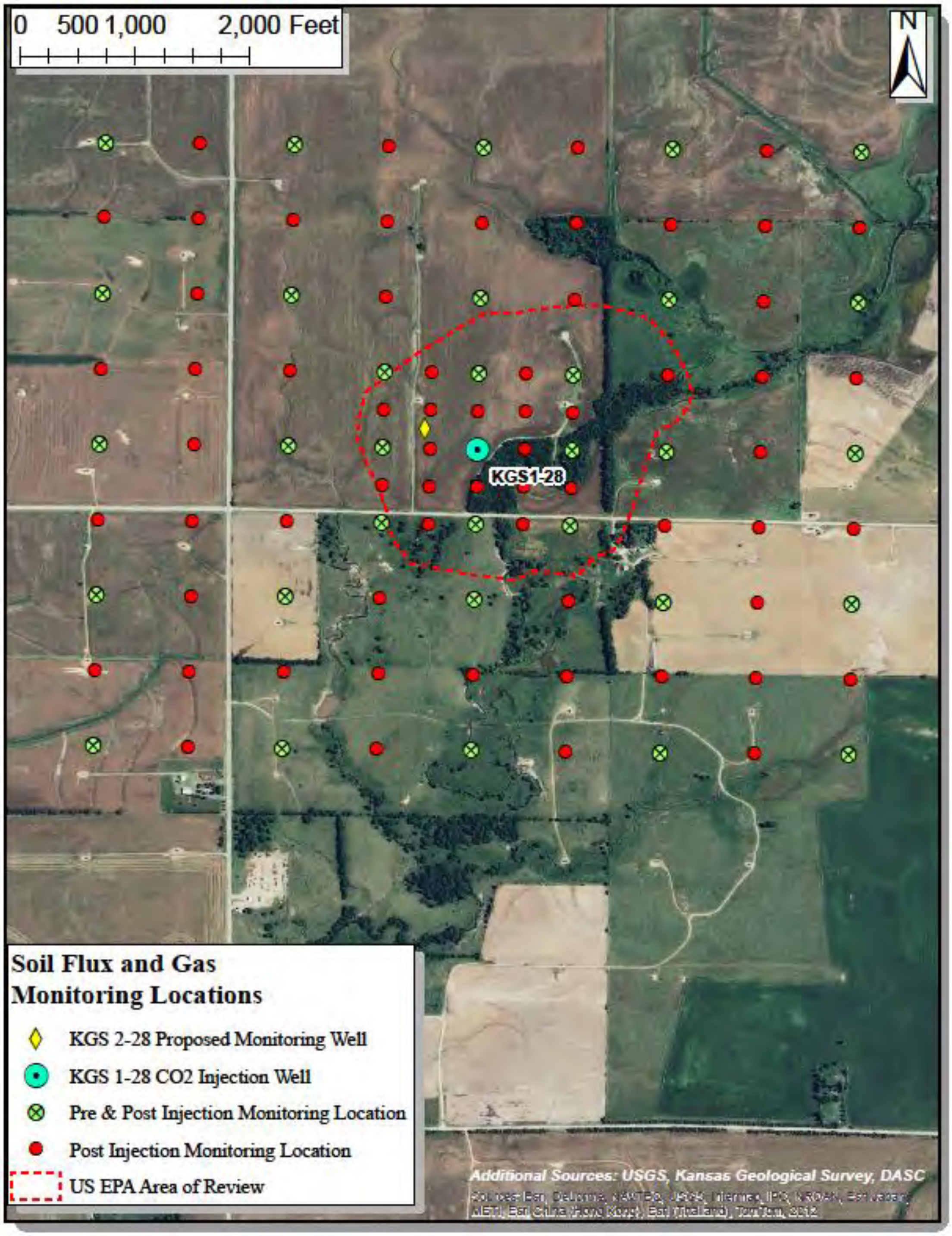


Figure G.3 Soil gas chemical and CO2 flux monitoring grid for the pre-injection and injection/post-injection phases.

G.3 Fiber Optic Sensor Array

{Information in this section provided in support of § 146.90 (g)(2)}

Distributed Fiber Optic (FO) sensing offers a transformational approach to monitoring CO_2 storage. High density, high resolution FO acoustic and thermal arrays that are semi-permanent could potentially be used to image horizontal and vertical migration of CO_2 in the subsurface over large areas and time spans of decades as required by regulators, replacing periodic seismic surveys that suffer from repeatability issues. Likewise, near continuous monitoring of CO_2 injection rates and allocations would provide site operators with a powerful tool to monitor and manage CO_2 floods, helping to optimize formation storage capacity in real time. FO-based sensor arrays are cost-effective and could be easily incorporated into future intelligent monitoring systems for long-term, real-time assessment of CO2 storage system performance.

KGS in collaboration with the Electric Power Research Institute, Lawrence Berkeley National Laboratory, Sandia Technologies, and Silixa, LLC, has submitted a proposal to the DOE to integrate fiber-optic based monitoring system at the Wellington sequestration site. The proposed approach combines a distributed acoustic sensor array for seismic monitoring with a distributed temperature sensor array and heater cable for hydrologic monitoring. If funding is approved, a 6 mm diameter, stainless-steel encased sensor array will be deployed at KGS 2-28 and extended across land surface for distances up to 2,000 feet, providing high-spatial resolution temperature and acoustic measurements at every 0.3-1 m along the entire cable length. The seismic pulses recorded by the FO acoustic sensor array will supplement standard geophones monitoring at KGS 2-28. The FO sensor assembly will be strapped to the outside of the production tubing where water in the annulus will couple it acoustically to the casing/cement/rock interface. The FO sensor assembly will run continuously from its terminus below the perforations (~5,000 ft depth) to the top of the well and across land surface for another 2,000 ft. This will allow simultaneous recording of both Vertical Seismic Profiling (VSP) and 2D surface seismic responses using one FO sensor assembly from multiple shot points collected during any given survey (Figure G.4). The VSP and 2D surveys will be performed before and after CO2 injection and compared to data collected using a limited set of standard mechanical geophones deployed on tubing at KGS 2-28 as part of the CASSM system.

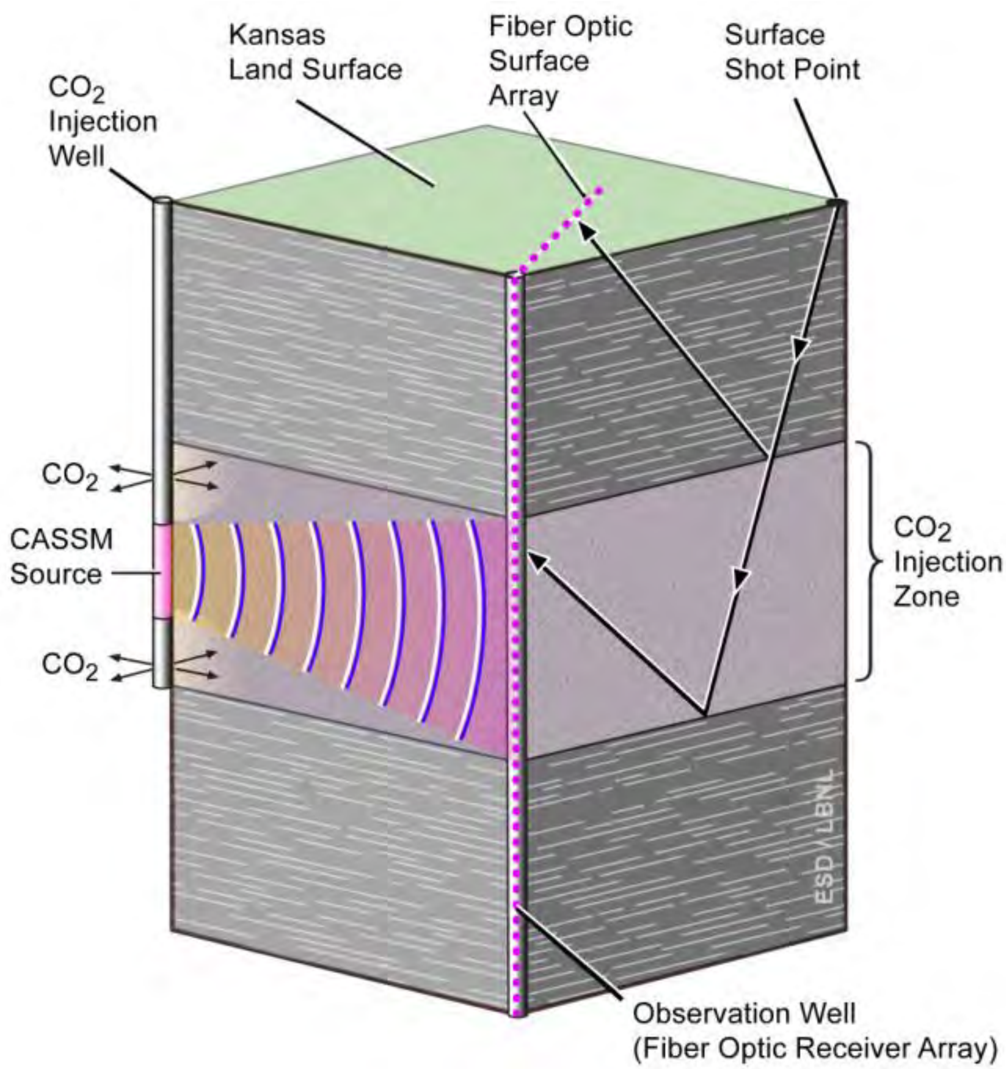


Figure G.4 Schematic showing seismic survey configuration to be performed at the Wellington Field, Kansas.

G.4 Seismic Monitoring

Seismic monitoring can provide information concerning rock deformation and seismicity induced by fluid injection in the subsurface. Seismicity is usually attributed to reactivation of existing fractures/faults which are lubricated by the injected fluids. No large faults are however known to exist at the stratigraphic level of injection at Wellington.

The initial design of the seismometer array consists of eighteen seismic stations in a six pointed star configuration (Figure G.5). The instruments to be utilized in this project will be borrowed from the IRIS Passcal Instrumentation Pool, which consists of a pool of seismometers, recording systems, and power systems available to researchers working on National Science Foundation and Department of Energy funded projects. Instrumentation is available for a maximum period of 1 year and will therefore be utilized during the injection period and a few weeks prior to injection. The configuration proposed in Figure G.5 may be modified based on Passcal instrument availability and potential reconfiguration to facilitate monitoring of the downhole source, if feasible. The array will monitor in the frequency range of 2 to 50 hz, which is considered 'intermediate frequency' monitoring and is suitable for detection of seismic events at local to regional scales. The array will be installed a few weeks prior to injection in order to obtain background estimates of seismicity in the area. The data from the array will be stored in the recording systems and downloaded approximately monthly.

In addition to monitoring seismicity, it is anticipated that the array will also be utilized to attempt additional analysis of the surface arrivals from events associated with the active source experiment to be run with the downhole source in the injection well (KGS 1-28) and downhole receivers in the monitoring well (KGS 2-28). It may even be possible to repurpose one or more of the recording systems from the surface array to record 'piggyback' signals from the downhole array for direct comparison of results.

An additional benefit of the seismic monitoring will be to provide protection and evidence against potentially damage claims in the event of seismic activity originating from events such as fracking at sites other than Wellington.

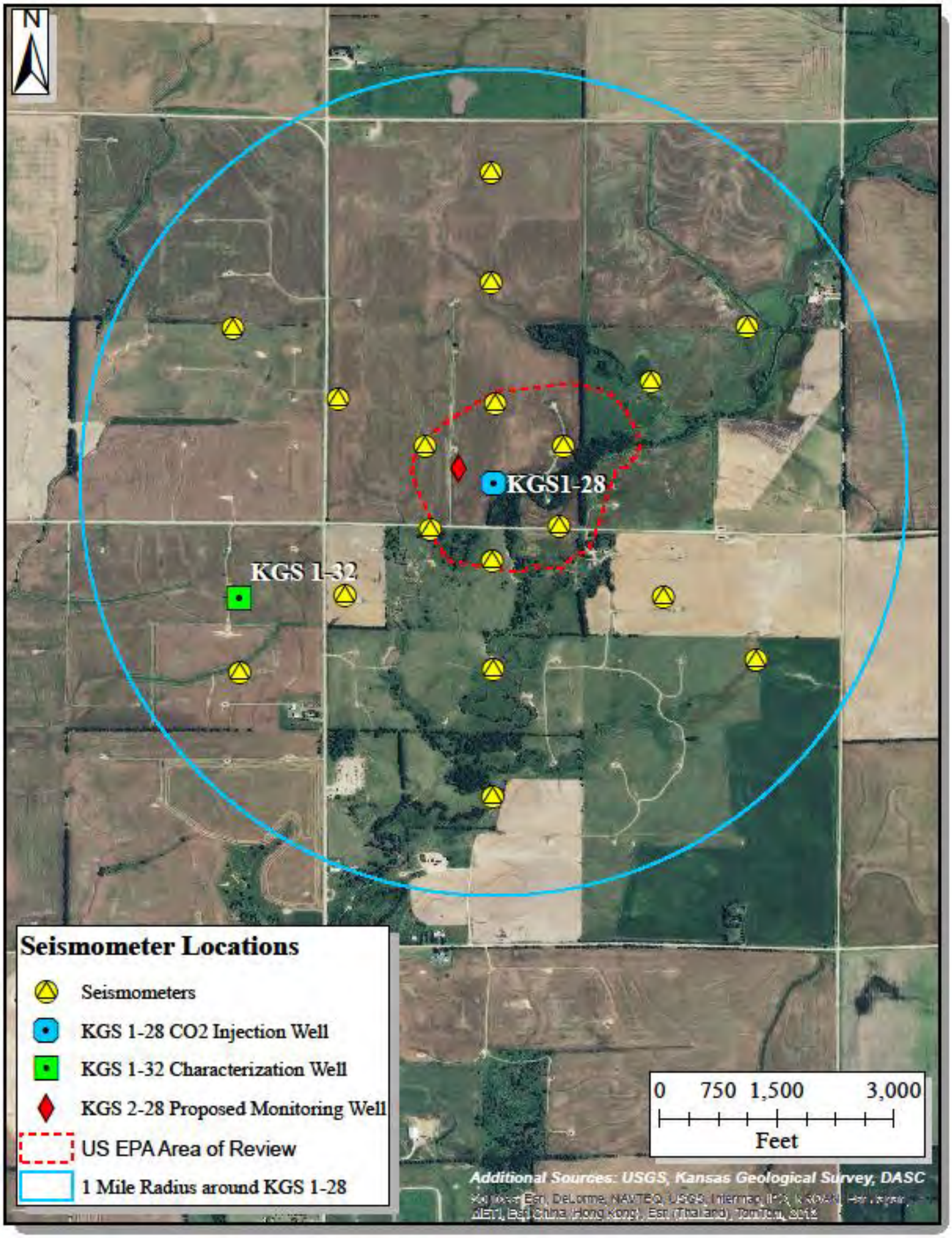


Figure G.5 Configuration of the seismic monitoring array at the Wellington sequestration site.

Appendix H

Well Logs and Tests - Analyst Report

Analyst: Dr. Lynn Watney, Senior Scientific Fellow, Kansas Geological Survey, Lawrence, KS

H.1 Introduction

The log, core, and geochemical data acquired during construction of the CO_2 injection well KGS #1-28 and geologic characterization well KGS #1-32 are listed in Table H.1 along with the relevant section in the Class VI permit document where the data is discussed in detail. The purpose of this appendix is primarily to summarize all the log data collected and tests conducted at the Wellington storage, and to provide a brief explanation of how the data was used to characterize the subsurface hydrogeologically. The log data itself is contained in Appendix B (KGS 1-28) and Appendix C (KGS #1-32). Detailed analyses of the acquired data and tests conducted are documented in Section 4 (Local Scale Hydrogeology).

Table H.1 Summary of logs acquired and tests conducted at the Wellington storage site

Acquired Data	Section of application where data documented/discussed
Geophysical Logs	
Array Compensated True Resistivity	Appendices B and C, Section 4.4
Temperature	Appendices B and C, Section 4.6.5
Compensated Spectral Gamma Ray	Appendices B and C, Section 4.6 and 4.7
Micrologs	Appendices B and C
Spectral Density Dual Spaced Neutron Log	Appendices B and C, Section 4.6 and 4.7
Annular Hole Volume Log	Appendices B and C
Extended Range Micro Imager Correlation Plot	Appendices B and C, Section 4.7
Magnetic Resonance Image Log	Appendices B and C, Section 4.6 and 4.7
Radial Cement Bond Log	Appendices B and C
CT Scan	Section 4.7.5.3
Core Samples (Arbuckle Group)	

Porosity and Permeability	Section 4.6.6
Mineralogy and Soil Characterization	Section 4.6.2
CO_2 Compatibility	Section 4.6.10
Swab Samples	
Geochemistry	Section 4.6.7
Core Samples (Confining Zone)	
Porosity and Permeability	Section 4.7.3
Mineralogy and Soil Characterization	Section 4.7.2
CO_2 Compatibility	Section 4.7.7
Drill Stem Test	Section 4.6.3
Pressure Pulse Test	Section 4.6.4

H.2 Well Logs

H.2.1 Array Compensated True Resistivity (ACTR)

ACTR involves obtaining multiple measurements of resistivity which reflects conditions at different distances beyond the borehole wall so that the effects of drilling-mud invasion can be factored out for a reading of the true resistivity of the formation. The log data is used for evaluation of (1) formation water salinity variations and (2) the subdivision of pore volume between electrically connected and unconnected porosity, which has important implications regarding permeability, particularly in the injection zone.

The ACTR was specifically used on the Wellington project to:

- Estimate formation salinity and thereby establish the Upper Wellington formation as the lowermost and only USDW at the injection site (Section 4.4).
- The resistivity log was used to distinguish between connected and unconnected pore space using the well-known Archie equation. Resistivity logs were used in combination with porosity logs including MRI, neutron, density, and sonic logs to divide the total pore space between inter-particle, connected and unconnected vugs.

H.2.2 Temperature Log

Temperature logs were acquired from surface to basement at both KGS 1-28 and KGS 1-32 following drilling. The data was used to specify temperature dependent formation properties (formation brine resistivity, solubility, and phase behavior of CO_2) in the CMG based compositional numerical model discussed in Section 5.

H.2.3 Compensated Spectral Natural Gamma Ray

The Compensated Spectral Natural Gamma Ray (CSNGR) log was acquired to provide insight into the mineral composition of the formations. Measurement of natural gamma-radiation of formations, partitioned between the three most common components of naturally occurring radiation in sandstones and shales (potassium, thorium, and uranium) is most commonly used for (1) correlation between wells, so that laterally continuous zones can be identified: (2) shale evaluation, which is particularly important in the evaluation of sealing intervals and baffles: and (3) the recognition of "hot" uranium zones, generally resulting from diagenesis and sometimes indicative of fractures.

The CSNGR data was used at the Wellington site for discrimination of rock texture, specifically determination of grainstone, mudstone, etc. The total gamma ray less the uranium contribution is a corrected gamma ray (CGR). In the case of the dolomites that comprise the Arbuckle, the rock intervals containing the lowest CGR are also highly correlated with grain-supported grainstone and packstone rock textures. These textures are in turn correlated to higher matrix porosity and permeability and thus, the CGR was useful in recognition and correlation of these textures when used in combination with the other log data. The data was also used for discrimination of potential uranium anomalies, of which none of which was found. The data was also used to establish the lithology at the site.

H.2.4 Microlog Log

The Microlog records normal and lateral microresistivity at a much higher vertical resolution than standard resistivity logs, but has less depth of investigation than standard resistivity logs. The data is typically used to (1) characterize resistivity of thin zones and (2) provide an indication of mudcake buildup as a good diagnostic of permeable zones. The log data at the Wellington site was used to determine high permeability zones and to identify suitable zones for Drill Stem Tests discussed in Section

4.6.3. While the magnitude of the permeability can not be determined with the microlog, it is lower cost tool that is commonly run and is useful in discriminating permeable from non-permeable rock.

H.2.5 Spectral Density Dual Spaced Neutron Log

This porosity logging suite was integrated with magnetic resonance imaging (MRI) and neutron-density crossplot (PHND) porosity logs for high grade interpretation of porosity at the Wellington site.

The photoelectric index (Pe) accompanies modern density logging tools and records the absorption of low-energy gamma rays by the formation in units of barns per electron. Logged value is a direct function of the aggregate atomic number (Z) of the elements in the formation, and so is a sensitive indicator of mineralogy http://www.kgs.ku.edu/PRS/ReadRocks/PEScale.html). Pe is combined with neutron porosity, and bulk density information to conduct a Rhomaa-Umma analysis (Appendix F). The results indicate that quartz (silt) is a dominant mineral in the low permeability Pierson Formation, which is consistent with observation from the core, thin section petrography, and XRD analyses discussed below.

H.2.6 Annular Hole Volume Log

The Annular Hole Volume log was used to estimate the amount of cement needed to fill the annular space. The volume calculation assisted in having sufficient cement to completely fill the annular volume. No unusual borehole enlargements were noted.

H.2.7 Extended Range Micro Imager Correlation (ERMIC) Plot

The high resolution electrical image of borehole wall provided by the (ERMIC) plot was used at the Wellington site for recognition and orientation analysis of (1) fractures, both natural and drilling-induced; (2) vuggy porosity, and (3) shaley zones. The fracture analyses is presented is Section 4.7.5.2. A consistency was noted between the observations from ERMIC, core, and MRI (discussed below). The ERMIC was used to extend the delineation of major pore types in the intervals that were not cored.

H.2.8 Magnetic Resonance Image (MRI) Log

The MRI log measures the relaxation time of hydrogen within the pores exposed to a powerful magnetic field, whose spectrum reflects the distribution of pore sizes. The MRI data was used to obtain a distribution of the pore size, and estimate permeability and porosity values by first calibrating to core measurements. The MRI log was also used to determine the sealing potential of caprock by deriving CO_2 entry pressure estimates in the confining zone above the Arbuckle aquifer (Section 4.7.4).

The MRI log is lithology-independent and its porosity curve showed a close match with the lithology-corrected neutron-density porosity. This correspondence provided mutually supporting evidence that both measurements are good estimates of effective porosity in the petrophysical sense, that is, the sum of pore space containing both moveable fluids and capillary-bound water associated with shale content.

H.2.9 Radial Cement Bond Log (RCBL)

Haliburton's RCBL tool captures downhole data that ensures reliable cement bond evaluation. The tool is equipped with one omni-directional transmitter, and two omni-directional receivers, as well as eight radial receivers for comprehensive borehole coverage. The RCB log at KGS 1-28 is presented in Appendix B. An inspection of the log indicates a competent cement bond in the well, and the absence of any vertical channels through which pressurized fluids could migrate upward into the USDW.

H.2.10 Helical Computerized Tomography (CT) Scan

CT scans were acquired to evaluate the texture of the rocks and to inspect for the presence of very minute fractures in the confining zone. The findings are summarized in Section 4.7.5.3. The scans indicate a very tight confining zone, especially the Pierson Formation, and the absence of transmissive fractures within this zone.

H.2.11 Sonic Log

The acoustic measurement of porosity records the first arrival of ultrasonic compressional waves and is primarily sensitive to interparticle porosity that occurs between grains or crystals within carbonates and is often referred to as "primary" or "matrix porosity". In contrast, the MRI, neutron, and density measurements respond to pore spaces at all scales and so provide a measure of total porosity. The difference between the acoustic porosity and the total porosity is termed the "secondary porosity" which can be interpreted to be vuggy porosity, where vugs can range in size anywhere from a dissolved grain to large cavities. As discussed in Appendix E, the overlay of the MRI porosity with the acoustic (sonic) porosity suggests "vuggy facies" in the top and bottom of the Arbuckle and tighter (less complex) "matrix facies" in the middle of the Arbuckle.

H.2.12 X-Ray Diffraction

X-Ray Diffraction (XRD) is the technique most heavily relied analysis for identification of minerals in rocks and soils. The bulk of the clay fraction of many soils is crystalline, but clay particles are too small for optical crystallographic methods to be applied. Therefore, XRD is used for identification of clay-sized minerals in soils.

As discussed in Appendix F, the X-ray diffraction count and phase (or scattering) angle for lower Pierson samples indicates that the dominant clay is chlorite while rock is mainly fine silt-sized quartz with scattered dolomite crystals. This is in conformance with core analysis which suggests that the quartz content is represented by detrital siltgrains, scattered siliceous sponge spicules, chert, , dispersed clays. All thave a density similar to quartz. The dolomite is also dispersed as silt sized particles that together with clay and minor (<2 %) organic matter create a tightly packed fabric.

H.2.13 Geochemical Logs

Geochemical logs were used at the Wellington site to characterize elemental composition and mineralogy and assist in evaluating reaction reaction rates in the presence of free phase CO_2. The geochemical data was also used in conjunction with Schlumberger's Techlog software to estimate hydrogeologic properties such as porosity.

H.3 Core Samples

As discussed in Section 4.6.1, core samples were obtained at KGS 1-32 within a 1600 feet interval spanning from the bottom of the Arbuckle into the Cherokee Shale above the Mississippian System. The samples were used for thin-section spectroscopy, geochemical analyses, lab based derivation of permeability of porosity estimates, and fracture investigations. The data and results are discussed throughout Section 4 as well as Appendix E, and are briefly referenced below:

- Petrophysical properties (permeability and porosity) - (Section 4.6.6, 4.7.2, and 4.7.3)
- Fracture studies (Section 4.7.5)
- Core images (Section 4.6.2 and 4.7.2)
- Mineralogical characterization (Section 4.6.2 and 4.7.2)
- CO_2 reaction kinetics (Section 4.6.10)
- X-Ray Diffraction (Appendix F)

H.4 Drill Stem Test (DST)

Four DST's were conducted at KGS #1-28 and four at KGS #-32 as documented and discussed in Section 4.6.3. The primary purpose was to obtain the ambient pressures and derive estimates of formation permeability. The DST's at KGS #1-28 were focused in the injection zone, while the DST's at KGS #1-32 were conducted at various intervals in the Arbuckle as well as the Mississippian reservoir. The acquired data indicates that the injection zone has relatively high permeability ranging between 217-229 mD, and that the confining zone functions as competent caprock between the Arbuckle and Mississippian systems.

H.5 Pressure Pulse Test

A pressure pulse test was conducted at the Wellington site (Section 4.6.4) in order to obtain permeability estimate in the injection zone. The results indicate that permeability in the injection zone is approximately mD, which is of the same order of magnitude as derived from Drill Stem Tests.

H.6 Geochemical Data

Formation waters were collected during Drill Stem Tests and swab sampling. The samples were analyzed to establish baseline geochemical conditions and salinity distribution throughout the Arbuckle injection zone (Section 4.6.7). Various geochemical studies (documented in Appendix E) were conducted in order to validate the geologic characterization derived from core and log studies. These are documented in Appendix E and briefly summarized below.

The ion composition analyses indicate that the Arbuckle Group is indeed highly stratified with high permeability zones in the top and bottom of this system. The data also indicates that there is sharp hydraulic separation between the Arbuckle Group and the Mississippian system, suggesting the presence of a competent caprock. The biomass concentrations and microbial counts also indicate the presence of a highly stratified Arbuckle reservoir.

Oxygen and hydrogen isotope analyses were conducted in order to obtain an understanding of the hydrodynamics of the Arbuckle system. The data suggests that the brines from the lower Arbuckle cluster tightly together and have values distinct from the upper Arbuckle. The upper Arbuckle brines have distinctly different δD and $\delta^{18}O$ values than in lower Arbuckle. This is in conformity with observations and conclusions from core, well logs, ion composition, and biochemistry data discussed above.

Appendix I

Seismic Data Acquisition and Recording Parameters

In order to confirm the regional presence of a (relatively high porosity) Arbuckle injection zone and a competent confining zone above it, a 3-D seismic survey was conducted to map the deep formations and estimate the suitability of the rock fabric for CO2 storage and confinement purposes. The data acquisition and recording parameters are documented below. Results of the seismic analyses and the accompanying discussions are presented in Section 4.8.

The 3-D survey incorporated the acquisition of multi-component data via geophones capable of detecting ground motion in 3 directions: vertical, x-component, and y-component. This data type yields both p-wave (vertical acceleration), as well as converted shear waves which are recorded in the x and y components. The survey also incorporated the acquisition of two 2-dimensional shear-to-shear recording (Figure I.1), in which the shear wave source was applied via vibrating devices mounted on the underside of a heavy truck capable of delivering approximately 41,000 pounds peak force, with the energy being recorded by multi-component geophones which captured ground motion in three dimensions. The recording parameters are presented in Table I.1.

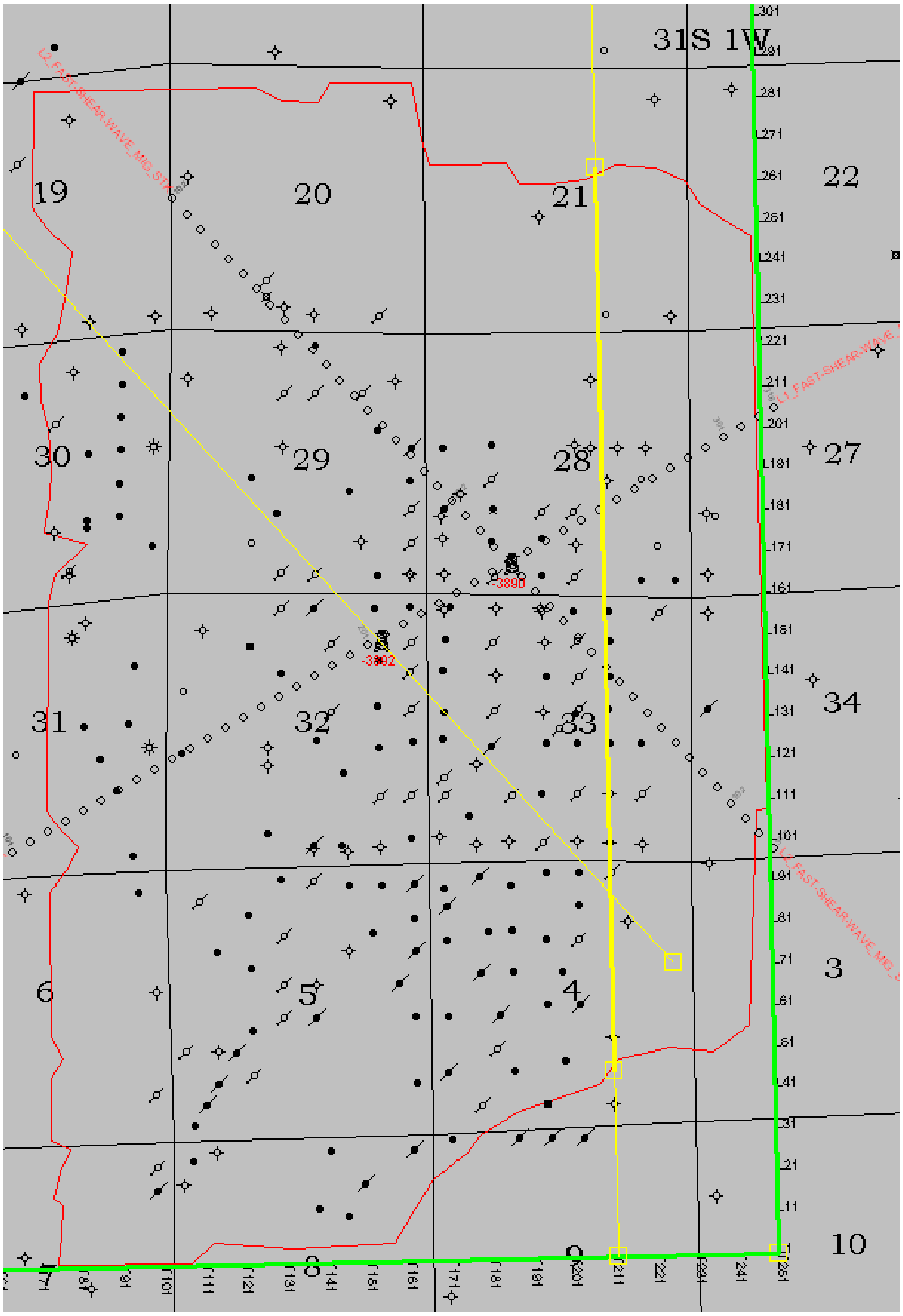


Figure I.1 Index map illustrating the location of the seismic profile (heavy yellow north-south line). Also shown are locations of 2D shear wave profiles, L1 oriented WSW-ENE and L2, oriented NW-SE. Indices to inlines appear on the east edge of the green boundary and indexes to crosslines (also referred to as traces) appear on the south boundary of the green outline. Extents of seismic data are indicated within the red line.

Table I.1 2-D Seismic Shear Wave Source Parameters

Acquisition Company:	Paragon Geophysical Services, Inc., Wichita, KS
Energy Source:	Shear Wave Vibroseis
	41,000 lb peak force, 2 vibrators at all times
Receiver interval:	82.5 ft
Total receivers:	Line 1-216; Line 2-219
Geophone type:	3C Digital per station
Geophone array:	single 3C
Instruments:	ION Scorpion
Sweep Parameters:	1-20 second sweeps/VP
Sweep frequency:	4-50 Hz
Source Interval:	165 ft
Total sources:	436
Record length:	4 seconds
Sample rate:	2 milliseconds

Multi-component seismic data acquisition via Paragon Geophysical Corporation commenced on March 5, 2010, with field testing to determine optimum vibroseis sweep parameters. These tests yielded a decision to record data with a pilot frequency of 6-150Hz, 3db/oct, 0.3 sec tapers, with 2 vibrators each applying 2-40 second sweeps, with a 3 second listening time. Additional details related to acquisition parameters are included in Table I.2 below.

Table I.2 3D Seismic P-wave Source Parameters

Energy Source:	Vibroseis
	62,000 lb peak force, 2 vibrators at all times
Recording patch:	64 receivers x 18 lines = 1152 channels
Receiver interval:	165 ft
Receiver line interval:	495 ft
Geophone type:	3C Digital per station
Geophone array:	single 3C
Instruments:	I/O System IV
Sweep Parameters:	2-40 second sweeps/VP
Sweep frequency:	6-150 Hz
Source Interval:	165 ft
Source line spacing:	660 ft
Total lines:	49
Total source points:	3831 (appx 255 per sq mi)
Total receivers:	5236 (appx 349 per sq mi)
Shooting technique:	Roll line by line
Record length:	3 seconds
Sample rate:	1 millisecond
Bin size:	82.5’ x 82.5’

Seismic data acquisition was completed late April, 2010, and data processing commenced soon thereafter. P-wave processing was accomplished by both Echo Geophysical and FairfieldNodal of Denver, Colorado, while multi-component processing was assigned exclusively to FairfieldNodal. Gravity statics (Grav-Stat) data acquired by Lockhart Geophysical, was processed and delivered to both Echo Geophysical and Fairfield Nodal. Echo and Fairfield completed their inclusion of this data into their P-wave processing flow, with evidence of improvement in the datum statics. However, due to the superiority of the refraction statics solution over the datum statics with Grav-Stat, all final processed p-wave data incorporated the results of refraction statics analysis. The data also included previously acquired 3D P-wave seismic database covering the Anson-Bates Field northwest of the Berexco Wellington Unit (courtesy: Noble Energy, Houston, Texas).