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Southeast Regional Carbon Sequestration Partnership (SECARB)

Gulf Coast Stacked Storage Project

Field Test Location

Cranfield Oilfield, Mississippi

Amount and Sources of CO_2

990,000 Tons (as of October 1, 2009) from Natural Source (Jackson Dome)

Primary Contacts

DOE/NETL Project Manager
Mr. Bruce Lani
bruce.lani@doe.netl.gov

Principal Investigator
Mr. Kenneth J. Nemeth
Southern States Energy Board (SSEB)
nemeth@sseb.org

Field Test Site Contact
Dr. Susan Hovorka
Gulf Coast Carbon Center,
Bureau of Economic Geology
Jackson School of Geosciences
The University of Texas at Austin
susan.hovorka@beg.utexas.edu

Field Test Partners

Primary Sponsors
DOE/NETL
SSEB
The University of Texas at Austin

Industrial Partners
Denbury Onshore LLC
Sandia Technologies
Schlumberger CO_2

Summary of Field Test Site and Operations

The Southeast Regional Carbon Sequestration Partnership's (SECARB) Gulf Coast Stacked Storage Project demonstrates the concept of phased use of subsurface volumes, combining early use of carbon dioxide (CO_2) for enhanced oil recovery (EOR) with later injection into deeper and larger volume brine formations. Technical focus areas are: (1) documenting retention in the injection zone; (2) quantifying capacity; and (3) quantifying pressure response to injection. The Cranfield unit in southwest Mississippi operated by Denbury Onshore LLC is the site of this test. The Gulf Coast Carbon Center (GCCC) at the University of Texas-Austin's Bureau of Economic Geology (BEG) leads the Cranfield stacked storage project.

The Gulf Coast of Alabama, Mississippi, Louisiana, and Texas is formed by the thickest sedimentary wedge in the onshore United States. This clastic sequence is comprised of late Mesozoic to Cenozoic age formations composed of porous and permeable fluvial, deltaic, shoreline, and marine sandstones, separated by regionally extensive thick impermeable marine shales that isolate fluids. Further compartmentalization and isolation of storage volumes throughout the Gulf Coast is provided by structures, which include anticlinal four-way closures, roll–over anticlines, and fault bounded traps.

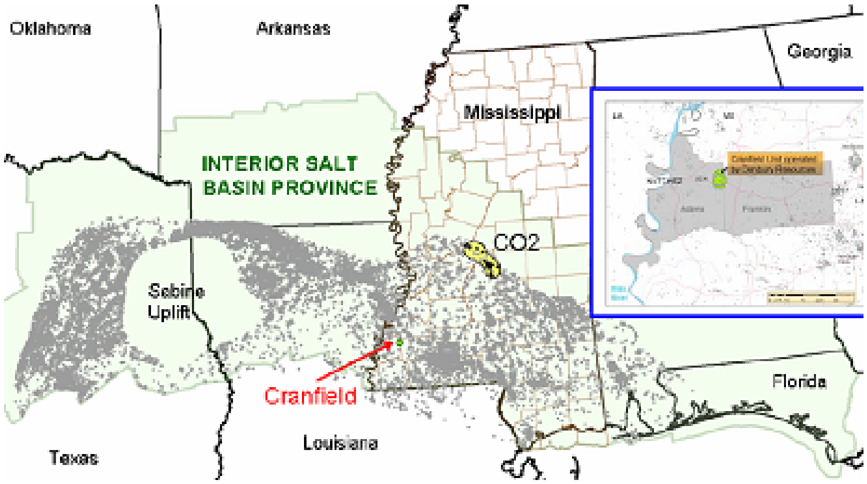

Figure 1. Geographical location of SECARB Phase II study at the Cranfield Field east of Natchez, Mississippi

The permanence of storage in these formations is well documented by oil and gas that has been trapped for long time periods by structures and seals. Representative world-class sequestration target formations in the Gulf Coast are the Cretaceous Tuscaloosa Formation of the Mississippi salt basin and the equivalent Woodbine Formation of the East Texas Basin, Cenozoic age Wilcox and Vicksburg/Frio formations, and Miocene formations of the lower Gulf Coast. The Tuscaloosa Formation lies beneath an area of approximately 46,000 square miles in southern Alabama and Mississippi, the Florida Panhandle, and Louisiana (Figure 1).

Using NATCARB 2008 assumptions, Massachusetts Institute of Technology (MIT) has estimated a minimum storage volume for the Tuscaloosa Formation of 14,000 million metric tonnes of CO_2. The Woodbine of East Texas, a continuation of this regionally significant CO_2 sink, can hold approximately equivalent volumes. Additional storage in the Gulf Coast Cenozoic reservoirs, expanded in 2008 to include offshore, is estimated to be more that 2,000 billion metric tonnes. Data from the Tuscaloosa trend can also help provide improved capacity estimates for the Cretaceous of the eastern seaboard, which presents the best target for this area, totaling an additional 134,000 million metric tonnes of CO_2.

The sequestration target being tested for the Gulf Coast Stacked Storage Project is within and associated with Denbury's Cranfield unit (Figure 1), east of Natchez, Mississippi. The injection target was selected to be representative of the high quality targets provided by the Gulf Coast, in that it lies within the thick marine-reworked to fluvial lower sandstone of the Tuscaloosa Formation in a typical Gulf Coast four-way closure (Figure 2). This test site was selected at a location where large volumes of pipeline CO_2 are available since July 2008 and where existing infrastructure and substantial industry match allow an ambitious field investigation to be completed on available budget and in the near term.

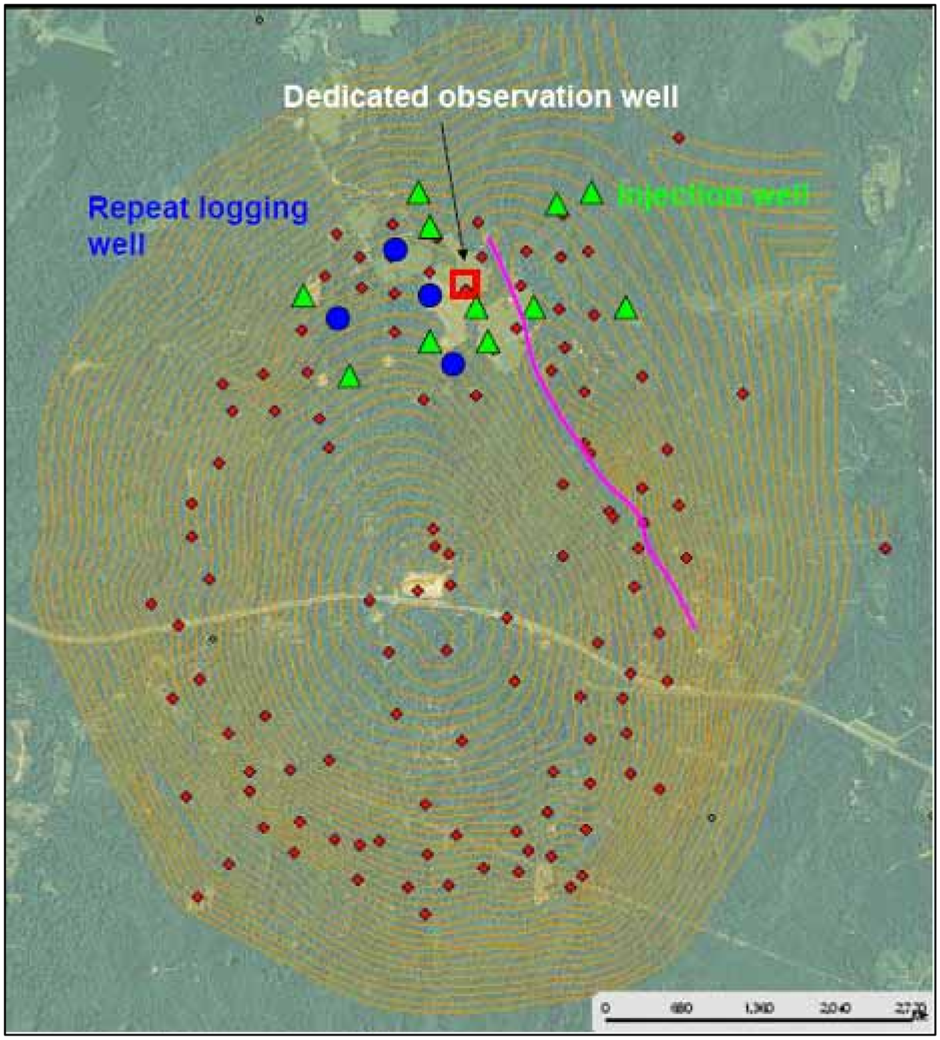

Figure 2. Injection target for the Stacked Storage Project lies within the thick marine-reworked to fluvial lower sandstone of the Tuscaloosa Formation in a typical Gulf Coast four-way closure

Research Objectives

Phased Use of Subsurface Volume

The stacked storage concept is based on the following assessment: Where large volume oil fields in decline exist in a region, market forces will determine that initial anthropogenic carbon capture will supply CO_2 for enhanced oil recovery (CO_2-EOR). As the CO_2 demand for EOR decreases over decades and volumes of CO_2 captured increase, brine storage will become widely utilized. Existing and developed pipeline infrastructure and a favorable geologic setting will favor continued injection in the same geologic trends that hosted EOR resources. Lack of cement behind casing in EOR production wells will limit the use of horizons shallow than the EOR interval for brine storage. However, injection into brine-bearing formations below and adjacent to former production may prove to be attractive targets. Deeper formations in the same footprint as oil production have attractive characteristics in that they are geologically well known, have well-defined surface and mineral ownership, and public acceptance of subsurface activities is high.

Key information needed to demonstrate the validity of this model are: (1) will CO_2 used for EOR be retained in the subsurface effectively so that benefit to the atmosphere is produced, especially considering the impact of well penetrations; (2) how should the capacity in large volumes below and downdip of the reservoirs be calculated, as this will determine how large a footprint will be underlain by CO_2; and (3) is the pressure response in the near and far field understood quantitatively well enough to safely move to large volume injection?

GCCC has partnered with Denbury Onshore LLC of Plano, Texas, to begin to answer these questions under realistic conditions associated with large volume injection (about 1 million tons per year CO_2). The CO_2 injection design used by Denbury is identical to that which would be used for large volume storage in that CO_2 is injected continuously, so that the CO_2 injection volume and field pressure is high as compared to the West Texas process of injection of water alternating with gas (WAG). The Cranfield oil field was depleted in the mid-1960's and wells plugged and abandoned (P&A), so that the field has had more than 40 years to reequilibrate. Over this time, pressure has recovered to near original pre-production pressure because of water incursion. Denbury has redeveloped the field to produce remaining oil with CO_2-EOR, with injection starting July 2008, however Denbury produces by gas lift so that a prolonged part of the test period did not have production.

The Denbury pipeline network is supplied by the Jackson Dome, a naturally occurring subsurface source of CO_2. Denbury's development plan calls for the incorporation of anthropogenic CO_2 into the pipeline network and further expansion of the network into Mississippi, Alabama, Louisiana, and Texas. Ultimately this pipeline network will connect depleted reservoirs and large volume brine storage to sequester anthropogenic CO_2 produced throughout the region.

Plan Implementation

Detailed characterization of the field, the foundation of both good flood design and successful monitoring strategy, was completed in the spring of 2008 by Denbury and GCCC. Two hundred 1940's vintage wireline logs provide stratigraphic and structural data; several hundred sidewall cores plugs and detailed field production records provide information on fluid flow. New characterization data contributed by Denbury includes a 3-D seismic survey and data from ten new wells including open-hole logs, whole cores from two wells, and side wall cores from two others have been provided to GCCC as matching data. Stratal slicing of the seismic volume to assess storage volume interconnectivity has been completed, as well as assessment of new and existing cores to evaluate seal and monitoring intervals.

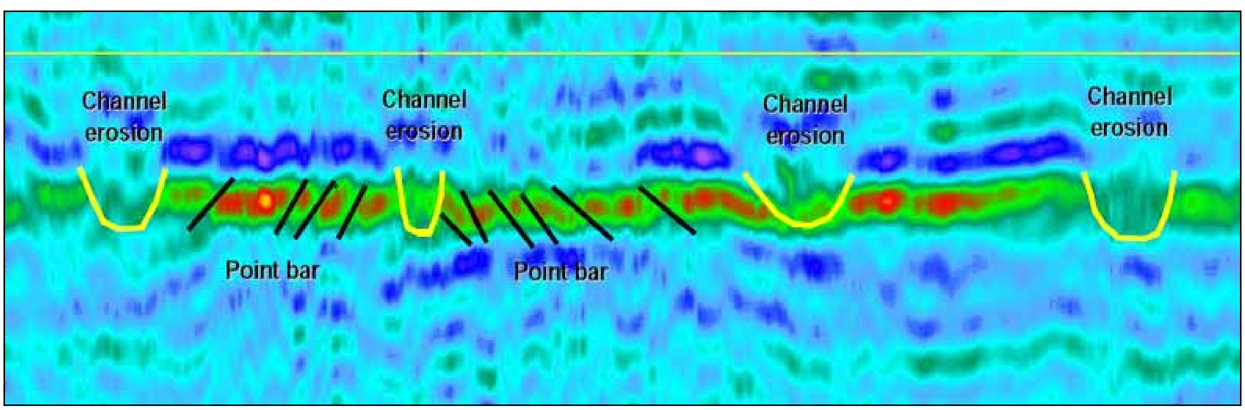

Figure 3. Stratal slicing and high resolution processing (Hongliu Zeng) shows an interpretation of the complexity within a fairly continuous lower Tuscaloosa sand body.

The lower Tuscaloosa injection zone at Cranfield is a highly heterogeneous complex of fluvial channel sandstones and conglomerates (Figure 3). Basal Tuscaloosa conglomerates (unit E) are incised into marine shales and silts of the Washita-Fredericksburg Group; overlying lithic arkoses are poorly sorted and show sinuous patterns with amalgamated cross-bedded and point bar deposits forming a fairly continuous sand-rich zone across the field (unit D). Calcite and Fe-chlorite cements further complicate the flow system developed in these rocks. Red overbank mudstones serve as seals on the oil-producing interval. Overlying fluvial sandstones (A though C) show more strongly aggradational characteristics in that they are not amalgamated and form more discontinuous sand-rich horizons across the field.

The SECARB monitoring program for Phase II Stacked Storage at Cranfield was deployed in the spring of 2008. A novel test element is a dedicated observation well to allow monitoring of two zones: the lower Tuscaloosa injection zone and an aerially continuous, 12 ft thick, 100 md sandstone in the upper Tuscaloosa which serves as an above-zone monitoring horizon. Modeling shows that, should significant leakage occur through the reservoir seal through preferred conduits such as flawed well completions or faults in the area, the flood would result in pressure increases in the monitoring zone. This test assessed the adequacy of established Mississippi well integrity standards for retaining CO_2 for greenhouse gas mitigation. Denbury donated access to a plugged and abandoned former production well, the Ella G. Lees #7, which was reentered and repaired to serve as a dedicated monitoring well. Real-time pressure and temperature data from both are transmitted via wireline to a satellite uplink at the well, providing real-time access to 10 minute data, with higher frequency data collected by download at the site. An option to sample fluids for geochemical confirmation of leakage is designed in case anomalies are detected. In the initial year, increasing pressure in the injection zone has been observed, but the above zone monitoring pressure has not correspondingly increased, suggesting that no leakage is occurring (Figure 4). Additional monitoring includes daily tracking well-head pressures, pressure memory gauges and dip-in pressures, and fluid composition changes measured with Schlumberger's Reservoir Saturation Tool (RST) in an area around the initial injection and observation well. A time lapse surface program monitoring soil gas at plugged and abandoned wells documents no changes in soil gas from pre – to post-injection.

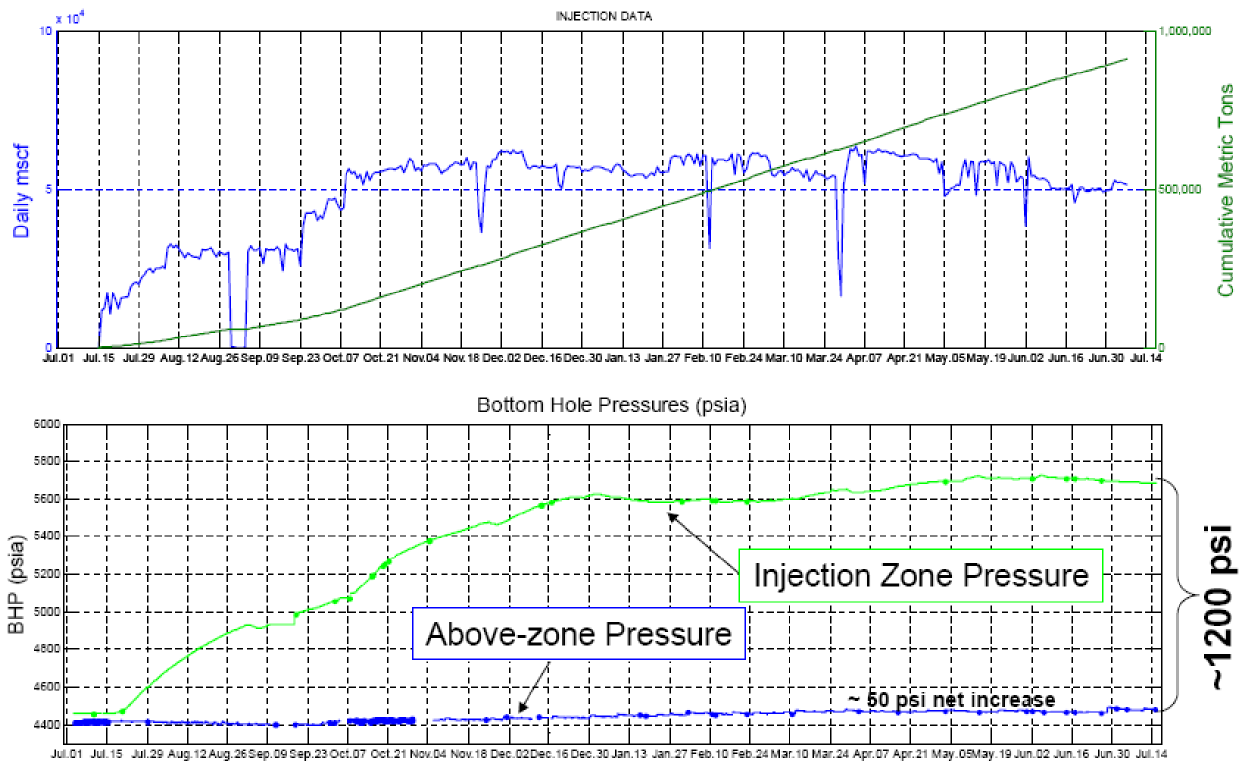

Figure 4. One year record of injection and corresponding pressure increase in the injection zone is not matched by corresponding pressure increase in the overlying monitoring zone shows the degree of isolation in an area with numerous wells.

Regional Significance

The economic engine that can help power the initial deployment of carbon capture and sequestration (CCS) technology is CO_2-based enhanced oil recovery. However, to use this technology to support CCS, it is important to document how well CO_2 is retained in an area with numerous existing well penetrations. This test will provide the first quantitative field test of well integrity across many wells. It complements the Southwest Regional Sequestration Partnership test at SACROC where CO_2 has been injected over decades.

The Bureau of Economic Geology has made a conservative estimate that over 5 billion barrels of oil are recoverable by CO_2 EOR in the target area of east Texas, Louisiana, Mississippi and Alabama. This activity can pay for the CCS equipment, regional CO_2 pipelines, and compression facilities that can also be used for putting CO_2 into long term storage in deep brine reservoirs in the Gulf Coast. Preliminary economic modeling by the BEG and the Massachusetts Institute of Technology (MIT) support the conclusion that such regional pipeline complexes linking many sources and sinks are more efficient than single pipelines linking individual sources and sinks. Such regional pipelines also allow matching capture and injection rates across multiple sites to reduce risk.

The Gulf Coast region contains more than 3,000 oil and natural gas reservoirs that could be used first for EOR and then for large-volume, long-term storage of CO_2 in nonproductive formations below the reservoir interval. Many oil reservoirs have at least one deeper brine aquifer that could be accessed by drilling deeper sequestration injection wells from existing field footprint.

By contrast, suitable sequestration formations do not exist in widespread areas of the southeast United States. SECARB is continuing its characterization of geologic formations in the 11-state region. Suitable target formations do not exist within eastern Virginia, North Carolina, South Carolina, and northern Georgia, raising the importance of the available subsurface to provide storage sites for parts of the region where the subsurface has been found to be unsuitable.

Cost

Total Field Project Cost (Years 1-4): $7,790,649

DOE Share: $4,634,562 59%

Non-DOE Share: $3,156,087 41%

Field Project Key Dates

Characterization Completed: Q1, FY08
Workover Operations Completed: Q2, FY08
Injection Operations Began: Q3, FY08
MVA Events:
- Pre-injection baseline completed: Q2, FY08
- One year injection monitored : Q2, FY09
- Injection monitoring continues: Q1, FY10

Tasks	FY2006				FY2007				FY2008				FY2009				FY2010			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
1.1 Project Definition	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■			
1.2 Design			■	■	■	■	■	■												
1.3 Implementation									■	■	■									
1.4 Operations												■	■	■	■	■	■	■		
1.5 Closeout/Reporting																■			■	■

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