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University of Alabama at Birmingham

Carbon-Dioxide-Enhanced Oil Production from the Citronelle Oil Field in the Rodessa Formation, South Alabama

Quarterly Progress Report

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Disclaimer

Executive Summary

The team of Alabama Agricultural and Mechanical University (AAMU), Denbury Resources, Inc., Geological Survey of Alabama (GSA), Southern Company Services, Inc., University of Alabama (UA), University of Alabama at Birmingham (UAB), and University of North Carolina at Charlotte (UNCC) are engaged in a Cooperative Agreement with the U.S. Department of Energy, National Energy Technology Laboratory, to evaluate the potential for carbon-dioxide-enhanced oil recovery and carbon dioxide sequestration in the Citronelle Oil Field in Mobile County, Alabama. The present report describes work and accomplishments during the second quarter of the second year of work, from April 1 to June 30, 2008.

The work being done has the following components, with the organizations having the relevant expertise and resources identified in parentheses following each topic: 1. Communication and Technology Transfer (all partners), 2. Geology and Petrology (GSA and Southern Company), 3. Reservoir Fluid Properties and Phase Behavior (UA), 4. Petroleum Reservoir Simulation (UA), 5. CO_2 Liquefaction, Transportation, and Storage (Southern Company and Denbury Resources), 6. Well and Site Preparation and CO_2 Injection (Denbury Resources), 7. Surface Monitoring (AAMU), 8. Seismic Imaging (UNCC), 9. Saline Formation Simulation (UAB), 10. Visualization of Geologic Structure and Flows (all partners), and 11. Reservoir Management Plan and Economic Analysis (all partners).

A collaboratory web site was established for rapid and effective dissemination of technical information through the research group. The site now has links to all of the existing reports on previous geological and engineering work in the Citronelle Oil Field, field data, reports generated under the present project, reservoir simulations, and the interpretation of interference test data.

Citronelle Unit B-19-10 #2 well (Permit No. 3232) will serve as the CO_2 injector for the first field test. CO_2 will be injected into the Upper Donovan 14-1 and 16-2 sands. Workover of the injector (B-19-10 #2) and two producers (B-19-7 and B-19-9) is complete, in addition to the well that was already in production (B-19-8). The plugged and abandoned producer (B-19-10) remains to be worked over and brought on line. A permanent packer was installed in the injector during June. Water injection will resume in July.

All well logs in the 4-square-mile area surrounding the test site have been digitized and used to construct a network of stratigraphic cross sections correlating Sands 12 through 20A in the Upper Donovan. The cross sections demonstrate the extreme facies heterogeneity of the Upper Donovan and show that it is well expressed in the five-spot test pattern. Many other features having bearing on the performance of the CO_2 injection test have been discovered. Detailed study of the petrology and sedimentology of Citronelle well cores has shown that depositional environments in the Rodessa Formation differ significantly from the model developed in early published work that has guided past development and production from the Citronelle Field.

A rolling ball viscometer, with which to measure minimum miscibility pressure, viscosity, and density of oil-CO_2 mixtures at reservoir temperature and pressure, is being assembled and tested. This instrument is an excellent tool with which to examine the extension of oil-CO_2 miscibility through addition of other gas constituents to CO_2, a component of the advanced CO_2-EOR technology proposed by Kuuskraa and Koperna (2006).

Based upon reservoir simulations using SENSOR, it is expected that 7500 tons of CO_2 will be sufficient to demonstrate CO_2-EOR in the 14-1 and 16-2 Sands of the Upper Donovan and that an unequivocal effect of CO_2 on oil production will be observed within the time frame of the project. According to the simulations, injection of 7500 tons of CO_2 can be completed in 215 days. Significant incremental oil first appears 275 days after the start of CO_2 injection and a strong peak in oil production occurs between 400 and 500 days from the start of injection. Cumulative incremental oil at 500 days is 11,500 STB.

An alternative simulation of the injection of 7500 tons of CO_2 using the MASTER 3.0 reservoir simulator indicated that breakthrough of CO_2 is expected 242 days from the start of injection, that the time required for injection of 7500 tons will be 292 days, and that the oil production rate will steadily increase during CO_2 injection, but will begin to decline soon after injection is switched from CO_2 back to water.

Sampling chambers and soil probes with which to measure soil gas composition versus depth, CO_2 flux from soil, soil temperature, and soil moisture have been installed at three locations surrounding each of the five wells in the test pattern. Test plots have been established near the injector, producers, and tank batteries, in which to monitor plant growth and species distribution. CO_2 is being monitored in ambient air at points on a grid across Citronelle, to establish the CO_2 background and its seasonal fluctuations.

A 24-Channel Refraction Microtremor (ReMi) data acquisition system has been tested at the UNCC Pilot Site. Construction of subsurface seismic profiles by recording ambient noise only (passive seismic source) achieved deeper penetration than was obtained by recording seismic waves generated by active sources. The ReMi test results compare favorably with Multichannel Analysis of Surface Wave (MASW) results, providing confidence in the potential of the ReMi technique.

The simulation results using SENSOR showed that cumulative oil production increases with increasing amount of CO_2 injected, regardless of the assumed permeability distribution. However, in all cases considered, there was an optimum CO_2 slug size, from the point of view of the profitability of a CO_2-EOR project. The optimum size of CO_2 slug increases with increasing oil price. The discount factor has little impact on the optimum size of CO_2 slug at high oil prices, but does have some impact at low oil prices.

Work during the coming quarter will focus on determination of the phase behavior of Citronelle oil using the rolling ball viscometer, preparation of the test site, the logistics of CO_2 supply for the test, resolution of the budget for CO_2 services, measurement of baseline conditions at the test site, testing of the ReMi technique for seismic imaging, work on construction of the database on position and thickness of sandstone units and pay zones, and refinement of the reservoir simulations.

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1. Introduction

1.1. Background

Combustion of fossil fuels for electric power generation and in the transportation, industrial, commercial, and residential sectors in the Southeastern U.S. makes this region a major contributor to nationwide anthropogenic CO_2 emissions (Pashin et al., 2005). Separation of carbon dioxide from combustion products followed by storage in geologic formations is among the most promising approaches to reducing the rate at which CO_2 accumulates in the atmosphere as a result of both human activity and natural processes (Stevens et al., 2001; Friedmann and Homer-Dixon, 2004).

The State of Alabama is endowed with a wealth of potential geologic carbon dioxide sinks, including conventional oil and gas reservoirs, coal bed methane reservoirs, and saline formations (Pashin et al., 2005; Esposito, 2006). Sequestration of carbon dioxide in coal beds, coupled with enhanced methane recovery, is the subject of an investigation by the Southeastern Regional Carbon Sequestration Partnership (Pashin et al., 2004, 2005, 2006). The present team of Alabama A&M University, Denbury Resources Inc., Geological Survey of Alabama, Southern Company, University of Alabama, University of Alabama at Birmingham, and University of North Carolina at Charlotte, will demonstrate enhanced oil recovery using carbon dioxide (CO_2-EOR) to increase oil yield and extend the productive life of the Citronelle Oil Field in Mobile County, Alabama. A parallel investigation will assess the capacity of the oil reservoir and adjacent saline formations for sequestration of carbon dioxide, when tertiary oil recovery operations are complete.

The Citronelle Oil Field is the largest oil producer in the State of Alabama. According to criteria proposed by Kovscek (2002), the field is an ideal site for CO_2 EOR and sequestration: (1) from the reservoir engineering prospective, the site is mature and water-flooded, with existing infrastructure, including deep wells, and (2) from the geological prospective, the field consists of fluvial-deltaic sandstone reservoirs in a simple structural dome and, because of the presence of the regionally extensive Ferry Lake Anhydrite seal, four-way structural closure, and lack of faulting, is naturally stable with respect to CO_2 storage. However, the geology of the heterogeneous siliciclastic rocks in this field is very different from those where CO_2-EOR has been applied commercially, such as in carbonate strata of the Permian Basin in Texas and New Mexico and in the Williston Basin in North Dakota and Montana. The proposed demonstration will introduce CO_2-EOR for tertiary recovery from Alabama's uniquely structured energy resources and realization of benefit to the Nation from additional petroleum production.

1.2. Objectives

The principal objective of the project is to provide the geologic and reservoir engineering analysis and field testing that will permit the operators of the Citronelle Oil Field to successfully apply CO_2-EOR to increase oil recovery and extend the productive life of the field. The project will proceed from the analysis of existing well logs to determine, in the greatest detail possible, the structure of the Rodessa Formation in the vicinity of the Citronelle Field, through seismic measurements to improve spatial resolution of the stratigraphy and movement of CO_2, to a demonstration of increased production from the wells. A second objective is to establish and transfer to industry the engineering expertise with which apply CO_2-EOR at other sites having geologic structure similar to that of the Rodessa Formation, which is very different from the Permian Basin structure where CO_2-EOR is a well established and successful tertiary oil recovery technology.

1.3. Scope of Work

Phase I. Baseline characterization of the reservoir and its fluids will be conducted, and a CO_2 injectivity test will be run in a selected test area. An analysis of the test data and associated environmental measurements will be done, as well as a determination of whether seismic instruments are able to detect changes in the formation and the presence and migration of CO_2 in the reservoir.

Phase II. Studies will include the effect of nitrogen on oil-CO_2 interaction, a stability analysis of the anhydrite dome overlying the reservoir, and refined reservoir simulations and visualizations. A second CO_2 injectivity test will be run, either in the same or in a new test area. An analysis of the test data and associated environmental measurements will be performed, as well as an analysis of whether seismic measurements are able to detect the migration of CO_2 in the formation, and comparison of simulation versus field test results.

Phase III. Migration of CO_2 and stability of the formation will continue to be monitored at the first two field test sites. The reservoir management plan will be refined and a third field test conducted. An analysis of all of the test data and associated environmental measurements will be performed, a comprehensive assessment compiled, and the results disseminated.

2. Research Plan - Phase I

The principal components of the work, the leaders of each activity, and the tasks from the Statement of Work to be executed under each component in Phase I (January 1, 2007 to August 31, 2008) are described below (please see Appendix A for the complete statement of work by task for the 5-year project).

2.1. Communication and Technology Transfer

Peter Walsh, University of Alabama at Birmingham
Eric Carlson, University of Alabama.

Task 1. Establish collaboratory environment. The investigators are located at multiple sites. To facilitate the research work and report preparation, a web-based system will be set up for on-line discussion, exchange of data, distribution of information, and monitoring of project activity. It will be a secure web site to which only the project partners will have access, where all data and documents related to the project will be stored, and where all members of the group can contribute to the preparation and revision of reports and other publications.

Task 2. Establish publicly accessible web site for two-way communication with industry. To facilitate technology transfer and feedback from industry, a website describing the project will be set up through which to disseminate results and receive suggestions and comments from industry and the public. This will be the site where any interested person can learn about the partners, purpose, objectives, and progress of the project. It should be of the highest quality, with respect to both technical content and graphic design. It will be constantly evolving over the life of the project and beyond.

2.2. Geology and Petrology

Jack Pashin and Denise Hills, Geological Survey of Alabama
Richard Esposito, Southern Company
Mark A. Rainer, Denbury Resources, Inc.

Task 6. Construct advanced geologic models of Rodessa reservoirs. An analysis of the geologic data available at the time was done for DOE by BDM Petroleum Technologies (Fowler et al., 1998) during their evaluation of the Citronelle Field for waterflood optimization. That work is being augmented by Southern Company Geologist Richard Esposito, in connection with a Southern Company/University of Alabama at Birmingham project to be completed at the end of this calendar year. We will incorporate in the model the results of his analysis and information from the updated site stratigraphy provided by the newly available cores mentioned in Task 4, above. Reservoir architecture and heterogeneity will be quantified and visualized using methods (i.e. architectural element analysis and sequence stratigraphy) and technologies (immersive 3D visualization) that were not employed in the earlier work by Fowler et al. This effort will improve the accuracy and level of detail in the geologic model, building upon, but not duplicating past work.

Task 4. Analysis of rock samples. Denbury Resources recently discovered drill cores from a previous DOE project that was initiated in the Citronelle Oil Field, but not fully implemented. Denbury is in the process of donating these cores to the Geological Survey of Alabama. The cores comprise eight complete, 800 foot sections through the full Rodessa Formation, from locations throughout the field. Because the cores are continuous, they are an invaluable resource for interpretation of existing well logs and construction of a detailed cross-section of the site. These cores have not been analyzed previously, so this new information will permit an updated review of Citronelle Oil Field geology for CO_2 EOR and sequestration. The cores to be examined first will be those most closely linked to target areas for the field tests. The measurements will include porosities, permeabilities, and microscopic analyses.

2.3. Reservoir Fluid Properties and Phase Behavior

Peter Clark, University of Alabama

Task 5. Analysis of oil and oil-CO_2 interaction. Determination of minimum miscibility pressure. Evaluation of propensity for oil components to precipitate in the presence of CO_2. Measurement of viscosity of the oil as functions of temperature and CO_2 pressure.

2.4. Petroleum Reservoir Simulation

Eric Carlson, University of Alabama
Konstantinos Theodorou, University of Alabama at Birmingham

Task 7. Reservoir simulation. Examine the available reservoir simulators, such as MASTER 3.0, Eclipse, and TOUGH2, and choose the one best suited for simulation of oil production using CO_2 EOR. Perform simulations throughout Phase I of the project to provide analysis that will assist in selection of the test and monitoring wells (Task 8), development of the reservoir management plan (Task 11), the economic and market analysis (Task 12), and visualization of the flows (Task 13).

2.5. CO_2 Liquefaction, Transportation, and Storage

Richard Esposito, Southern Company
Jack Harper, Denbury Resources

The logistics of procuring, transporting, and storing CO_2 at the injection site in Citronelle were not called out as a separate task in the original proposal. However, it has become clear that there are a number of options that need evaluating and that the timing, costs, and availability of equipment pose significant challenges.

2.6. Well Preparation, Water Flood, and CO_2 Injection

Jack Harper, Gary Dittmar, Mark Rainer, and Alec Bailey, Denbury Resources
Richard Esposito, Southern Company
Peter Walsh, University of Alabama at Birmingham

Task 3. Application for permit to conduct Field Test No. 1. A Class II Underground Injection Control (UIC) permit from the State of Alabama will be required for the injection of CO_2 at the site. The application process will be begun at this early stage, so lack of the permit does not result in delays. At this point we intend to list all of the likely candidate wells, then amend the application as the list of potential test wells is narrowed down.

Task 8. Selection of test and monitoring wells. Based upon analysis of drill cores from the Geological Survey of Alabama collection, production records of the State Oil and Gas Board of Alabama, and calculations using the reservoir simulator, choose an injection well and four surrounding wells for testing.

Task 14. Preparation of wells for Field Test No. 1. Preparation of the test wells for CO_2 injection. In addition to updating Citronelle Oil Field and Rodessa Formation geology, the Southern Company Geologist, Richard Esposito, will serve as interface with Denbury regarding the logistics of transport, storage, and injection of CO_2 for the project. This includes provision for onsite storage of CO_2, installation of CO_2-compatible flow lines, the skid for the compressor, refitting the well head, and possible workover of the well. Since Southern Company's objectives are to supply CO_2 for future EOR projects, including identification of sites for CO_2 storage, its involvement in the field operations will facilitate the establishment of mutually beneficial source-sink relationships.

Task 15. Field Test No. 1. Injection of 5000 tons of carbon dioxide into the reservoir for measurement of transient behavior (pressure decay following an injection pulse) and flow versus pressure. Monitor adjacent wells for produced oil, water, and gas, including CO_2.

Task 19. Analysis of data from Field Test No. 1. Perform complete analysis and summary of the test data and associated environmental measurements.

2.7. Surface Monitoring

Ermson Nyakatawa, Alabama A&M University
Xiongwen Chen, Alabama A&M University

Task 10. Baseline soil CO_2 fluxes and ecology. Establish baseline CO_2 concentrations and fluxes from soil and vegetation and the ecology of the field and surrounding landscape, as found.

Task 17. Ecological processes dynamics. Monitor changes in the surrounding landscape during and following injection of carbon dioxide into the oil reservoir. Work under this task monitors any evolution of the types, populations, and spatial distributions of vegetation on the site and surrounding landscape over the course of the project. Even in the likely event that any CO_2 seepage is completely absorbed by soil and water, it might still influence ecological processes in soil biological communities.

Task 18. Monitor for seepage. Monitoring of CO_2 and fluorocarbon tracer in shallow boreholes and concentration profiles in soil near the surface to determine whether CO_2 seeps from the formation to the atmosphere.

2.8. Seismic Imaging

Shen-En Chen, University of North Carolina at Charlotte

Task 9. Site characterization by geophysical testing. Perform seismic measurements to provide more detail in the vicinity of the test wells.

Task 16. Geophysical testing for influence of CO_2. Determine if seismic measurements are able to detect changes in the formation and the presence and migration of CO_2.

2.9. Saline Formation Simulation

Konstantinos Theodorou, University of Alabama at Birmingham

Simulation of CO_2 injection and analysis of the fate of CO_2 injected into saline formations were not explicitly called for in the original statement of work, though the possibility of CO_2 storage in formations adjacent to the oil reservoir is mentioned in the text of the proposal and contract. It has become increasingly clear that the saline formations above, between, and below the oil-bearing strata are likely to have much larger capacity for storage of CO_2 than the depleted oil reservoirs, so this topic has assumed greater importance.

2.10. Visualization of Geologic Structure and Flows

Alan Shih, University of Alabama at Birmingham
` Jack Pashin, Geological Survey of Alabama
Eric Carlson, University of Alabama
Konstantinos Theodorou, University of Alabama at Birmingham

Task 13. Visualization of geologic structure and flows. Display, in the UAB Enabling Technology Laboratory and on the project web site, of the geologic structure in the vicinity of the test wells and the results of the calculations of oil, water, and CO_2 flows using the reservoir simulator.

2.11. Reservoir Management Plan and Economic Analysis

Peter Walsh, University of Alabama at Birmingham.

Task 11. Reservoir management plan. On the basis of the available data, develop a preliminary CO_2 injection strategy to ensure efficient oil sweep.

Task 12. Economic and market analysis. Verify that production using CO_2 EOR at this site is viable under current and projected economic conditions. Input to the analysis will be obtained from the results of the analysis of miscibility (Task 5), geologic modeling (Task 6), reservoir simulation (Task 7), and development of the reservoir management plan (Task 11).

Task 20. Justification for proceeding to Phase II. Update economic and market analysis in light of results obtained to date and reevaluate the long-term viability of the project.

3. Progress of the Work

3.1. Communication and Technology Transfer

Eric S. Carlson, University of Alabama
Xiongwen Chen, Alabama A&M University
Richard A. Esposito, Southern Company Services
Jack C. Pashin, Geological Survey of Alabama
Peter M. Walsh, University of Alabama at Birmingham

3.1.1. Communication among the Partners

The collaboratory web site at <http://www.citronelleoil.us/>, set up and maintained by Eric Carlson and his research group, has already become an indispensable resource to members of the project team. It now contains links to most of the previous engineering work on the Citronelle Oil Field, all of the reports prepared under the present project, the results of Eric Carlson's simulations of CO_2 injection into the five-spot test pattern, Eric's economic analysis of CO_2-EOR, and his interpretation of the interference test run by Denbury Resources between the injector and a producer in the five spot. Eric's simulations, economic analysis, and interpretation of the interference test are also described in the present report.

3.1.2. Publications

The paper by Richard Esposito, Jack Pashin, and Peter Walsh, entitled, "Citronelle Dome: A Giant Opportunity for Multi-Zone Carbon Storage and Enhanced Oil Recovery in the Mississippi Interior Salt Basin of Alabama," appeared in the June issue of *Environmental Geosciences*, Vol. 15, No. 2, 2008. pp. 1-10. The paper documents the analysis of hydrocarbon reservoirs and saline formations in Citronelle Dome that make them, respectively, ideal sites for CO_2-EOR and CO_2 storage. Estimates are presented of the CO_2 storage capacities of the Eutaw and Upper Tuscaloosa Sands, the Pilot and Massive Sands, and the Donovan Sands of the Rodessa Formation. The total capacity of these zones for CO_2 storage is estimated to be from 500 million to 2 billion short tons.

A paper by Xiongwen Chen, entitled, "Topological properties in the spatial distribution of amphibians in Alabama USA for the use of large scale conservation," was published in the journal *Animal Biodiversity and Conservation*, Vol. 31.1, 2008, pp. 1-13. The paper analyzes the spatial distribution of 60 species in 12 families of amphibians using a clustering coefficient that measures the strength of a population group, the statistical distribution of occurrence localities of species, the fractal dimension of occurrence localities, and distances to nearest neighbor. The implications for species conservation of these topological characteristics of the spatial distribution of species are explored and discussed. The paper continues the study, by Xiongwen Chen and his coworkers, of state-wide patterns of species richness, diversity, and spatial distribution, upon which the properties of species in the region of Citronelle are superimposed. This will enable them to determine whether any changes in species patterns at Citronelle are associated with local influences, or are driven by processes occurring on larger spatial scales.

3.1.3. Citronelle Field Data

A bibliography of publications containing data and information on the Citronelle Oil Field and Southwestern Alabama geology is attached as Appendix C to this report. The bibliography is revised as additional publications are found and as new studies of the Field and region are published, including those resulting from work under the present project. The reports containing engineering data on the Field are also available to members of the research team at the web site set up and maintained by Eric Carson at <http://www.citronelleoil.us/>.

3.1.4. Meetings of the Research Group

Richard Esposito meets on a regular basis with Jack Pashin, Denise Hills, and David Kopaska-Merkel at the Geological Survey of Alabama, to participate in the characterization and correlation of well logs from the State Oil and Gas Board collection and petrographic analysis of the drill cores from Citronelle provided by Denbury Resources. The results of that work are described in Section 3.2 of the present report, below. Richard Esposito and Jack Pashin are working on a paper describing the design and planning of the pilot-scale CO_2 injection test to begin in October 2008.

The next meeting of the full team will be held in Birmingham on July 24, 2008.

3.1.5. Visits to Citronelle Oil Field

Good coordination of visits to the test site by project team members with Denbury Resources' personnel in Citronelle is essential to the successful execution of the work. Four types of work are in progress or planned:

- Set-up and monitoring of the test plots chosen to observe the growth of vegetation near the injector, producers, and tank batteries by Xiongwen Chen and Kathleen Roberts of Alabama A&M University.
- Measurement of soil properties and CO_2 concentration and flux from soil near the injector and producers by Ermson Nyakatawa and his students at Alabama A&M University.
- Seismic imaging using sensors laid out in an "X" across the test well pattern by Shen-En Chen and Wenya Qi of the University of North Carolina at Charlotte.

- Collection of reservoir fluid samples (oil, water, and gas) by Peter Clark of the University of Alabama and Peter Walsh of the University of Alabama at Birmingham.

The frequency of visits to the test site to set up equipment and collect data, the number of hours to be spent in the field during each visit, and the specific work to be done in connection with each of these components of the project were described in detail in our April 30, 2008 Quarterly Progress Report (Walsh et al., 2008, pp. 14-15). The schedule for the visits during the 11-month period from April 2008 to February 2009 is shown in Table 3.1.1. Alec Bailey in Denbury Resources' office in Citronelle is consulted at least a week in advance to determine the most convenient timing for each visit.

Table 3.1.1. Schedule of visits by the DOE project team to Citronelle Oil Field.*

Purpose	Organization	Investigators	2008 Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2009 Jan	Feb
Plant species, growth rate, ambient air, CO_2 flux	AAMU	X. Chen K. Roberts	1x6h	2x8h	1x6h	1x6h	1x6h	1x6h	2x6h	2x8h	2x6h	2x6h	2x6h
Soil properties, CO_2 flux, soil samples	AAMU	E. Nyakatawa		2x8h	1x6h	1x6h	1x6h	1x6h	1x6h	1x6h	1x6h	1x6h	1x6h
Seismic imaging	UNCC	S. Chen W. Qi						2x8h		2x8h			2x8h
Reservoir fluid sampling	UA UAB	P. Clark P. Walsh		1x4h	1x4h	1x4h	1x4h	1x4h	1x4h	1x4h	1x4h	1x4h	1x4h

*The notation "*a*x*b*h" is meant to indicate *a* visits to the field during that month, lasting *b* hours. Where two or three investigators are requesting visits in a given month, the visits will be scheduled to overlap.

3.2. Geology and Petrology

Jack C. Pashin, David C. Kopaska-Merkel, and Denise J. Hills
Geological Survey of Alabama

Much of the effort last quarter focused on characterization and correlation of well logs in the 4-square-mile area containing the test site at the center. All of these well logs have now been digitized. Most wells have SP-resistivity logs, and where these logs are unavailable, gamma-neutron logs were digitized in their place.

The digital logs were used to construct a network of 19 stratigraphic cross sections using the base of the Ferry Lake Anhydrite as a datum. Sandstone-conglomerate units in the upper Donovan Sand were correlated from the 12 Sand through the 20-A Sand. The cross sections demonstrate the extreme facies heterogeneity of the upper Donovan, and this heterogeneity is well expressed within the five-spot well pattern where the field test will be conducted. Of particular interest is the 16-2 Sand, which is interpreted as a composite of two tiers of channel fills. Pay strata are typically developed in the lower tier, and this is where CO_2 will be injected. The upper tier is highly heterogeneous and is interpreted to contain sandstone fills of variable reservoir quality, as well as mudstone plugs. In the northwest corner of the five-spot (Well B-19-7), interestingly, the pay zone is in the upper tier, thus the degree of hydraulic communication with the main pay zone needs to be determined to understand the effects of reservoir heterogeneity on the performance of CO_2 injection operations.

Cores continue to be described, and petrologic analysis of thin sections also continues. Analysis of cores and thin sections indicates that the composition and reservoir quality of the upper Donovan Sand reflects diverse processes driven by alternating episodes of subaerial exposure and marine flooding, as well as burial diagenesis. Subaerial exposure led to formation of oxidized paleosols and erosional relief that in places may have approached 20 meters. Sand bodies were preserved primarily during inundation of the erosional landscape, and trace fossil assemblages and calcareous faunas consisting of oysters, foraminifera, and algae (Figure 3.2.1) indicate that most sandstone bodies have been reworked by marine processes. Pore-filling clay adversely affects reservoir quality and apparently formed as sediment was homogenized during burrowing and by infiltration during subaerial exposure. Exposure and marine flooding further contributed to oxidation of sandstone bodies, dissolution of feldspar and other labile grains (Figure 3.2.2), and precipitation of carbonate cement. Cementation continued during burial and culminated in precipitation of pore-filling dolomite cement prior to petroleum entrapment.

Efforts next quarter will continue to focus on analysis of well logs, cores, and thin sections. Maps of net sandstone and net pay thickness are being constructed for each mappable sandstone unit between the 20-A and 12 Sands. A database is being constructed on the position and thickness of each sandstone unit and pay zone, and this database will form the basis for 3-D visualization of upper Donovan sandstone bodies in the northeastern part of Citronelle Field.

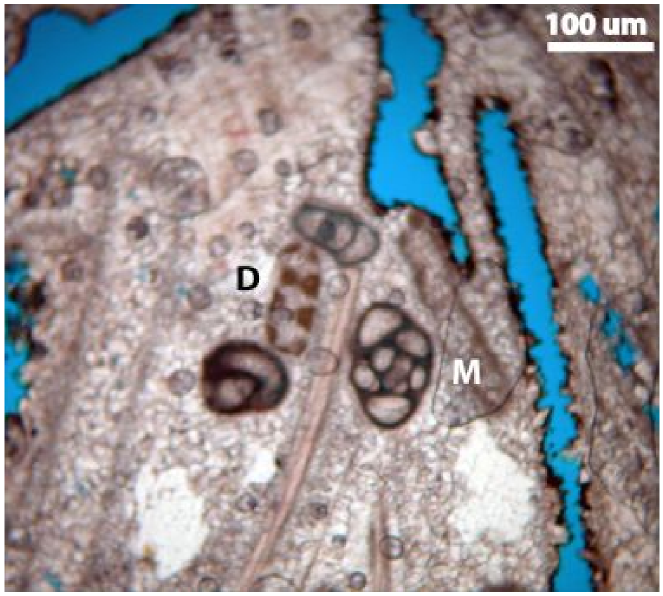


Figure 3.2.1. Oyster hash with moldic porosity, miliolid foraminifera (M), and a dasycladacean alga (D). Well C-11-5 #2, 10,758 ft. (Geological Survey of Alabama)

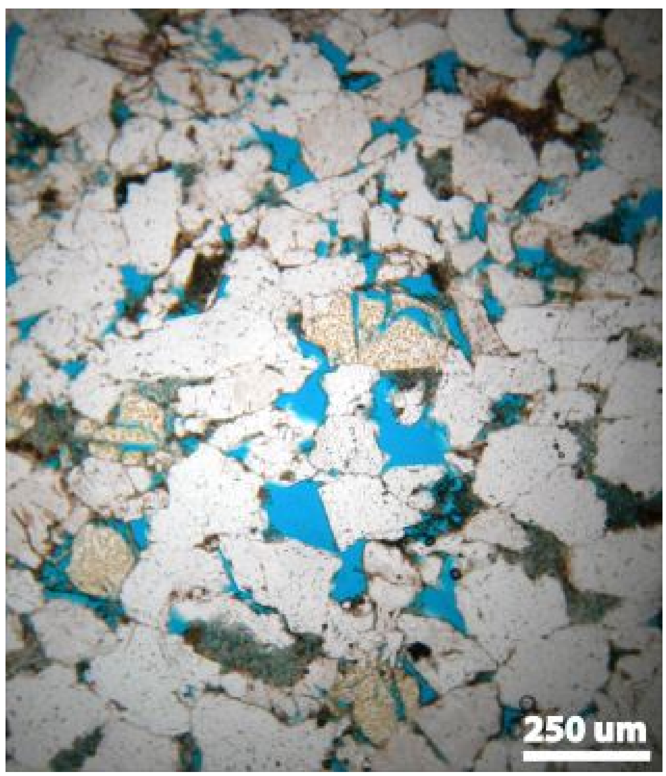


Figure 3.2.2. Porous sandstone containing poorly rounded and poorly sorted grains. Quartz grains are white, potassium feldspar grains are stained speckled yellow. Porosity is filled with blue epoxy and consists of a combination of primary interparticle pores and feldspar molds. (Geological Survey of Alabama)

3.3. Reservoir Fluid Properties and Phase Behavior
Peter E. Clark, University of Alabama

In order to obtain more quantitative measurements of minimum miscibility pressures (MMP) than are possible using the traditional slim-tube method, a high-pressure rolling ball viscometer, shown in Figure 3.3.1, has been constructed. The rolling ball viscometer relies on timing the movement of a ball down a measurement tube containing the fluid of interest. In addition to MMP, this instrument also offers the promise of determining viscosity and density as a function of carbon dioxide partial pressure, at reservoir temperature, for oil samples from all locations in the Field. Using these data, maps of oil-CO_2 mixture properties can be constructed, should there be significant variation from sand to sand.

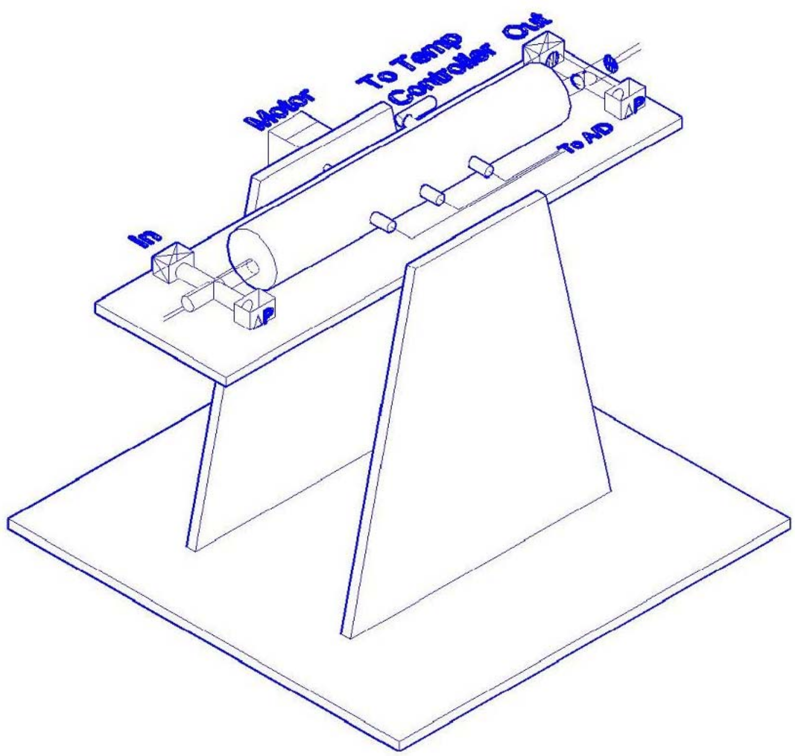


Figure 3.3.1. Rolling ball viscometer (Peter E. Clark, University of Alabama).

Advanced Resources International (Kuuskraa and Koperna, 2006) examined the benefits and costs of a number of possible improvements to traditional CO_2-EOR practice. One component of the proposed advanced CO_2-EOR technology is the extension of oil-CO_2 miscibility by addition of other gas constituents to CO_2. The rolling ball viscometer is an excellent tool with which to evaluate the gas composition dependence of oil-solvent properties.

3.4. Petroleum Reservoir Simulation

Eric S. Carlson, University of Alabama

3.4.1. Simulation of CO_2 Injection Using SENSOR

Simulations of CO_2 injection into the five-spot well pattern chosen for the first test were performed using the SENSOR (System for Efficient Numerical Simulation of Oil Recovery) reservoir simulator from Coats Engineering, Inc. (http://www.coatsengineering.com/). The construction of the model, assumptions, and properties of the reservoir used to describe the five-spot test well pattern were as follows.

Quarter five-spot
Area = 800 ft by 800 ft
Average thickness = 20 ft
10 layers, using a 10 by 10 by 10 grid (cell block size of 2 x 80 x 80 ft)
Injector and producer in opposite corners
No impediment to vertical flow
Different layers have different permeabilities, but permeability is uniform within each layer
Porosity = 0.154
Initial average water saturation = 0.6
Irreducible water saturation = 0.21
"Irreducible" oil saturation = 0.25
Capillary pressure neglected
Reservoir temperature = 210 ^oF (results are not very sensitive to temperature)
Viscosity of water at 5000 psi = 0.4 cP
Injection pressure of 7500 psia and producing pressure of 3000 psia
SENSOR default productivity indices for each well
No allowance for CO_2 dissolution in water
No interaction of CO_2 with the formation

The programs used to calculate oil, water, and CO_2 properties are listed in Appendix D.

Five cases were constructed having different distributions of permeability over the ten layers, as specified in Table 3.4.1. Case PW most closely approximates the distribution of permeabilities in the two sands that will be the targets of the first test injection, according to data in a report on previous reservoir engineering in the Citronelle Field. However, Case PW suffers from its inability to account for heterogeneity and lack of continuity within each layer. Of the cases considered, Case LN was best at reproducing the effective permeability of the formation in an interference test using downhole pressure sensors, run by Denbury Resources between the injector and one of the producers in the five spot, described in Section 3.6.2. However, even with the layering and adjustment of the permeabilities to account for heterogeneity, the simulation is a highly idealized description of the reservoir.

Six different CO_2 and water injection scenarios, described in Table 3.4.2, were run for each of the permeability distribution cases. The calculated injection and production histories for the permeability distribution of Case LN and all six injection scenarios are shown in Figure 3.4.1. The results for the other permeability distributions are presented in Appendix E.

Table 3.4.1. Assumed distributions of permeability of the ten layers.

Case Name	Permeability Distribution, top to bottom (millidarcy)	Location of the Results in the Present Report
Homogeneous	7, all layers the same	Appendix E
H2L	19 10 9 8 7 6 5 3 2 1	Appendix E
L2H	1 2 3 5 6 7 8 9 10 19	Appendix E
LN	6 7 5 7 19 7 10 8 7 9	Section 3.4
PW	161 48 0.7 1.1 8.6 1.9 1.5 2.0 4.6 2.9	Appendix E

Several features of the injection and production histories shown in Figure 3.4.1 are worth noting: (1) cumulative oil production steadily increases with increasing total amount of CO_2 injected (figure at top left), (2) a significant increase in oil production rate occurs approximately 400 days after the start of CO_2 injection, accompanied by CO_2 breakthrough (figures at top right and third from the top on the right), and (3) there is not a great difference in the cumulative oil produced by a single injection of 15,000 tons of CO_2, compared with the oil produced by two CO_2 slugs of 7500 tons each separated by water injection (10% of pore volume).

Table 3.4.2. WAG scenarios run for each of the permeability distributions.

Short Name	Description
waterflood	Continuous water injection only
2x7500	7500 tons CO_2, then 10% of pore volume water, then 7500 tons CO_2, then continuous water
1x15000	15000 tons CO_2, then continuous water
1x22500	22500 tons CO_2, then continuous water
1x30000	30000 tons CO_2, then continuous water
CO_2 only	Continuous CO_2 injection only, up to a maximum of 2 billion scf

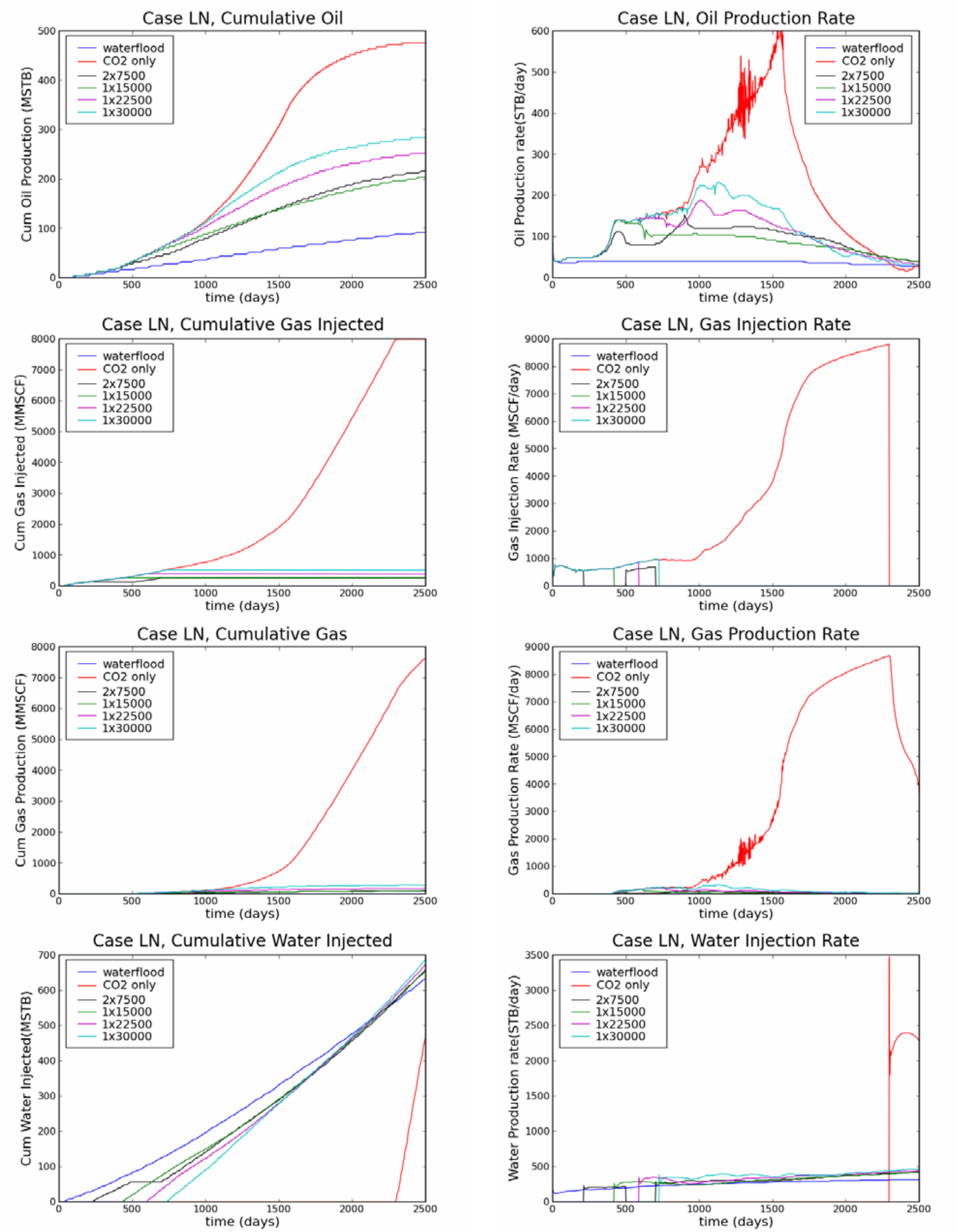


Figure 3.4.1. Injection and production histories calculated using SENSOR for the permeability distribution of Case LN (Table 3.4.1) and six different CO_2 and water injection scenarios (Table 3.4.2).

3.4.2. Expanded Analysis of Case LN

This section expands on the results for Case LN presented in the previous section, examining oil recovery versus CO_2 slug size. Based on the fits of the present section, a useful comparative analysis of project economics can be performed, as described in Section 3.11. In particular, it will be shown that it is possible to find the optimum CO_2 slug size for various pricing scenarios.

The results of Case LN were analyzed more closely to provide comparative results for different slug sizes. Prior to this analysis, three more slug-size simulation cases were performed, including runs for 7500 tons, 60000 tons, and 90000 tons of CO_2. Under the assumptions made here about the system, it turned out that the cumulative oil versus time for the water-injection-only case could be fit with a straight line [= (t days)(37.8 STB/day)]. Using this as a baseline, it was assumed that the production above this value was the incremental oil due to CO_2 injection. This cumulative incremental production, shown in Figure 3.4.2, was fit as a function of time and CO_2 slug size using the following function:

```
function y=thefit(slug,t)
%slug size in tons, t in days
u = log10(slug);
tau=-81.928*u^2+1020.545*u-1795.586;
A=48.97*(1-exp(-2.13E-05*slug ))*4 %MSTB;
y=A*(1+tanh(.00211*(t-tau)));
end
```

Although the fit to the curves in Figure 3.4.2 is not perfect, the correlation provides a simple and convenient continuous representation of incremental oil recovery versus CO_2 slug size and time that can be used for comparative analysis. Total cumulative oil recovery, including oil that would have been produced by waterflood, without injection of CO_2, is shown in Figure 3.4.3.

Other functions useful for the economic analysis were also generated. Cumulative incremental oil recovery at 1800 days from the start of CO_2 injection is shown as a function of the total amount of CO_2 injected in Figure 3.4.4. The cumulative amount of CO_2 injected is shown as a function of time in Figure 3.4.5. The smoothed rate of CO_2 injection versus time, obtained by differentiating the function describing the cumulative CO_2, is shown in Figure 3.4.6.

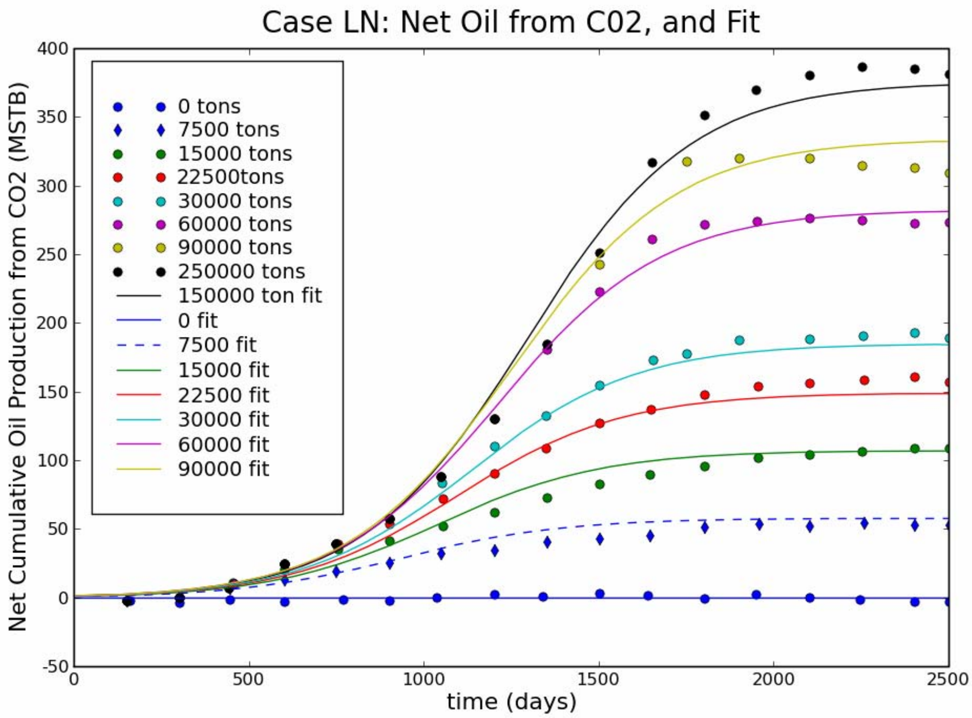


Figure 3.4.2. Simulation results for incremental oil production due to CO_2 injection, and the approximate fit to each data set using the function given in the text.

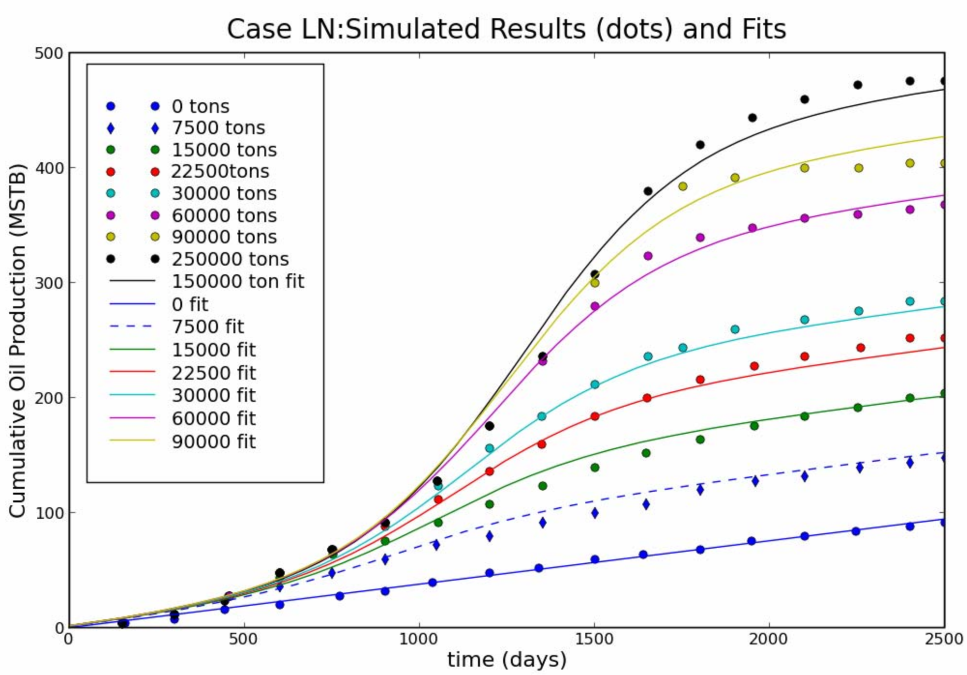


Figure 3.4.3. Total produced oil and corresponding fits, obtained by adding the production by waterflood only [(t days)(37.8 STB/day)] to the curves of Figure 3.4.2.

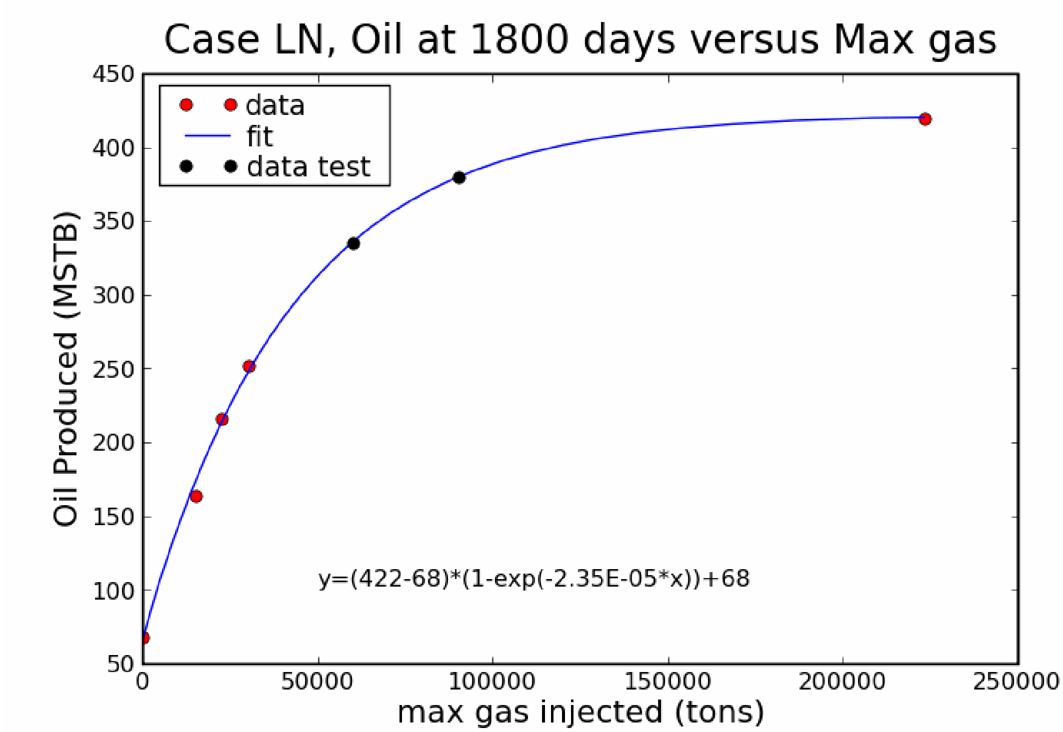


Figure 3.4.4. Simulation results for cumulative oil recovery at 1800 days from the start of injection versus the CO_2 slug size. The curve was fit using the red dots. The black dots are the results of simulation runs made to test the accuracy of the correlation.

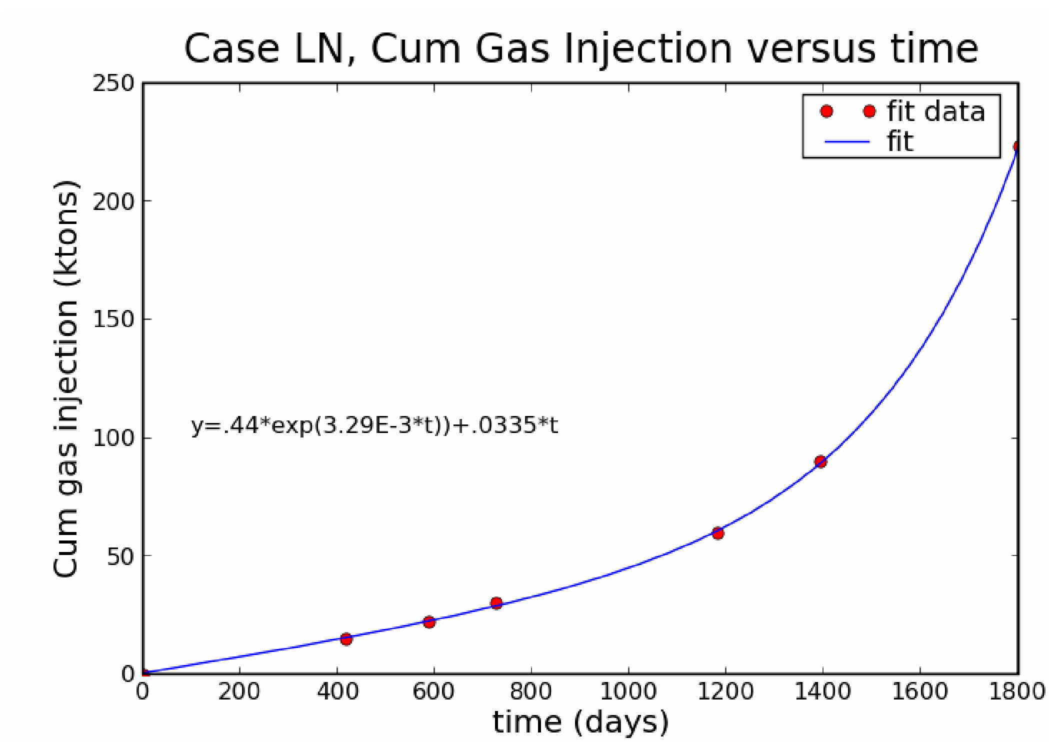


Figure 3.4.5. Cumulative CO_2 injection versus time. The red dots here indicate the endpoints for 15000, 22500, 30000, 60000, and 90000 tons of CO_2, from left to right.

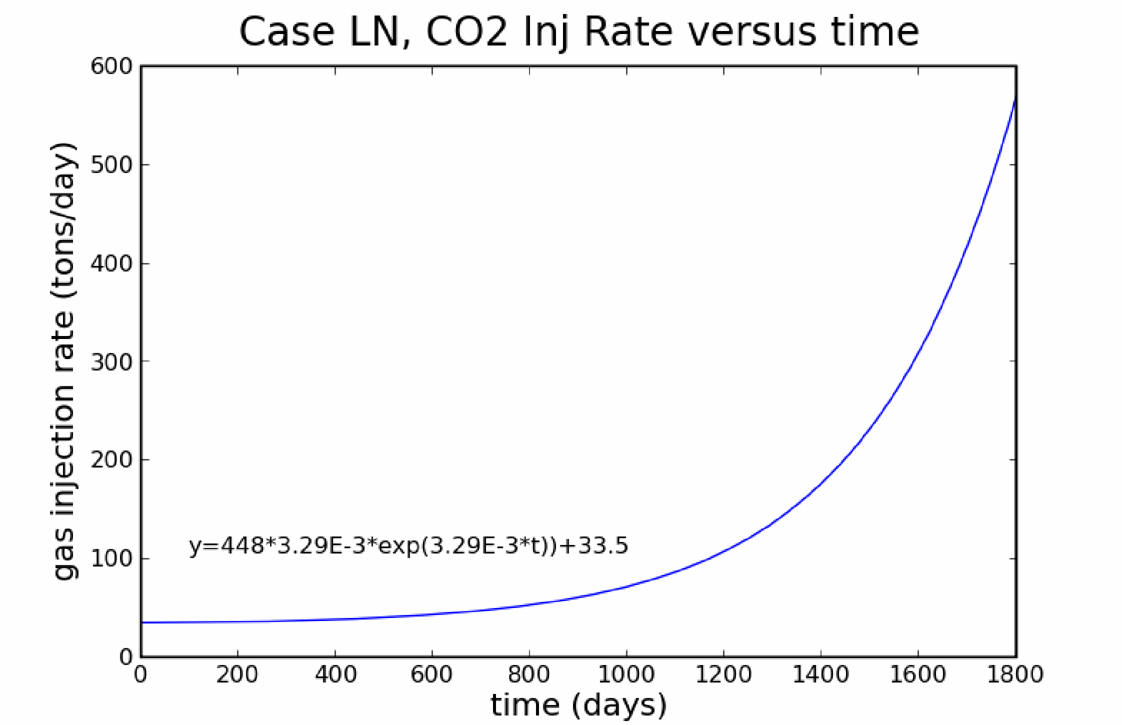


Figure 3.4.6. Smoothed CO_2 injection rate obtained by taking the derivative of the cumulative CO_2 injection versus time (Figure 3.4.5).

3.5. CO_2 Liquefaction, Transportation, and Storage

We are actively engaged in the identification of gas service providers offering the optimum combination of liquefaction, transportation, and storage options for CO_2. The costs for all of these services have turned out to be much greater than anticipated.

3.6. Well Preparation and CO_2 Injection

3.6.1. Preparation for CO_2 Injection

Gary N. Dittmar, Jack Harper, and Alec Bailey, Denbury Resources, Inc.

The injector, Well B-19-10 #2 is currently injecting 150 to 170 bbl/day of water. A step rate test is planned as soon as a steady water injection rate is achieved. The injector is already equipped with a well head and tubing that can be used for CO_2 injection.

Producers B-19-7 and B-19-9 have been worked over, returned from temporarily abandoned status, and are each producing 4 to 5 bbl/day of oil. Producer B-19-8 is producing 9 bbl/day of oil. The potash pile placed by the land owner has been removed from producer B-19-10, but the well is still plugged and abandoned. Well work will begin as soon as the State permit for the work is granted.

The gas-liquid cylindrical cyclone for separating oil and water from gas, shown in Figure 3.6.1, has been installed at the B-19-8 tank battery. Flow meters have been ordered to more accurately meter the power oil going to the wells, because oil production is the relatively small difference between the power oil flow rate to a well and the power oil plus produced oil received at the tank battery. Variation in dissolved solids in produced water, causing variation in the density of the water, complicate the measurement of liquid flow rates. The injection pump at the B-19-8 tank battery is prepared to inject CO_2. Denbury Resources is awaiting specifications for the pad that will support the CO_2 storage tanks.

Figure 3.6.1. Gas-liquid cylindrical cyclone, to separate gas from water and oil, at B-19-8 tank battery.

3.6.2. Interference Test Results

Eric S. Carlson, University of Alabama

3.6.2.1. Summary

An interference test was run at the project pattern between April 17, 2008 and May 23, 2008. Pressure gauges were placed in the shut-in Wells B-19-9 and B-19-7, while injection of water occurred in Well B-19-10 #2. The pressure measurements are shown in Figure 3.6.2. Well B-19-9 is about 822 ft southeast of the injector, while Well B-19-7 is about 1049 ft to the northwest. Injection commenced on May 3, 2008. The injection rate was variable, but stayed close to approximately 140 STB/day of water.

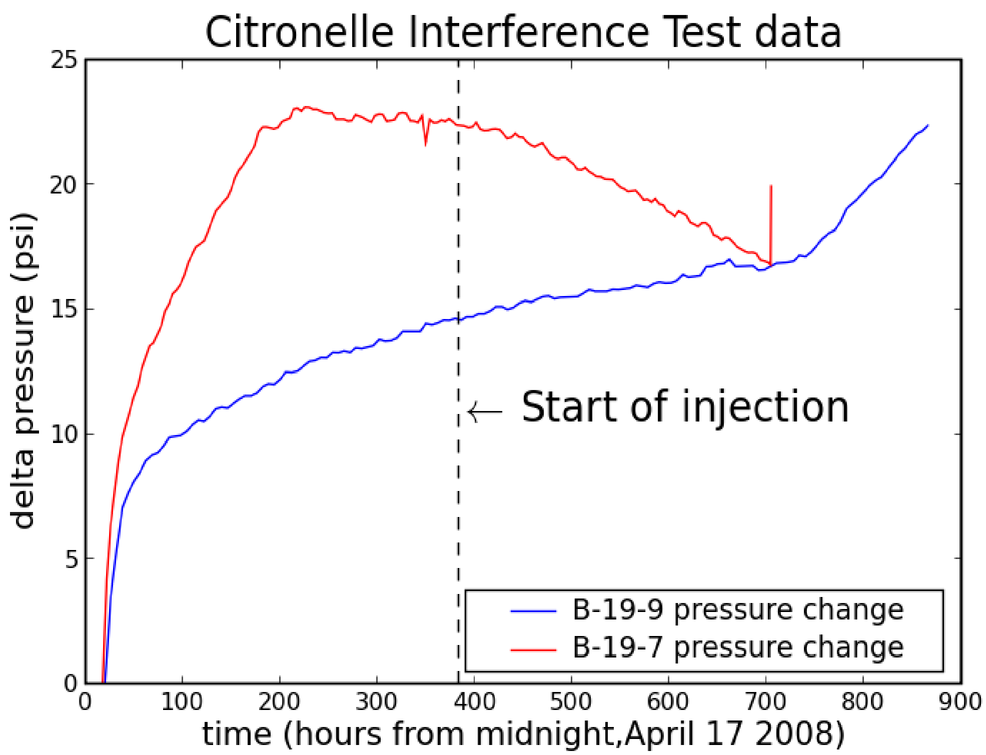


Figure 3.6.2. Pressure responses relative to an "initial" pressure.

An analysis of the interference test provided some clear evidence of communication between the injector and Well B-19-9. A fit of the data, shown in Figure 3.6.3, gave a total mobility, $\lambda_T = k\ (k_{ro}/\mu_o + k_{rw}/\mu_w)$, of approximately 0.61 mdarcy/cP, and an average production thickness, h, of approximately 20 ft, assuming a porosity of 15.5%, total compressibility of 10 x 10^{-6}/psi, and average reservoir injection rate of 140 bbl/day.

Due to unforeseen difficulties at the injection well, leading to a delay in the start of water injection, the pressure gauge in Well B-19-7 was pulled before it could show a response. At this point, no "cause-and-effect" can be performed with the data from this well because the observed pressure response could be explained by a multitude of causes. In fact, the gauge was pulled before the closer well, B-19-9, had responded to injection. If the reservoir properties determined for B-19-9 apply, then it would have taken another five days to get an initial response in Well B-19-7 to the injection started on May 3.

The Good News:

1. The injector is in communication with at least one nearby producer.
2. No obvious "short circuits" between the injector and either production well.
3. There was no evidence of significant layering (at least for the duration of the test).
4. The higher pressure of 5500 psi in Well B-19-9 versus the lower 5130 psi pressure in Well B-19-7, suggests reasonable levels of communication between some of injectors and producers in the vicinity. B-19-7 is closer to low-pressure producers, and B-19-9 is closer to high-pressure injectors.

The Ambiguous:

1. Cannot say for certain that Well B-19-7 is in communication with the injector.
2. The low permeability of 0.6 mdarcy/cP versus 20 to 40 mdarcy/cP from cores suggests either low-permeability baffles between the injector and producer and/or some mobile water and mobile oil (near the average water saturation where λ_T is minimized).

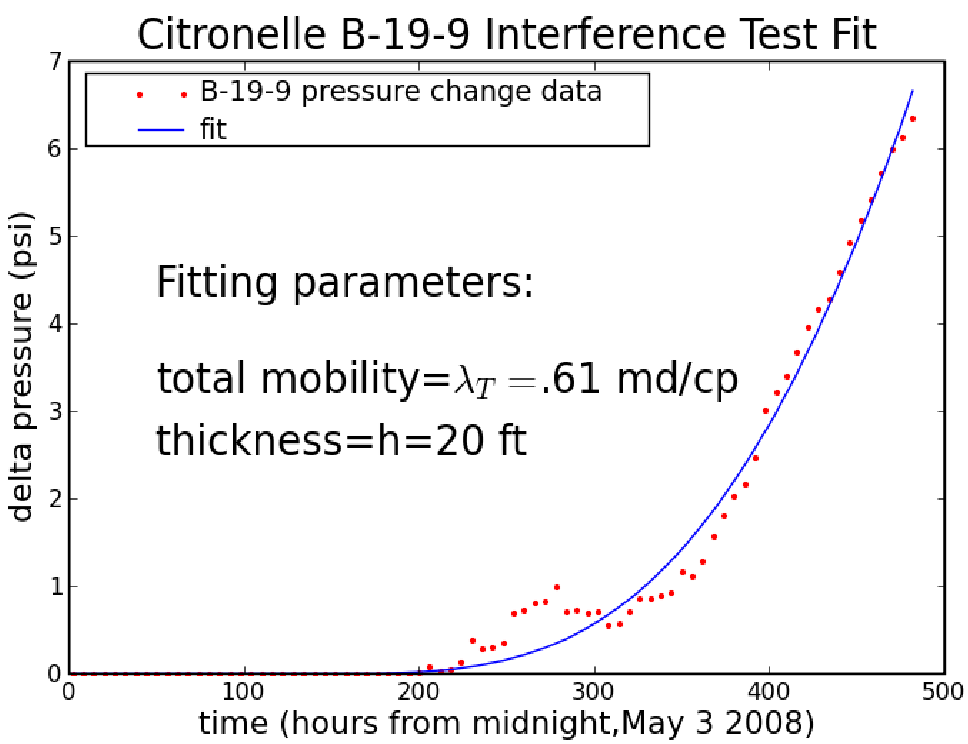


Figure 3.6.3. Curve fit results for Well B-19-9.

3.6.2.2. Methodology and Assumptions

The fitting program (a listing of the program may be found in Section D.4 of Appendix D) performs a least-squares match of the pressure changes to the equation

$$p(r,t) - p_i = \frac{70.6qB\mu}{kh} \cdot E_1\left(\frac{\phi\mu c_t r^2}{.00105kt}\right) \tag{3.6.1}$$

where:

$E_1(x) = \int_x^\infty \frac{\exp(-u)}{u} du$

$\frac{k}{\mu} \approx \lambda_T = k(k_{ro}/\mu_o + k_{rw}/\mu_w)$ for multiphase flow conditions (mdarcy/cP)

h = average thickness (ft)

qB = the reservoir flow rate (assume 140 bbl/day)

φ = average porosity (assume 0.155)

c_t =average total compressibility (assume 10 x 10^{-6}/psi)

r = distance from the injector = 822 ft for Well B-19-9

t = time (hours).

The pressures were changing due to injection and production at other wells in the vicinity of the test. This change had to be filtered out of the results, so the prevailing pressure at the observation well when the initial response to injection at Well B-19-10 #2 occurred was subtracted from the actual pressure. Although superposition theory could have been applied, no attempt was made to do this because the rate data at the injection well were not detailed, nor did we have any information regarding what was inducing the background pressure changes.

Despite these assumptions, a few considerations make the analysis credible. First, the time at which the initial response to injection occurs at the observation well depends primarily on the total mobility. Changing this initial response by as much as ± 2 days has little impact on the calculated mobility. Second, the amplitude of the pressure change is most influenced by $\lambda_T h/qB$. The rate appears to be good to roughly ± 20%, so the fact that the calculated thickness comes close to those estimated from geological studies means that the calculated λ_T is probably okay. Finally, our simulation studies assumed a single-phase permeability of around 10 mdarcy, but relative permeability effects severely impacted injection rates so that the calculated rates were comparable to the rates observed during the interference test and the effective mobility was comparable to that derived from the interference test results.

3.7. Surface Monitoring

Xiongwen Chen, Ermson Z. Nyakatawa, and Kathleen A. Roberts
Alabama A&M University

The Alabama A&M University groups and Pete Walsh of UAB met in Citronelle on June 11 and 12, 2008, to install soil gas monitoring instrumentation near the wells in the CO_2 injection test pattern, continue the set-up of vegetation test plots, and measure CO_2, other minor gaseous species, and particulate matter in the ambient air. The group was accompanied in the field by Jeremy Weaver of Denbury, who was very knowledgeable regarding field operations and a great help with the set-up and sampling work.

Ermson Nyakatawa is focused primarily on measurement of CO_2 in soil and the effects it would have on biological activity in the soil. Xiongwen Chen and Kathleen Roberts are concentrating on the measurement of CO_2 in ambient air and the effects of changes in ambient CO_2 on plant growth.

The group led by Ermson Nyakatawa consisted of Ermson and three of his students: Adeboye Omidiran, Rogers Atugonza, and Christina Igono. Their goal during the visit on June 11-12 was to collect soil samples and set up instrumentation for measurement of soil conditions at points surrounding the injection well and each of the production wells. The instrumentation consists of a soil moisture probe, from which a profile of soil moisture content can be obtained at depths up to 1 m, a soil thermometer placed at a depth of 0.46 m (18 in.), soil gas probes at depths of 0.2, 0.4, 0.6, 0.8, and 1.0 m, and a chamber for capturing gas evolved from soil at the surface. The probes were installed and samples collected at three locations equally spaced around each well, beyond the tree line at the edge of the clearing surrounding the well, as shown in Figure 3.7.1. On June 11 Ermson and his coworkers installed complete sets of instrumentation and collected soil samples at Wells B-19-9, B-19-10 #2, and B-19-10. On June 12, they completed the installation of probes at Wells B-19-7 and B-19-8. The group is shown in Figure 3.7.2 installing their instruments at the location southwest of Well B-19-9. The completed installation at the location north of Well B-19-9 is shown in Figure 3.7.3.

Kathleen Roberts and Stephanie Freeman continued the work begun by Xiongwen Chen and Kathleen during their visits to the test site in January and February 2008. On June 11 Kathleen and Stephanie established new test plots for monitoring the plant species distribution and growth of vegetation at the B-19-8 and B-19-11 tank batteries, and continued the tagging and measurement of the circumferences of trunks of trees and stems of plants in test plots that had already been established at Wells B-19-10, B-19-10 #2, and B-19-8 (see Figure 3.7.4).

On June 12, Kathleen Roberts measured the concentrations of CO_2 and CH_4 in ambient air at 29 wells in sections A-24, A-25, B-17, B-18, B-19, B-20, and B-30, making measurements at each well in the morning and afternoon, for assessment of the dependence of the species concentrations on time of day.

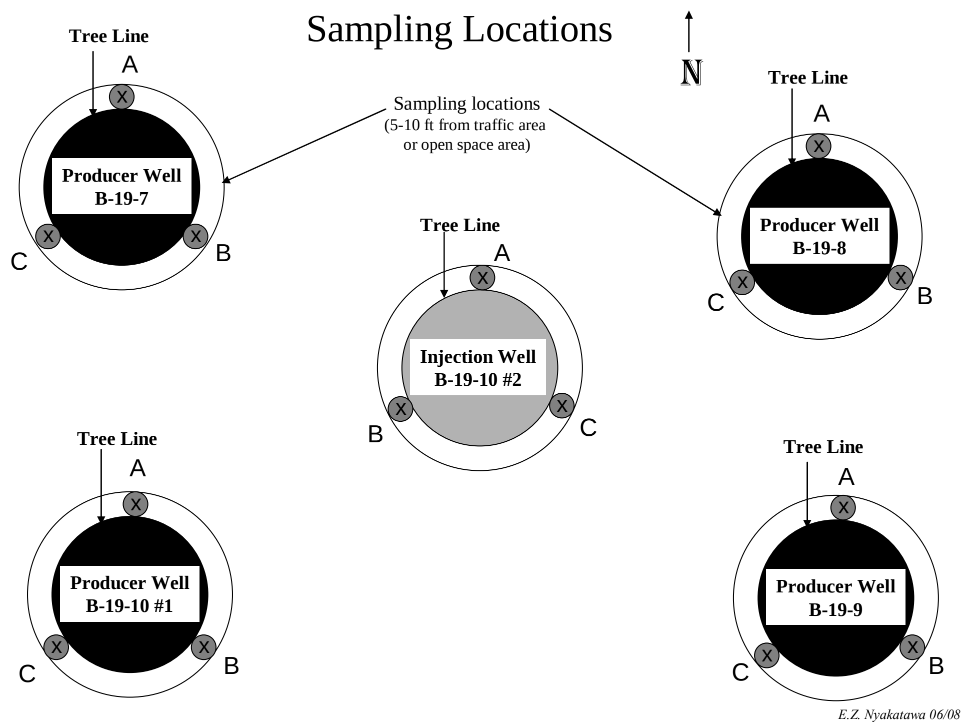


Figure 3.7.1. Arrangement of three soil gas sampling stations at the CO_2 injection well and each of the four producers in the test injection well pattern (Ermson Z. Nyakatawa, Alabama A&M University).

Figure 3.7.2. Installation of instruments for measurement of soil conditions at Well B-19-9. Left to right: Christina Igono, Rogers Atugonza, Adeboye Omidiran, and Ermson Nyakatawa of Alabama A&M University.

Figure 3.7.3. Instruments for measurement of soil conditions. Top, center: ¼ in. o.d. Teflon tubes for extraction of soil gas samples. Top, to right of center: collar on which the chamber to capture gas evolved from soil will be mounted. Top, above and to right of collar: dial soil temperature gauge. Bottom, right (with red cap): soil moisture probe.

Figure 3.7.4. Kathleen Roberts (left) and Stephanie Freeman tagging, recording species, and measuring the circumferences of trunks of trees and stems of plants in the test plot near Well B-19-8.

3.8. Seismic Imaging

Shen-En Chen and Wenya Qi, University of North Carolina at Charlotte

A visit was made on April 4 and 5 to the Geological Survey of Alabama (Jack Pashin and Denise Hills) to collect literature related to geophysical testing theory and density and sonic log data from the Citronelle Field. The bulk density and compression wave speed close to the injection well will be used as reference values in the modal simulation and future seismic testing. A density log from Well B-19-2 and a sonic log from Well B-19-5 are shown in Figure 3.8.1.

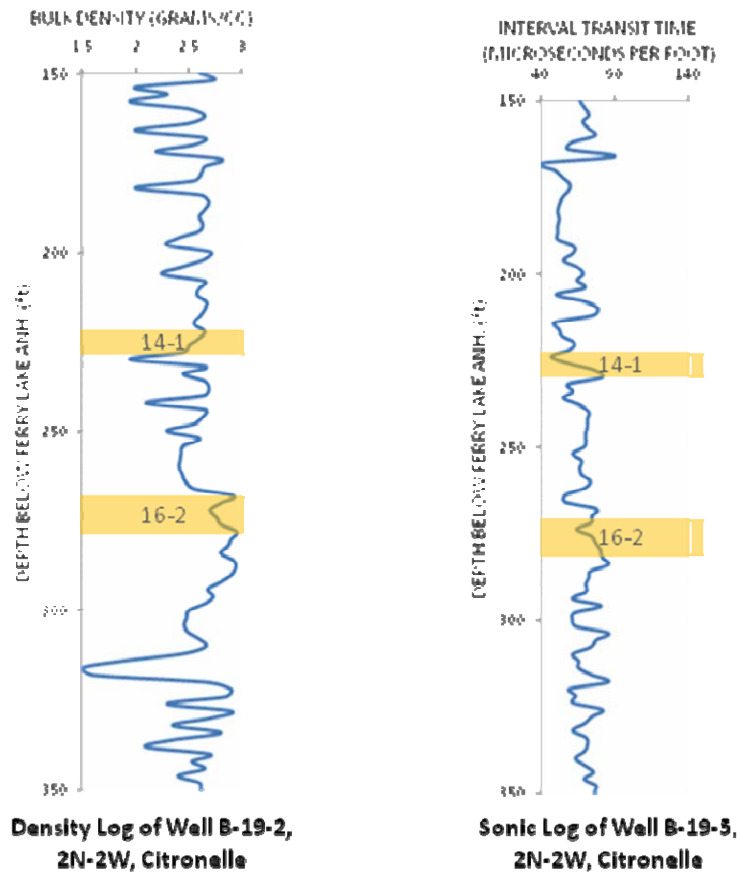
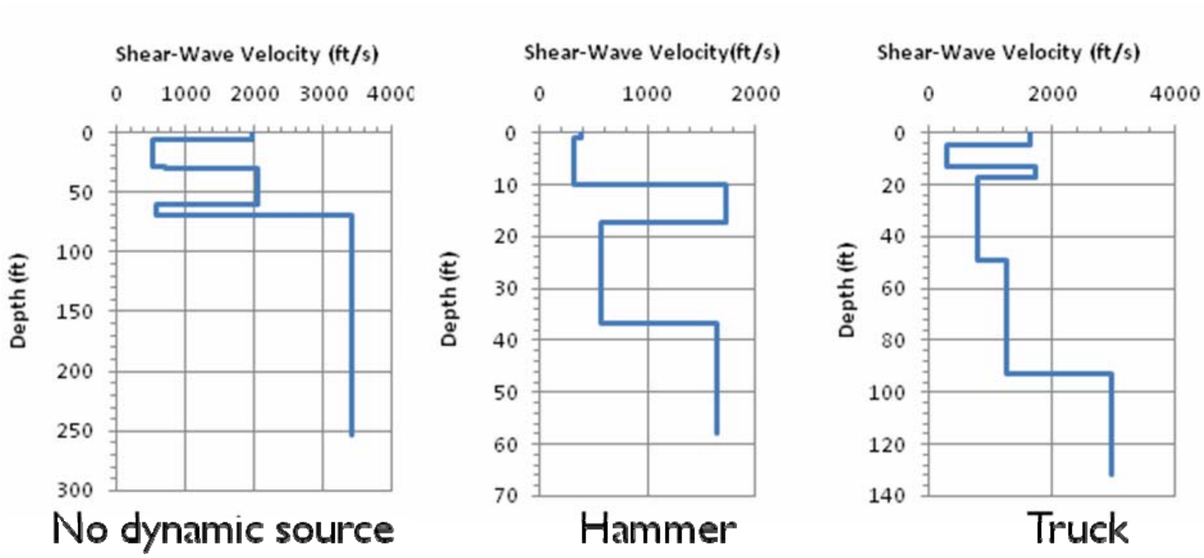


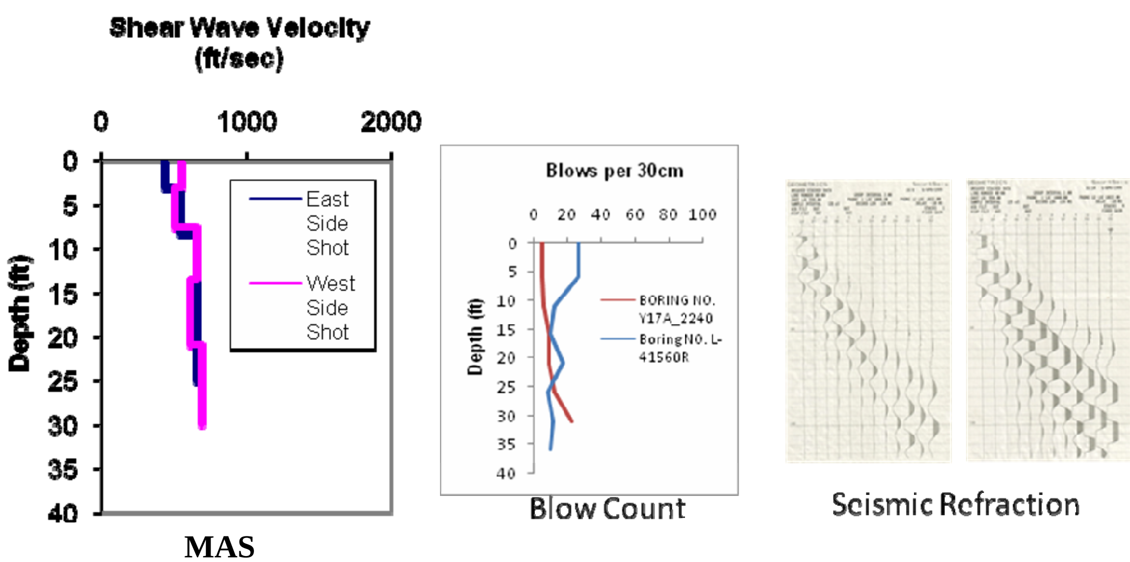
Figure 3.8.1. Density log from Well B-19-2 (left) and sonic log from Well B-19-5 (right).

The 24-Channel Refraction Microtremor (ReMi) data acquisition system has been purchased and tested at the UNCC Pilot Site. Construction of subsurface seismic profiles by recording ambient noise only (passive seismic source) achieved deeper penetration than was obtained by recording seismic waves generated by active sources. The test results have been compared to those obtained by other techniques such as SASW, MASW, Seismic Refraction, and bore logs. The ReMi test results are compared with MASW results in Figure 3.8.2, giving us confidence in the potential of the ReMi method.

The next steps will be to attempt to pick up seismic signals using wireless sensors and comparison of those data with the ReMi results.



a. 1-D Shear-Wave Profile from ReMi test data.



b. Soil Profiles obtained by other test methods.

Figure 3.8.2. a. 1-D Shear-Wave Profile from ReMi test data.
b. Soil Profiles obtained by other test methods.

3.9. Saline Formation Simulation

Konstantinos Theodorou and Peter Walsh, University of Alabama at Birmingham

Simulation work during the quarter under review has been focused entirely on the oil reservoir, to confirm the suitability of the amount of CO_2 planned for injection during the first test and to estimate the time required to inject the CO_2 and observe enhanced oil recovery. We will return to simulation of saline formations during the next quarter.

3.10. Visualization of Geologic Structure and Flows

Eric S. Carlson, University of Alabama
Jack C. Pashin, Geological Survey of Alabama
Alan M. Shih and Dino Theodorou, University of Alabama at Birmingham

Great progress has been made during the past quarter on the development of both the stratigraphic cross sections and the reservoir simulations using SENSOR and MASTER 3.0. In its present form, the reservoir model in the simulation using SENSOR contains ten layers having a distribution of permeabilities, with each layer having uniform permeability and thickness. In the simulation using MASTER 3.0, wells outside the five spot and variable sand thickness were incorporated into the model, but without variation in permeability. Introduction of more detailed geologic structures into the simulations will continue during the coming quarter.

Maps of net sandstone and net pay thickness are being constructed at GSA for each mappable sandstone unit between the 12 and 20-A Sands in the Upper Donovan. A database is being constructed on the position and thickness of each sandstone unit and pay zone, and this database will form the basis for 3-D visualization of Upper Donovan sandstone bodies in the northeastern part of Citronelle Field.

3.11. Reservoir Management Plan and Economic Analysis

Eric S. Carlson, University of Alabama

Using the expanded analysis of Case LN, presented in Section 3.4.2, a preliminary optimization of the CO_2 slug size was performed for Case LN. The motivation for this analysis is the following: although all of the simulation results show that cumulative oil production increases as more CO_2 is injected, regardless of the layer permeability distribution, this observation does not address the question of whether additional CO_2 injection results in economical oil recovery.

Although Case LN shares many characteristics with the pilot test area, the optimization results shown below should only be used as examples for comparison and discussion; under no circumstances should they be used as a basis for recommending designs.

The assumptions used for the economic calculations were the following:

The calculations are based on the correlations for cumulative oil production due to CO_2 (Figure 3.4.2) and cumulative CO_2 injection (Figure 3.4.5), which were based on the Case LN simulation performance, as described in Section 3.4.2, "Expanded Analysis of Case LN."

The calculations consider only the incremental oil produced due to CO_2 injection.

The calculations consider only those costs associated with CO_2 injection, except for the allowance of a $2/(produced STB) extra lifting/operating cost due to such things as separation, corrosion, pumping problems, etc.

Oil prices are assumed to be constant for each scenario.

Discount factors are constant for each scenario.

There is a CO_2 storage and injection cost of $1000/day, while injection takes place.

Total transportation plus liquefaction costs of $80/ton CO_2.

Cost of CO_2 is constant for each scenario (the cost over and above transportation and injection).

"Severance" tax of 6% of gross sales.

Income tax rate of 35% of net profit/loss.

Royalty rate of 25% of gross sales.

5-year duration for the calculations, done by monthly periods, beginning October 1, 2008.

Operator picks up all costs (no consideration for cost assistance).

Representative examples of Cumulative-After-Federal-Income-Tax-Cash Flow Behaviors versus time, for CO_2 injection-slug sizes from 7500 to 90000 tons, are shown in Figure 3.11.1. The two most important features to note in the figure are:

a. The minimum cumulative cash [also referred to as Cumulative Net Present Value (Cumulative NPV)] occurs just at the end of CO_2 injection for amounts up to 30000 tons, while the minimum occurs prior to the end of injection for amounts greater than 30000 tons.

b. The cumulative cash at 5 years (at the far right in the figure) increases with increasing CO_2 slug size, up to 60000 tons, then decreases with further increase in CO_2 to 90000 tons. This clearly suggests an optimum value of the 5-year cumulative cash with respect to slug size.

The optimum slug size and 5-year-After-Tax-Net-Present Value are shown in Table 3.11.1, for various nominal annual discount rates (0%, 5%, 10%, and 15% per year, from top to bottom), as functions of oil price and CO_2 wellhead cost per thousand cubic feet.

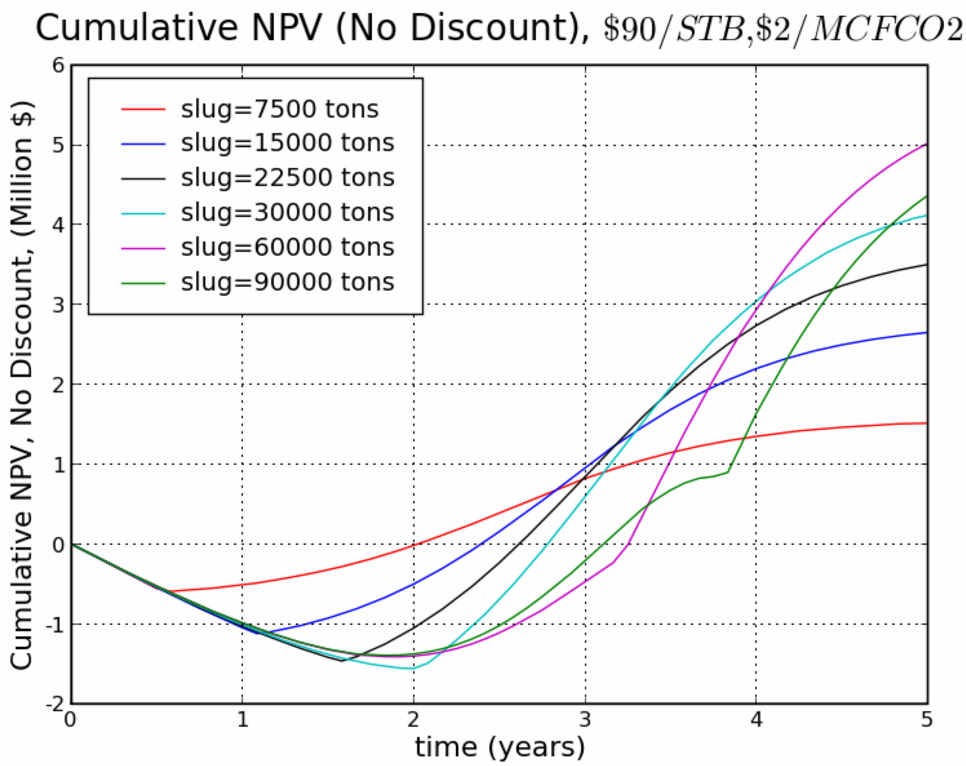


Figure 3.11.1. Cumulative-After-Federal-Income-Tax-Cash Flow behaviors versus time, for CO_2 injection-slug sizes from 7500 to 90000 tons.

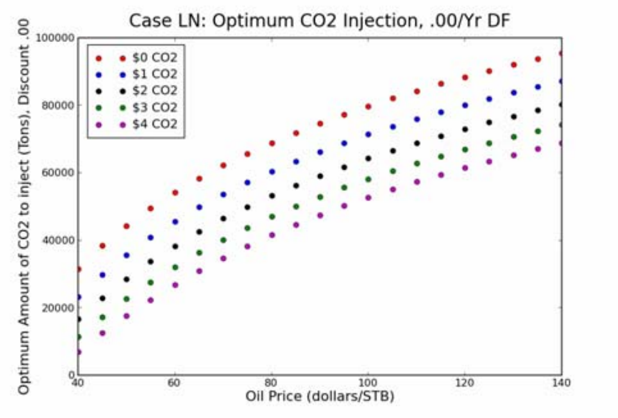
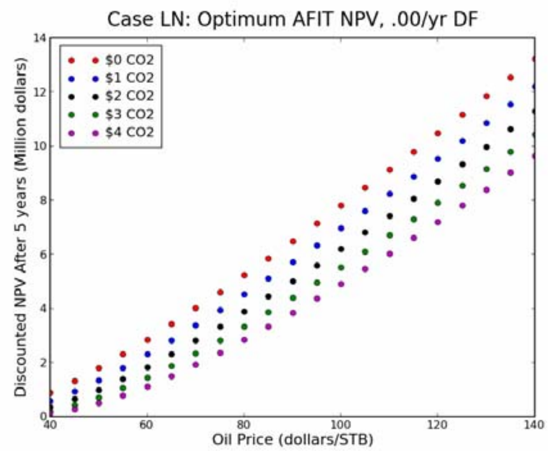
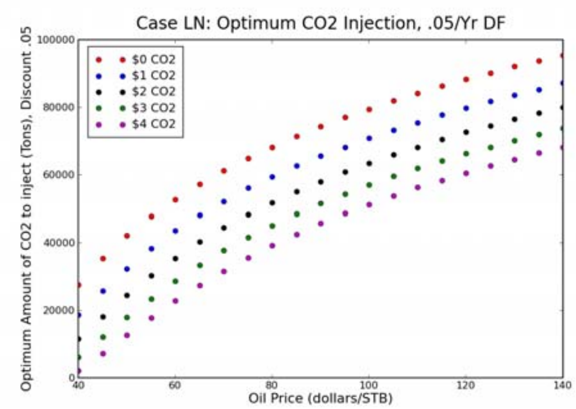
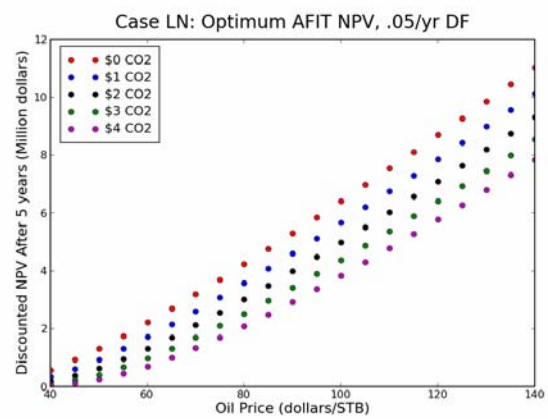
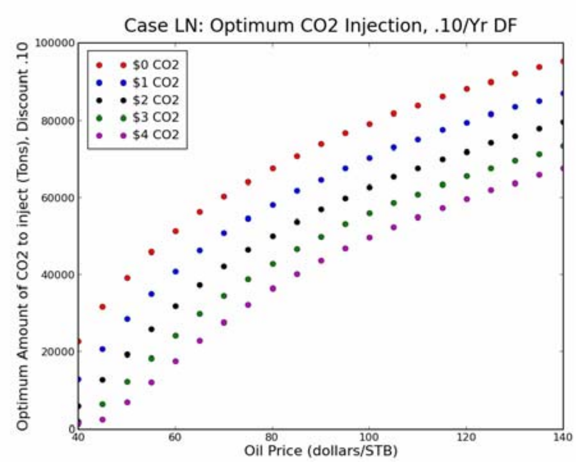
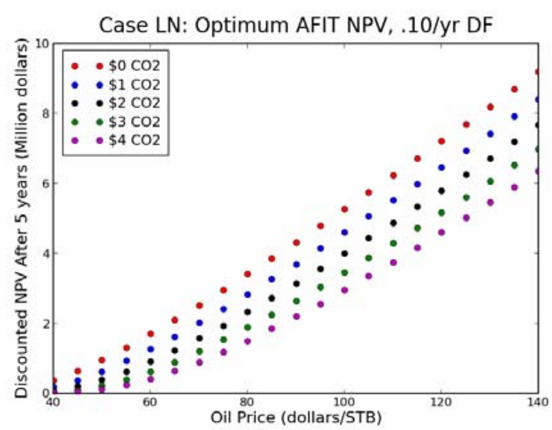
The most important points to be drawn from Table 3.11.1 are:

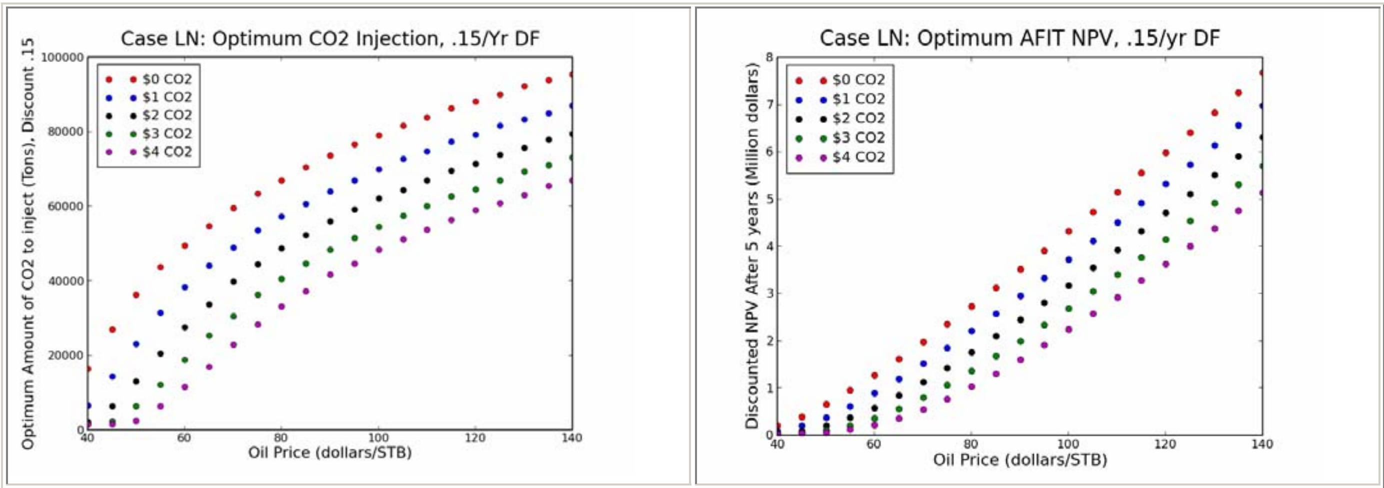
a. The optimum slug size increases with increasing oil price.
b. Cumulative Discounted Cash Flow (DCF) is strongly affected by the discount factor.
c. The discount factor (DF) has almost no impact on Optimum Slug Size at higher oil prices, and has some impact at lower oil prices.
d. The minimization routine used bounded intervals, with a minimum of 1500 tons of CO_2 allowed and a maximum of 150000 tons. The lower bound impacted some of the results for low oil prices at higher discount rates, while the upper bound had no impact on the optimum values.

The undiscounted cumulative cash flow, shown in Figure 3.11.2, illustrates the conflicting interests of various stake holders. As the figure suggests, Alabama tax revenues increase when CO_2 injection goes from 58000 tons (a value near the optimum) to 90000 tons, so this increase in injection (and subsequent production) is beneficial to the State. In contrast, cumulative cash flow to the Operator and Federal Government decrease as a result of the increased CO_2 injection.

The most important conclusion from this analysis is that there is an optimum injected-CO_2-slug size with respect to project economics, for each of the scenarios considered, and the optimum slug size depends strongly on oil price.

Table 3.11.1. Optimum slug sizes and After-Federal-Income-Tax Cumulative Discounted Cash Flow (AFIT NPV) as functions of oil price for various CO_2 costs and discount factors. (Table continued on the following page)

Optimum Slug Size	**Cumulative DCF at 5 years**
	
	
	



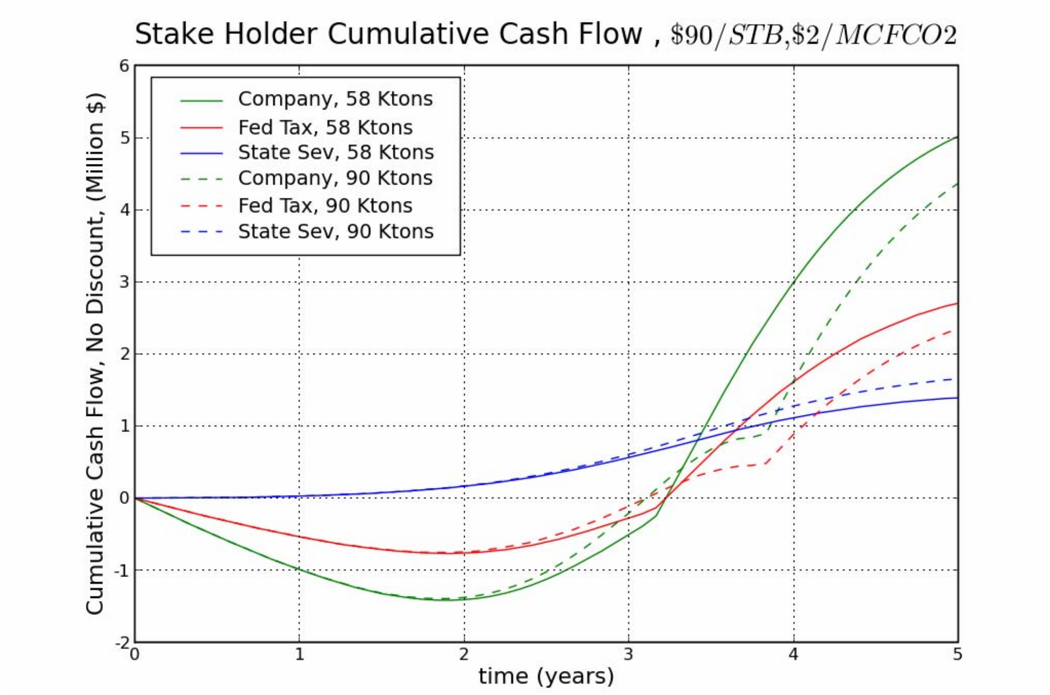


Figure 3.11.2. A cumulative cash flow diagram illustrating various stake-holder interests.

4. Project Status

4.1. Task and Milestone Status

Please see Appendix A for the Statement of Work for Phase I (pages A1 to A3) and Project Schedule (page A8). Ten tasks were scheduled for completion at the end of the quarter under review: Tasks 1, 2, 3, 4, 8, 9, 10, 11, 12, and 14. The status of work under these tasks is described below.

Task 1. Establish collaboratory environment. The collaboratory web site at <http://www.citronelleoil.us/>, set up and maintained by Eric Carlson and his research group, has already become an indispensable resource to members of the project team. It now contains links to most of the previous engineering work on the Citronelle Oil Field, all of the reports prepared under the present project, and the results of Eric Carlson's simulations of CO_2 injection into the five-spot test pattern, his economic analysis of CO_2-EOR, and his interpretation of the interference test run by Denbury Resources between the injector and a producer in the five spot.

Task 2. Establish publicly accessible web site for communication with industry. A web site for the project has been set up at <http://me.eng.uab.edu/co2-eor-sequestration/> for transfer of technology and information to the public, to students, and to other workers in the areas of tertiary oil recovery and carbon sequestration.

Task 3. Application for permit to conduct Field Test No. 1. The well chosen for the test injection (B-19-10 #2, Permit No. 3232) was originally permitted as an injector, so it only required repermitting. The supporting documents specified under UIC regulations were submitted to the State Oil and Gas Board of Alabama in January 2008. The permit of B-19-10 #2 as an injector was renewed. We are currently waiting for permission to bring plugged and abandoned Well B-19-10 back into production.

Task 4. Analysis of rock samples. A comprehensive examination of drill cores from Citronelle Field is being performed by Jack Pashin, Denise Hills, and David Kopaska-Merkel at GSA. The most recent results are described in Section 3.2 of the present report. This work has led to significant revision of the conventional geologic model for the field, received from early studies of the formation in the 1950's and 1960's, and will have significant bearing on the approach to the test injection and interpretation of its results. All of the available spontaneous potential, resistivity, sonic, density, and gamma-ray logs over a four-square-mile area around the test injection well have been digitized. The group at GSA is in the process of correlating all the well logs in the cross sections, with emphasis on characterization of the 14-1 and 16-2 sands, the targets of the first CO_2 injection. Study of other cores from Citronelle continues, having become a more ambitious undertaking, and having greater significance than anticipated in the original proposal. Nineteen sample plugs from Sands 14-1 and 16-2 (one sample per foot of formation thickness) were analyzed for porosity and permeability.

Task 8. Selection of test and monitoring wells. The five-spot for the first test injection was identified during a meeting of DRI, GSA, SO, and UAB on July 2, 2007. Analysis of well logs and cores has shown that the reservoir heterogeneity characteristic of Citronelle Field is well represented in this test pattern.

Task 9. Site characterization by geophysical testing. Because of the invasive nature of surface excitation methods and the residential character of the oil field, which is interspersed through the Town of Citronelle, and the great depth of the oil reservoirs, geophysical testing will be more difficult to implement than was anticipated. UNCC will use the Refraction Microtremor (ReMi) technique to observe shear wave anomalies caused by fracturing in the shallow subsurface in the immediate vicinity of the injection well. The UNCC group are conducting trials of the technique at a site near their University and plan to conduct background measurements during the water flood at Citronelle in September 2008.

Task 10. Baseline soil CO_2 fluxes and ecology. Ermson Nyakatawa and his students at AAMU have installed soil probes and sampling chambers to measure soil gas composition versus depth, CO_2 flux from soil, soil temperature, and soil moisture at three locations surrounding each of the five wells in the test pattern. Xiongwen Chen and Kathleen Roberts of AAMU have established test plots near the injector, producers, and tank batteries, in which to monitor plant growth and species distribution. They are also monitoring CO_2 in ambient air at points on a grid across Citronelle, to establish the CO_2 background and its seasonal fluctuations.

Task 11. Reservoir management plan. Features of a reservoir management plan that would qualify the present project as "next generation CO_2-EOR," according to Kuuskraa and Koperna (2006), are: increasing the amount of CO_2 injected to 1.5 HCPV, addition of one horizontal and one vertical well to each injection-production well pattern, use of viscosity enhancers in injected water, enhancement of miscibility by addition of other gases to CO_2, implementation of flood performance diagnostics, and employment of a professional technical team. The technical group focused on Citronelle at Denbury Resources, augmented by the group engaged in the present project, more than meets the latter requirement. The costs and benefits of the other components of next generation CO_2-EOR will be examined in turn. A comparison of reservoir simulations of the performance of continuous CO_2 injection versus WAG is presented in Section 3.4.1 of the present report.

Task 12. Economic and market analysis. CO_2-EOR in Citronelle is expected to add approximately 30 million barrels of oil to economically recoverable U.S. oil reserves. Under the oil and CO_2 prices expected to prevail, on average, for the foreseeable future, and incorporating some of the features of "next generation CO_2-EOR" (though not, for example, the drilling of horizontal wells) specified by Kuuskraa and Koperna (2006), the analysis by Advanced Resources International (2006) indicates that a CO_2-EOR project in Citronelle would be profitable. A reservoir simulation analysis of WAG oil recovery, described in Section 3.11 of the present report, shows that there is an optimum injected-CO_2-slug size with respect to project economics, that occurs for all of the assumed permeability distributions of the sands, and that depends strongly on oil price.

Task 14. Preparation of wells for Field Test No. 1. Workover of the injector (B-19-10 #2) and two producers (B-19-7 and B-19-9) is complete. One producer (B-19-8) required no workover. The current water injection rate is 150 to 170 bbl/day. Wells B-19-7 and B-19-9 are each producing 4 to 5 bbl/day of oil and Well B-19-8 is producing 9 bbl/day of oil. We are awaiting approval to restore the plugged and abandoned Well B-19-10 to production. The injector has been equipped with a well head and tubing compatible with CO_2. A CO_2 pump and gas-liquid cylindrical cyclone are in place at B-19-8 tank battery.

4.2. Findings and Accomplishments

Work during the first 17 months of the project (February 2007 through June 2008) was focused on the following components: geology and petrology of the formation, reservoir fluid properties, preparation of the wells and planning for the first CO_2 injection, estimates of CO_2 storage capacity, reservoir simulation, CO_2-EOR economics, and preparation for CO_2 monitoring. The findings and accomplishments on each of these fronts are described below.

Identification of a five-spot well pattern for the first test injection of CO_2 that is representative of the field, in a remote location away from private homes, and includes a well already permitted as a gas injector. The injector is ready to inject CO_2 and is currently injecting 150 to 170 bbl/day of water. Three producers are on line and producing oil. One producer remains to be worked over and brought on line. The CO_2 pump and gas-liquid separator are in place at the tank battery.

A collaboratory web site was established for rapid and effective dissemination of technical information through the research group. The site now has links to reports of previous engineering work in the Citronelle Oil Field, field data, reports generated under the present project, reservoir simulations, the interpretation of the interference test data, and the CO_2 slug size optimization study.

Minimum miscibility pressure of Citronelle oil is less than 2800 psi (Gilchrist, 1981). A rolling ball viscometer is nearing completion, for determination of minimum miscibility pressure, density, and viscosity of oil samples from the field at reservoir conditions, and examination of the effects of solvent composition, such as the nitrogen content of CO_2 captured from combustion sources or light hydrocarbons added to enhance miscibility.

Identification of the geologic characteristics that make the Citronelle Dome an attractive site for CO_2-EOR and storage.

The total CO_2 storage capacity of the Eutaw Formation, Upper and Lower Tuscaloosa Groups, and Rodessa Formation in the Citronelle Dome was estimated to be between 500 million and 2 billion short tons of CO_2.

A detailed study of the petrology and sedimentology of Citronelle well cores, showing that depositional environments in the Rodessa Formation differ significantly from the model developed in early published work that has guided past development and production from the Citronelle Field.

All well logs in the 4-square-mile area surrounding the test site were digitized and used to construct a network of 19 stratigraphic cross sections correlating Sands 12 through 20A in the Upper Donovan. The cross sections demonstrate the extreme facies heterogeneity of the Upper Donovan and show that it is well expressed in the five-spot test pattern. Many other features having bearing on the performance of the CO_2 injection test have been discovered.

Measurements of background levels of CO_2 in ambient air across Citronelle, showing variability induced by automobile and truck exhausts and plant respiration.

Establishment of 10 m x 10 m test plots at the injector, four producers, and two tank batteries, in which to monitor plant growth and species distribution.

Installation of sampling chambers for measurement of CO_2 fluxes from soil, and probes for soil gas composition, soil moisture, and soil temperature at three locations surrounding each of the five wells in the test pattern.

Data from an interference test between the injector and a producer, conducted by Denbury Resources and analyzed by Eric Carlson, provided evidence for communication between the injector and at least one nearby producer. No obvious short circuits or evidence for significant layering were detected. The low effective permeability suggested the presence of low permeability baffles and relative permeability effects on total mobility.

A simulation of the test pattern, incorporating a distribution of permeabilities, was developed using the SENSOR reservoir simulator and successfully reproduced the observed water injection rate and effective mobility determined from the interference test.

Simulation of CO_2 injection, using the necessarily idealized model implemented in SENSOR, showed that as the amount of CO_2 injected as a slug increased, a large and distinct peak in the oil production rate first appeared with injection of 7550 tons of CO_2. The peak production rate increased with further increase in the amount of CO_2 injected, but became insensitive to the amount of CO_2 above 10000 tons. The conclusion from these simulations is that approximately 7500 tons of CO_2 is a necessary and sufficient amount to demonstrate CO_2-EOR in Citronelle (Upper Donovan) sands having average thickness in the 10 to 20-ft range.

According to the simulation using SENSOR, injection of 7550 tons of CO_2 is complete in 215 days. Significant incremental oil first appears 275 days after the start of CO_2 injection and the strong peak in oil production occurs between 400 and 500 days from the start of injection. Cumulative incremental oil in the stock tank at 500 days is 11,500 STB.

All of the simulation results using SENSOR showed that cumulative oil production increases with increasing amount of CO_2 injected, regardless of the assumed permeability distribution. However, in all cases considered, there was an optimum CO_2 slug size, from the point of view of the profitability of the CO_2-EOR project. The optimum size of CO_2 slug increases with increasing oil price.

An alternative simulation of CO_2 injection into the test pattern was developed using the MASTER 3.0 reservoir simulator, including three injectors outside the five-spot chosen for testing, and incorporating the history of injection and production from the eight wells back to 1982. Simulation of the injection of 7500 tons of CO_2 indicates that breakthrough of CO_2 will occur 242 days from the start of injection, that the time required for injection will be 292 days, and that the oil production rate will steadily increase during CO_2 injection but begin to decline soon after injection is switched from CO_2 back to water.

The TVTK/MayaVi package from Enthought Inc. (Austin, TX) was identified as the software of choice for visualization of the reservoir simulations.

4.3. Technology Transfer

A paper by Jack Pashin, Richard Esposito, and Peter Walsh, presenting a detailed analysis, from the geological perspective, of the characteristics that make the Citronelle Dome an attractive candidate for CO_2-EOR and storage, including estimates of storage capacity, appeared in the June 2008 issue of *Environmental Geosciences*, the archival journal of the Division of Environmental Geosciences of the American Association of Petroleum Geologists.

Jack Pashin presented his work on the geology and petrology of Citronelle Dome at the Annual Convention and Exhibition of the American Association of Petroleum Geologists in San Antonio, TX, in April 2008, then at the DOE/NETL Seventh Annual Conference on Carbon Capture and Sequestration, in Pittsburgh, in May. Jack has also been invited to give a presentation about the Citronelle CO_2-EOR project at a meeting of the New Orleans Geological Society in November.

A paper by Xiongwen Chen and Kathleen Roberts of AAMU, in which they present an analysis of the relationships between roadless area and local species richness in Alabama appeared in the July 2008 issue of the peer-reviewed journal, *Biodiversity and Conservation*.

A paper by Xiongwen Chen, presenting his analysis of the topological properties of the spatial distribution of amphibians in Alabama appeared in the latest issue (31.1) of the peer-reviewed journal, *Animal Biodiversity and Conservation*.

A complete bibliography of the presentations, workshops, publications, and reports describing work supported by, or connected with, the present project, since its beginning, may be found in Appendix B.

The publications and presentations are intended to keep the reservoir engineering and carbon storage communities informed about the progress of the work and its implications for successful CO_2-EOR and storage in formations of the type found in Citronelle Dome.

5. Conclusions

The progress, findings, accomplishments, and conclusions from each of the principal research efforts in which the team has been engaged since the beginning of the project (February 6, 2007 through June 30, 2008) are summarized below.

Communication and Technology Transfer. The wiki-based collaborative web site has proven to be an effective means for rapid dissemination of technical information through the research group. The site contains links to difficult-to-find reports of previous engineering work in the Citronelle Oil Field, reports generated under the present project, a wealth of data from the field, and results of the simulations of CO_2-EOR using the SENSOR reservoir simulation software package.

Geology and Petrology. Stratigraphic cross sections constructed from digitized well logs demonstrate the extreme facies heterogeneity of the Upper Donovan Sand. Of particular interest is the 16-2 Sand, a target of the CO_2 test injection, which is interpreted as a composite of two tiers of channel fills. Pay strata are typically developed in the lower tier, where the CO_2 will be injected. The upper tier is highly heterogeneous and is interpreted to contain sandstone fills of variable reservoir quality, as well as mudstone plugs. In the northwest corner of the five-spot (Well B-19-7), the pay zone is in the upper tier, thus its degree of hydraulic communication with the main pay zone needs to be determined in order to understand the effects of reservoir heterogeneity on the performance of the CO_2 injection.

Analysis of cores and thin sections indicates that the composition and reservoir quality of the upper Donovan Sand reflects diverse processes driven by alternating episodes of subaerial exposure and marine flooding, as well as burial diagenesis. Subaerial exposure led to formation of oxidized paleosols and erosional relief that in places may have approached 20 meters. Sand bodies were preserved primarily during inundation of the erosional landscape, and trace fossil assemblages and calcareous faunas consisting of oysters, foraminifera, and algae indicate that most sandstone bodies have been reworked by marine processes. Pore-filling clay adversely affects reservoir quality and apparently formed as sediment was homogenized during burrowing and by infiltration during subaerial exposure. Exposure and marine flooding further contributed to oxidation of sandstone bodies, dissolution of feldspar and other labile grains, and precipitation of carbonate cement. Cementation continued during burial and culminated in precipitation of pore-filling dolomite cement prior to petroleum entrapment.

This work represents significant revision of the conventional geologic model for the field, received from early studies of the formation in the 1950's and 1960's, and has significant bearing on the approach to the test injection and interpretation of its results.

Reservoir Fluid Properties and Phase Behavior. Peter Clark and his research group at the University of Alabama are completing the assembly and testing of a rolling ball viscometer with which to measure minimum miscibility pressure, viscosity, and density of oil-CO_2 mixtures at reservoir temperature and pressure. This instrument will provide the means to determine oil-CO_2 mixture properties for oil samples from all locations in the Field and construction of a map of minimum miscibility pressure, should there be significant variation from sand to sand. The rolling ball viscometer is also an excellent tool with which to evaluate the extension of oil-CO_2 miscibility through addition of other gas constituents to CO_2, a component of the advanced CO_2-EOR technology proposed by Kuuskraa and Koperna (2006).

Petroleum Reservoir Simulation. Based upon reservoir simulations using SENSOR, we expect that 7500 tons of CO_2 will be sufficient to demonstrate CO_2-EOR in the 14-1 and 16-2 Sands of the Upper Donovan, that the 15,000 tons allocated for the project will be sufficient for two such tests, and that an unequivocal effect of CO_2 on oil production will be observed within the time frame of the project.

According to the simulation using SENSOR, injection of 7500 tons of CO_2 can be completed in 215 days. Significant incremental oil first appears 275 days after the start of CO_2 injection and a strong peak in oil production occurs between 400 and 500 days from the start of injection. Cumulative incremental oil at 500 days is 11,500 STB.

Simulation of the injection of 7500 tons of CO_2, using the MASTER 3.0 reservoir simulator, indicated that breakthrough of CO_2 is expected 242 days from the start of injection, that the time required for injection of 7500 tons will be 292 days, and that the oil production rate will steadily increase during CO_2 injection, but will begin to decline soon after injection is switched from CO_2 back to water.

CO_2 Liquefaction, Transportation, and Storage. Costs for these services are much higher than anticipated during the preparation of the original proposal and budget.

Well Preparation, Water Flood, and CO_2 Injection. The water injection rate is currently 150 to 170 barrels per day. Three of the four producers are on line; one remains to be worked over. An interference test established that there is communication between the injector and at least one nearby producer. No obvious short circuits or evidence for significant layering were detected. The low effective permeability of the sands suggests the presence of low permeability baffles and relative permeability effects on total mobility.

Surface Monitoring. Ermson Nyakatawa and his students at AAMU have installed sampling chambers for measurement of CO_2 fluxes from soil, and probes for soil moisture, temperature, and gas composition at three locations surrounding each of the five wells in the test pattern.

Xiongwen Chen and his coworkers at AAMU have documented the dependence of species richness and species density in Alabama on location and environmental factors, such as latitude, elevation, annual average temperature, precipitation (Chen and Wang, 2007), and roadless area (Chen and Roberts, 2008). Another paper by Dr. Chen (2008) analyzes the spatial distribution of 60 species in 12 families of amphibians using a clustering coefficient that measures the strength of a population group, the statistical distribution of occurrence localities of species, the fractal dimension of occurrence localities, and distances to nearest neighbor. The implications for species conservation of these topological characteristics of the spatial distribution of species are explored and discussed. The state-wide view of species distributions taken by this group will help to discriminate whether any changes observed at Citronelle are associated with local conditions, or with processes occurring on larger spatial scales.

Seismic Imaging. Shen-En Chen at UNCC proposes to use the Refraction Microtremor (ReMi) technique to observe shear wave anomalies caused by fracturing in the shallow subsurface in the immediate vicinity of the injection well. A longer array of wireless accelerometers would be used to detect CO_2 migration in the reservoir. Both methods make use of signals from naturally-occurring seismic events, so would be least disruptive to the Citronelle community, least likely to upset conventional oil production, and of greatest interest to researchers at the forefront of seismic imaging technology. Imaging of the CO_2 plume at 11,000 ft is expected to be a significant challenge for the technique.

Saline Formation Simulation. The total storage capacity of Citronelle Dome, including saline formations in the Lower and Upper Tuscaloosa Groups and Eutaw Formation, and the Donovan Sands of the Rodessa Formation is estimated to be in the range from 500 million to 2 billion short tons of CO_2. The TOUGH2 numerical simulation program for multi-phase fluid flow in porous and fractured media, from Lawrence Berkeley National Laboratory (Pruess, Oldenburg, and Moridis, 1999) and the accompanying fluid property module, ECO2N (Pruess, 2005), specifically designed for study of CO_2 storage in saline formations, are being implemented to refine these calculations, determine injectivity of the formations, and assess the long-term migration and fate of stored CO_2, including mineralization.

Preliminary estimates of the potential for leakage of CO_2 through cap rock, based upon the analysis by Berg (1975), indicate that leakage is not expected from any of the formations considered above as storage reservoirs. However, a refined assessment using more accurate values for the input parameters (brine-CO_2 surface tension and pore radii in reservoir rock and seals) is recommended.

Reservoir Management and Economics. All of the simulation results using SENSOR showed that cumulative oil production increases with increasing amount of CO_2 injected, regardless of the assumed permeability distribution. However, in all cases considered, there was an optimum CO_2 slug size, from the point of view of the profitability of the CO_2-EOR project. The optimum size of CO_2 slug increases with increasing oil price. The discount factor has little impact on the optimum size of CO_2 slug at high oil prices, but does have some impact at low oil prices.

Acronyms

AAMU	Alabama Agricultural and Mechanical University, Normal, AL
AAPG	American Association of Petroleum Geologists
AFIT	after Federal income tax
API	American Petroleum Institute
DCF	discounted cash flow
DF	discount factor
DOE	U.S. Department of Energy, National Energy Technology Laboratory, Pittsburgh, PA
DRI	Denbury Resources Inc., Plano, TX, and Citronelle, AL
EOR	enhanced oil recovery
GSA	Geological Survey of Alabama, Tuscaloosa, AL
HCPV	hydrocarbon pore volume, dimensionless
LBNL	Lawrence Berkeley National Laboratory, Berkeley, CA
MASTER	Miscible Applied Simulation Techniques for Energy Recovery (Ammer and Brummert, 1991; Ammer, Brummert, and Sams, 1991; Zeng, Grigg, and Chang, 2005)
MASW	multichannel analysis of surface wave
MMP	minimum miscibility pressure
NPV	net present value
SENSOR	System for Efficient Numerical Simulation of Oil Recovery, Coats Engineering
STB	stock tank barrel
ReMi	refraction microtremor
SO	Southern Company, Birmingham, AL
SP	spontaneous potential
UA	University of Alabama, Tuscaloosa, AL
UAB	University of Alabama at Birmingham, Birmingham, AL
UIC	Underground Injection Control
UNCC	University of North Carolina at Charlotte, Charlotte, NC
WAG	water-alternating-gas method of enhanced oil recovery

Symbols

B	formation volume factor, dimensionless
c_t	average total compressibility, psi^{-1}
$E_I(x)$	$= \int_x^{\infty} \frac{e^{-u}}{u} du$
h	average thickness, ft
k	permeability, darcy
p	pressure, psi
q	flow rate, barrel/day
r	distance from the injector, ft
t	time, hours
λ	mobility, mdarcy/cP
μ	viscosity, cP
φ	porosity, dimensionless

Subscripts

o	oil
r	residual (oil, water)
T	total (mobility)
w	water

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Walsh, P. M., E. Z. Nyakatawa, X. Chen, J. Harper, G. N. Dittmar, A. Bailey, J. C. Pashin, D. J. Hills, D. C. Kopaska-Merkel, R. A. Esposito, E. S. Carlson, P. E. Clark, A. M. Shih, G. Cheng, S.-E. Chen, K. Theodorou, K. A. Roberts, and W. Qi, "Carbon-Dioxide-Enhanced Oil Production from the Citronelle Oil Field in the Rodessa Formation, South Alabama," Quarterly Progress Report to the U.S. Department of Energy for the period January 1 to March 31, 2008, DOE Cooperative Agreement No. DE-FC26-06NT43029, University of Alabama at Birmingham, Alabama Agricultural and Mechanical University, Denbury Resources, Inc., Geological Survey of Alabama, Southern Company Services, Inc., University of Alabama, and University of North Carolina at Charlotte, April 30, 2008.

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Appendix A: Statement of Work, December 20, 2007

Contents:

A.1. Tasks to be Performed

The original statement of work (February 6, 2007) was modified, in the contract for the second year (present version, December 20, 2007) by adding water injection to the first field test (Task 15) and moving tasks depending directly on the field test (Tasks 16, 17, 18, and 19) from Phase I to Phase II. The field test now begins with water injection during Phase I, followed by CO_2 injection in Phase II. Task 15 is still included in Phase I. The original task numbers were retained, so the tasks in the list below are no longer in numerical order.

Phase I (January 1, 2007 – August 31, 2008):

Task 1. Establish collaboratory environment.
The investigators are located at multiple sites. To facilitate the research work and report preparation, a web-based system will be set up for on-line discussion, exchange of data, distribution of information, and monitoring of project activity. It will be a secure web site to which only the project partners will have access, where all data and documents related to the project will be stored, and where all members of the group can contribute to the preparation and revision of reports and other publications. UA

Task 2. Establish publicly accessible web site for two-way communication with industry.
To facilitate technology transfer and feedback from industry, a website describing the project will be set up through which to disseminate results and receive suggestions and comments from industry and the public. This will be the site where any interested person can learn about the partners, purpose, objectives, and progress of the project. It should be of the highest quality, with respect to both technical content and graphic design. It will be constantly evolving over the life of the project and beyond. UA

Task 3. Application for permit to conduct Field Test No. 1.
A Class II Underground Injection Control (UIC) permit from the State of Alabama will be required for the injection of CO_2 at the site. The application process will be begun at this early stage, so lack of the permit does not result in delays. At this point we intend to list all of the likely candidate wells, then amend the application as the list of potential test wells is narrowed down. SO, UAB, DRI

Task 4. Analysis of rock samples.

Denbury Resources recently discovered drill cores from a previous DOE project that was initiated in the Citronelle Oil Field, but not fully implemented. Denbury is in the process of donating these cores to the Geological Survey of Alabama. The cores comprise eight complete, 800 foot sections through the full Rodessa Formation, from locations throughout the field. Because the cores are continuous, they are an invaluable resource for interpretation of existing well logs and construction of a detailed cross-section of the site. These cores have not been analyzed previously, so this new information will permit an updated review of Citronelle Oil Field geology for CO_2 EOR and sequestration. The cores to be examined first will be those most closely linked to target areas for the field tests. The measurements will include porosities, permeabilities, and microscopic analyses. UAB, GSA, UA

Task 5. Analysis of oil and oil-CO_2 interaction.

Determination of minimum miscibility pressure. Evaluation of propensity for oil components to precipitate in the presence of CO_2. Measurement of viscosity of the oil as functions of temperature and CO_2 pressure. DRI, UA, UAB

Task 6. Construct advanced geologic models of Rodessa reservoirs.

An analysis of the geologic data available at the time was done for DOE by BDM Petroleum Technologies (Fowler et al., 1998) during their evaluation of the Citronelle Field for waterflood optimization. That work is being augmented by Southern Company Geologist Richard Esposito, in connection with a Southern Company/University of Alabama at Birmingham project to be completed at the end of this calendar year. We will incorporate in the model the results of his analysis and information from the updated site stratigraphy provided by the newly available cores mentioned in Task 4, above. Reservoir architecture and heterogeneity will be quantified and visualized using methods (i.e. architectural element analysis and sequence stratigraphy) and technologies (immersive 3D visualization) that were not employed in the earlier work by Fowler et al. This effort will improve the accuracy and level of detail in the geologic model, building upon, but not duplicating past work. GSA, SO, UA, UAB

Task 7. Reservoir simulation.

Examine the available reservoir simulators, such as MASTER 3.0, Eclipse, and TOUGH2, and choose the one best suited for simulation of oil production using CO_2 EOR. Perform simulations throughout Phase I of the project to provide analysis that will assist in selection of the test and monitoring wells (Task 8), development of the reservoir management plan (Task 11), the economic and market analysis (Task 12), and visualization of the flows (Task 13). UA, UAB, GSA

Task 8. Selection of test and monitoring wells.

Based upon analysis of drill cores from the Geological Survey of Alabama collection, production records of the Alabama State Oil and Gas Board, and calculations using the reservoir simulator, choose an injection well and four surrounding wells for testing. All

Task 9. Site characterization by geophysical testing.

Perform seismic measurements to provide more detail in the vicinity of the test wells. UNCC

Task 10. Baseline soil CO_2 fluxes and ecology.

Establish baseline CO_2 concentrations and fluxes from soil and vegetation and the ecology of the field and surrounding landscape, as found. AAMU

Task 11. Reservoir management plan.
On the basis of the available data, develop a preliminary CO_2 injection strategy to ensure efficient oil sweep. UA, GSA, SO, UAB

Task 12. Economic and market analysis.
Verify that production using CO_2 EOR at this site is viable under current and projected economic conditions. Input to the analysis will be obtained from the results of the analysis of miscibility (Task 5), geologic modeling (Task 6), reservoir simulation (Task 7), and development of the reservoir management plan (Task 11). UA, UAB, SO, DRI

DECISION POINT: Based on the results of the economic and market analysis, UAB will re-evaluate the projected economic viability of the project.

Task 13. Visualization of geologic structure and flows.
Display, in the UAB Enabling Technology Laboratory and on the project web site, of the geologic structure in the vicinity of the test wells and the results of the calculations of oil, water, and CO_2 flows using the reservoir simulator. UAB, UA, GSA, SO

Task 14. Preparation of wells for Field Test No. 1.
Preparation of the test wells for CO_2 injection. In addition to updating Citronelle Oil Field and Rodessa Formation geology, the Southern Company Geologist, Richard Esposito, will serve as interface with Denbury regarding the logistics of transport, storage, and injection of CO_2 for the project. This includes provision for onsite storage of CO_2, installation of CO_2-compatible flow lines, the skid for the compressor, refitting the well head, and possible workover of the well. Since Southern Company's objectives are to supply CO_2 for future EOR projects, including identification of sites for CO_2 storage, its involvement in the field operations will facilitate the establishment of mutually beneficial source-sink relationships. DRI, UAB, UA, SO

Task 15. Field Test No. 1.
Five to six months of water flooding into the well chosen as the injector, to provide background production data, to bring the five-spot to a typical water-flooded condition, and to reach the minimum miscibility pressure, followed by injection of 5000 tons of carbon dioxide into the reservoir for measurement of transient behavior (pressure decay following an injection pulse) and flow versus pressure. Monitor adjacent wells for produced oil, water, and gas, including CO_2. All

Task 20. Justification for proceeding to Phase II.
Update economic and market analysis in light of results obtained to date and reevaluate the long-term viability of the project. UAB, UA, SO, DRI

DECISION POINT: Based on the results obtained from Field Test No. 1, UAB will update the economic and market analyses for CO_2 flooding, and re-evaluate the long term viability of the project.

Phase II (September 1, 2008 – April 30, 2010):

Task 16. Geophysical testing for influence of CO_2.
Determine if seismic measurements are able to detect changes in the formation and the presence and migration of CO_2. UNCC

Task 17. Ecological processes dynamics.
Monitor changes in the surrounding landscape during and following injection of carbon dioxide into the oil reservoir. Work under this task monitors any evolution of the types, populations, and spatial distributions of vegetation on the site and surrounding landscape over the course of the project. Even in the likely event that any CO_2 seepage is completely absorbed by soil and water, it might still influence ecological processes in soil biological communities. AAMU

Task 18. Monitor for seepage.
Monitoring of CO_2 and fluorocarbon tracer in shallow boreholes and concentration profiles in soil near the surface to determine whether CO_2 seeps from the formation to the atmosphere. AAMU

Task 19. Analysis of data from Field Test No. 1.
Perform complete analysis and summary of the test data and associated environmental measurements. All

Task 21. Application for permit to conduct Field Test No. 2.
Another Class II Underground Injection Control (UIC) permit from the State of Alabama will be required for the second injection of CO_2 at the site. At this point we again intend to list all of the likely candidate wells, then amend the application as the list of potential test wells is narrowed down. SO, UAB, DRI

Task 22. Effect of nitrogen on oil-CO_2 interaction.
Determination of the sensitivity of the minimum miscibility pressure and viscosity on the nitrogen content of the gas, to establish the degree of separation of flue gas and other process streams required for successful and economic CO_2 EOR and sequestration. UA, UAB, SO

Task 23. Geomechanical stability analysis.
Geomechanical stability study will be conducted, including production-induced stress analysis and reservoir stability analysis through finite element nonlinear static stress analysis (ANSYS) and Distinct Element Analysis (3DEC from Itasca). A stability analysis of the anhydrite dome will be conducted assuming uplift pressure from supercritical CO_2 permeating into the dome via fault or fracture points. UNCC

Task 24. Refine the reservoir simulation.
Based upon the results of Field Test No. 1, refine the physical submodels and parameters describing the geologic structure and flows to improve the accuracy of the simulation of supercritical carbon dioxide behavior in oil-bearing porous rock formations. UA, UAB, GSA

Task 25. Refine the visualization of oil, water, and CO_2 flows.
Improve the visualization and perform a parametric study of oil yield using the reservoir simulator. UAB, UA, GSA

Task 26. Refine the reservoir management plan.
Incorporate the results from Phase I in an updated reservoir management plan. UA, GSA, SO, UAB

Task 27. Selection of test and monitoring wells for Field Test No. 2.
Based upon the results from Phase I, decide whether to conduct Field Test No. 2 using the same wells, or choose another set of five for testing. The first choice would be to choose different wells, but it is possible that the analysis of the data from Field Test No. 1 will indicate that we should conduct other types of tests, or tests under different conditions, on the same wells. All

Task 28. Geophysical testing.
Continue seismic measurements at the site of Field Test No. 1 and perform measurements at the site of Field Test No. 2, if different wells are selected. UNCC

Task 29. CO_2 fluxes and ecology.
Continue to monitor for CO_2 and tracer seepage at the site of Field Test No. 1 and perform baseline measurements at the site of Field Test No. 2, if different. AAMU

Task 30. Preparation for Field Test No. 2.
Preparation of wells for CO_2 injection, including provision for onsite storage of CO_2, installation of CO_2-compatible flow lines, the skid for the compressor, refitting the well head, and possible workover of the well. DRI, UAB, UA, SO

Task 31. Field Test No. 2.
Injection of 5000 tons of carbon dioxide into the reservoir through the test well under conditions identified in the parametric study using the reservoir simulator and established in the revised reservoir management plan. Measurement of transient behavior (pressure decay following an injection pulse) and flow versus pressure. Monitor adjacent wells for produced oil, water, and gas, including CO_2. All

Task 32. Geophysical testing for influence of CO_2.
Seismic measurements to observe the migration of CO_2 and changes in the formation. UNCC

Task 33. Ecological processes dynamics.
Monitor soil respiration and ecology surrounding the test wells during and following injection of carbon dioxide in Field Test No. 2. AAMU

Task 34. Monitor for seepage.
Monitoring of CO_2 and tracer in shallow boreholes and concentration profiles in soil near the surface to detect seepage from the formation to the atmosphere. AAMU

Task 35. Analysis of data from Field Test No. 2.
Perform complete analysis and summary of the test data and associated environmental measurements. All

Task 36. Justification for proceeding to Phase III.
Update the economic, market, and environmental analyses in light of the results obtained to date and reevaluate the long-term viability of the project. UAB, SO, DRI

DECISION POINT: Based on the results obtained from Field Test No. 2, UAB will update the economic and market analyses for CO_2 flooding, and re-evaluate the long term viability of the project.

Phase III (May 1, 2010 – December 31, 2011):

Task 37. Application for permit to conduct Demonstration.
Another Class II Underground Injection Control (UIC) permit from the State of Alabama will be required for the third injection of CO_2 at the site. At this point we again intend to list all of the likely candidate wells, then amend the application as the list of potential test wells is narrowed down. SO, UAB, DRI

Task 38. Monitoring by geophysical testing.
The geophysical tests conducted in Phases I and II will be repeated on a semiannual basis at the sites of the earlier injections, to monitor the migration of CO_2 and the stability of the formation, and to identify possible deviations from initial projections. UNCC

Task 39. Ecosystem dynamics.
Modeling of the behavior of surrounding ecosystems and landscapes associated with CO_2 injection. The Alabama A & M University Investigators, Xiongwen Chen and Ermson Nyakatawa, are specialists in the effects of land use and soil treatments on soil and landscape ecosystems. This task was formulated under the assumption that there is very limited or no CO_2 emission. However, the absence of CO_2 emission does not necessarily imply no impact to the environment. CO_2 may be absorbed by soil, water, and biological communities. This task will use as input the results from Task 17, with supplemental information about streams, bodies of water, and regional processes such as carbon cycling. Using these data, in combination with the underlying mechanisms of ecological processes, the ecosystem and landscape dynamics in subsequent years will be modeled. Cellular automata and ecosystem dynamics models will be used in the first stage, then, depending on impacts, more comprehensive spatially explicit models can be employed. AAMU

Task 40. Presentation of results as dynamic simulations.
Using the reservoir simulation, display the flow of CO_2, oil, and water as functions of reservoir properties and time, the oil yield by CO_2 EOR, and the capacity of the formation for CO_2 sequestration. UAB, UA

Task 41. Refine the reservoir management plan.
Incorporate results of Phase II in an updated reservoir management plan. UA, GSA, SO, UAB

Task 42. Selection of test and monitoring wells.
Based upon the results from Phase II, decide whether to conduct the Demonstration using the same wells, or choose another set of five. All

Task 43. Geophysical testing.
Continue seismic measurements at the sites of Field Test No's 1 and 2 and perform measurements at the site of the Demonstration, if different wells are selected. UNCC

Task 44. Soil fluxes and ecology.
Continue to monitor for seepage at the site of Field Test No's 1 and 2, and perform baseline measurements at the site of the Demonstration, if different. AAMU

Task 45. Demonstration.
Preparation of wells and injection of as much CO_2 as possible (at least 5000 tons) into the reservoir through the test well under the optimum conditions identified in Field Test No's 1 and 2 and in parametric studies using the reservoir simulator. Collection of detailed surface and

downhole data for refinement of the CO_2 EOR simulation. Monitor adjacent wells for produced oil, water, and gas, including CO_2. All

Task 46. Geophysical monitoring of the flood.
Seismic measurements to monitor the progress of the CO_2 flood and changes in the formation. UNCC

Task 47. Ecological processes dynamics.
Continue to monitor ecology at the sites of Field Test No's 1 and 2 and at the site of the Demonstration. AAMU

Task 48. Monitor for seepage.
Continue to monitor CO_2 and tracer at the sites of Field Test No's 1 and 2 and at the site of the Demonstration. AAMU

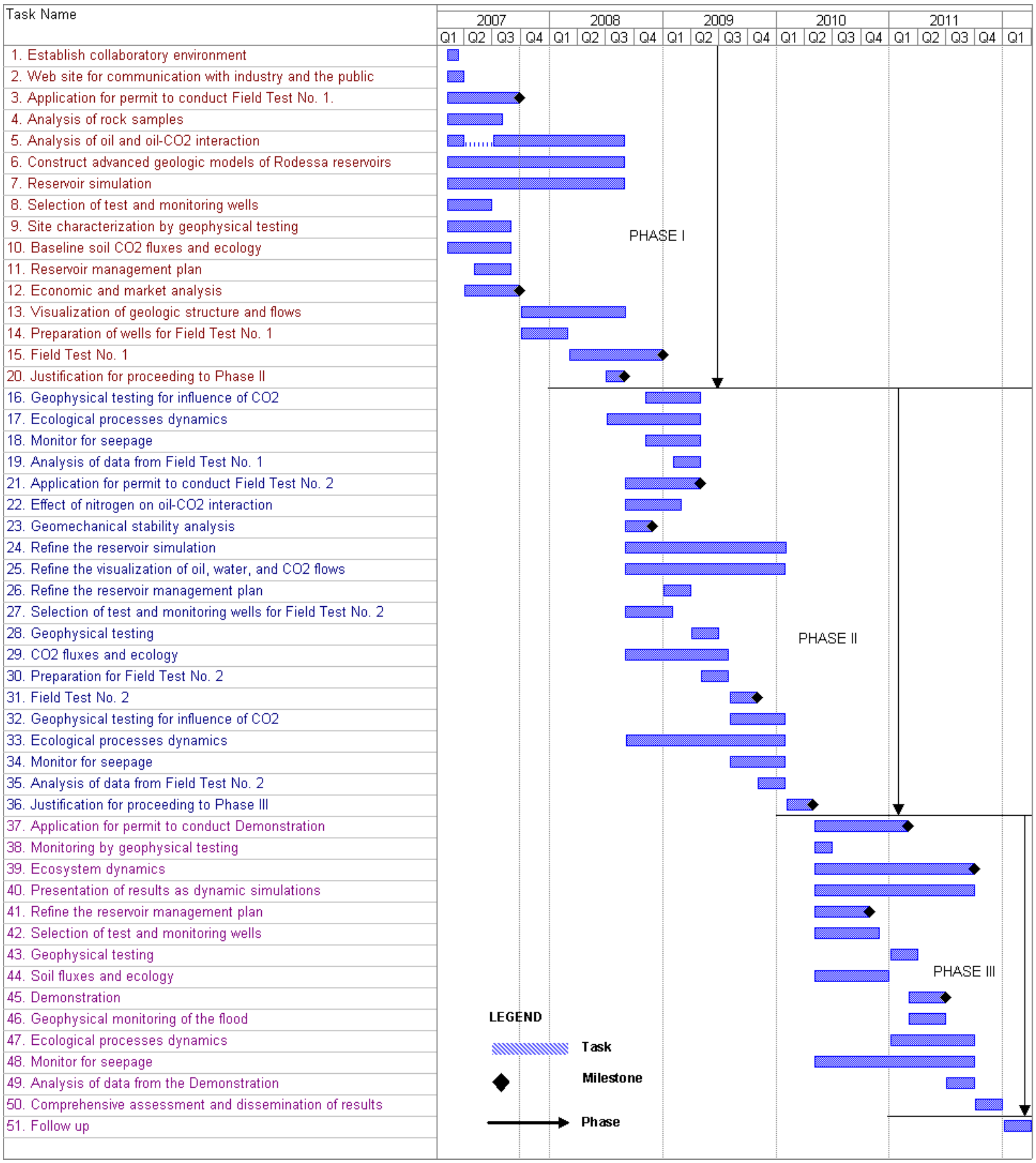
Task 49. Analysis of data from the Demonstration.
Perform complete analysis and presentation of the test data and associated environmental measurements. All

Task 50. Comprehensive assessment and dissemination of results.
Complete analysis of oil recovery, estimates of capacity and integrity of storage, ecological effects, economic and market analysis, and the prospects for separation and sequestration of CO_2 from sources in the region. This will include a topical report on the capability of the Rodessa Formation for storage of CO_2. Dissemination of results via the web site, the final report to DOE, presentations, and publications. All

Task 51. Follow up.
Continue to monitor production, seepage, ecological effects, and progress of negotiations for transition of the Citronelle Oil Field to a CO_2 sequestration site on completion of the wells. Continue to inform industry and DOE of new developments. All

A.2. Project Schedule

The schedule for execution of the tasks is given on the following chart. The project began on January 1, 2007, and its duration is 60 months.



A.3. Milestones

Phase and Critical Path Milestone Description	Task	Planned Dates
Phase I		Jan. 1, 2007 - Aug. 31, 2008
Oil and CO_2 miscibility testing completed	5	Mar. 31, 2007
Economic and market analysis completed	12	Sep. 30, 2007
Permit to conduct Field Test No. 1 issued	3	Sep. 30, 2007
Justification for proceeding to Phase II submitted	20	Aug. 31, 2008
Phase II		Sep. 1, 2008 - Apr. 30, 2010
Geomechanical stability analysis completed	23	Nov. 30, 2008
Field Test No. 1 completed	15	Dec. 31, 2008
Permit to conduct Field Test No. 2 issued	21	Apr. 30, 2009
Field Test No. 2 completed	31	Oct. 31, 2009
Justification for proceeding to Phase III submitted	36	Apr. 30, 2010
Phase III		May 1, 2010 - Dec. 31, 2011
Refinement of the reservoir management plan completed	41	Oct. 31, 2010
Permit to conduct Demonstration issued	37	Feb. 28, 2011
Demonstration completed	45	Jun. 30, 2011
Report on ecosystem and landscape evolution submitted	39	Sep. 30, 2011

A.4. Deliverables

Quarterly Progress and Financial Status Reports will be submitted within 30 days after the end of each quarter.

Special Status Reports will be submitted immediately (within 3 working days), to transmit results having major impact on the course of the project.

Informal Reports will be submitted to the DOE Contracting Officer's Representative on completion of Critical Path Milestones.

A Topical Report will be prepared on the Rodessa Formation CO_2 sequestration capability (Task 50). Other Topical Reports will be submitted, when appropriate, to describe significant new technical advances.

Each investigator plans to present the results of his work at a workshop, at a conference, or by publication at least once a year, beginning in the second year of the project. Because there are many investigators associated with the project, this will represent a substantial and effective means by which to communicate the results of the work to the petroleum, electric utility, and industrial combustion communities. This reporting will continue even after the current project ends.

Patent and Property Certifications will be submitted at the conclusion of the project, on December 31, 2011. The Final Scientific/Technical Report and Final Financial Status Report will be submitted within 90 days after the end of the project, before March 30, 2012.

Appendix B: Presentations, Publications, and Reports

B.1. Presentations and Workshops

J. C. Pashin and R. A. Esposito, "Citronelle Dome: A Giant Opportunity for Multi-Zone Carbon Storage and Enhanced Oil Recovery in the Mississippi Interior Salt Basin of Alabama," Presented at the Annual Convention and Exhibition of the American Association of Petroleum Geologists, Long Beach, CA, April 1-4, 2007.

J. C. Pashin, R. A. Esposito, and P. M. Walsh, "Citronelle Dome: A Giant Opportunity for Multi-Zone Carbon Storage and Enhanced Oil Recovery in the Mississippi Interior Salt Basin of Alabama," Poster presentation at the DOE/NETL Sixth Annual Conference on Carbon Capture and Sequestration, Pittsburgh, PA, May 7-10, 2007.

E. S. Carlson, Workshop on visualization for reservoir simulation, Rocky Mountain Mathematics Consortium Summer School, "Flow in Porous Media with Emphasis on Modeling Oil Reservoirs," University of Wyoming, Laramie, WY, June 18-29, 2007.

Wen-Ya Qi, Shen-En Chen, P. M. Walsh, R. A. Esposito, and J. C. Pashin, "Geosensing for CO_2 Sequestration Monitoring in an Oil Field: Possible Global Warming Solution," Presented at the 3rd National Conference on Environmental Science and Technology, North Carolina A&T State University, Greensboro, NC, September 12-14, 2007.

J. C. Pashin and R. A. Esposito, "Citronelle Dome: A Giant Opportunity for Multi-Zone Carbon Storage and Enhanced Oil Recovery in the Mississippi Interior Salt Basin of Alabama," Presented at the 2007 Annual Convention of the Gulf Coast Association of Geological Societies and the Gulf Coast Section of the Society for Sedimentary Geology, Corpus Christi, TX, October 21-23, 2007.

R. A. Esposito, J. C. Pashin, and P. M. Walsh, "Citronelle Dome: A Giant Opportunity for Multi-Zone Carbon Storage and Enhanced Oil Recovery in the Mississippi Interior Salt Basin of Alabama," *Gulf Coast Association of Geological Societies Transactions,* **2007**, *57*, 213-224.

J. C. Pashin, "CO_2-EOR Pilot in Tidal Deposits of the Cretaceous Donovan Sand, Citronelle Field, SW Alabama," Presented at the Annual Convention and Exhibition of the American Association of Petroleum Geologists, San Antonio, TX, April 20-23, 2008.

R. A. Esposito, J. C. Pashin, and P. M. Walsh, "Pilot Design for CO_2-EOR and Sequestration Potential in the Citronelle Oil Field in the Mississippi Interior Salt Basin of Alabama," Presented at the Seventh Annual Conference on Carbon Capture and Sequestration, Pittsburgh, PA, May 5-8, 2008.

B.2. Publications

X. Chen and Y. Wang, "Emergent Spatial Pattern of Herpetofauna in Alabama, USA," *Acta Herpetologica*, **2007**, *2* (2), 71-89.

X. Chen and K. A. Roberts, "Roadless Areas and Biodiversity: A Case Study in Alabama, USA," *Biodiversity and Conservation*, **2008**, *17*, 2013-2022.

R. A. Esposito, J. C. Pashin, and P. M. Walsh, "Citronelle Dome: A Giant Opportunity for Multi-Zone Carbon Storage and Enhanced Oil Recovery in the Mississippi Interior Salt Basin of Alabama," *Environmental Geosciences*, **2008,** *15* (2), 1-10.

X. Chen, "Topological Properties in the Spatial Distribution of Amphibians in Alabama USA for the use of Large Scale Conservation," *Animal Biodiversity and Conservation*, **2008**, *31.1*, 1-13.

B.3. Reports

P. M. Walsh, E. Z. Nyakatawa, X. Chen, J. Harper, J. C. Pashin, R. A. Esposito, E. S. Carlson, P. E. Clark, G. Cheng, A. M. Shih, K. Theodorou, and S.-E. Chen, "Carbon-Dioxide-Enhanced Oil Production from the Citronelle Oil Field in the Rodessa Formation, South Alabama," Quarterly Progress Report to the U.S. Department of Energy for the period January 1 to March 31, 2007, Contract No. DE-FC26-06NT43029, University of Alabama at Birmingham, Alabama Agricultural and Mechanical University, Denbury Resources, Inc., Geological Survey of Alabama, Southern Company Services, Inc., University of Alabama, and University of North Carolina at Charlotte, April 30, 2007.

P. M. Walsh, E. Z. Nyakatawa, X. Chen, J. Harper, G. N. Dittmar, M. A. Rainer, J. C. Pashin, D. J. Hills, R. A. Esposito, E. S. Carlson, P. E. Clark, K. Theodorou, A. M. Shih, G. Cheng, S.-E. Chen, and W. Qi, "Carbon-Dioxide-Enhanced Oil Production from the Citronelle Oil Field in the Rodessa Formation, South Alabama," Quarterly Progress Report to the U.S. Department of Energy for the period April 1 to June 30, 2007, Contract No. DE-FC26-06NT43029, University of Alabama at Birmingham, Alabama Agricultural and Mechanical University, Denbury Resources, Inc., Geological Survey of Alabama, Southern Company Services, Inc., University of Alabama, and University of North Carolina at Charlotte, July 30, 2007.

P. M. Walsh, E. Z. Nyakatawa, X. Chen, J. Harper, G. N. Dittmar, M. A. Rainer, J. C. Pashin, D. J. Hills, R. A. Esposito, E. S. Carlson, P. E. Clark, K. Theodorou, A. M. Shih, G. Cheng, S.-E. Chen, and W. Qi, "Carbon-Dioxide-Enhanced Oil Production from the Citronelle Oil Field in the Rodessa Formation, South Alabama," Quarterly Progress Report to the U.S. Department of Energy for the period July 1 to September 30, 2007, Contract No. DE-FC26-06NT43029, University of Alabama at Birmingham, Alabama Agricultural and Mechanical University, Denbury Resources, Inc., Geological Survey of Alabama, Southern Company Services, Inc., University of Alabama, and University of North Carolina at Charlotte, October 27, 2007.

P. M. Walsh, E. Z. Nyakatawa, X. Chen, J. Harper, G. N. Dittmar, M. A. Rainer, A. Bailey, J. C. Pashin, D. J. Hills, D. C. Kopaska-Merkel, R. A. Esposito, E. S. Carlson, P. E. Clark, K.

Theodorou, A. M. Shih, G. Cheng, S.-E. Chen, K. Roberts, and W. Qi, "Carbon-Dioxide-Enhanced Oil Production from the Citronelle Oil Field in the Rodessa Formation, South Alabama," Quarterly Progress Report to the U.S. Department of Energy for the period October 1 to December 31, 2007, DOE Cooperative Agreement No. DE-FC26-06NT43029, University of Alabama at Birmingham, Alabama Agricultural and Mechanical University, Denbury Resources, Inc., Geological Survey of Alabama, Southern Company Services, Inc., University of Alabama, and University of North Carolina at Charlotte, January 30, 2008.

E. Nyakatawa and P. Walsh, "Proposal for Measurements of Soil Conditions and CO_2 Flux at Citronelle," Report to J. Harper and G. Dittmar at Denbury Resources, February 19, 2008.

P. Walsh, "Summary of Meeting of CO_2-EOR Group in Citronelle, February 21, 2008," Report to partners and participants in the meeting, February 26, 2008.

P. Walsh, "Visits to Citronelle Oil Field to gather data for the DOE project," Report to J. Harper at Denbury Resources, April 4, 2008.

P. Walsh, E. Carlson, J. Harper, and J. Pashin, "Project #43029. Material for Conference Call, April 15, 2008, to Discuss CO_2 Injection Volume for Test at Citronelle Oil Field," Report to J. Ammer, R. Long, and C. Nautiyal at NETL, April 15, 2008.

P. M. Walsh, E. Z. Nyakatawa, X. Chen, J. Harper, G. N. Dittmar, A. Bailey, J. C. Pashin, D. J. Hills, D. C. Kopaska-Merkel, R. A. Esposito, E. S. Carlson, P. E. Clark, A. M. Shih, G. Cheng, S.-E. Chen, K. Theodorou, K. A. Roberts, and W. Qi, "Carbon-Dioxide-Enhanced Oil Production from the Citronelle Oil Field in the Rodessa Formation, South Alabama," Quarterly Progress Report to the U.S. Department of Energy for the period January 1 to March 31, 2008, DOE Cooperative Agreement No. DE-FC26-06NT43029, University of Alabama at Birmingham, Alabama Agricultural and Mechanical University, Denbury Resources, Inc., Geological Survey of Alabama, Southern Company Services, Inc., University of Alabama, and University of North Carolina at Charlotte, April 30, 2008.

E. Carlson, "Interference Test Results," Report to J. Harper and G. Dittmar at Denbury Resources, June 2, 2008.

P. Walsh, "Report on Visit to Citronelle by Alabama A&M University Team, June 11-12, 2008," Report to CO_2-EOR and Storage Group, June 24, 2008.

Appendix C: Bibliography of Publications on the Citronelle Oil Field and Southwest Alabama Geology

Advanced Resources International, "Basin Oriented Strategies for CO_2 Enhanced Oil Recovery: Onshore Gulf Coast," Report to U.S. DOE, February 2006.

Alverson, R. M., "Deep Well Disposal Study for Baldwin, Escambia and Mobile Counties," Alabama, Alabama Geological Survey, Circular 58, 1970.

Anonymous, "Engineering Study and Appraisal Report," Vol. I, Tables and Figures. The report is not dated, but the latest data included in it are from 1987. Contains a profitability analysis, projected operating expenses, predicted water flood performance data, an index of cored wells, production data, fluid rates, porosity and permeability data, oil and water saturations, and pilot water flood performance results.

Bolin, D. E., S. D. Mann, D. Burroughs, H. E. Moore, Jr., and T. L., Powers, "Petroleum Atlas of Southwestern Alabama," Alabama Geological Survey, Atlas 23, 1989.

Claypool, G. E., and E. A. Mancini, "Geochemical Relationships of Petroleum in Mesozoic Reservoirs to Carbonate Source Rocks of Jurassic Smackover Formation, Southwestern Alabama," *AAPG Bulletin*, Vol. 73, 1989, pp. 904-924.

Donahoe, R. J., "An Experimental Study of a Waterflood Enhanced Oil Recovery Case History: The Citronelle Field, Mobile County, Alabama," Final Report for 1986/1987 SOMED Project, Department of Geology, University of Alabama, Tuscaloosa, March 1988.

Eaves, E., "Citronelle Oil Field, Mobile County, Alabama," American Association of Petroleum Geologists Memoir 24, 1976, pp. 259-275.
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Appendix D: Computer Programs

Eric S. Carlson

The programs are written in MATLAB/octave. The first three programs were used to estimate fluid properties for most reservoir calculations using SENSOR.

Contents:

D.1. Oil and Water Properties

```
1;
function dBodP=fmain(Rs,gamma_g, API,T,Pb,P,Bo)
%use definition of compressibility and correlation to create ODE for Bo
% Vasquez-Beggs correlation for compressibility
  co = 1.705E-7*Rs^.69537*gamma_g^.1885*API^.3272*T^.6729*(P-Pb+1).^(-.5906);
  dBodP = -co.*Bo;
end

%All input params here assumed
API = 42; % degrees API
gamma_O=141.5/(131.5+API); %specific gravity of oil
Rs = 150; %SCF/STB at Pb
T = 210; %Degrees F
gamma_g = 1.36; %gas gravity
% Following uses Standing's (1981) correlation for bubble point pressure
hold1=0.00091*T-0.0125*API;
Pb = 18.2*((Rs/gamma_g)^0.83*10^hold1-1.4)
% Standing's (1981) correlation for Bo at Bubble point
BoBP = 0.9759+0.00012*(Rs*(gamma_g/gamma_O)^0.5+1.25*T)^1.2

% The following calculates B0 as a function of pressure,
%   given B0 at the bubble point pressure,
%   Vasquez-Beggs correlation for compressibility
%   and ODE definition of compressibility (co=-(1/B0)*dBo/dP)
Bo0 = BoBP; %Initial Bo at Pb
P = linspace(Pb,8000,21); %output at 21 equally spaced points
fsys = @(P,B) fmain(Rs, gamma_g,API, T, Pb, P, B);
[t_num u_num] = ode45(fsys, P, Bo0);%solve it
x_tab = u_num(:,1); %extract table for y output
cx = spline(t_num, x_tab);%fit y to spline
x_n = @(t) ppval(cx,t);%create continuous function

tplot = linspace(800, 8000,201);
plot(tplot', x_n(tplot'), '-b')
xlabel('p (psi)', '{"fontsize" : 16}')
ylabel('Bo', '{"fontsize" :16}')
title('Bo','{"fontsize" :20}')
P = [Pb 1000:500:8000]; %Pressures for table
```

```
[P' x_n(P')] %table of P Bo
[P' -(fsys(P,x_n(P))./x_n(P))'] %table of P and co
[P' (62.4*gamma_O+.0136*Rs*gamma_g)./x_n(P')] %table of pressure and density

% calculation of various dead oil viscosities
% Glasco (1980)
mu_odGC = [3.141E10]*(T)^(-3.444)*[log10(API)]^(10.313*[log10(T)]-36.447)
%Beggs-Robinson (1975)
mu_odBRC = 10^((10^(3.0324-0.02023*API))*T^(-1.163))-1
%Beal 1946
mu_odBC = (.32+1.8E7/API^4.53)*(360/(T+460-260))^(10^(0.43 + 8.33/API))
%Egbogah
mu_odEC = 10^(10^(1.8653-.025086*API-.5644*log10(T)))-1
%wide variation in correlation values, so just go with BR
mu_od = mu_odBRC;
%Beggs-Robinson Mu_o at Pb
mu_opb = (10.715*(Rs + 100)^(-0.515))*mu_od^(5.44*(Rs + 150)^(-0.338))
%Vasquez-Beggs (1980) correlation for pressure-dependent viscosity
mu_o=mu_opb*(P/Pb).^(2.6*P.^1.187.*10.^(-3.9E-5*P - 5));
[P' mu_o'] %table of pressure and oil viscosity

%%start water properties
%Formation volume factor calcs, 1982 HP Petroleum fuilds PAC (as described by
Ahmed)
a= [0.9947 5.8E-6 1.02E-6 -4.228E-6 1.8376E-8 -6.77E-11 1.3E-10 -1.3855E-12
4.285E-15];
A1 = a(1)+a(2)*T+a(3)*T^2;
A2 = a(4)+a(5)*T+a(6)*T^2;
A3 = a(7)+a(8)*T+a(9)*T^2;
%Bw = A1+A2*P+A3*P.^2;

%Water Formation Volume factor from McCain
dVwt=-1.0001E-2+1.33391E-4*T+5.50654E-7*T^2;
dVwp=-1.95301E-9*P*T-1.72834E-13*P.^2*T-3.58922E-7*P-2.25341E-10*P.^2;
Bw = (1+dVwt).*(1+dVwp);
[P' Bw'] %output table P Bw

Y=12;%water salinity for Meehan, ppm
B = 70.634 + 9.576E-10*Y^2;
A = -4.518E-2 + 9.313E-3*Y - 3.93E-4*Y^2;
% Meehan (1980)
mu_wd = A+B/T
%Brill and Beggs (1978)
mu_wd2= exp (1.003 - 1.479E-2*T + 1.982E-5*T^2)
%mu_wd3 from McCain as listed in Craft et al
S=12; %Asssumed per cent of solids for McCain Water Props
A=109.574-8.40564*S+.313314*S^2+8.72213E-3*S^3;
B=-1.12166+2.63951E-2*S-6.79461E-4*S^2-5.47119E-5*S^3+1.55586E-6*S^4;
mu_wd3=A*T^B
%Big Problem with Meehan as shown in Ahmed;
%
mu_w = mu_wd*(1+3.5E-12* P.^2*(T-40));
%McCain's water viscosity adjustment for pressure
%mu_w = mu_wd3*(.9994+4.0295E-5*P+3.1062E-9*P.^2);
[P' mu_w']

%
%Octave Output citronelle_Bo.m:
% Pb =  392.82
```

```
%BoBP =  1.1622
%Pressure (psi)  Bo(bbl/STB)
%
%    392.8219      1.1622
%   1000.0000      1.1053
%   1500.0000      1.0994
%   2000.0000      1.0936
%   2500.0000      1.0889
%   3000.0000      1.0848
%   3500.0000      1.0812
%   4000.0000      1.0780
%   4500.0000      1.0750
%   5000.0000      1.0722
%   5500.0000      1.0696
%   6000.0000      1.0671
%   6500.0000      1.0648
%   7000.0000      1.0626
%   7500.0000      1.0605
%   8000.0000      1.0585
%
%   P (psia) and co (1/psi)
%
%  3.9282e+002  7.3086e-004
%  1.0000e+003  1.6580e-005
%  1.5000e+003  1.1633e-005
%  2.0000e+003  9.3363e-006
%  2.5000e+003  7.9567e-006
%  3.0000e+003  7.0169e-006
%  3.5000e+003  6.3264e-006
%  4.0000e+003  5.7929e-006
%  4.5000e+003  5.3655e-006
%  5.0000e+003  5.0136e-006
%  5.5000e+003  4.7177e-006
%  6.0000e+003  4.4646e-006
%  6.5000e+003  4.2450e-006
%  7.0000e+003  4.0522e-006
%  7.5000e+003  3.8814e-006
%  8.0000e+003  3.7286e-006
%
%  P (psia)  and co (lb/ft^3)
%
%    392.822     46.177
%   1000.000     48.552
%   1500.000     48.816
%   2000.000     49.072
%   2500.000     49.285
%   3000.000     49.469
%   3500.000     49.633
%   4000.000     49.784
%   4500.000     49.923
%   5000.000     50.052
%   5500.000     50.174
%   6000.000     50.289
%   6500.000     50.399
%   7000.000     50.504
%   7500.000     50.604
%   8000.000     50.700
% Glasco (1980)
%mu_odGC =  0.74124  #
```

```
%Beggs-Robinson (1975)
%mu_odBRC =  1.0109  #
%Beal 1946
%mu_odBC =  0.64327
%Egbogah
%mu_odEC =  1.0748
%wide variation in correlation values, so just go with BR
%Beggs-Robinson Mu_o at Pb
%mu_opb =  0.62918

% Pressure (psi) mu_oil(cp)
%
%  3.9282e+002  6.2918e-001
%  1.0000e+003  6.8214e-001
%  1.5000e+003  7.5273e-001
%  2.0000e+003  8.4336e-001
%  2.5000e+003  9.5292e-001
%  3.0000e+003  1.0811e+000
%  3.5000e+003  1.2278e+000
%  4.0000e+003  1.3929e+000
%  4.5000e+003  1.5760e+000
%  5.0000e+003  1.7763e+000
%  5.5000e+003  1.9926e+000
%  6.0000e+003  2.2234e+000
%  6.5000e+003  2.4667e+000
%  7.0000e+003  2.7201e+000
%  7.5000e+003  2.9809e+000
%  8.0000e+003  3.2462e+000
%
% Pressure(psi) Bw(bbl/STB)
%
%    392.8219      1.0419
%   1000.0000      1.0412
%   1500.0000      1.0405
%   2000.0000      1.0396
%   2500.0000      1.0386
%   3000.0000      1.0374
%   3500.0000      1.0361
%   4000.0000      1.0347
%   4500.0000      1.0332
%   5000.0000      1.0315
%   5500.0000      1.0296
%   6000.0000      1.0277
%   6500.0000      1.0256
%   7000.0000      1.0233
%   7500.0000      1.0209
%   8000.0000      1.0184
%
%mu_wd =  0.34634 % Meehan (1980)
%mu_wd2 =  0.29263  %Brill and Beggs (1978)
%mu_wd3 =  0.39551 %Vasquez-Beggs (1980) correlation for pressure-dependent
viscosity
% Pressure(psi)  mu_w (cp) %Meehan
%
%  3.9282e+002  3.4637e-001
%  1.0000e+003  3.4654e-001
%  1.5000e+003  3.4680e-001
%  2.0000e+003  3.4716e-001
%  2.5000e+003  3.4762e-001
```

```
%  3.0000e+003  3.4819e-001
%  3.5000e+003  3.4886e-001
%  4.0000e+003  3.4963e-001
%  4.5000e+003  3.5051e-001
%  5.0000e+003  3.5149e-001
%  5.5000e+003  3.5257e-001
%  6.0000e+003  3.5375e-001
%  6.5000e+003  3.5504e-001
%  7.0000e+003  3.5643e-001
%  7.5000e+003  3.5793e-001
%  8.0000e+003  3.5952e-001
```

D.2. CO_2 Density

```
1;
patm=14.696; %psi/atm
clear; clear

function zero=EOS_Duan_CO2(T,P, V)
%following uses Duan correlation for CO2 z-factor
%the unknown here is actually 10000*(specific volume)
%the 10000 is used here to assure that solution is on order of 1
a=[8.9928849700E-002
-4.9748312700E-001
4.7792224500E-002
1.0380888300E-002
-2.8251686100E-002
9.4988756300E-002
5.2060088000E-004
-2.9354097100E-004
-1.7726511200E-003
-2.5110197300E-005
8.9335344100E-005
7.8899856300E-005];
alpha=-1.6672702200E-002;
beta1=1.3980000000E+000;
gamma1=2.9600000000E-002;
Tc = 3.0978200000E+001+273.15;
Pc = 0.986923267*73.773; %(atm)
R = 8.2057458700E-005; %m^3 atm/(K mole)
Vc = R*Tc/Pc;
Vr = V/Vc/10000;
Tr = T/Tc; Pr=P/Pc;
B=a(1)+a(2)/Tr^2+a(3)/Tr^3;
C=a(4)+a(5)/Tr^2+a(6)/Tr^3;
D=a(7)+a(8)/Tr^2+a(9)/Tr^3;
E1=a(10)+a(11)/Tr^2+a(12)/Tr^3;
F=alpha/Tr^3;
zero=-
Pr*Vr/Tr+1+B./Vr+C./Vr.^2+D./Vr.^4+E1/Vr^5+F./Vr.^2*(beta1+gamma1./Vr.^2).*ex
p(-gamma1./Vr.^2);
end

function y= rho_CO2(T,P)
   %returns moles/m^3
   %T in K
   %P in atm
   [nr nc]=size(P); np=nr*nc;
   P = reshape(P,[np,1]);
```

```
   y(np)=0;
   for k=1:np
     clear fdum
     fdum=@(x) EOS_Duan_CO2(T,P(k), x);
     y(k) = fzero(fdum,1.5);
   end
   y = reshape(y,[nr nc])/10000;
end

T_res = (245.0-32)*5.0/9.0 +273.15;
P = [544.78 1000:500:8000];
%P=4195;
P_res = P/14.696;

rho_in_moles_per_m3 = 1./rho_CO2(T_res,P_res)
rho_in_lbm_per_ft3=rho_in_moles_per_m3*44.00980/1000/1000*62.4;
[P' rho_in_lbm_per_ft3'] %table output pressure and density
[P' (rho_in_lbm_per_ft3'*379.4/44.0098).^-1]

%  Pressure (psia) rho (lbm/ft^3)
%
%    544.7800      3.4277
%   1000.0000      6.7604
%   1500.0000     11.0263
%   2000.0000     15.9719
%   2500.0000     21.3934
%   3000.0000     26.7125
%   3500.0000     31.3366
%   4000.0000     35.0974
%   4500.0000     38.1290
%   5000.0000     40.6156
%   5500.0000     42.7033
%   6000.0000     44.4943
%   6500.0000     46.0594
%   7000.0000     47.4480
%   7500.0000     48.6956
%   8000.0000     49.8282
%
%Pressure (psia) rho (SCF/ft^3)
%
%  5.4478e+002  3.3841e-002
%  1.0000e+003  1.7158e-002
%  1.5000e+003  1.0520e-002
%  2.0000e+003  7.2626e-003
%  2.5000e+003  5.4222e-003
%  3.0000e+003  4.3425e-003
%  3.5000e+003  3.7017e-003
%  4.0000e+003  3.3050e-003
%  4.5000e+003  3.0423e-003
%  5.0000e+003  2.8560e-003
%  5.5000e+003  2.7164e-003
%  6.0000e+003  2.6070e-003
%  6.5000e+003  2.5185e-003
%  7.0000e+003  2.4447e-003
%  7.5000e+003  2.3821e-003
%  8.0000e+003  2.3280e-003
%
```

D.3. CO_2 Viscosity

```
1;
function y = viscosity_pressure_correction(Tpr,Ppr)

a0 = -2.46211820; a8 = -7.93385648E-1;
a1 = 2.970547414; a9 = 1.39643306;
a2 = -2.86264054E-1; a10 = -1.49144925E-1;
a3 = 8.05420522E-3; a11 = 4.41015512E-3;
a4 = 2.80860949; a12 = 8.39387178E-2;
a5 = -3.49803305; a13 = -1.86408848E-1;
a6 = 3.60373020E-1; a14 = 2.03367881E-2;
a7 = -1.044324E-2; a15 = -6.09579263E-4;
y = (a0 + a1*Ppr +  a2*Ppr.^2 + a3*Ppr.^3 + ...
 Tpr*(a4 + a5*Ppr +  a6*Ppr.^2 + a7*Ppr.^3)+ ...
 Tpr^2*(a8 + a9*Ppr +  a10*Ppr.^2 + a11*Ppr.^3) +...
 Tpr^3*(a12 + a13*Ppr +  a14*Ppr.^2 + a15*Ppr.^3));
 y=exp(y)/Tpr
end
TC=(3.0978200000E+001+273.15)*1.8 %actual 547.91
PC=0.986923267*73.773*14.696  %actual 1071
P = [544.78 1000:500:8000];;
T = 245;
TA = T+459.67;
Ppr = P/PC;
Tpr=(245+459.67)/TC;
T0 = 527.67; %Param for CO2 Viscosity
mu_l=.0148*(.555*T0+240)/(.555*TA+240)*(TA/T0)^1.5
ratio=viscosity_pressure_correction(Tpr,Ppr)
mu_CO2=mu_l*ratio
gammag=44/28.9;
Mu_l_standing=(1.709E-5-2.062E-6*gammag)*T+8.118E-3-6.15E-
3*log(gammag)+9.08E-3*log(gammag)+6.24E-3
Mu_CO2_standing = Mu_l_standing*ratio;
[P' Mu_CO2_standing' mu_CO2']

%%Octave Output viscosity_pressure_correction_test.m:
%%TC =  547.43
%%PC =  1070.0
%%mu_l =  0.019285
%%Mu_l_standing =  0.019008
%%ans =
%%
%%  5.4478e+002  1.8152e-002  1.8417e-002
%%  1.0000e+003  2.1043e-002  2.1350e-002
%%  1.5000e+003  2.4500e-002  2.4857e-002
%%  2.0000e+003  2.8234e-002  2.8645e-002
%%  2.5000e+003  3.2216e-002  3.2686e-002
%%  3.0000e+003  3.6411e-002  3.6942e-002
%%  3.5000e+003  4.0779e-002  4.1374e-002
%%  4.0000e+003  4.5272e-002  4.5932e-002
%%  4.5000e+003  4.9841e-002  5.0568e-002
%%  5.0000e+003  5.4433e-002  5.5227e-002
%%  5.5000e+003  5.8996e-002  5.9857e-002
%%  6.0000e+003  6.3481e-002  6.4407e-002
%%  6.5000e+003  6.7839e-002  6.8829e-002
%%  7.0000e+003  7.2028e-002  7.3078e-002
%%  7.5000e+003  7.6009e-002  7.7117e-002
%%  8.0000e+003  7.9751e-002  8.0915e-002
```

D.4. Program for Analysis of the Interference Test Data

```
%data for well B-19-7
data1=[19.87   5506.86
25.87  5510.35
%lots of data in between
859.87  5528.99
865.87  5529.22];
data2=[17.63           5128.77
21.63          5132.95
25.63          5135.11
%lots of data in between
697.63         5145.7
701.63         5145.64
704.18         5145.55
704.76         5148.7];
t1=data1(:,1);
t2=data2(:,1);
dp1=data1(:,2)-data1(1,2);
dp2=data2(:,2)-data2(1,2);
plot(t1,dp1,'b-',t2, dp2,'r-', [384;384],[0;25],'k--')
xlabel('time (hours from midnight,April 17 2008)', '{"fontsize" : 16}')
ylabel('delta pressure (psi)', '{"fontsize" :16}')
legend('("B-19-9 pressure change","B-19-7 pressure change")','loc=0')
title('Citronelle Interference Test data','{"fontsize" :20}')
text(384,10,'"$\leftarrow$ Start of injection", {"fontsize" :20}')
p1 = t1>16*24;
t_int=t1(p1)-16*24;
dp1_int=max(0,dp1(p1)-16);
%figure()
%plot(t_int,dp1_int,'ro')
%p1=(t1>100&t1<600)
%a=polyfit(t1(p1),dp1(p1),5)
%tplot=linspace(200,900,401)
%plot(tplot,polyval(a,tplot),'-g')
%figure()
%plot(t_int,dp1_int,'ro')

% For general curve fits, you only need to change
%  1. data
%  2. parameter names
%  3. initial guesses for parameters
%  4. function formula in terms of your parameter names
%  5. gls(x) defined at bottom can be used for EPIC MAID stuff

x = t_int; y=dp1_int;
%CHANGE param names and give guess corresponding to each param
param_names ={'kp','h'};
guess =       [.5 ,   20];

function y=e1x(x)
a=size(x); ns=prod(a);
y(1:ns,1)=0;
x=reshape(x,[ns,1]);
x=max(0,x);%nonnegative argument
p1=x>1;
p2=~p1;
a1=[.00107857 -.00976004 .05519968 -.24991055 .99999193 -.57721566];
a2=[1 8.5733287401 18.0590169730 8.6347608925 .2677737343];
```

```
b1=[1 9.5733223454 25.6329561486 21.0996530827 3.9584969228];
if sum(p1)~=0
y(p1) = exp(-x(p1))./x(p1).*polyval(a2,x(p1))./polyval(b1,x(p1));
end
if sum(p2)~=0
y(p2) = -log(x(p2))+polyval(a1,x(p2));
end
y=reshape(y,a);

function y = my_ls_func(x,cmi,par_names)
   % x is the independent variable
   % cmi are the function parameters
   % par_names are the param names
% DO NOT CHANGE _______
   global kount
   kount=kount+1;
   % following loop changes params into readable names
   for k = 1:length(par_names)
      eval(sprintf('%s=%20.15e;',par_names{k},cmi(k)));
   end
   % Write formula in terms of your param names
%  CHANGE FOLLOWING FORMULA FOR YOUR PROBLEM
      %WRITE YOUR FUNCTION IN TERMS OF YOUR PARAM NAMES
      % NOTE THE ELEMENT OPERATIONS With Respect To x IN THE STATEMENT
   ct=10*10^(-6); %psi^-1
   phi = .155;
   mu = 1;%cp probably high
   %k = 1;%md
   qB = 140; %injection rate STB/day
   %h = 20; %height, ft
   r=823; %distance from injector, ft
   m1 = 70.6*qB*mu/(kp*h);
   y=m1*e1x(948*phi*mu*ct*r^2./(kp*x));

end

fls=@(x,c) my_ls_func(x,c, param_names);
[c, iter, funcs, kvg]=fit_general_curve(fls, x, y, guess);
if kvg
   fprintf('\nprogram succeeded with %0.0f function evaluations and %0.0f
iterations\n\n',funcs, iter)
else
   fprintf('\nprogram did not succeed, try different guess\n\n')
end

for k = 1:length(param_names)
   fprintf('%s = %10.5f\n',param_names{k},c(k));
end

gls = @(x) fls(x,c);

xeval=linspace(min(x), max(x),200)';
figure()
plot(x, y,'.r',xeval,gls(xeval),'-b')
xlabel('time (hours from midnight,May 3 2008)', '{"fontsize" : 16}')
ylabel('delta pressure (psi)', '{"fontsize" :16}')
legend('("B-19-9 pressure change data","fit")','loc=0')
title('Citronelle B-19-9 Interference Test Fit','{"fontsize" :20}')
```

Appendix E: Simulations of CO_2 Injection Using SENSOR

Eric S. Carlson

The simulation is described in Section 3.4.1 and the case having the permeability distribution thought to best represent the reservoir is presented there. The injection and production histories for remaining cases are presented below. The permeability distributions are specified in Table 3.4.1 and the CO_2 and water injection scenarios run for each case are defined in Table 3.4.2.

Table 3.4.1. Assumed distributions of permeability of the ten layers.

Case Name	Permeability Distribution, top to bottom (millidarcy)	Location of the Results in the Present Report
Homogeneous	7, all layers the same	Appendix E
H2L	19 10 9 8 7 6 5 3 2 1	Appendix E
L2H	1 2 3 5 6 7 8 9 10 19	Appendix E
LN	6 7 5 7 19 7 10 8 7 9	Section 3.4
PW	161 48 0.7 1.1 8.6 1.9 1.5 2.0 4.6 2.9	Appendix E

Table 3.4.2. WAG scenarios run for each of the permeability distributions.

Short Name	Description
waterflood	Continuous water injection only
2x7500	7500 tons CO_2, then 10% of pore volume water, then 7500 tons CO_2, then continuous water
1x15000	15000 tons CO_2, then continuous water
1x22500	22500 tons CO_2, then continuous water
1x30000	30000 tons CO_2, then continuous water
CO_2 only	Continuous CO_2 injection only, up to a maximum of 2 billion scf

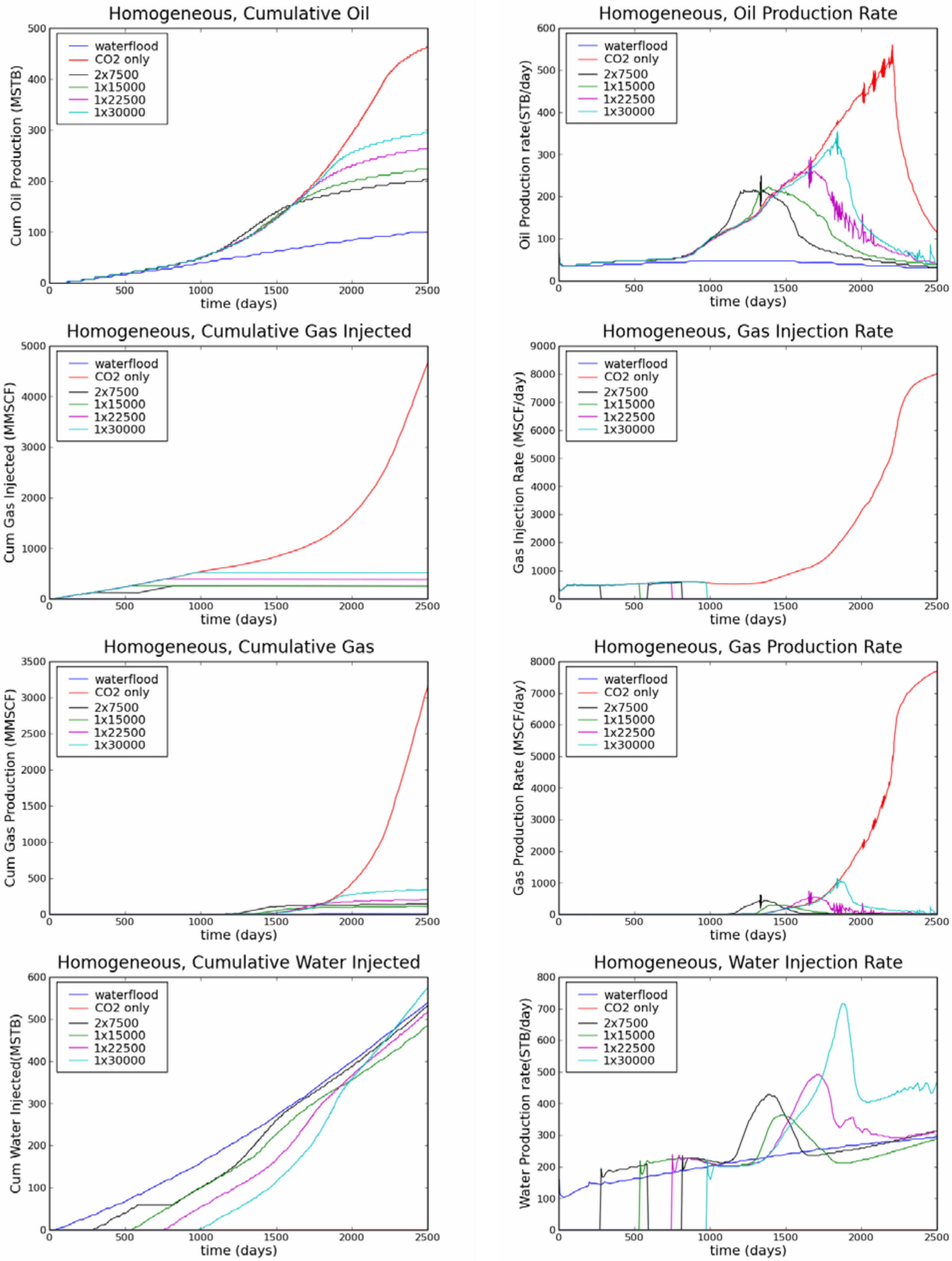

Figure E.1. Injection and production histories calculated using SENSOR for the permeability distribution of Case Homogeneous (Table 3.4.1) and six different CO_2 and water injection scenarios (Table 3.4.2).

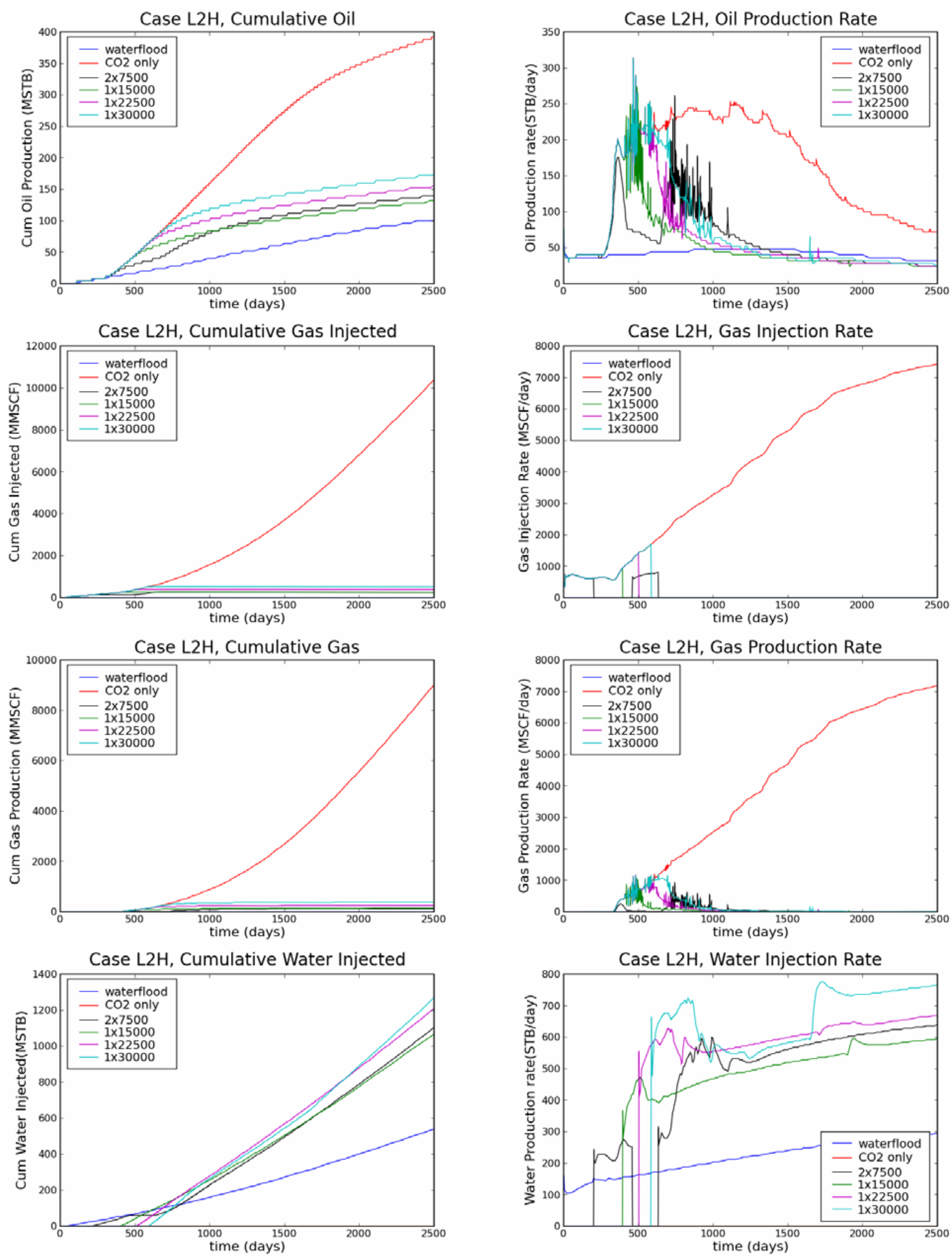

Figure E.2. Injection and production histories calculated using SENSOR for the permeability distribution of Case L2H (Table 3.4.1) and six different CO_2 and water injection scenarios (Table 3.4.2).

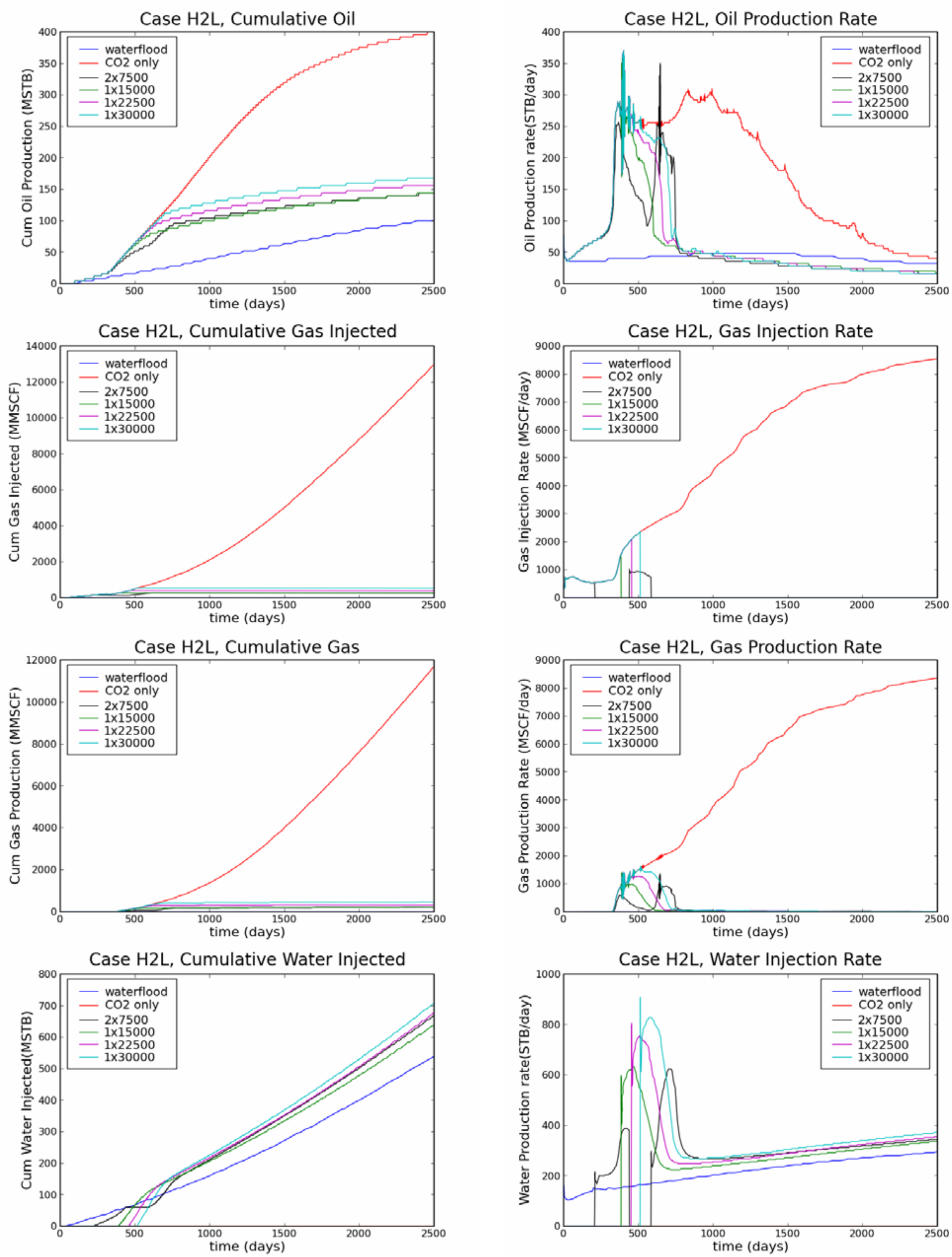

Figure E.3. Injection and production histories calculated using SENSOR for the permeability distribution of Case H2L (Table 3.4.1) and six different CO_2 and water injection scenarios (Table 3.4.2).

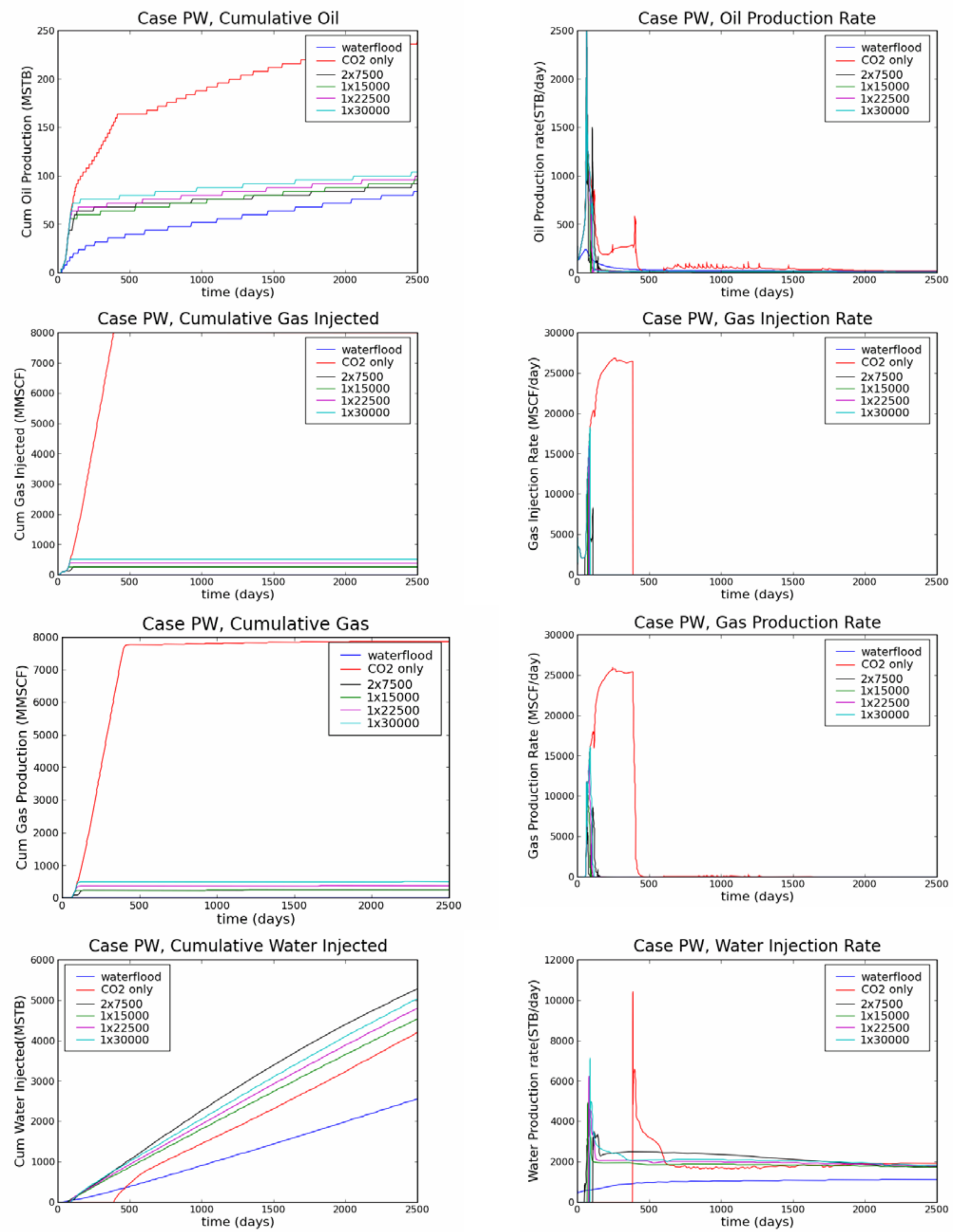

Figure E.4. Injection and production histories calculated using SENSOR for the permeability distribution of Case PW (Table 3.4.1) and six different CO_2 and water injection scenarios (Table 3.4.2).