CLASS VI PERMIT FINANCIAL RESPONSIBILITY DEMONSTRATION

LAC 43:XVII Subpart 6. Statewide Order No. 29-N-6, §3609.C

STRATEGIC BIOFUELS
LOUISIANA GREEN FUELS, PORT OF COLUMBIA FACILITY

Revision 1
May 2025

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1.0 FACILITY INFORMATION

Facility Name:	Louisiana Green Fuels, Port of Columbia Facility Three Class VI Injection Wells Five In-Zone (IZ) Monitor Wells Four Above-Confining-Zone (ACZ) Monitor Wells
Facility Contact:	Bob Meredith, COO 303 Wall St., Columbia, LA 71418 318-502-4053 bobmeredith@strategicbiofuels.com
Well Locations:	Caldwell Parish, Louisiana **Latitude / Longitude** Well 1 (W-N1): NAD 27 32° 11' 17.24" / -92° 06' 35.50" NAD 83 32° 11' 17.78" / -92° 06' 36.00" Well 2 (W-N2): NAD 27 32° 11' 12.72" / -92° 04' 08.96" NAD 83 32° 11' 13.26" / -92° 04' 09.45" Well 3 (W-S2): NAD 27 32° 09' 50.18" / -92° 05' 15.15" NAD 83 32° 09' 50.72" / -92° 05' 15.65"

Strategic Biofuels has reviewed LAC 43:XVII Subpart 6, Statewide Order No. 29-N-6 ("SWO 29-N-6") §3609.C (as amended on March 20, 2025) and understands acceptable demonstrations of financial responsibility must be made to the Commissioner of Conservation prior to issuance of the Permit to Construct and the subsequent Permit to Inject, and must be maintained throughout the period of active injection and for so long thereafter as required by law or regulation.

2.0 FINANCIAL INSTRUMENTS

Strategic Biofuels will provide Financial Responsibility pursuant to LAC 43:XVII Subpart 6 §3609.C in the form of a Surety Bond, Letter of Credit or commercial insurance policy (or other financial instrument acceptable to the Commissioner of Conservation) as appropriate. The form of each will be as prescribed by and in sole favor of the Office of Conservation to cover the costs of **Corrective Action, Injection Well Plugging and Abandonment** (both pre-injection and post-injection), **Post-Injection Site Care and Site Closure,** and **Emergency and Remedial Response**.

Prior to issuance of the Permit to Construct, Strategic Biofuels will provide a Letter of Credit in sole favor of the Office of Conservation, in a form prescribed by the commissioner and in an amount that is in excess of the specific itemized costs of injection well plugging and abandonment should such be required prior to issuance of a Permit to Inject (pre-injection P&A), a well condition with fewer mechanical requirements and much less cost than a post-injection P&A.

Prior to issuance of the Permit to Inject, Strategic Biofuels will provide a Surety Bond, replacing the Letter of Credit, that covers the full cost of (1) **Corrective Action,** (2) **Injection Wells Plugging and Abandonment** (both pre- and post-injection) and (3) **Post-Injection Site Care and Site Closure**. The summarized estimated costs of Corrective Action and Injection Wells Plugging and Abandonment (by Geostock Sandia and/or other approved third party contractors) and of the Post-Injection Site Care and Site Closure (by Strategic Biofuels) are presented in Table 1.

Also prior to issuance of the Permit to Inject, Strategic Biofuels will provide a Certificate of Insurance, annotated as required by the Office of Conservation, with coverage in an amount substantially more than the estimated costs of the **Emergency and Remedial Response** (ERR). A commercial insurance policy was chosen for this cost category because, unlike the other categories of Financial Responsibility that will be necessary and the actual expenditures covered by a Surety Bond, ERR costs are contingent and not anticipated to be incurred. The basis of the ERR is the assumption of a reasonable and most plausible "worst-case" incident scenario. That most plausible scenario has been determined to be the detection of vertical injectate movement behind casing above the Primary Confining Zone (but well beneath the USDW) in an injection well, requiring immediate and direct intervention to remediate.

This scenario was selected as the model for cost determination because (1) other than those that will be repurposed as In-Zone monitor wells, there are no artificial penetrations of the Primary Confining Zone within the plume area that could provide a leak path from the Injection Zone; (2) as documented elsewhere in this application, there are no faults within the AoR that are interpreted to intersect with and thus could provide a leak path through and above the Primary Confining Zone; and (3) each injection well will be constructed with three concentric casing strings that extend below the base of the USDW, all individually cemented and thoroughly tested. (All three of these casing strings would have to, in some undetectable way over time and despite vigilant monitoring, lose cement integrity in the same wellbore *at the same time* in order to provide a vertical leak path to and above the base of the USDW, requiring the remediation of the USDW.)

The results of recent research conducted at the Cranfield, Mississippi CO2 EOR facility operated by Denbury Resources, Inc., approximately 80 miles southeast of the proposed Louisiana Green Fuels plant site, provides further support for the assertion that any upward migration of injectate past the Upper Confining Zone would most likely be completely interrupted (halted) by its dissipation into the thick saline aquifers and shale baffles of the overlying Eocene Wilcox Formation. This research (*Analysis of potential leakage pathways at the Cranfield, MS, U.S.A., CO2 sequestration site*), conducted by the DOE-sponsored SECARB risk assessment analysis of the Cranfield facility (Nicota et al, 2013), concluded the following:

"Results show that overpressure from CO2 injection is rapidly dissipated in the upper Tuscaloosa and can be further reduced in the underpressured Wilcox Group. But for CO2, the buoyancy effect allows a residual leakage flux to continue flowing up the well, resulting in the possibility of nonnegligible CO2 leakage for wells with poor-quality cement. For brine, the lack of buoyancy renders brine-leakage negligible as overpressure dissipates into the upper Tuscaloosa and Wilcox.

"Given the large volumes of potable aquifers and above-ground dissipative processes, CO2 fluxes of this magnitude are expected to have negligible impact on USDW, ECA, and HS compartments.

"Because salinity generally increases with depth and temperature equilibrates rapidly with the formation, there is no buoyancy to move brine up a well. In fact, any buoyancy effect of the mobilized brine relative to the formation brine may be expected to reduce the movement of brine up a well (Birkholzer et al., 2011). Analysis shows that no brine flow is expected to occur in wells above the upper Tuscaloosa, even for the highest wellbore permeability investigated for CO2."

The geology of the Cranfield area is very similar to that of the AoR, and both areas involve the sequestration of CO2 within the sandstones of the Tuscaloosa Formation (in the Lower Tuscaloosa at Cranfield and in the Upper Tuscaloosa (and underlying Paluxy Formation) in the AoR). It should be emphasized, however, that Cranfield Field – the subject of the SECARB study – has many more artificial penetrations and at least one significant fault that could potentially impact the seal integrity of its Upper Confining Zone. For this reason, the likelihood of upward movement of injectate reaching the USDW is even less plausible at the LGF AoR than at Cranfield.

The Wilcox Formation is approximately 1,700 feet thick within the AoR. The base of the Wilcox is approximately 1,500 feet above the top of the Upper Confining Zone. Almost all of the intervening 1,500 feet consists of impermeable strata, including the approximately 600 foot-thick Midway Shale, the important Secondary Confining Zone (directly underlying the Wilcox Formation). The Annona Sand is stratigraphically developed approximately 450 feet above the top of the Upper Confining Zone and represents the first significant Above Confining Zone (ACZ) porous and permeable reservoir present in the AoR. Any upward leakage of injectate must first make it past the Annona Sand, which has been intensively studied and is interpreted to be capable of fully dissipating any vertically-leaking injectate and pressure. The Annona Sand will be closely monitored by the system of ACZ monitor wells Strategic Biofuels will construct prior to receiving its Permit to Inject.

In the highly unlikely scenario contemplated here, any upward leakage of injectate must further rise an additional 1,000 feet, more or less, above the Annona Sand before it reaches *the base* of the Wilcox Formation. The Wilcox interval consists of 50 or more porous and permeable sandstones encased within an equal number of impermeable intraformational shale baffles. Some of the sandstones in the Wilcox Formation exceed 100 feet in thickness. The prior production of methane from several sands and porous lignites located in the lower 400 feet of the Wilcox (i.e., the (now-abandoned) Riverton Gas Field) has incrementally drawn down the original reservoir pressure of those partially-depleted reservoirs.

This means that any upward leakage of injectate must make it past the partially drawn-down reservoirs of the Lower Wilcox as well as an additional 40 saline aquifers developed above those drawn-down reservoirs – each of which is encased in impermeable shale. Overlying the Wilcox Formation are the 200 to 300 feet of additional impermeable shales of the Cane River and Tallahatta Formations, which represent yet another barrier to upward migration.

Thus any upward leakage of injectate must first make it past the porous and permeable Annona Sand, 450 feet above the (250 foot-thick) Upper Confining Zone, then somehow make it past 50 or more porous and permeable sandstones of the 1,700 foot-thick Wilcox Formation, several of which are underpressured. This is a highly implausible and unrealistic scenario. The dissipation of pressure and injectate into the porous and permeable sandstones of the Annona and Wilcox intervals, while clearly an event Strategic Biofuels will take every precaution to avoid, would not have any negative impact upon any dissipative reservoir or the overlying USDW, still protected further uphole by the thick impermeable shales of the Cane River and Tallahatta Formations.

Based upon the SECARB analysis at Cranfield and the more optimal conditions at the AoR, it is reasonable and plausible to assume any upward-migrating injectate will not reach the USDW.

A loss of containment (vertical defect) attributable to an artificial penetration, a fault, or a loss of cement integrity in an injection well above the base of the USDW is thus considered much less likely than the chosen model for ERR cost determination, as described above. Details regarding the required rig operation and costs associated with the chosen model were provided by applicant's consultant, Geostock Sandia. As further described later in this report, Strategic Biofuels will acquire a commercial insurance policy covering the remediation of a hypothetical incident such as the one described (or any other potential remediation related to the sequestration project, including but not limited to the remediation of groundwater contamination) with an approved insurer on terms acceptable to the Commissioner of Conservation. The Office of Conservation will be designated by the commercial insurance policy as the contingent Loss Payee, with a coverage amount of not less than $25,000,000, to facilitate its response to any emergency and its performance of any remedial action that meets the requirements of §3623.

3.0 COST ESTIMATES

Cost estimates for all categories of Financial Responsibility as set forth in SWO 29-N-6 are provided in Table 1 below.

Table 1. Summarized Cost Estimates for Activities to be Covered by Financial Responsibility.

Proposed Project Activity	Total Cost - Pre-Injection*	Total Cost - Post-Injection**
Corrective Action Required / Undertaken pursuant to §3615.C Re-entry of the four (4) formerly plugged and abandoned artificial penetrations and the (currently shut in) Class V stratigraphic test well located within the AoR (total five (5) wells), all of which penetrated the Upper Confining Zone (requiring corrective action), and converting all five (5) wells to either compliant In-Zone or Above-Confining-Zone monitor wells (cost estimates by Geostock Sandia and/or other third-party contractors)	$0	$19,122,706
Injection Wells Plugging and Abandonment pursuant to §3631 **(Pre-Injection, if required – 3 wells) (least likely scenario)** (Estimate by Geostock Sandia and/or other third-party contractors)	$1,048,853	$0
Injection Well Plugging and Abandonment pursuant to §3631 **(Post-Injection – 3 wells) (most likely scenario)** (Estimate by Geostock Sandia and/or other third-party contractors)	$0	$3,820,866
Emergency and Remedial Response (ERR) pursuant to §3623 (See discussion below for the detailed description of the most plausible and reasonable emergency incident scenario and remedial procedure used as basis for ERR cost estimate by Geostock Sandia and/or other third-party contractors)	$0	$4,991,573
Post-Injection Site Care (PISC) and Site Closure pursuant to §3633 (Estimate by Strategic Biofuels, Geostock Sandia and/or other third-party contractors)	$0	$22,692,743
Total Costs to be Covered by Financial Responsibility	**$1,048,853**	**$50,627,888**

** least likely scenario; assumes injection wells plugged and abandoned prior to injection, no monitor wells constructed, and site abandoned*
*** most likely scenario*

The Letter of Credit and Surety Bond referred to above will comply with all provisions of SWO 29-N-6 §3609.C, as it may be amended. The instruments will be issued by and drawn on a bank or other financial entity acceptable to the Commissioner of Conservation and authorized under state or federal law to operate in the State of Louisiana. The applicable instrument will contain the protective conditions of coverage required by SWO 29-N-6 §3609.C.4.c, including a provision that it may not be terminated except due to failure to make payment and such termination may not be final until 120 days after receipt by the Commissioner of a cancellation notice.

3.1 Corrective Action

Pursuant to §3601, the definition of Corrective Action is "*the use of UIC program-approved methods to ensure that wells within the area of review do not serve as conduits for the movement of fluids into USDWs*." Within the AoR, extensive CO2 plume modeling and pressure-front analysis along with a thorough review of the historical plugging and abandonment records available from the Office of Conservation have determined there exists a total of five (5) legacy wells (including applicant's Class V stratigraphic test well) that will require Corrective Action. This will be accomplished with the repurposing of four (4) of the wells as In-Zone Monitor Wells and the remaining well will be plugged back and completed as an ACZ Monitor Well.

There are six (6) additional legacy (plugged and abandoned) wells located within the AOR, outside the maximum extent of the CO2 plume (i.e., in the pressure front area), which penetrated the Primary Confining Zone (five of these six wells being located near the outer perimeter of the AoR).

Each such well was evaluated with consideration of (1) the magnitude of modelled pressure front ("delta p") impact at the legacy well location; (2) a review of each such well's plugging and abandonment records (filed with the State) pertaining to the casing run and the protection of the USDW, as well as the proper placement and thickness of the cement plugs set at the time of abandonment; and (3) an analysis of the adequacy, at the Injection Zone level, of the static fluid column pressure provided by the mudweight (drilling fluid density) at time of abandonment, which would more than offset any "delta p" potential increase in the reservoir pressure of the injection zone and thus prevent any out-of-zone upward movement of formation brine.

Because of the reliance of this analysis upon the drilling fluid density at time of abandonment, while not taking into account the typically higher static gel strength demonstrated to develop over time as the drilling fluid in the plugged well sets up and becomes more dense, this derivation of the adequacy of the legacy well's plugging and abandonment is considered to be highly conservative.

Taking all three factors into account, the six plugged and abandoned legacy wells located within the pressure front area (outside of the maximum extent of the plume) have been projected to remain hydraulically stable and undisturbed throughout the life of the sequestration project and the 100-year post-injection closure period, without any upward movement of formation brine within the wellbore annulus that could impact, let alone reach, the USDW; therefore, these six wells do not require Corrective Action.

The cost estimates for the repurposing of the five legacy wells requiring Corrective Action were prepared by Geostock Sandia and/or another third-party contractor and are presented below and on the following pages.

For the one repurposed ACZ Monitor Well (plugging back and repurposing of legacy well AP #69 - Bradford Brown Trust #1 Shipp):

Above Confining Zone Monitor Wells	Shipp / ACZ-1
Plugging Back / Cementing	**$1,563,735**
Tangibles	$134,591
Rig Operations	$380,038
Project Management	$134,980
Civil Works	$71,302
Drilling & Completions Services	$552,429
Formation Evaluation	$142,600
Other Services	$147,795
Completion (1 Packer / 1 Gauge)	**$719,004**
Tangibles	$280,440
Rig Operations	$94,843
Project Management	$39,829
Civil Works	$4,782
Completion Services	$210,739
Formation Evaluation	$45,000
Other Services	$43,369
Total Cost	**$2,282,739**

For the four re-entered and repurposed IZ Monitor Wells (repurposing of legacy wells AP #76 - Bass #1 Keahey, AP #101 - Southern Carbon #1 USA, AP #137 - Whitetail (LGF) #1 Louisiana Green Fuels (the Class V stratigraphic test well), and AP #276 - Murphy #1 Meredith*):

In Zone (Repurposed) Monitor Wells	Keahey / M-2	USA / M-3	LGF / M-4	Meredith / M-5
Drilling / Deepening	**$3,564,730**	**$3,375,906**	**(NA)**	**$4,132,323**
Tangibles	$641,321	$191,879	------------	$723,091
Rig Operations	$579,405	$535,639	------------	$831,634
Project Management	$184,842	$170,882	------------	$179,316
Civil Works	$75,481	$78,193	------------	$79,122
Drilling & Completions Services	$912,033	$1,193,069	------------	$1,073,905
Formation Evaluation	$991,738	$999,611	------------	$1,002,310
Other Services	$179,910	$206,634	------------	$242,944
Completion	**$1,485,533**	**$1,211,680**	**$1,647,680**	**$1,422,116**
Tangibles	$591,303	$414,354	$1,050,868	$591,303
Rig Operations	$189,235	$169,030	$128,372	$184,168
Project Management	$98,761	$41,638	$103,745	$44,876
Civil Works	$41,001	$8,862	$67,353	$9,715
Completion Services	$458,986	$475,614	$228,867	$486,215
Formation Evaluation	$45,000	$45,000	$0	$45,000
Other Services	$61,248	$57,183	$68,475	$60,838
Total Cost	**$5,050,263**	**$4,587,586**	**$1,647,680**	**$5,554,438**

* *Note – IZ Monitor Well M-1 will be a* ***new drill well*** *located adjacent to ACZ Monitor Well ACZ-1.*

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3.2 Injection Wells Plugging and Abandonment

The itemized cost estimates for Pre-Injection and Post-Injection Wells Plugging and Abandonment scenarios were prepared by Geostock Sandia and/or another third-party contractor as follows:

Abandonment Scenario	WN-1	WN-2	WS-2	TOTAL
Pre-Injection	**$355,325**	**$346,497**	**$347,031**	**$1,048,853**
Abandonment Services	$162,911	$162,911	$162,911	**$488,733**
Project Management	$31,879	$29,994	$32,400	**$94,273**
Other Services	$16,094	$15,874	$15,688	**$47,656**
Rig Operations	$144,441	$137,718	$136,032	**$418,191**
Post-Injection	**$1,298,543**	**$1,273,472**	**$1,248,851**	**$3,820,866**
Abandonment Services	$799,197	$799,197	$799,197	**$2,397,591**
Project Management	$80,015	$74,875	$74,529	**$229,419**
Other Services	$54,202	$52,602	$43,828	**$150,632**
Rig Operations	$320,129	$301,798	$286,296	**$908,223**
Formation Evaluation	$45,000	$45,000	$45,000	**$135,000**

*Note: the **Post-Injection** abandonment cost scenario shown above reflects the most likely cost scenario.*

3.3 Post-Injection Monitoring, Site Care and Site Closure

Post-Injection Site Care and Site Closure costs are estimated by Strategic Biofuels (monitoring, reporting, site restoration) and Geostock Sandia and/or other third-party contractors as follows:

Post-Injection Monitoring	
Walk-Away Vertical Seismic Profile (VSP) plume monitoring	$12,000,000
Fluid sampling and analysis, pressure / temperature monitoring	$5,000,000
Regulatory reporting	$1,000,000
Subtotal	**$18,000,000**
Site Closure	
Plugging and Abandonment (P&A) of all remaining unplugged monitor wells	$4,143,852
Site restoration of all remaining unplugged monitor wellsites	$500,000
Subtotal	**$4,643,852**
TOTAL	**$22,643,852**

3.4 Emergency and Remedial Response

The cost estimate for the Emergency and Remedial Response was prepared by Geostock Sandia and is based on a detailed itemization of costs for the procedures required to remediate a specific loss-of-containment emergency scenario deemed to be the most reasonable and plausible event that may occur (as discussed earlier in this report).

The scenario assumes that injectate has been detected moving upward behind the 9-5/8” and 13-3/8” casings, at some depth above the Primary Confining Zone, the Austin Chalk Equivalent, and the Secondary Confining Zone, the Midway Shale (but below the base of the Wilcox interval, and still well below the USDW).

The following procedure is the recommended program prepared by Geostock Sandia to address this hypothetical situation, ending with final plug and abandonment. Such an emergency incident would be a named peril in a commercial insurance policy providing $25,000,000 of coverage. The cost estimate is itemized here, followed by the detailed work procedure:

ERR: Remediation of Loss of Containment - Most Reasonable & Plausible Event That May Occur	
Job Planning and Location Preparation	$128,498
Rig Mobilization to Location and Rig Up	$225,452
RIH, Retrieve Tubing and Completion Equipment	$198,717
Run Evaluation Logs	$308,617
Cement Squeeze Upper and Lower Injection Intervals	$1,288,759
Log No Flow, Section Mill 9 5/8” Csg, Underream, Cement Squeeze at 4600’	$1,057,422
Log No Flow, Section Mill 9 5/8” & 13 3/8” Csg, Underream, Cmt Sqz at 3,620’	$1,268,660
Log No Flow, Set CIBP at 1400’, Circulate Cement to Surface	$216,056
Cut Off and Cap Well, Rig Down, Demobilize Rig, Report Preparation	$299,392
TOTAL	**$4,991,573**

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4.0 WORK PLAN TO ADDRESS HYPOTHETICAL EMERGENCY INCIDENT

Proposed Scope of Work to Address Loss of Containment Behind Injection Well Casing

1. Shut-in the well.

2. Conduct a Project Safety Meeting (PJSM).

3. Mobilize (MI) and rig up (RU) a workover rig with pump tank, pipe racks, power swivel, and other necessary equipment.

4. Set up the field office.

5. Mobilize and rig up five frac tanks, one blending tank within containment, a generator, and manifold tanks and pumps for operations. The frac tanks will include:

  - o One freshwater tank
  - o One tank filled with 11.5 ppg $CaCl_2$ brine
  - o Two saturated brine storage tanks
  - o One blended fluids tank

Kill Fluid Circulation

6. Blend ~500 bbls. of kill-weight brine (10.5 lb./gal). Additional kill-weight brine will be blended as needed. It is assumed that 10.5 lb./gal brine will be required to kill the well. The kill-weight fluid and drilling fluid densities will be adjusted for the actual bottom hole pressure.

7. Adjust the Smart Well system to pump into the lower perforated interval (~5,250 - 6,990 feet). Displace the tubing and 9-5/8” casing volumes with twice the calculated volume (~500 bbls.).

8. Switch Smart Well valving to the upper perforated injection interval (~4,910 - 5,210 feet). Displace the upper injection interval with ~75 bbls. of brine.

9. Verify that the well is dead. If necessary, displace the wellbore with a heavier fluid or drilling fluid to prevent CO_2 influx.

Isolation & Equipment Setup

10. Install a packer or retrievable bridge plug in the 5-1/2” tubing (~500 feet below the surface). Release from the tool and remove the workstring.

11. Pressure test the packer for isolation.

12. Nipple down the wellhead tree assembly and install a blowout preventer (BOP) stack:

  o 11” 5K double ram BOPs (with 5-1/2” pipe rams on top and blind rams on the bottom)

  o 11” 5K annular preventer

13. Function-test the annular BOP. Pressure test the blind rams to 250 psi low pressure and 3,000 psi high pressure. Test the annular rams to 250 psi low pressure and 1,500 psi high pressure.

14. Set up spooling equipment and sheaves; prepare to remove tubing while spooling up hydraulic control lines and wireline cable for downhole pressure gauges.

15. Rig up casing crew for tubing removal. Confirm that the well is dead.

Logging & Isolation

16. Release the packer/bridge plug and remove tubing and packers while spooling up hydraulic lines and pressure gauge lines.

17. Close the blind rams, remove the 5-1/2” pipe rams, and install 2-7/8” pipe rams.

18. Run a casing scraper to ~4,850 feet and circulate well clean. Circulate the well clean with 10.5 lb./gal. brine.

19. Rig up logging crew with pressure control and run the following logs from ~4,850 feet to surface:

  o Casing inspection log

  o Cement bond log

  o Pulse neutron/water flow log to confirm fluid migration behind casing

Cement Squeeze & Casing Milling

20. Pick up and set a 9-5/8” cement retainer at ~5,700 feet. Test for integrity.

21. Rig up cementing crew and squeeze the injection interval with ~100 bbls. of 11.0 ppg epoxy resin cement. Set up two 75 bbl. blenders for batch mixing 100 bbl. of epoxy resin cement. Assumes ~35 bbl. of epoxy resin cement will be squeezed into the lower perforated interval from ~5,250 feet to ~6,990 feet.

· Pump ~92 bbl. below the retainer.

· Pull out of the cement retainer and spot 8 bbl. above the retainer (~100 feet of cement) from ~5,600 ft to ~5,700 feet.

22. Allow cement to cure (~24 hours).

23. Tag top of cement with workstring. Spot 10.5 lb./gal. drilling mud from top of cement at ~5,600 feet to ~5,210 feet, 30 bbl.

24. Pick up and set a 9-5/8" cement retainer at ~4,800 feet. Test for integrity.

25. Rig up cementing crew and squeeze the injection interval with ~100 bbl of 11.0 ppg epoxy resin cement. Assumes 60 bbl. of epoxy resin cement will be squeezed into the upper perforated interval assumed to be from 4,910 feet to 5,210 feet.

· Pump ~92 bbl. below the retainer.

· Pull out of the cement retainer and spot 8 bbl. above the retainer (~100 feet of cement)

22. Allow cement to cure (~24 hours). Tag top of cement and pressure test casing to 1,500 psi.

23. Rig up the logging unit and repeat the pulsed neutron / water flow logs to evaluate fluid migration behind casing over the interval above the top cement in the 9-5/8" casing. Compare results to the log performed before the first squeeze.

24. Pick up a casing section mill and remove (mill out) ~60 feet of the 9-5/8" casing (~4,600 - 4,660 feet). Assume two milling runs will be required.

25. Underream the wellbore to ~14 inches from ~4,605 - 4,650 feet. Circulate well clean.

26. Blend and pump ~83 bbls. of 11 ppg epoxy resin cement. Leave a balanced plug from ~4,700 - 3,700 feet. Pull end of workstring up to ~3,500 feet and reverse circulate clean.

27. Perform a bradenhead squeeze (800–1,000 psi) and a hesitation squeeze (1 to 2 hours).

28. Shut in squeeze pressure and wait ~24 hours.

Further Isolation & Final Cementing

28. Pick up bit and scraper; run in well and tag top of cement. If cement top is below 3,700 feet, fill the 9-5/8" casing with 10.5 lb./gal. drilling mud to 3,700 feet. If the cement top is above 3,700 feet, dress the cement down to ~3,720 feet.

29. Assume cement top in 9-5/8" casing at ~4,100 feet. Fill 9-5/8" casing with 10.5 lb./gal. drilling mud from ~4,100 - 3,700 feet.

30. Rig up the logging unit and repeat the pulsed neutron / water flow log to evaluate fluid migration behind casing over the interval above the top cement in the 9-5/8" casing. Compare results to the log performed before the first squeeze. This log will determine if any fluid movement is still observed behind the casing.

31. Set a 9-5/8" bridge plug at ~3,700 feet.

32. Section mill the 9-5/8" casing (~3,620–3,680 feet). Assume three runs.

33. Section mill the 13-3/8" casing (~3,630–3,670 feet).

34. Underream from ~3,635–3,665 feet to 18 inches. Circulate well clean.

35. Blend and pump 75 bbls. of 11 lb./gal. epoxy resin cement slurry. Leave a balanced plug from ~3,700 - 2,865 feet.

36. Perform a bradenhead squeeze (800–1,000 psi) and hesitation squeeze (~1 hour).

37. Wait ~24 hours for cement to set.

38. Pick up bit and scraper, run in well and tag top of cement. If the cement top is above 3,000 feet, dress the cement down to ~3,000 feet. Circulate 9-5/8" casing clean with 10.5 lb./gal. brine.

39. Rig up the logging unit and repeat the pulsed neutron / water flow log to confirm no fluid migration behind casing over the interval above the top cement in the 9-5/8" casing. Compare results to the log performed before the first squeeze. This log will determine if any fluid movement is observed behind the casing. If flow is determined the path forward will be evaluated before proceeding to the next step.

40. Circulate 10.5 lb./gal. drilling mud in the 9-5/8" casing from ~3,000–1,400 feet.

41. Set a 9-5/8" bridge plug at ~1,400 feet.

42. Mix and pump 110 bbl of Class A neat cement slurry. Ensure cement returns to surface.

Final Abandonment & Site Restoration

41. Remove the workstring while washing up.

42. Fill the 9-5/8" casing with cement to ~5 feet below ground level.

43. Clean up and release the cementing contractor.

44. Rig down and release the workover rig and equipment.

45. MI backhoe, roustabout crew.

46. Lay down a 30 mm ground sheet for spoils from the near wellhead excavation.

47. Excavate around the wellhead to ~5 feet below ground level.

48. Use 3 gas monitors to check the excavated area.

49. Rig up the welder.

50. Hold PJSM and sign hot work permit and JSA, post fire watch.

51. Cut off casings ~4 feet below ground level.

52. Weld a 3/8” OD plate inside the 9-5/8” casing and another on the 18-5/8” surface casing. Include:

    o Operator's Name

    o Well Name

    o Permit Number

    o Plugging Date

53. Rig down the welder.

54. Clean up and backfill the location, leveling the area.

55. Move off equipment and personnel; close the job.

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5.0 PROVIDERS OF FINANCIAL RESPONSIBILITY

A Letter of Insurability from insurance provider AON plc confirming the commercial availability and AON's willingness to provide acceptable forms of Financial Responsibility in favor of the Office of Conservation for all cost categories, to be placed prior to the issuance of the Permit to Inject (other than pre-injection plugging and abandonment), is provided at the end of this section.

To cover any and all pre-injection plugging and abandonment obligations (that might arise before issuance of the final Permit to Inject), a letter from the Homeland Federal Savings Bank in Columbia, Louisiana, confirming the willingness to provide a Letter of Credit in favor of the Office of Conservation immediately upon applicant's receipt of its *draft* Permit to Construct and prior to applicant's receipt of its *final* Permit to Construct in an amount in excess of the estimated "pre-injection P&A" cost, is also provided at the end of this section.

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Daren Gretz
Senior Vice President
200 East Randolph Street
Chicago, Illinois 60601

+1 312 259 0885
Daren.Gretz@aon.com

March 27, 2025

Mr. Bob Meredith
COO, Strategic Biofuels LLC
COO, Louisiana Green Fuels LLC
303 Wall St.
P. O. Box 1269
Columbia, LA 71418

Re: Financial Responsibility of Class VI Well and Letter of Insurability

Dear Mr. Meredith:

As the insurance and risk management consultant for Strategic Biofuels LLC, and its affiliate, Louisiana Green Fuels LLC [Strategic] Aon plc [Aon] is pleased to provide this letter of insurability and intent to issue the commercial risk insurance policies and/or performance bonds with respect to Strategic Biofuels for its Class VI Wells for the Louisiana Green Fuels project detailed herein.

Whereas Aon understands the following business objective and process description:

Process Description:
Louisiana Green Fuels (LGF) is planning construction of a renewable fuels bio-refinery in northeast Louisiana using forestry waste as a feedstock, powered by onsite-generated “green” electric power, and including Carbon Capture and Sequestration (CCS) of the carbon dioxide (CO_2) from all processes. The bio-refinery will manufacture Sustainable Aviation Fuel and renewable naphtha that will be shipped by rail to California. The feedstock will be the abundant forestry residues (or “biomass”) in the region in the form of wood chips from commercially managed and sustainable forest plantations, primarily pine. The residues used to manufacture the renewable fuels are waste material with little economic value that would in many cases be left in the forest to decompose or be burned, in either case resulting in the release of greenhouse gases (GHG). The feedstock will be compliant with the requirements of the EPA’s Renewable Fuel Standard (RFS) to allow for the generation of Renewable Identification Numbers, or RINs. The fuel produced will also qualify for generating carbon credits under California’s Low Carbon Fuel Standard (LCFS). Additionally, the sequestered CO_2 tonnages will qualify for substantial tax credits, referred to as “45Q” credits in the federal tax code.

LGF will also construct a 79-MW biomass-boiler power generation plant to provide "green" electric power to operate the bio-refinery. It will be located on the same site and adjacent to the bio-refinery. The fuel for the power plant will be sawmill waste and other available biomass material that does not need to be RFS-compliant.

An essential feature of the overall project that drives its robust economics is the CCS facility that will capture over 90% of the CO2 produced from both the bio-refinery and the electric power plant. The CO2 will be compressed into a "supercritical" or near-liquid state and, through several LA DENR-regulated "Class VI" wells located on the renewable fuels facility site and nearby, injected and stored permanently underground in a mile-deep sequestration reservoir. In early 2021, LGF drilled a "Class V" stratigraphic Test Well near the Port of Columbia site that confirmed the presence of a thick porous and permeable injection interval and also the impermeable confining zones above and below needed to seal the CO2 in place. Subsequent injection testing further confirmed that the injection zone was capable of accepting the projected volumes of produced CO2.

Underwriting and Risk Assessment:
Aon has partnered with several insurers to provide insurance for the Financial Responsibility of the Strategic Class VI Wells rated A+ / A XV (A.M. Best/S&P). Aon has completed an initial risk assessment and concluded the insurability of the Class VI Wells and the sequestration operations. We are informed the Class VI application requires a demonstration of Financial Responsibility in a form satisfactory to the Louisiana Commissioner of Conservation to cover the following cost categories in amounts no less than those set forth in the application or such higher amounts as may be required by the Commissioner:

Corrective Action
Injection Wells Plugging and Abandonment (post-injection)
Post-Injection Site Care and Site Closure
Emergency and Remedial Response

You have indicated that it is very likely that the actual coverages requested will substantially exceed the required minimum coverages.

We are also informed that a commercial bank will separately provide interim pre-injection coverage for the costs of Plugging and Abandonment of the Injection Wells during the period beginning with LA DENR's issuance of a Permit to Construct through the date of its issuance of a final Permit to Inject.

The risk assessment included review of the project overview, project agreements, financial models, technical specification, and other files provided by Strategic, as well as Underwriters and Aon having completed telephone risk control interviews, a site inspection and an observational site visit of feedstock testing. Risk control calls and site visits addressed Heat & Material Balance results with biomass feedstock with the goal of understanding the efficiency and reliability of the Strategic technology and the planned Class VI Wells.

Risk Transfer and Insurance:
Aon is a leading insurance broker in the waste to energy industry with technical knowledge of the Strategic system and experience working with many of the developers commercializing bioconversion technology and CCS Class VI Wells.

Based on our pre-underwriting of the foregoing planned developments, Aon is pleased to provide confirmation and support of the required insurance and/or performance bonds providing Financial Responsibility for the cost categories set forth above to be procured on behalf of Strategic and its partners and effective at such date as required by the Commissioner of Conservation and subject to all other statutory or regulatory provisions.

Subject to the project specific requirements, terms, conditions, limits, and exclusions of the policies, Aon has confirmed the commercial availability of coverage and pre-qualified Strategic with insurers with a minimum rating AM Best A Superior and S&P investment grade, conditional on complete underwriting review of the project.

We are available to discuss any questions your potential partners or regulatory personnel may have.

Daren Gretz

Daren Gretz
Senior Vice President

HOMELAND BANK

RONNIE L. DARDEN
PRESIDENT &
CHIEF EXECUTIVE OFFICER

April 16, 2025

Mr. Bob Meredith
Strategic Biofuels LLC
P. O. Box 1269
Columbia, LA 71418

Re: Notice of Approved Application for a Letter of Credit in favor of the Louisiana Office of Conservation

Dear Mr. Meredith:

Reference is made to the pending application of Strategic Biofuels LLC to the Louisiana Office of Conservation for a permit to construct a carbon dioxide sequestration complex with the drilling of three "Class VI" injection wells associated with its Louisiana Green Fuels renewable fuels project in Caldwell Parish.

We are informed that issuance of a Class VI permit has two stages, an initial "Permit to Construct" and a final "Permit to Inject" and that the regulations specify certain required financial assurances covering several cost categories that must be in place prior to issuance of the Permit to Inject for a Class VI project.

We are further informed that the issuance of the Permit to Construct requires that financial assurance also be in place for the contingent plug and abandonment (P&A) of the three proposed injection wells in the event that such are drilled and constructed pursuant to the Permit to Construct but never receive a final Permit to Inject. You have referred to that highly unlikely circumstance as a "pre-injection P&A" and have estimated a total cost of $1,048,853.00 for such operations.

For that limited pre-injection P&A purpose, this letter shall affirm our bank's offer to provide the financial assurance needed. Upon your request and subject to the terms discussed, a Letter of Credit (LOC) in sole favor of the Office of Conservation and in a form acceptable to the Commissioner of Conservation will be issued in the amount of $1,100,000.00 for the contingent costs of pre-injection P&A of the three drilled wells. We understand that the request for issuance of the LOC will come soon after your notification from the Office of Conservation that it has prepared a draft Permit to Construct and has scheduled a hearing for public comment.

You have provided us with correspondence from Aon, a global financial services firm that is routinely engaged in similar matters for large industrial projects. That entity has confirmed its willingness and ability to provide the more expansive Financial Responsibility assurances required by the Office of Conservation that must be in place for the issuance of a Permit to

Inject. The assurances provided by Aon will include the long-term costs of post-injection P&A of the drilled wells and overall sequestration site closure and will negate the need for continued pre-injection P&A coverage. Accordingly, upon issuance of a Permit to Inject, at which time the Aon coverage will be in effect, the LOC issued pursuant to this letter will become unnecessary and will expire of its own terms. Furthermore, should we not receive your request for issuance of the LOC by December 31, 2025, this offer shall expire.

Sincerely,

Ronnie L Darden

Ronnie Darden
President & CEO

6.0 NEED FOR ADJUSTMENT OF FINANCIAL RESPONSIBILITY

Over the active life of the geologic sequestration project, and as prescribed by §3609.C.4(h), the cost estimates provided above will be adjusted for inflation and other factors impacting cost within 60 days of the anniversary of the establishment of the Financial Responsibility instruments and, if necessary to maintain full coverage of such costs, the face amount of the instruments will also be adjusted. All revised cost estimates and changes to the face amounts of the instruments will be provided to the Commissioner within 60 days after a determination of an increase in cost and will be subject to the Commissioner's approval.

References

Analysis of potential leakage pathways at the Cranfield, MS, U.S.A., CO2 sequestration site

International Journal of Greenhouse Gas Control, 18 (2013) 388–400

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Analysis of potential leakage pathways at the Cranfield, MS, U.S.A., CO_2 sequestration site

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ABSTRACT

A 1.5-million-ton CO_2 sequestration project took place in a 3000-m-deep historical oilfield, combined with a CO_2-EOR flood. The Cranfield reservoir is found within a multikilometer domal structure related to a deep-salt diapir and consists of fluvial sediments of the Tuscaloosa Formation. An earlier analysis determined that plugged and abandoned wells provide the most likely leakage pathways to aquifers and potentially to the ground surface. Fourteen Cement Bond Logs (CBL's) were used to assess the risk. The present quality of the cement bond ranges from excellent to poor.

Geological insights, stochastic numerical modeling of the pressure field, analysis of the CBL's, and application of a wellbore flow model were used to conclude that the limited pressure increase and mostly intact wellbores result in a low CO_2- and brine-leakage risk. Statistical estimates of well properties suggest that at most two (and possibly none) could be capable of conveying a total of 1800 kg/yr CO_2 to the surface (0.0002% of annual injection rate). Given that the oilfield is an active operation, it is improbable that well leakage to the surface will go unnoticed and certain that risks will be managed through active risk mitigation and remediation if necessary.

1. Introduction

A risk assessment or analysis (RA) of processes and events that can derail an otherwise perfectly planned enterprise is often undertaken before the launching of any large industrial endeavor. Developing an enhanced oil recovery (EOR) operation to extract some of the remaining oil from a depleted oil reservoir that has historically produced is no different. When Denbury Onshore, LLC from Plano, TX (the operator), made the decision to invest in the Cranfield, Mississippi (MS), field in the mid-2000s, the operators performed standard technical, financial, and economic analysis of the project and brought with them their practical expertise, stemming from several similar operations across the southeast U.S. In agreement with Denbury and with its operational support, the site was also chosen by the Bureau of Economic Geology (BEG) to achieve some of the goals set forth by the DOE-sponsored SECARB partnership (Hovorka et al., 2013). Phase III of the collaborative project is geographically focused on the northeast section of Cranfield field. This limited section of the field has been called the HiVIT (high-volume injection test) and includes a smaller area, called the DAS (detailed area of study), on which BEG has performed many tests and research investigations (Fig. 1). The HiVIT area is the focus of this paper. There, the operator and BEG collaborated to inject 1.5 million tons of CO_2 over 1.5 years (Choi et al., 2013), both within the historically determined boundaries of the field and into the downdip leg of the field, where the DAS is located.

Developing a CO_2-storage operation next to a historical and active oil-production site introduces the issue of leakage through wells and prompted a risk-assessment study. However, the work presented here is not a risk assessment of the oil operation itself, which is handled by the operating company. The study followed the certification framework (CF) procedure (Oldenburg et al., 2009). CF focuses on events that are deemed the most likely to cause problems from past historical evidence, that is, wellbores and faults, as well as spill points (Fig. 2). The objective of the present analysis is to investigate the potential impact of these three categories of features on site integrity. We first describe the relevant attributes of the site and the volumes potentially impacted from the surface to the reservoir itself. We then present details of the methodology to estimate leakage potential and impacts and then apply the method to calculate risks semi-quantitatively. A discussion of the results follows that also includes likely attenuation factors limiting the negative impacts of some events.

2. Site description

The Cranfield oil and gas field is located in a rural area of southwestern Mississippi near the Louisiana border (Fig. 1). The area is

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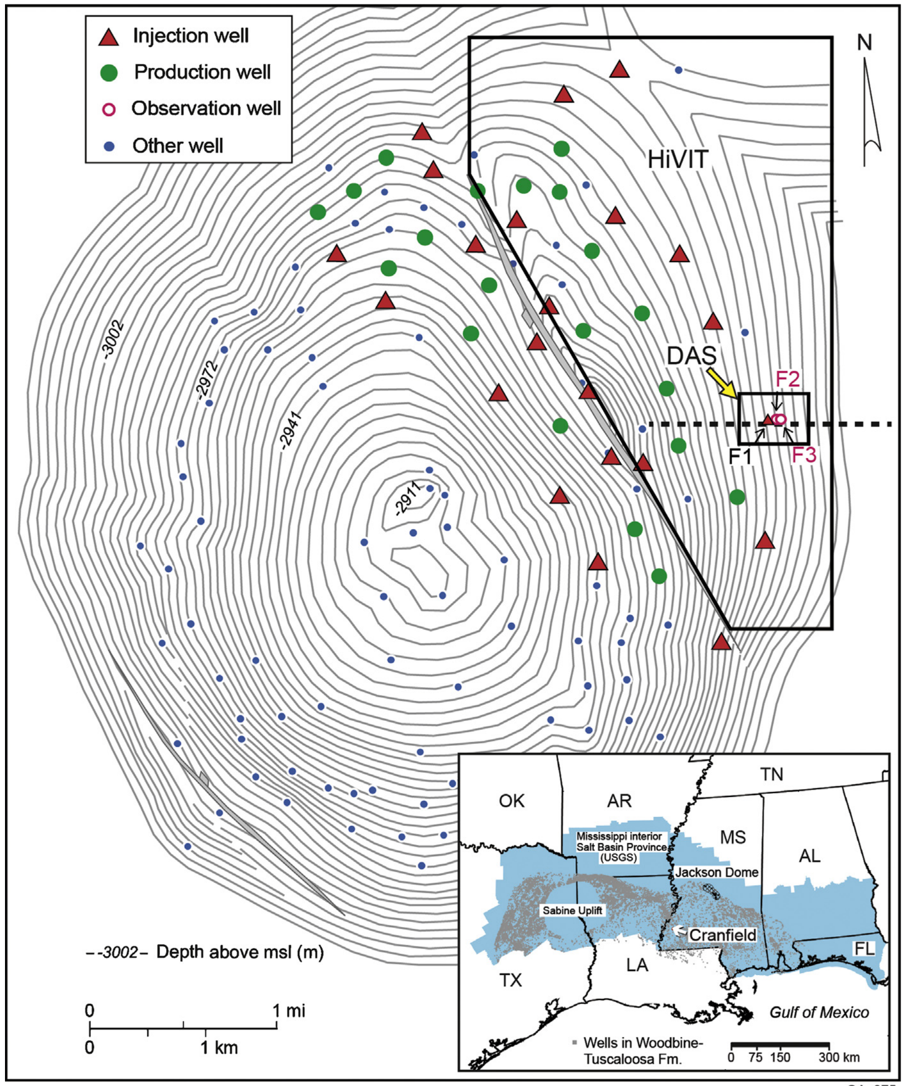

Fig. 1. Site map showing relationship between investigative domains. SECARB Phase II focused on monitoring of pressure in so-called EOR domain, and SECARB Phase III focuses on HiVIT and DAS domains. Note spill point at extreme northeast of domal structure. Inset map shows location of Cranfield field in southwestern Mississippi close to Louisiana state line and Mississippi River. Black dots represent oil and gas wells reaching the Tuscaloosa Formation.

heavily wooded with clearings and is moderately hilly with flat terrace areas near streams; elevations above mean sea level range from 60 to 120 m (200–400 ft). Surface drainage is provided by two small creeks. The closest large population center is Natchez (~18,000 inhabitants) 25 km (15 miles) to the west, although isolated residences spread out over the area, and oil and gas workers are present around the site.

2.1. Shallow subsurface—fresh-water aquifers

Shallow formations typically contain protected aquifers and, more generally, underground sources of drinking water (USDW). USDWs are defined as aquifers having a TDS of <10,000 mg/L. In the study area, they lie within a shallow aquifer system, which is ~700 m (2300 ft) thick there (Fig. 3). The local fresh-water aquifer is hosted by the confined Catahoula Sands overlying the mostly confining Jackson–Vicksburg Group. The area is blanketed by loess, fine-grained material that limits recharge and confines the underlying aquifers. The depth at which salinity of 1000 mg/L occurs varies between 180 and 240 m (600–800 ft)—perhaps 300 m (1000 ft)—below ground surface (bgs) at the site (Marble, 1976; Gandl, 1982). Transition to a salinity of >3000 mg/L occurs at depths ranging from 365 to 425 m bgs (1200–1400 ft) in the site area (Marble, 1976). Transition to a salinity of >10,000 mg/L occurs at a depth ranging from 425 to 550 m bgs (1400–1800 ft) (Marble, 1976).

The closest municipal well field is that serving the City of Natchez >16 km (10 miles) from the oilfield. USGS reports (Boswell and Bednar, 1985; Strom et al., 1995) state that wells withdrew water from three different levels of the Catahoula Sands at a total rate of 9.2 million gallons per day (in March 1995, 35,000 m^3/day). Only some shallow domestic wells, as well as water-supply wells to support oilfield activities at <100 m (300 ft), exist in the study area.

At the site, groundwater chemistry of the shallow alluvial aquifer at 60–100 m bgs (200–300 ft) is mainly of the $Ca—Mg—HCO_3$ to $Ca—Mg—HCO_3—Cl$ types (Changbing Yang, BEG, personal communication, 2012), similar to that of deeper aquifers (Boswell and Bednar, 1985, their Table 3). Heavy metals, including As, Cr, Mo, and Se, are nondetectable. Sediment samples taken from a water well within the footprint of the oilfield indicate that the aquifer material is free of pH-buffering carbonate minerals (Jiemin Lu, BEG,

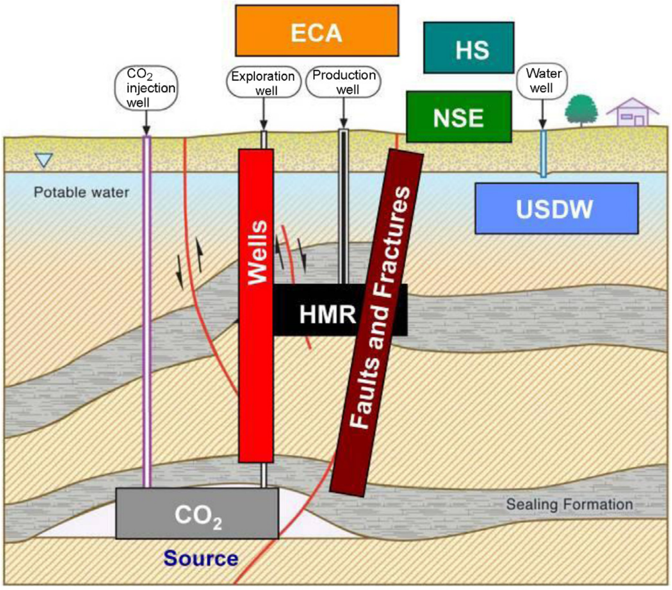

Fig. 2. Generic schematic diagram of compartments and conduits in the CF.

personal communication, 2012). Calcite, dolomite, and gypsum are undersaturated in all groundwater samples (Changbing Yang, BEG, personal communication, 2012), corroborating the petrographic analyses.

2.2. Overburden

The Jackson–Vicksburg confining unit separates the shallow aquifer system from underlying formations consisting of poorly consolidated rocks of Late Cretaceous to middle Eocene age with alternating layers of sands, mudstones, and siltstones. The base of the sedimentary sequence in the Gulf Coast Basin consists of thick, extensive salt layers of Jurassic age that were found at 6000 m (~20,000 ft) in a deep well at the site. Cockfield, Sparta, and Carrizo are three formations with significant thickness and permeability and TDS levels >10,000 mg/L near the site (Fig. 3). The Carrizo Formation (Fm.) is hydrologically connected to the underlying Wilcox Group, which is a thick, ~900-m (~3000-ft) accumulation of interbedded sandstone units. Wilcox brines are somewhat saline, varying from <100,000 to 150,000 mg/L, with a mostly Na-Cl composition and no sulfate. The Wilcox Group is separated from Cretaceous sediments by the thick Midway claystones (Fig. 3). The Upper Cretaceous sediments show a strong carbonate imprint with the Austin Chalk and allied formations, as well as the carbonate-rich Eagle Ford "Shale" mudstone.

2.3. Reservoir

The reservoir targeted for CO_2 sequestration lies at a depth of ~3000 m (10,000 ft). Regionally the lower sandstone beds of the Cretaceous Tuscaloosa Fm. are fluvial-deltaic sediments interpreted as having been deposited in a semiarid climate characterized by aggradational deposition (Hovorka et al., 2013). The oil-producing and injection interval is hosted by basal sandstones and conglomerates of the lower Tuscaloosa Fm. The average total thicknesses of the productive sand in the gas cap and in the oil zone are 19 m (63 ft) and 9.4 m (31 ft), respectively, although they vary across the field. Numerous discontinuous mudstone layers vertically compartmentalize the dominant sandstone lithology. The basal sandstones are overlain by local fluvial mudrocks capping the reservoir (Hovorka et al., 2013). Additional, mostly nonproductive, alternating sandstones and mudrocks complete the lower Tuscaloosa section (Fig. 4). An overlying fine-grained marine sandstone is used as an above-zone monitoring interval (Tao et al., 2013). The fine-grained marine sandstone is overlain by dark marine mudstones of the middle Tuscaloosa Fm. (Lu et al., 2011), forming an additional seal. The Tuscaloosa Fm. is then overlain by the thick carbonate mudstones of the Upper Cretaceous.

The complex deep structure at the top of the salt layers is reduced to a crestal graben in the Tuscaloosa interval at the depth of the oilfield. The faults trend NW–SE, one cutting through the northeast section of the oilfield, with the southeast compartment being downthrown, and the other just southwest of the oilfield, with the same downthrown compartment northeast of the fault. The relevant fault for this study is the one that bounds the study area in the northeast part of the field and divides the reservoir into two unequal parts. A spill point is also visible at the extreme northeast of the structure (Fig. 1).

The reservoir sandstones are petrophysically complex. Textures range from conglomerate to sandstone to mudstone, and lithological units have channel geometries incised into one another. Lateral and vertical continuity of rock types is low. Sandstones are cemented by variable amounts of authigenic chlorite, quartz, and calcite. Chlorite cement is interpreted as preserving porosity, but it does not uniformly preserve permeability. Chlorite cementation adds complexity to the porosity and permeability fields that in some locations overwhelms the expected properties associated with the primary fluvial depositional system (Lu et al., 2013). Localized secondary porosity occurs as a result of quartz-grain and carbonate-cement dissolution. This complexity suggests that a stochastic approach is best for evaluating permeability and porosity fields. Local Tuscaloosa brines have a TDS of ~150,000 mg/L, and they are of the Na-Cl type, with no sulfate but with nonnegligible Ca.

2.4. Mineral resources

Cranfield field is a depleted gas and oil reservoir. Oil was originally discovered in 1943 by a predecessor of Chevron, and the field produced >37 MMbbl oil and >672 Bcf (~19 Teram^3) gas from 1944 through 1965 (Weaver and Anderson, 1966). The original resource consisted of a large gas cap surrounded by an oil ring with a diameter of ~4 miles (6.4 km). The economic mineral map of the State of Mississippi (MDEQ, 2009) shows only hydrocarbons and shallow deposits of gravels and sands as resources near the field. However, observation used later in the analysis, hydrocarbon accumulations exist both above and below the Tuscaloosa interval.

The Wilcox oilfield above the reservoir of interest is still producing through two stripper wells, according to the private database vendor IHS (a total of a few thousand barrels of oil and a few hundreds of thousands of barrels of brine a month). Production from the Wilcox has been overall steadily declining for the past 40 years, with an increasing water cut (>90%) and includes mostly oil (~12 MMbbl) and little gas (3 Bcf – 0.087 Teram^3). The older Paluxy Fm. (Fig. 3) produced moderate amounts of oil (1 MMbbl) and gas (38 Bcf – 1.07 Teram^3) from a depth of ~12,300 ft (3750 m).

2.5. Operations

Tuscaloosa Cranfield field was unitized early in its life, allowing consistent well construction, production, and abandonment—elements of importance for some assumptions of subsequent analysis. Oil was recovered using recycled gas drive until the gas cap was blown down. Even though the production removed a significant percentage of the initial fluid volume in the pore space, the strong water drive restored reservoir pressure to near-initial

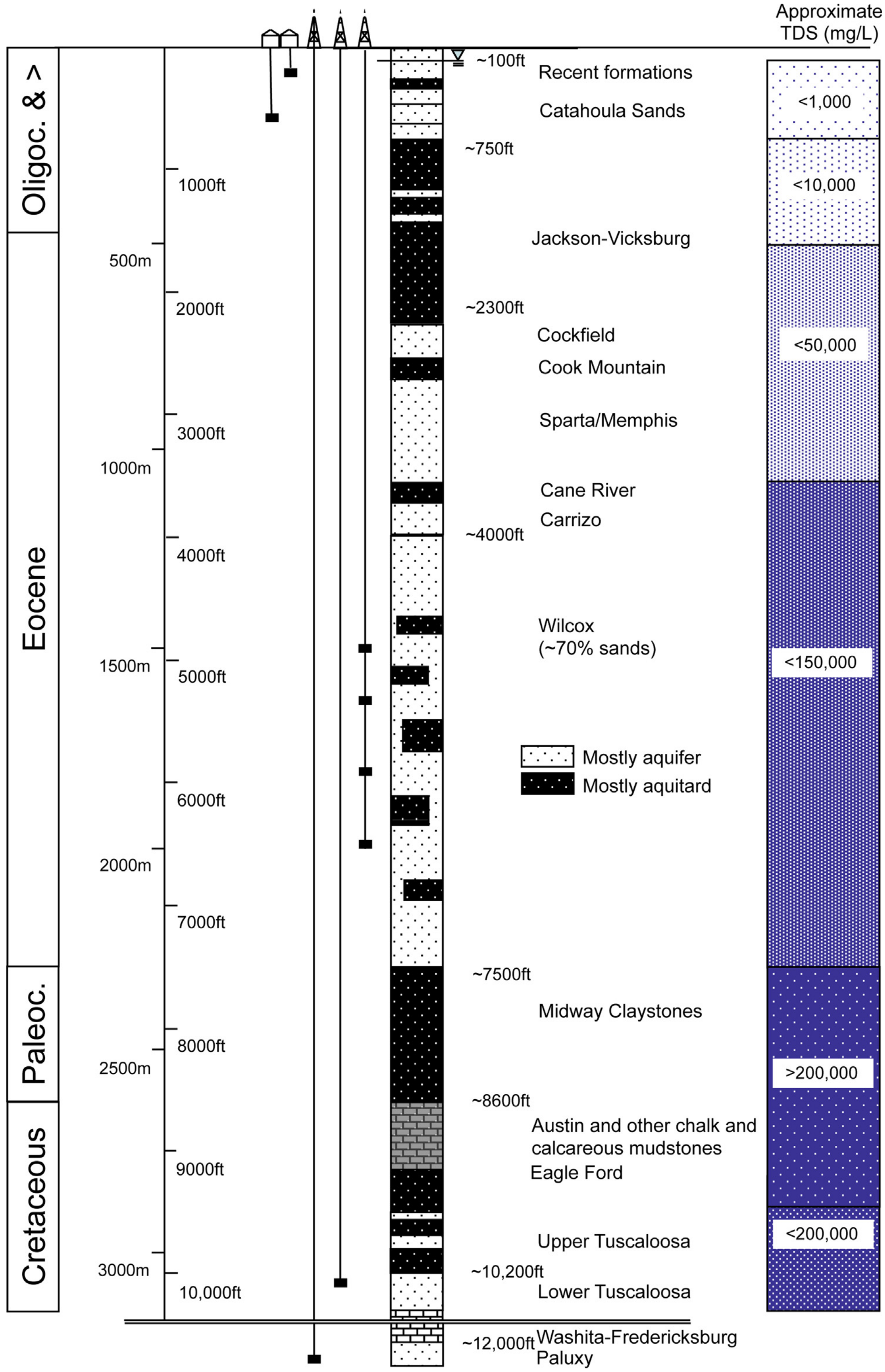

Fig. 3. Simplified hydrostratigraphic column with water quality. Catahoula and more recent formations crop out and are part of lowland aquifer system. Other formations (Sparta, Carrizo, Wilcox) are brackish to saline but fresh in their updip sections farther north. Cretaceous formations (Tuscaloosa/Woodbine, Paluxy) contain saline water at site but also form aquifers farther north in their updip equivalent sections in Arkansas. The Tuscaloosa Formation is represented by the basal sands (injection formation) overlain by local fluvial and regional marine mudstones, then another mudstone-dominated section with a few sand intervals capped by the calcareous mudstones of the late Cretaceous.

levels in the decades following production, despite the deep pressure drop following gas blow-down.

According to IHS, 287 documented wells were in the footprint of the Cranfield reservoir domal structure at the time of analysis. A total of 108 (~10) wells were drilled to the Wilcox (~2000 m [~6000 ft] deep), >150 (~20) wells to the Tuscaloosa (3000 m [10,000 ft] deep) and >20 (~4) to deeper horizons, in the entire field footprint (and east of the fault, respectively). Most of the wells in the Wilcox, Tuscaloosa, and Paluxy Fms. were drilled in the 1950s. The Wilcox reservoirs were revived twice—in the 1960s and 1970s—presumably with wells of increasing construction quality, as operators drilled new wells and retrofitted older wells. Thanks

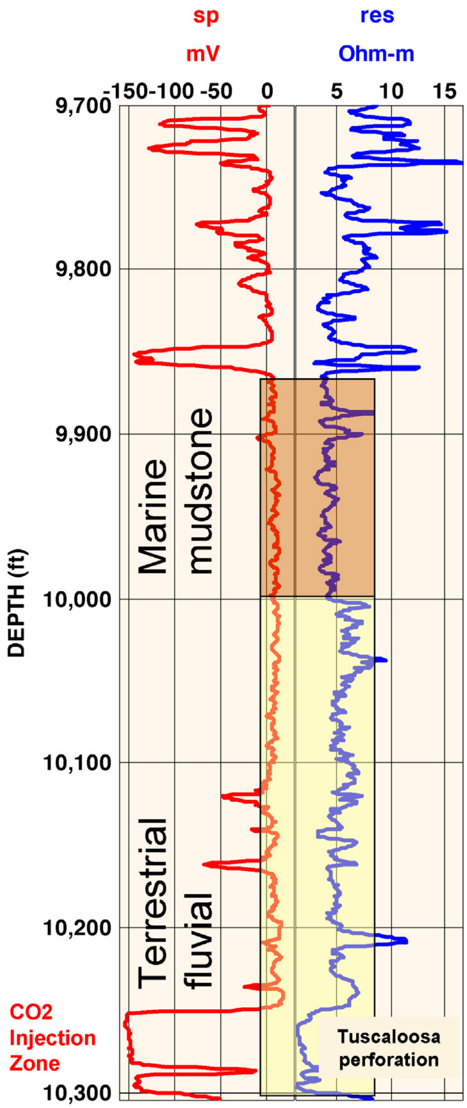

Fig. 4. Type log in study area showing basal massive sands of injection interval (top at ~10,260 ft) overlain by more fluvial deposits, including local seal of reservoir with some sandier intervals transitioning (10,000–10,100 ft) to a thick marine mudstone (top at ~9870 ft) making up the regional seal. A likely marine sand overlies the marine mudstone and is monitored at site for pressure changes. The remainder of the Tuscaloosa section (not shown) includes additional sand intervals that disappear toward the top of the formation. Courtesy of Tip Meckel.

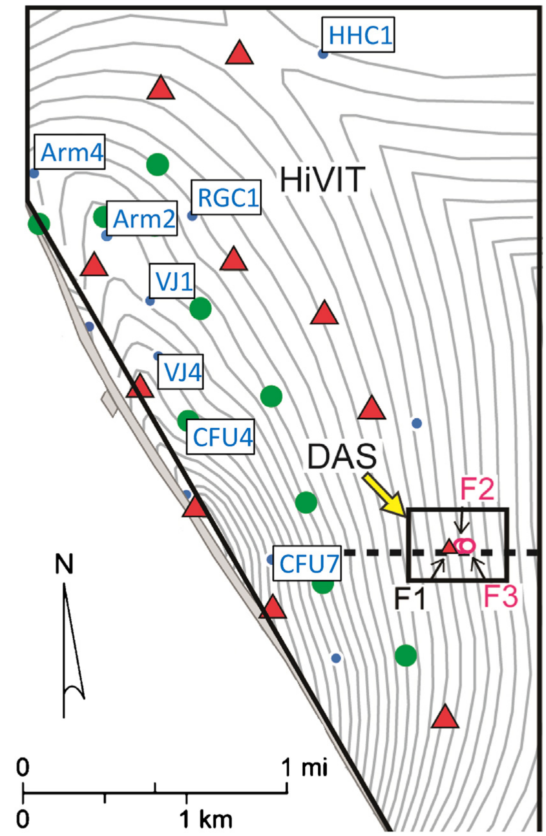

Fig. 5. P&A well location in HiVIT domain. Symbols from Fig. 1.

to a single operator during most of its history, unrecorded wells in the Tuscaloosa Fm. do not seem to be an issue. The domain of interest contained nine injection wells and six producers at the time of analysis, as well as seven known plugged and abandoned (P&A) wells (Fig. 5).

After a production hiatus of several decades, the area has been under CO_2 flood since mid-July 2008 to sweep bypassed and residual oil (Hovorka et al., 2013).

3. Methodology

The approach presented in this paper follows the CF methodology (Oldenburg et al., 2009, 2011). The CF conceptualizes the system as source, conduits and pathways (wells and faults), and compartments. It focuses on subsurface leakage risks, particularly leakage through new and historical wells, and leakage through faults. The CF is designed to be simple by (1) using a simple framework for calculating leakage risk and (2) using proxy concentrations or fluxes for quantifying impact rather than complicated exposure functions. In the CF, five compartments can be impacted: hydrocarbon and mineral resource (HMR), underground source of drinking water (USDW), health and safety (HS), near-surface environment (NSE), and emission credits and atmosphere (ECA) (Fig. 2).

These steps were followed in the analysis:

- Define the storage region.
- Identify vulnerabilities. We performed a FEP (feature, event, processes) analysis (not shown), concluding that focus should be on wells and faults as conduits and spill points. We also examined the likelihood of seismic events related to fluid injection.
- Characterize vulnerabilities. Spill points, faults, and wells as leakage pathways were characterized, including a cement bond log (CBL) analysis to determine wellbore flow properties and likelihood of being an actual pathway. This step also included an assessment of compartment vulnerabilities to CO_2 and brines.
- Model injection, migration of CO_2, and brine pressurization. This step consisted of two substeps: (1) use of a compositional multiphase-flow model to determine pressure buildup in the reservoir and brine/CO_2 leakage driving forces at locations of the wells of concern, including P&A wells, and (2) use of a semianalytical model to determine CO_2 and brine flow and flux in the wellbore as they ascend toward the surface.
- Estimate likelihood of leakage.
- Model impact of leakage on compartments and compare leakage to natural CO_2 sources
- Discuss risk semi-quantitatively.

3.1. CBL analysis to determine well integrity

A conservative assessment of the quality of well cementing throughout the entire oilfield was performed using CBL logs

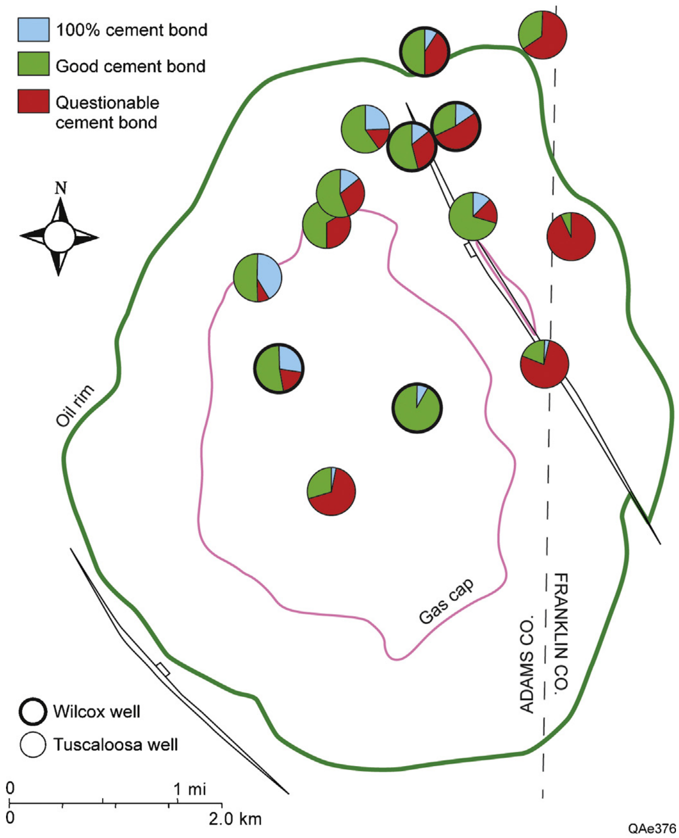

Fig. 6. Site map illustrating location and quality of each CBL log. Slice of each circle represents percentage of cement that fits defined classification. Map also shows location and orientation of two graben-bounding faults associated with the oilfield. Source of data IHS and MOGB. Drawing courtesy of Stuart Coleman.

acquired from IHS and Mississippi Oil & Gas Board databases. A CBL is used to analyze the integrity of bonding between the cement and well casing. A total of 14 CBL logs were analyzed, with the oldest log from 1961 and most recent from 2010. Five CBL logs were from wells drilled to the Wilcox Fm., six from wells drilled on the west side of the fault outside but close to the study area, and three from wells directly drilled into the zone of interest in this study (Fig. 6). Having a single operator during most of the field history strongly suggests that including nearby wells to increase the sample size is a valid approach and that the failure rate obtained through this sample would be valid for the study area. Findings from historical CBL logs were observed to be consistent with the actual state of the well when later reentered, increasing confidence in the appropriateness of CBL logs in this analysis.

We followed cutoffs established by Schlumberger (2009) to evaluate zones of questionable cement, good cement (that is, some nonconnected areas with a poorer bond), and 100% cement (that is, a near-perfect bond between casing and cement) bonds along the casing. We assumed that both 100% cement and good cement bonds translate into no flow along the well, provided that the good-cement interval is long enough.

3.2. Numerical model to determine pressure buildup

To assess pressure buildup, we developed a 3-phase 3-D numerical model of the injection process using CMG-GEM, a standard commercial multiphase compositional-flow simulator used by the oil and gas industry. The objective was to determine projected pressure history at the locations of interest. The model domain includes only the section of the northeast part of the Tuscaloosa reservoir

Table 1
Geostatistical parameter used to generate flow-parameter fields.

Parameter	
Mean porosity and standard deviation	19.88 and 7.26
Mean log *k* and standard deviation (*k* in md)	0.65 and 1.47
Log *k* variogram model	Spherical
Log *k* variogram nugget	1.4
Vertical range of log *k* variogram	4.3 m (14 ft)
Lateral NS range of log *k* variogram	305 m (1000 ft)
Lateral EW range of log *k* variogram	61 m (200 ft)
Nugget	0.14

that is northeast of the fault where CO_2 injection was in progress at the time that RA was performed. It also includes a large downdip brine section added to the east of the reservoir for better handling of boundary conditions. The numerical model was constructed specifically for this study, using much of the same information as other Cranfield models (Hosseini et al., 2013; Choi et al., 2011).

The static model was created based on both seismic data and well logs using the Petrel software. Data from 45 wells were used as control points. Because the downdip section of the model is not covered by either seismic data or wells, the model assumes a constant dip of 2°. The dimensions of the flow model are 6096 m × 6096 m × 24.4 m (20,000 ft × 20,000 ft × 80 ft), with a total of 100 × 100 × 10 uniform cells.

The PVT data of C2+ oil components were those internally available within CMG-GEM, whereas PVT data for CO_2 and CH_4 were independently tuned for reservoir temperature of 125 °C (257 °F) and reservoir pressure of 32 MPa (4700 psi). Oil composition from Weaver and Anderson (1966) has been confirmed by recent analysis by the current operator.

We generated stochastic permeability fields using the sequential Gaussian simulation (SGS) tool within Petrel (Table 1) on the basis of well data, and so that we could consider both (1) the lack of permeability data in interwell areas in the horizontal direction and (2) the difficulty of uniquely correlating rock units at an interwell scale, given the fluvial stratigraphic architecture. Results of the different realizations were accepted when total fluid production approximately matched recent oil production (not shown). Eventually, five realizations of the permeability and porosity fields were retained.

The vertical range of the spherical variogram was computed from a selected set of wells, but with the three wells of the DAS area being weighted more heavily because porosity and permeability are constrained by measurements on core plugs. Horizontal correlation ranges were estimated from interpreted stratal slices of seismic data (Hongliu Zeng, BEG, personal communication, 2012) and our interpretation of depositional units that was based on core interpretation and outcrop analogs. The nugget was set at 0.14 to minimize the smoothing effect of upscaling and still keep some of the stratigraphic fabric. Porosity was upscaled to the numerical mesh using simple arithmetic averaging of porosity values. Permeability upscaling was based on directional methods using a harmonic–arithmetic average to generate k_x, k_y, and k_z. We used only one rock type and a single set of relative-permeability curves (Table 2), assuming a Brooks–Corey formalism. Following Weaver and Anderson (1966), we estimated water residual saturation at 0.4. Oil and gas relative permeability at residual water saturation was set at 0.65 and 0.8, respectively. A value of 0.2 was used for the oil and gas residual saturations. Water relative permeability was set at 0.5 at residual oil and gas saturation.

The top and bottom boundaries of the model are assumed no-flow and the injection formation is vertically bounded by low-permeability layers. The fault on the west side of the model domain is modeled as a no-flow boundary. The far-field boundary on the east side of the domain is an open boundary, with constant pressure

Table 2
Flow parameters for reservoir rock in the model.

Parameter	Value
Brooks-Corey lambda (pore-size distribution index)	2.0
Water/oil rel. perm. curve	
Water residual saturation	0.4
Oil rel. perm. end point at residual water	0.65
Oil residual saturation	0.2
Water rel. perm. end point at residual oil	0.5
Liquid/gas rel. perm. curve	
Minimum residual fluid (water)	See "Water residual saturation"
Gas rel. perm. end point at min. residual fluid	0.8
Fluid rel. perm. end point	See "Oil rel. perm. end point at res. water"

set at hydrostatic to model an infinite-acting system. The historical shut-in period pressure behavior shows a strong water drive and good communication with the saline aquifer that justifies the open far-field boundary. Both side boundaries are set to no-flow mostly for convenience. Previous work (Choi et al., 2011) has shown that when the mix of injectors and producers is relatively balanced, these boundaries do not matter as much, particularly because one side of the domain is open. Initial conditions are assumed hydrostatic, with no CO_2 in the system. After a short virtual transient of a few years, the model is at numerical equilibrium, and injection can start. We then model a period of 5 years, at which time the system has reached a quasi-steady state in terms of pressure because of the continuous CO_2 injection balances the oil production. The injection schedule follows a simplified version of field-injection rates for the recent CO_2 flood period, whereas future injection rates are extrapolated high from some measure of the previous months' activity. Production starts at individual production wells when the CO_2-rich oil can self-lift to the surface.

3.3. Semianalytical model to assess leakage

We used a semianalytical solution for assessment of well leakage (Zhang and Oldenburg, 2011). The underlying concept relies on leak-off from the wellbore into the neighboring formations if the pressure gradient is favorable. The analysis is for a steady-state-flow condition, which is based on one-dimensional, single-phase flow in the well, coupled with horizontal (radial) single-phase flow from the well into the formation. Wellbore permeability is computed from the CBL results. Because permeability values cannot be estimated from CBL logs and because of a lack of specific data, measured permeabilities for intact and degraded cement made by Bachu and Bennion (2009) are used for quantifying the cement bond. These measurements indicate that intact cement has a low permeability, 10^{-21} m^2, whereas degraded cement has permeability on the order of 10^{-15} m^2. The intact-cement permeability is assigned to the "100%" and "good" categories from the CBL, and the degraded-cement permeability is assigned to the "questionable" category. Because no specific measurements are available for uncemented intervals, these are assigned a value of 10^{-11} m^2 to allow for quantitative evaluation. Mean permeabilities for the wells were computed using these permeability assignments and the lengths of the sections in the CBL (Fig. 7). The means are harmonic because of the serial nature of the permeability variations, and wells with at least one section with cement of appropriate quality are assumed safe. For those wells with "questionable" quality, the wellbore permeability depends on the relative cumulative length of sections with "questionable" and "no" cement. Because the no-cement section length is not known, we assume that the well population of interest has the same distribution as the 14 wells for which we have data.

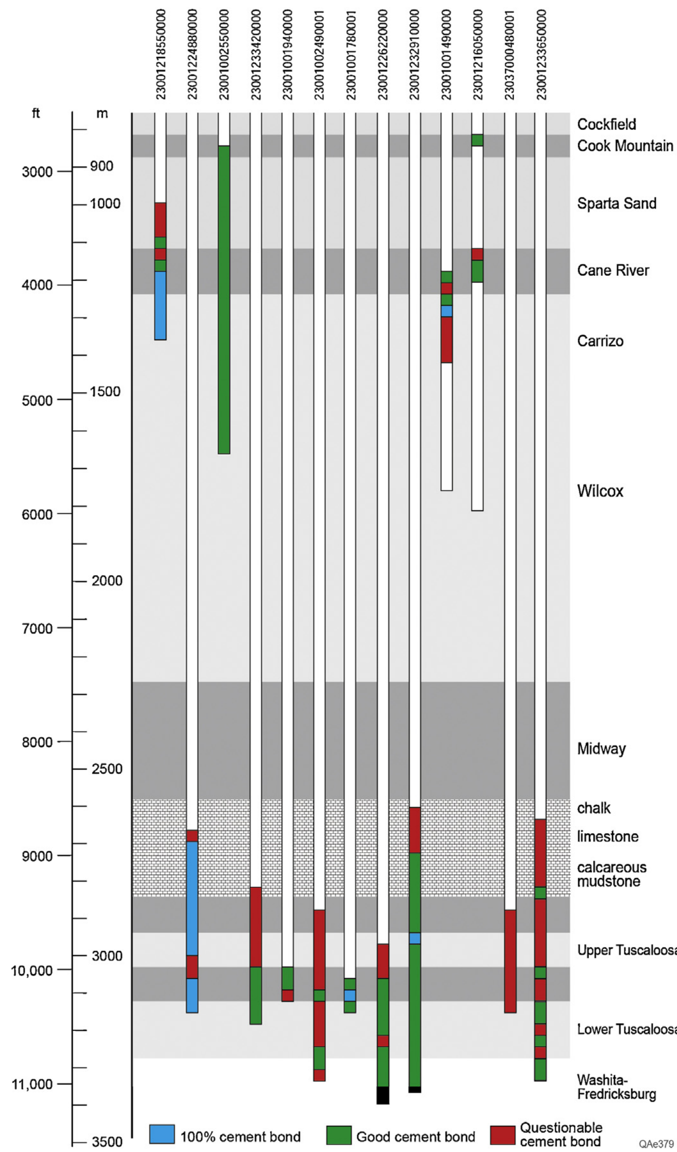

Fig. 7. Cross section illustrating cemented intervals of each well with a CBL log. White sections represent lack of logs or unusable logs. Of nine wells intersecting the Tuscaloosa Formation, one (#2 starting from RHS) has questionable cement, and wellbore integrity cannot be guaranteed. Aquitards are represented by darker tones. The Tuscaloosa section is illustrated by the basal sands (injection formation) overlain by the local and regional seals then by a more sand-rich interval transitioning to a mudstone capped by the calcareous mudstones of the Late Cretaceous. Work by S. Solano, C. Puerta, and S. Coleman.

4. Results

Central to application of the CF for leakage-risk assessment is specification of the storage region, defined as the volume beyond which CO_2 migration is considered leakage. In this study, the storage region is defined as the subsurface volume comprising the Tuscaloosa Fm. reservoir on the upthrown side of the fault. The lower boundary of the storage region consists of the uppermost confining unit of the Washita–Fredericksburg Group, in direct contact with the Tuscaloosa at depth of ~3200 m (Fig. 3). The upper boundary of the storage region is formed by the base of the regional marine calcareous mudstones overlying the Tuscaloosa Fm at depth of ~2800 m. The regional seal of the middle Tuscaloosa, which is an extensive marine mudstone, adds to the defense-in-depth (Fig. 4). The nonmarine mudstones at the top of the oil reservoir are not considered the storage region upper boundary because, although able to contain hydrocarbons for millions of years, they are not as extensive as the middle Tuscaloosa. It follows that the confining system is composed of, from bottom to top: (1) nonmarine local mudstones; (2) intermediate, mostly low-permeability rocks; (3) regional marine mudstones of the middle Tuscaloosa; (3) upper Tuscaloosa rocks (that contain a few sand layers including the monitoring interval); and (4) calcareous marine mudstones of the Navarro, Taylor, and equivalent formations of Late Cretaceous age. The updip limit is the fault. The downdip limit (to the northeast and east) of the storage region is arbitrarily placed at 10 miles (16 km) from the original oil–water contact in all other directions.

4.1. Fault analysis

The NW–SE-trending fault bounding the domain to the southwest has a throw of ~25 m (80 ft), with the southwest compartment down. This throw, approximately equivalent to the injection-layer thickness, places the reservoir sands of the downthrown compartment against a thick, underlying shale, whereas the reservoir sands of the upthrown compartment abut the fluvial low-permeability material overlying the reservoir. Several arguments can be made to support the contention that the faults are not horizontally transmissive: (1) elevations of the oil–water contact on either side of the northeast fault were different at discovery, (2) observations (Meckel and Hovorka, 2009) show that there is no pressure response from CO_2 injection in the northeast section of the reservoir across the fault, and (3) well breakout observations suggest that the current maximum horizontal stress closes the fault (Tip Meckel, BEG, personal communication, 2012).

The fault is not active; salt-dome growth is quiescent in the Mississippi salt basin (Mancini, 2005, p. 126). It can be traced ~300 m (~1000 ft) into the overlying strata to where it becomes undetectable in the available seismic data in the Midway claystones (Tip Meckel, BEG, personal communication, 2012) and below where the fault would intersect the permeable Wilcox sands. Although the fault is not a likely leakage pathway, the recent concern of induced seismicity and potential related leakage when injecting next to a fault has come to the forefront (Mazzoldi et al., 2012; Zoback and Gorelick, 2012; Nicot and Duncan, 2012). Two elements suggest that such an event has a low probability—(1) the area is not seismically active (Petersen et al., 2011) and (2) although the pressure goes beyond hydrostatic, CO_2 injection is soon balanced by production of oil, CO_2, and brine.

4.2. CBL analysis and wellbore permeability

From CBL-analysis results (Figs. 6 and 7), we can determine that two wells are of highest concern in terms of cement-bond quality. Because these wells do not have an adequate segment of "good" cement across the confining middle Tuscaloosa, significant potential exists for CO_2 migration along the wellbore.

Results of permeability averaging over the entire wellbore length for wells that penetrate the Tuscaloosa are given in Table 3. Note that the eight wells with any (even a small) section of 100% or good cement bonds have mean permeabilities of ~10^{-19} m^2 or lower. These permeabilities are orders of magnitude lower than that of well CFU1 (Fig. 7), which has a mean permeability of 1.3×10^{-14} m^2 and is located slightly outside the area of study on the west side of the boundary fault. Therefore, well permeability is negligible unless all of the cement falls into the "bad" category on the CBL. The fact that all cement is identified as "bad" in only one of the nine wells is used to segregate the total population of P&A wells into (1) a smaller group of more permeable wells (1/9 of the total) and (2) the remainder of the P&A wells (89%) that would have low permeabilities and, as a result, negligible CO_2 releases. The remaining 11% may have higher permeabilities that could lead to higher CO_2 leakage rates. Perhaps coincidently, but supporting the limited Cranfield data set, this fraction of P&A wells with more permeable cement seals is similar to the leakage-occurrence rate of the 14% found by Watson and Bachu (2009) for cased P&A wells in Alberta, Canada, or the ~11% of production wells with sustained casing pressure on the outer continental shelf (Bourgoyne et al., 1999).

Table 3
Mean wellbore permeabilities for the nine wells with CBLs that penetrate the Tuscaloosa Fm. (same order as in Fig. 7).

Well ID	Mean Wellbore Permeability (m^2)
23001224880000	8.68×10^{-21}
23001233420000	3.72×10^{-20}
23001001940000	5.21×10^{-20}
23001002490001	1.30×10^{-19}
23001001780001	5.79×10^{-20}
23001226220000	5.21×10^{-20}
23001232910000	8.01×10^{-21}
23037000480001	1.30×10^{-14}
23001233650000	5.21×10^{-20}

We constructed the distribution function of mean permeability of wells with exclusively "bad" cement by noting that it is the harmonic average of the permeability of the section with bad cement and the permeability of the section without cement. Because the permeabilities of these sections are fixed, the distribution of well permeabilities is a function only of the relative lengths of the two sections. If no correlation is assumed between the length of the cemented section and the cement categories on the CBL, the variable lengths of the cemented sections in the other eight wells can be used to develop the distribution of mean well permeability for the more permeable group of wells. Using this approach, we computed the permeabilities of the nine wells with CBLs by assigning the permeability of "bad" cement to all of the cement in the CBLs. The harmonic mean permeabilities for the nine wells were then expressed as a probability distribution on the basis of an ordered ranking of the values. The empirical cumulative probabilities P_j were assigned using the relationship ($P_j = j/n+1$), where $n=9$ is the total number of wells in the sample and j represents the jth value. The empirical distribution was fit to a theoretical log-normal distribution with the same mean and standard deviation as that of the data used in the analysis (Fig. 8). The mean and standard deviation for the log-permeability data points are −13.9 and 0.32, respectively, which correspond to a mean permeability

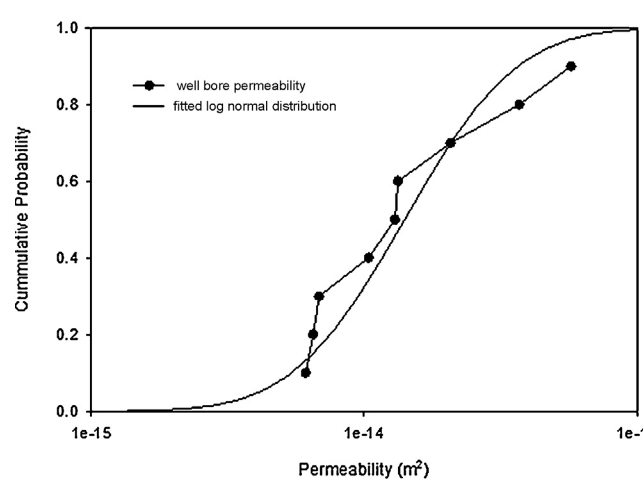

Fig. 8. Wellbore permeability distribution for wells without 100% cement bonds.

Table 4
Maximum excess pressure (MPa/psi) at P&A wells, not necessarily at the same time relative to reservoir pressure before start of CO_2 injection.

Well name	CFU7	CFU4[b]	VJ1	Arm4	Arm2	RGC1	HHC1
Realiz. 1	9.95/1443	6.16/894	4.72/684	2.68/389	2.12/307	2.59/376	7.63/1107
Realiz. 2	7.06/1024	12.05/1748	8.54/1238	0.46/67	3.82/554	5.41/784	8.39/1217
Realiz. 3	3.39/492	11.74/1703	5.92/858	3.6/522	3.35/486	6.14/891	10.34/1500
Realiz. 4	6.63/961	12.33/1789	9.13/1324	6.04/876	7.15/1037	8.1/1175	9.87/1431
Realiz. 5	18.33/2658[a]	13.53/1962	6.32/917	3.87/562	4.32/627	2.94/427	10.2/1479

[a] Prescribed rate was forced into a low-permeability area.
[b] This well (CFU4) has been reentered and put under production by the operator since model was constructed.

of $1.4 \times 10^{-14}\,m^2$ and a two-standard-deviation range of $3.2 \times 10^{-15}\,m^2$ to $6.2 \times 10^{-14}\,m^2$.

4.3. Pressure field

This section focuses on the P&A wells because this is where potential leakage could occur (leakage could also occur at producers; however, during production, the pressure is lowered at these wells). Excess-pressure values (above hydrostatic as computed by the model) generated in hypothetical permeability fields are consistent mostly across the different realizations and mostly <6.8 MPa (1000 psi) (Table 4). We examined pressure at the seven P&A wells. Wells CFU4 and HHC1 are just below and above 10 MPa (1500 psi), respectively. Well CFU4 (Fig. 9) was reentered in 2011 and upgraded by the operator and is thus considered actively managed, in good condition, and unlikely to lead to significant leakage. Time for the excess pressure to peak is also variable, and maximum excess pressures are not sustained for very long. Production wells are allowed to produce as soon as the oil–CO_2 mixture is self-lifting, decreasing or at least stabilizing the

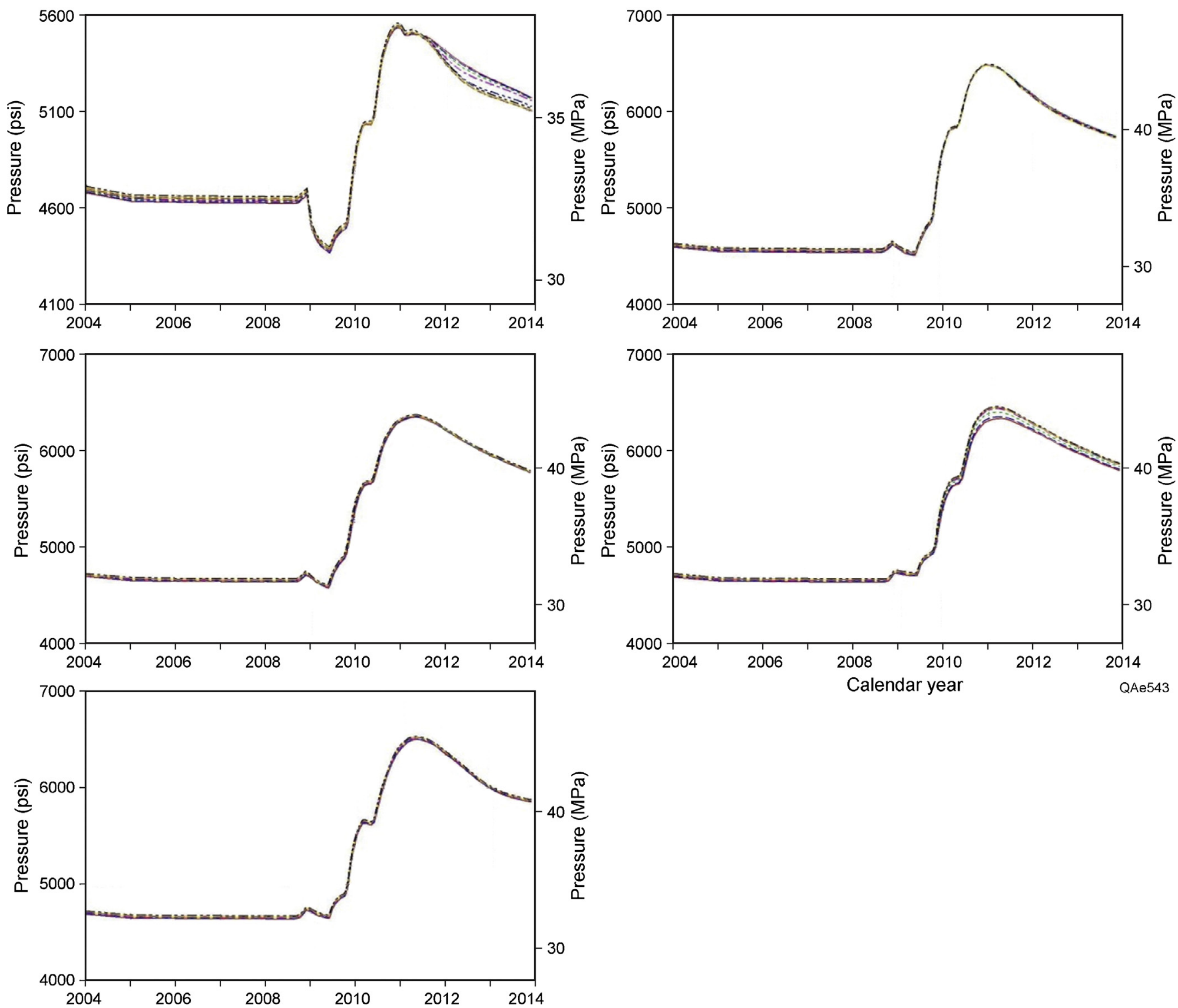

Fig. 9. Pressure history at CFU4 for realizations 1 through 5. Overlapping lines represent different cells on a vertical section at the well location.

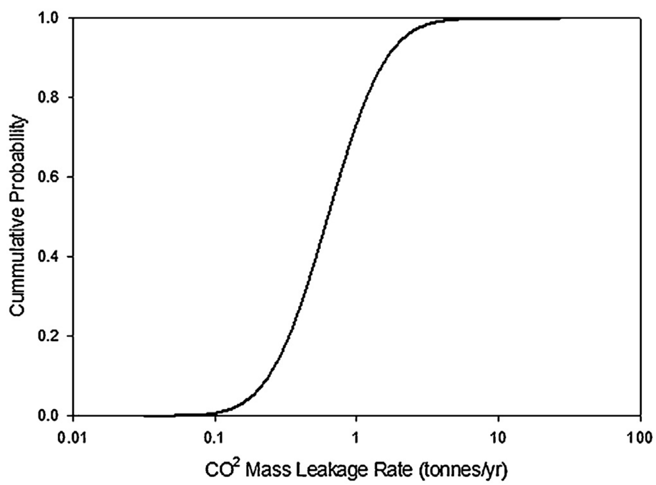

Fig. 10. CO_2 mass leakage rate distribution for wells without 100% cement bond.

bottom-hole pressure in the process. These simulated pressures tend to overpredict conditions relative to well leakage that could actually occur in the oilfield and are higher than may occur during operations because the model does not consider optimization of the flood by the operator, who will adjust injection and production rates in response to pressure measurements.

Simulation results show that CO_2 and displaced brine at elevated pressures will encounter multiple P&A wells, meaning that for the CF approach, the likelihood of potential leakage pathways (in this case, P&A wells) being intersected by CO_2 and brine at elevated pressure is high. Therefore, the calculation of leakage risk in the CF reduces to a calculation of leakage-impact severity along any conduits that exist through flaws in the cement placed in the rock-casing annulus. In the CF, impacts are evaluated on the basis of proxy leakage fluxes, as presented next.

4.4. CO_2 leakage through P&A wells

Because the storage region is capped by multiple thick mudstones and the nontransmissive fault dies out in the thick Midway claystones, there is no natural pathway for brine or CO_2 to leak upward. Therefore, the only leakage pathways that need to be considered are the wells in the area. The only wells that penetrate the Tuscaloosa are the deep wells related to oil and gas exploration and production, including the CO_2 injection well(s).

The P&A well permeability distribution developed from the CBL data helps to provide more realistic estimates of CO_2 leakage through wells. This distribution applies only to the higher-permeability subset (~11%) of P&A wells. Permeabilities of the formations next to the wellbores are from Carlson (2010). Results show that overpressure from CO_2 injection is rapidly dissipated in the upper Tuscaloosa and can be further reduced in the underpressured Wilcox Group. The CO_2 mass-flow rates at the ground surface were computed over the range of wellbore permeabilities from $7 \times 10^{-16}\,m^2$ to $6 \times 10^{-13}\,m^2$ and weighted by log-normal probability distribution. This computation was made based on the fitted log-normal distribution from a set of 35 cases, with varying wellbore permeabilities ranging from four standard deviations below the mean to five standard deviations above the mean. The mean CO_2 mass-flow rate for these wells is 0.9 ton/yr per well, with a standard deviation of 0.8 ton/yr (Fig. 10). Releases range from <0.1 ton/yr to >10 ton/yr. The CO_2 mass-flow rate for wells with 100% cement bonds is negligible (5.8×10^{-6} ton/yr).

4.5. CO_2 leakage through active wells

The operator has retrofitted 10 P&A wells as producers (all injectors are new wells), and some of these wells possibly share the same flaws as untouched P&A wells. The leakage driving force due to pressure is smaller because of oil production, but there could be exposure to CO_2 after it comes out of solution with the oil upon decompression. Here, only the impact of chronic flow of CO_2 through wells is considered. Such flows by definition do not significantly disrupt wellbore conditions and may be distinguished from a complete loss of wellbore integrity in a “blowout” in which the cement plugging and casing can be substantially damaged, resulting in a high-rate, uncontrolled release of CO_2. This aspect will be treated in a subsequent section.

Therefore, the estimate of overall potential CO_2 leakage through wells is based on 10 P&A wells retrofitted as producers and 7 unaltered P&A wells, for a total of 17 wells. And because there is no additional information concerning the potential permeability distribution of leaking P&A wells retrofitted for production, the permeability distribution for these wells is assumed to be the same as for that of the unaltered P&A wells.

4.6. Upward brine leakage

Brine leakage can be difficult to identify at the surface or in the shallow subsurface because of the extensive oil and gas history going back to the first half of the 20th century, when surface disposal of produced brines was the norm. Contamination (Childress, 1976; Kalkhoff, 1986) next to a P&A well could have been caused by past practices rather than by a defective cement job. The significant difference between CO_2 and brine is fluid density. CO_2 is forced up a wellbore by injection pressure and buoyancy effects because of its low density relative to formation brine. Because salinity generally increases with depth and temperature equilibrates rapidly with the formation, there is no buoyancy to move brine up a well. In fact, any buoyancy effect of the mobilized brine relative to the formation brine may be expected to reduce the movement of brine up a well (Birkholzer et al., 2011). Analysis shows that no brine flow is expected to occur in wells above the upper Tuscaloosa, even for the highest wellbore permeability investigated for CO_2.

4.7. Along-dip leakage of CO_2 and brine

The spill point was not reached by the CO_2 plume during the modeling exercise, as confirmed by recent 4-D seismic (S. Hovorka, BEG, personal communication). The plume reached its maximum extent early in the operation, when injection dominated over production; both are currently more balanced. Should some CO_2 move beyond the spill point, most will be trapped in high points of minor elevation undulations of the Tuscaloosa. There is no barrier to migration of brine or CO_2 locally downdip to the northeast or east. However, given that no vulnerable resources lie in this direction that could be impacted by injection into the reservoir, the consequences of downdip leakage of either CO_2 or brine are negligible.

5. Discussion

5.1. Impact to compartments

From bottom to top, the compartments in the CF that are vulnerable are HMR, USDW, NSE, HS, and ECA (Fig. 2). Because the oilfield is under CO_2-EOR and no other significant mineral resources are recognized in the area, we conclude that there are no potential negative impacts of CO_2 on the hydrocarbon resource (HMR) at the site.

Significant USDWs in the area could be impacted if CO_2 or brine were to leak up a P&A well and out of the storage region beyond the Wilcox Fm., There are 17 wells that may be impacted by CO_2 injection. According to the Results Section, one-ninth, or perhaps two of these wells, may be expected to present a higher-permeability pathway, leading to a total CO_2 leakage-rate estimate of ~1.8 ton/yr. The remaining 15 wells are expected to have sufficiently tight cement closures to limit releases from these wells to a negligible level of 9×10^{-5} ton/yr. Strom et al. (1995) reported on groundwater pumping rates from wells in the Natchez area, the smallest rate of water withdrawal being 0.024 million gallons per day. If the entire 900 kg/yr of CO_2 leaking up a single well were captured in this low-rate water-supply well, the mass ratio of leaked CO_2 to water in the withdrawal would be $\sim 3 \times 10^{-5}$. This level may be compared with the natural bicarbonate levels in groundwater used for water supply, as reported by Boswell and Bednar (1985). The average bicarbonate level is 287 mg/L (as $CaCO_3$), or an equivalent CO_2 to water mass ratio of $\sim 1 \times 10^{-4}$. Therefore, even despite the absence of buffering material, the leaked-CO_2 release is not expected to perturb natural CO_2 levels significantly in groundwater withdrawn from the USDW because the perturbation is similar to that of natural variations in equivalent CO_2 content and a factor of three less than the average equivalent CO_2 content.

If P&A wells were improperly plugged at the ground surface only and leaking CO_2 somehow discharged into the shallow vadose zone, CO_2 concentrations could possibly build up to high levels in the soil locally around the well and affect the NSE because the potential for dissipation of CO_2 in the soil is less than what it would be above ground (Oldenburg and Unger, 2003). High concentrations in the root zone could cause plant stress, which would be visible in wilting leaves and/or dying trees or plants. The impact of 1.8 ton/yr of CO_2 leakage on the NSE may be better understood in a comparison with soil–gas CO_2 mass-flow rates. Biological activity in soil produces CO_2, and a natural flux of CO_2 occurs from the soil gas into the atmosphere. Klusman (2005) measured CO_2 soil–gas fluxes at Teapot Dome oilfield, Wyoming. Measurements there were conducted in the winter and, as such, represent minimum values. Based on measurements at 40 locations, the CO_2 flux from soil gas was found to give an average value of ~0.091 kg/m^2/yr, a standard deviation of ~0.088 kg/m^2/yr without noticeable damage to natural flora. CO_2 flux values during the summer were expected to be higher by an order of magnitude or more (Klusman, 2005), suggesting that damage to flora will not occur if the leakage flux is <~0.91 kg/m^2/yr. Assuming similar natural soil–gas CO_2 fluxes at the present site, the flux from one leaking well, 0.9 ton/yr, must disperse over an area of ~1000 m^2 or more to remain <0.91 kg/m^2/yr. Therefore, for two leaking wells, the risk of damage to flora is for a maximum area of ~2000 m^2. The risk to the NSE compartment is considered low because it would be a local impact and the presence of stressed vegetation would, in fact, alert the operator to the potential problem, which could then be mitigated by various well-workover processes.

Regarding the HS compartment, in the absence of homes or enclosed buildings on top of P&A wells, such low fluxes will not lead to hazardous concentrations in open-air conditions. A suitable comparison for the HS compartment is the rate of ecosystem utilization of CO_2. The net ecosystem exchange (amount of CO_2 taken up and emitted by plants and soil) is typically ~14 kg/m^2/yr. Therefore, the well-leakage rate is similar to the rate of CO_2 usage by an 11 m × 11 m plot of land with natural vegetation. The small area of equivalent ecosystem exchange indicates that the impacts of CO_2 leakage through wells to the HS are negligible.

A suitable comparison of CO_2 fluxes for the ECA is the ratio of CO_2 leakage to CO_2 injection. One goal of the Phase III study is to inject 1 million ton/yr of CO_2. Thus, the well-leakage rate is seen to be ~0.0002% of the injection rate, well below the oft-mentioned threshold value of 0.01% (IPCC, 2005). A blowout event on a P&A well could clearly release more CO_2 to the atmosphere. However, Jordan and Benson (2009) reported that the blowout rate in oilfields using steam injection is 1 per 98,000 P&A wells per year; similar rates for blowouts are expected for CO_2 sequestration operations. Impact severity is therefore offset by a low occurrence rate. Furthermore, during the operational period for oil recovery and carbon sequestration activities, any blowout would be immediately recognized, and mitigation measures would be implemented. In the case of steam blowouts, wells were brought under control for 95% of the cases in <3.5 days (Jordan and Benson, 2009), resulting in an even lower probability for long-duration blowouts and associated higher impact severity.

5.2. Mitigating elements

General and site-specific mitigating elements counteract some of the concerns addressed earlier. The analysis benefits from a deep knowledge of the local and regional geology because of the long history of oil and gas exploration and production. The great depth of injection into the Tuscaloosa Fm. and the presence of several seals, including marine mudstones, which are typically more extensive and uniform than those deposited in deltaic or fluvial environments (the primary seal), are also protective of the site. A pressure sink most likely results from shallower oil and gas production from the overlying Wilcox Fm. Because Wilcox wells date back >70 years and are currently operated as stripper wells, the availability of well tests and pressure data is actually limited for determining whether the Wilcox reservoirs are underpressured and, therefore, a likely sink for potential upward-migrating fluids. Only one well from the Wilcox had pressure data, and it had a final shut-in pressure of 15.2 MPa (2235 psi), which is 1.4 MPa (~200 psi) below the hydrostatic gradient of 9.8 MPa/km (0.433 psi/ft) at a depth of 1700 m (5540 ft). This data point suggests that the Wilcox is underpressured owing to extensive production, but it is allied with a strong water drive.

In addition, several studies by Warner et al. (1997) provide factors applicable to this study that may limit the ability of a wellbore to maintain open space in the rock-casing annulus, even in the absence of cement. Mitigating effects, such as the presence of sloughing (caving in) or squeezing (expanding) mudstones in the Gulf Coast, can be expected and are well documented. For example, corroborating drillers' experiences in the Gulf Coast, a controlled test performed at a depth of ~900 m (2953 ft) and presented by Clark et al. (2003) effectively observed well closure through these mechanisms. All these elements combined tend to suggest that the modeling analysis presented earlier is conservative and that CO_2 leakage fluxes up P&A wells, if any even occur, are likely to be lower than the model shows.

Recent anecdotal field observations tend to reduce P&A well integrity concerns created by the CBL logs that show questionable cement. A typical P&A 1954 production well, Ella G. Lees #7 (on the west side of the fault), which provided information about well performance (Meckel et al., 2013), was reentered and recompleted. Multiple mechanical integrity tests and CBL and casing-integrity logs were run. The permitted cement and drilling-mud plugs inside the casing were located where the P&A records reported, and they had pressure integrity. Runs showed some poor cement quality, but during the subsequent cement squeeze, no pressure was communicated to a pressure gage hung below the bridge plug and in communication with the injection zone through the historic perforations. The well was therefore shown to have no communication through what CBL logs indicated was poor- or questionable-quality cement.

Other important factors include a thick vadose zone, a low population density, and, more important, active management by a responsible operator whose field technicians actively control pressure via balancing the flood and performing daily site inspection. In addition, because two dedicated above-zone observation wells monitor pressure (Hovorka et al., 2013), any deviation from the expected stable reading would be quickly noticed.

5.3. Post-RA observations

The observation that one well with a questionable cement bond turned out to have better integrity than anticipated (Ella G. Lees, as described earlier) suggests that the study is conservative. However, a counterpoint can be made in the detection of high soil-gas concentrations of CH_4 and CO_2 next to a P&A well in the study area. The source of the high concentrations is under investigation and could be related to high microbial activity, as well as deep leakage (Katherine Romanak, BEG, personal communication, 2012). This well was subsequently entered and completed as a producer. Sampling of other P&A wells in the study did not detect high CH_4 and CO_2 concentrations, suggesting that, at most, one well (out of nine) could be leaking.

6. Summary and conclusion

We applied the CF approach to assessment of the risk of CO_2 and brine leakage from a deep reservoir to various compartments that could be impacted. The reservoir is located at a great depth (~3050 m) in an interval of the Tuscaloosa Fm. of fluvial origin capped by a mudstone that has prevented further migration of hydrocarbon and, higher in the section, by an extensive thick marine-mudstone confining zone. The reservoir produced oil and gas from 1943 through ~1965 and has been recently the subject of a CO_2-EOR flood.

Minor concerns set by the presence of a fault and a nearby spill point were dismissed through geologic arguments and field observations. However, 287 documented wells are in the domal structure, 100+ of which have tapped the Tuscaloosa reservoir. The large number of P&A wells provides many potential flow paths for leakage upward to potable aquifers and, potentially, to the ground surface and represents the main concern at the site. The general approach was to compute an upper bound of the bottom-hole pressure (<2.7 to >10.2 MPa) at locations of P&A wells, both untouched and recompleted. To assess wellbore integrity and permeability, we relied on 14 CBLs. The present quality of the cement bond ranges from excellent to poor.

A simple 1-D, single-phase model for flow up a P&A well with a degraded or poor cement bond was developed and run for a range of assumed effective permeabilities representing a statistical sampling of well properties from the 14 CBLs available from the oilfield. Flow in the well is allowed to move into the adjacent formation, as controlled by local rock properties. Results show that overpressure from CO_2 injection is rapidly dissipated in the upper Tuscaloosa and can be further reduced in the underpressured Wilcox Group. But for CO_2, the buoyancy effect allows a residual leakage flux to continue flowing up the well, resulting in the possibility of nonnegligible CO_2 leakage for wells with poor-quality cement. For brine, the lack of buoyancy renders brine-leakage negligible as overpressure dissipates into the upper Tuscaloosa and Wilcox. A total of 7 unaltered P&A wells and 10 P&A wells retrofitted for production were evaluated as potential leakage pathways within the Phase III area. Statistical estimates of properties for these 17 wells used in the simplified model suggest that at most, 2 (and possibly none) could be capable of conveying a total CO_2 flow rate of 1.8 ton/yr, either to USDW or to the ground surface, with the remaining 15 wells effectively sealed.

With a 100% probability of overpressured CO_2 and brine encountering potential leakage pathways provided by P&A wells, the leakage-risk assessment is based directly on assessment of impacts. Given the large volumes of potable aquifers and above-ground dissipative processes, CO_2 fluxes of this magnitude are expected to have negligible impact on USDW, ECA, and HS compartments (Fig. 2). According to analyses of impact severity on HMR, USDW, NSE, and HS, potential leakage of CO_2 through wells is expected to have negligible impacts as well.

In summary, the CF approach applied to the SECARB Phase III CO_2 injection site suggests that CO_2 leakage risk is low and that brine-leakage risk is even lower. Given that the oilfield is an active operation, it is improbable that well leakage to the surface will go unnoticed, and certain that risks will be managed through active risk mitigation and remediation if necessary.

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