Geologic Sequestration of CO_2 in West Pearl Queen Field: Results of a Field Demonstration Project

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ABSTRACT

Sequestration of Carbon dioxide (CO_2) in deep, geologic formations is one of the options currently being studied to reduce the amount of CO_2 released to the atmosphere. Depleted oil and gas reservoirs are one of the geologic targets considered for sequestration. Even though CO_2 is currently being used in the enhanced oil recovery operations, injection of CO_2 in depleted oil reservoirs as a carbon sequestration strategy needs validation. This paper provides an overview of the first U.S. field demonstration project on CO_2 sequestration in a depleted oil reservoir, sponsored by the United States Department of Energy. The main thrust of the project is characterization of CO_2 migration through an integrated study that includes, field/laboratory experiments and numerical simulations. The field experiment consisted of injection of ~2100 tons of CO_2 in the West Pearl Queen Field over a two-month period. Migration of CO_2 was monitored using high-resolution 4-dimensional surface seismic surveys as well as downhole pressure monitors. Comparison of pre-injection and post-injection surveys indicates presence of an anomaly within the vicinity of the injection well, which could be resulting from injected CO_2. After a 6-month soaking period CO_2 was vented from the injection well. The amount of reservoir fluids produced during venting was monitored. A number of produced fluid and gas samples were collected for chemical compositional analysis. Changes in chemical compositions of fluid samples were observed indicating interaction between CO_2 and reservoir fluids. The results of the field/laboratory experiments, geophysical surveys and numerical simulations are being integrated to determine reservoir response to CO_2 injection and to perform long-term fate calculations.

INTRODUCTION

Atmospheric concentrations of carbon dioxide (CO_2) continue to increase as a result of its release from anthropogenic sources. The increasing concentration has resulted in a need to capture and sequester large volumes of CO_2. The strategy of injecting CO_2 into geologic formations is one of the most direct methods for preventing its escape into the atmosphere. Although saline aquifers, deep coal seams, depleted gas reservoirs and several other potential reservoirs are available, depleted oil reservoirs are especially attractive because of their site-characterization, infrastructural and economic advantages. A large number of oil reservoirs have been extensively characterized and a knowledge base for the reservoirs and interactions between CO_2/rock/fluids is publicly available. Numerous wells have already been drilled in these fields. Not only does extensive experience in transporting carbon dioxide exist but also some pipeline infrastructure is in place for use in ongoing enhanced oil recovery projects, most extensively in the Permian Basin in Texas. In addition, the economics can be improved considerably by using the CO_2 for its oil production enhancement.

In order for geologic sequestration to become an acceptable technology, a regulatory apparatus needs to be developed, safety issues must be specifically addressed, and overall economics need to be better characterized. This would require undertaking projects specifically targeted towards sequestration studies, rather than typical enhanced-oil-recovery projects that are driven by oil production factors. This sequestration project is one such test to evaluate sequestration phenomena without the need to adhere to production related schedules, economics, or other direct business factors. This project is also the first ever U.S. field sequestration test.

The objective of this project is to provide some of the important elements of the science and technology base that would be necessary to properly evaluate the safety and efficacy of long-term CO_2 sequestration in a depleted oil reservoir in particular, but in any geologic reservoir in general. Even though the ultimate goal of such studies is to improve our understanding of the main sequestration mechanisms and resultant reservoir processes, a complete assessment of geologic sequestration will eventually require a number of test programs to assess different geologic settings. In this project, experiments at different scales (field and laboratory) are combined with computer simulations to understand reservoir response to CO_2 injection and storage. For such integration it is helpful to be in a field which will be similar to a large number of oil reservoirs with geologically simple formations, having recent development and production history, without secondary water injection or previous enhanced oil recovery activities. This paper provides details of the results of the field experiments. Details of other project activities have been provided in Warpinski et al. (2003).

EXPERIMENT

This project combines a small-scale field injection experiment with geophysical monitoring, numerical simulation, and laboratory experiments with following objectives:

- Characterize the oil reservoir and its capacity to sequester CO_2.
- Predict the migration and interactions of multi-phase fluids.
- Assess the ability of geophysical techniques to monitor the process.
- Determine the reservoir interactions driven by CO_2 injection.

The field experiment was performed at the West Pearl Queen field (location shown in Figure 1), which is owned and operated by Strata Production Company of Rowell, NM. The field has produced about 250,000 barrels of oil since 1984 through primary recovery. Even though the reservoir pressure has dropped in recent years, no secondary or tertiary recovery operations have been applied in the field. Figure 2 shows the map of the field with structural contours and the wells operated by Strata Production Company. Well Stivason Federal #4 was used for the injection experiment, while well Stivason Federal #5 was available for monitoring and cross-well surveys. At the current time, Stivason Federal #5 is the only producing well in the field.

The field demonstration project was divided over three phases:

I. Pre-injection baseline characterization.
II. CO_2 injection and soaking
III. Post-injection characterization and venting.

Phase I consisted of reservoir characterization through log, core, and fluid analyses as well as geophysical surveys, which included cross-well and high resolution 3-dimensional surface seismic surveys. In addition, Phase I also included pre-injection legal permit acquisition and injection well preparation. Phase II consisted of the design of a micro-pilot field injection test, preparation of the surface facilities, injection of ~2100 tons of CO_2 over a nearly 2 month period, geophysical monitoring during injection and post-injection pressure and temperature monitoring in the injection well.

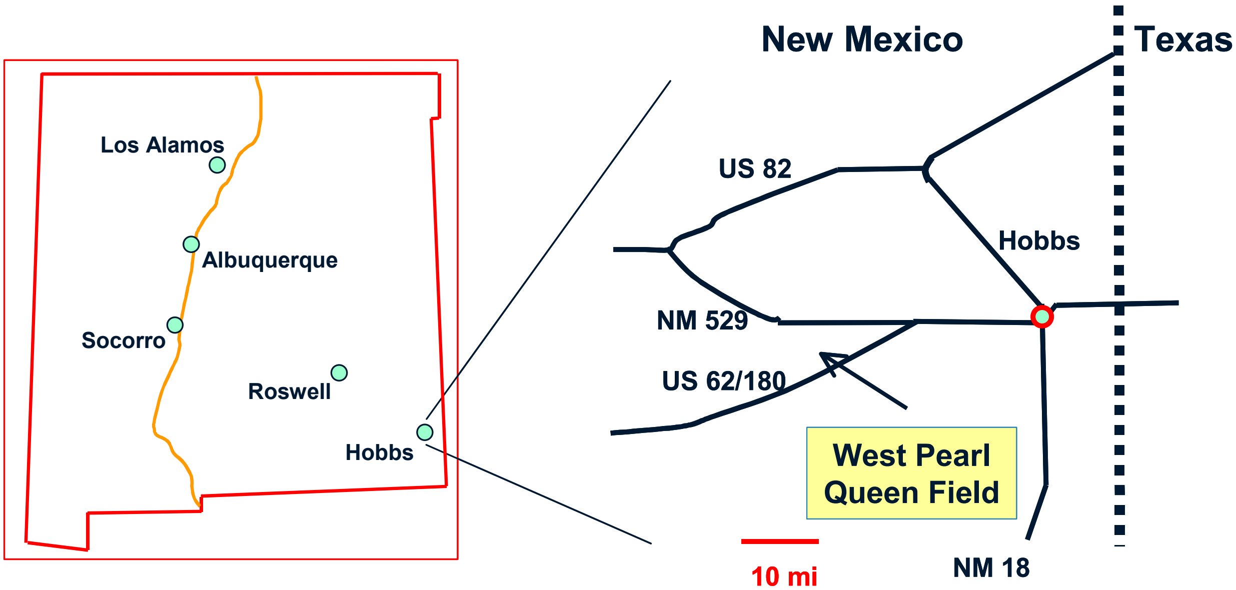

Figure 1. Location of sequestration project near Hobbs, NM.

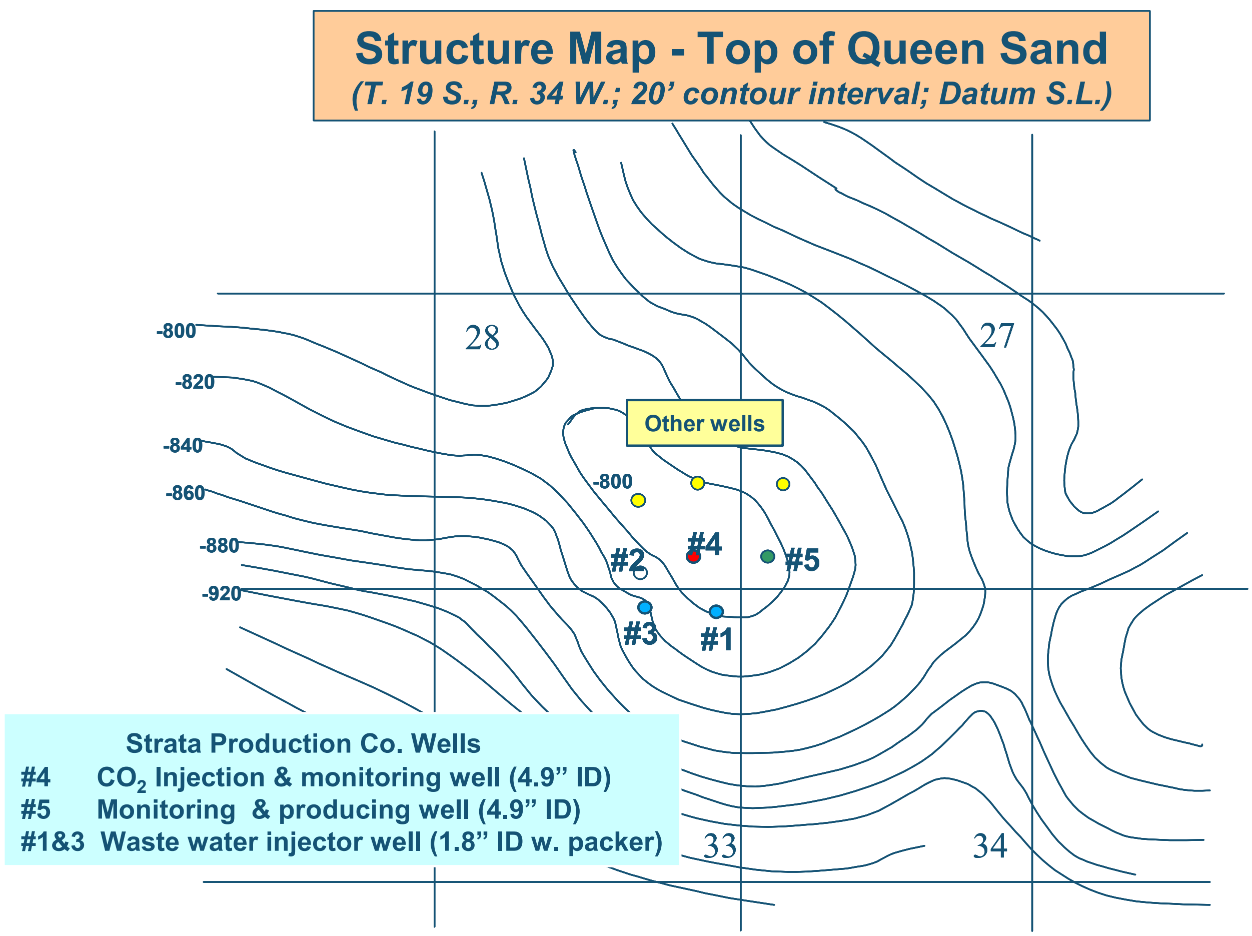

Figure 2. Location of Strata West Pearl Queen wells relative to sections and structural contours.

Phase III of the project consisted of post-injection monitoring of injected CO_2 plume with high resolution 3-dimensional geophysical survey, preparing well-head for venting and collecting fluid samples, actual venting of CO_2, collecting produced fluid samples, and analyzing chemical compositions of produced fluids.

RESULTS

Details of some of the Phase I and II results have been provided in Warpinski et al. (2003). A 3-dimensional, 9-component seismic survey was acquired prior to the injection as part of the Phase I characterization work. The details of the grid layout used for this high-resolution survey have been provided in Warpinski et al. (2003). Some of the preliminary interpretations of the pre-injection (baseline) seismic data are shown in Figures 3 & 4. Figure 3 shows distribution of the acoustic impedance in an east-west cross-section through the reservoir. The Queen formation as interpreted through the survey is marked on the figure along with wells Stivason Federal #4 and Stivason Federal #5. Figure 4 shows a map view of the acoustic impedance. Geologic characterization performed through analysis of log and core data suggest that the Queen formation is further sub-divided in four distinct zones. The average gross thickness of Queen formation is about 40 feet. As can be seen from Figure 3, individual zones cannot be further distinguished through the survey. The seismic interpretations are further refined with the help of additional well control data from the field. The pre-injection survey was used as a baseline for monitoring injected CO_2.

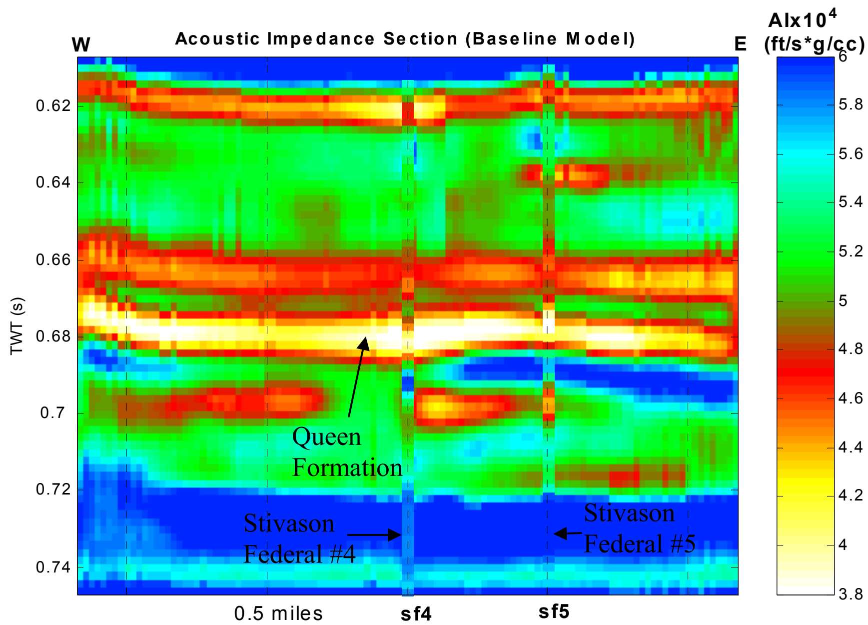

Figure 3. An east-west cross-sectional view through the reservoir showing distribution of the acoustic impedance in the baseline survey.

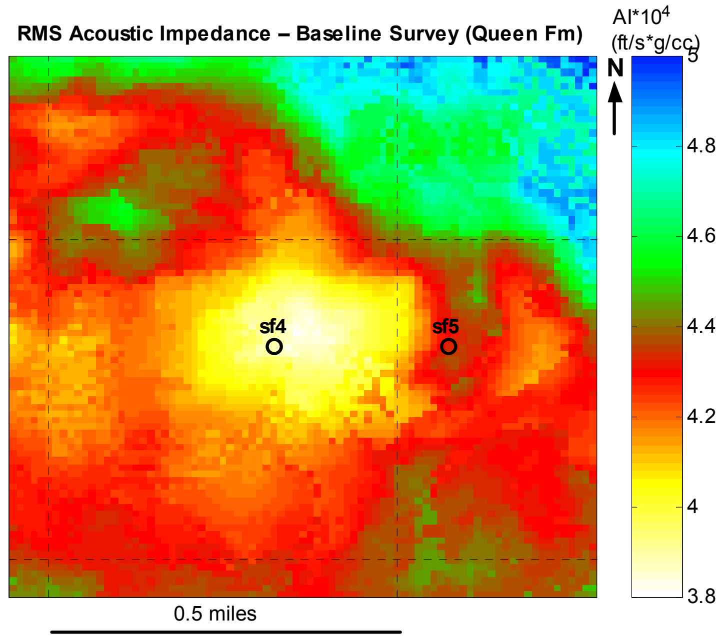

Figure 4. A map view of the distribution of the RMS acoustic impedance in the baseline survey.

Immediately after the baseline survey was acquired injection of CO_2 was started. Injection of CO_2 was completed on February 10, 2003. Following the injection a pressure transducer was deployed in the well before it was shut off. The well was shut off over a period of six months allowing the CO_2 to soak in the reservoir. The pressure in the reservoir was monitored through the down-hole pressure monitor at periodic intervals. A second 3-dimensional survey was acquired at the end of soak period. The second survey was acquired using acquisition grid identical to the one used for baseline survey. Figure 5 shows a map view of the acoustic impedance from the post-injection (monitor) survey.

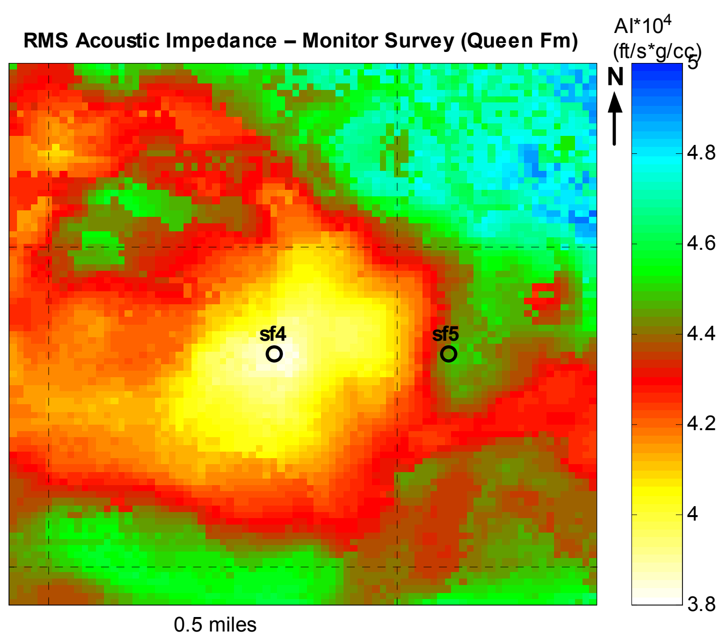

Figure 5. A map view of the distribution of the RMS acoustic impedance in the monitor survey.

Figure 6 provides difference in the acoustic impedance between the baseline survey and the monitor survey. As can be seen from the figures, an anomaly is seen on the south-west side of well Stivason Federal #4. Though this anomaly could be attributed to CO_2 plume, additional interpretation of the seismic data is still in progress to refine the interpretations. Information obtained through shear wave data is also being interpreted and will be integrated in the final analysis.

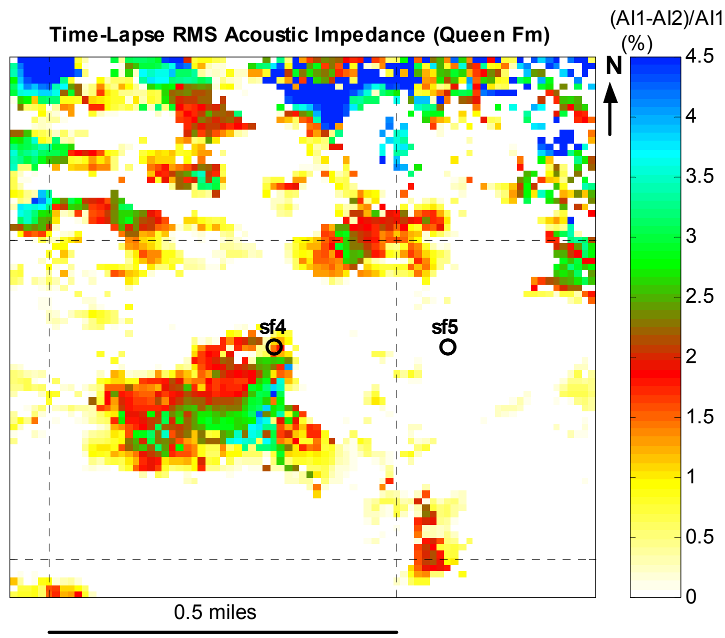

Figure 6. A map view showing the difference between the acoustic impedance of the baseline and monitor surveys.

In addition to the geophysical surveys, pressure in the reservoir near well Stivason Federal #4 was also monitored intermittently during the soak period. Figure 7 shows the time-dependent pressure near the wellbore.

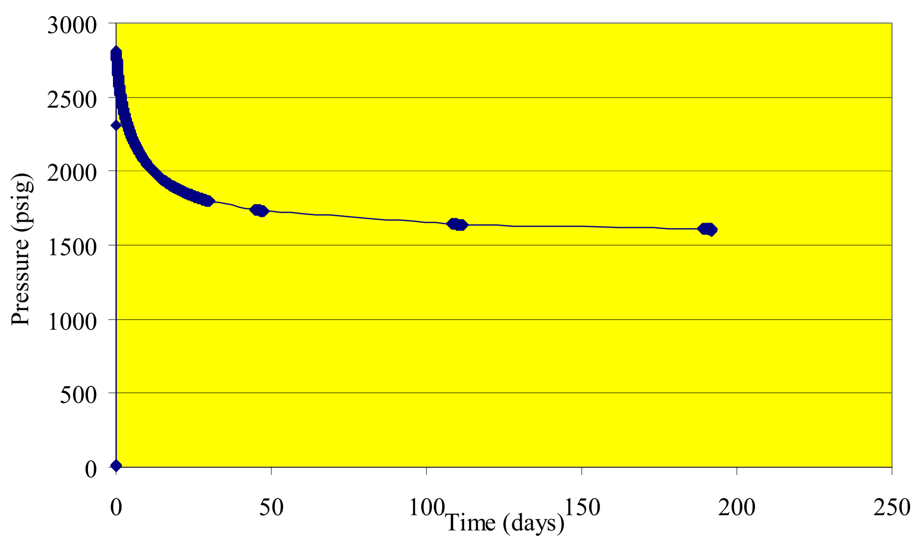

Figure 7. Bottom hole pressure in well Stivason Federal #4 during the post-injection soak period.

As can be seen from the figure the pressure reached an asymptotic value after the initial drop off, indicating that a steady state was reached and that there was no significant leak of CO_2 from the plume. Numerical and analytical models are currently being applied to analyze the post-injection pressure response.

After the post-injection seismic survey was acquired at the end of soak period, CO_2 was vented from well Stivason Federal #4. In order to monitor the amounts of fluids produced from the well, it was connected to a separator and a fluid collection facility. In addition to monitoring produced fluid volumes, periodic samples of oil, gas and water samples were collected for chemical analysis. Figures 8 and 9 show the pressure and temperature in the well bore during the initial venting operation. Figure 10 shows the amount of gas produced from the well. During the initial venting operation the well was flowed through a choke at the wellhead. As can be seen from the figures, the well flowed for about 9 days but the CO_2 production rate gradually decreased. The well stopped flowing after about 9 days and had to be shut off. The continued decrease in production rate is due to the fact that the pressure and temperature in the well bore changed during the production, changing density of CO_2 in the well bore. After 9 days of production the reservoir pressure dropped below the bottom hole pressure in the well bore resulting in well shut off. After the well stopped flowing, a pumping unit was installed to produce it. As seen from Figure 10, even after installation of the pumping unit the production rate did not change significantly. In addition to the amount of gas produced, the quantity of liquid produced from the well was also monitored. The daily rates of production of oil and gas are plotted in Figure 11. During the initial production stage only gas and minor amounts of liquid condensates were produced. The well started producing some water and oil after the pumping unit was installed. As can be seen from Figure 11, very little oil was produced. The amount of water produced was similar to the amount produced during the final active production days of the well.

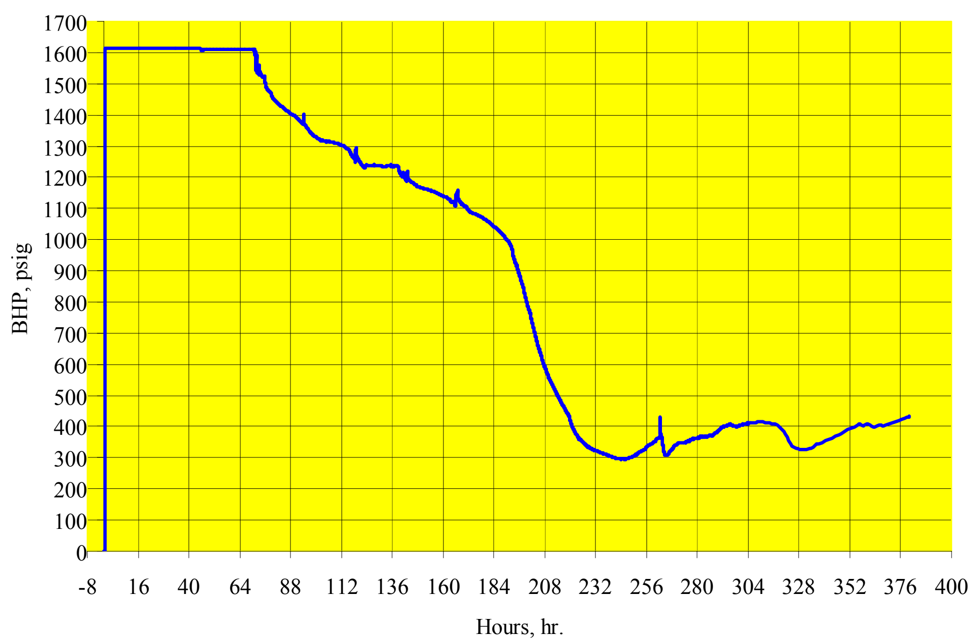

Figure 8. Pressure in well Stivason Federal #4 during venting of CO_2.

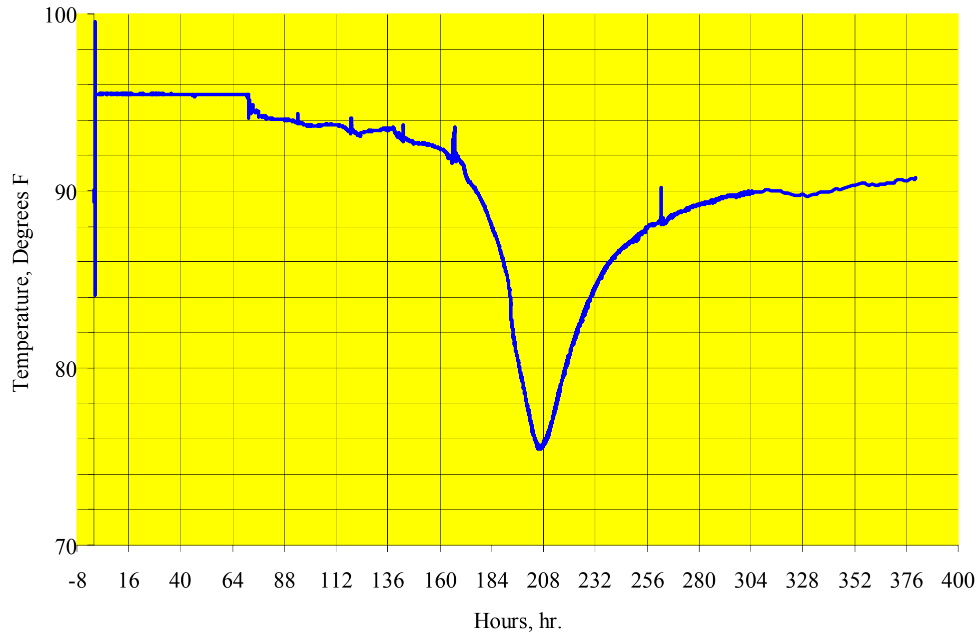

Figure 9. Temperature in well Stivason Federal #4 during venting of CO_2.

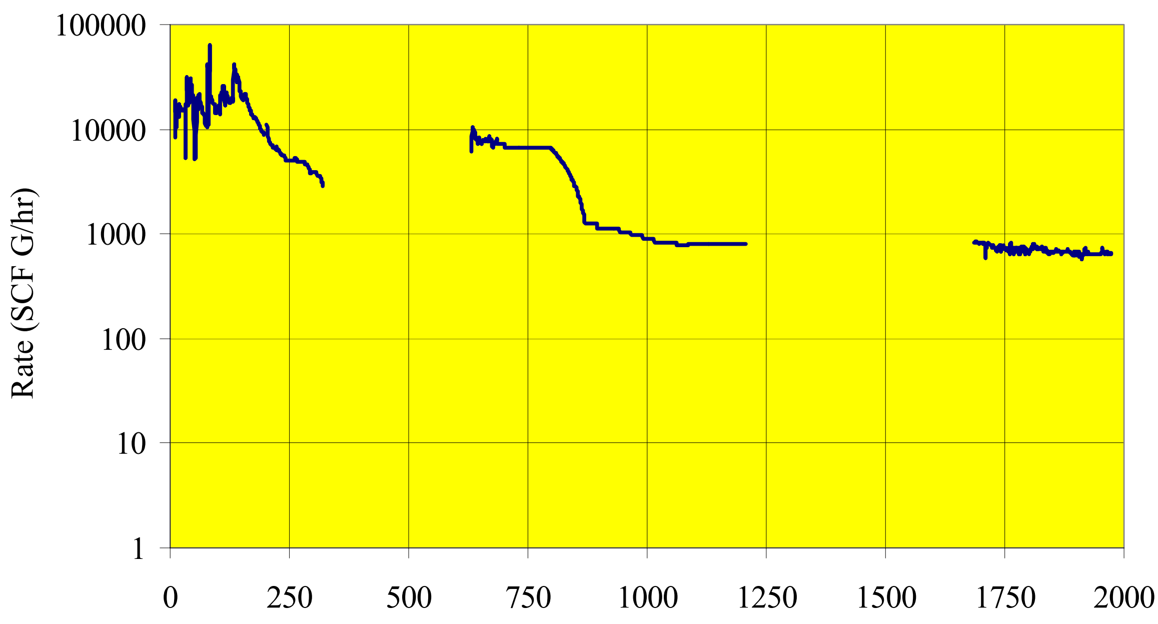

Figure 10. A plot of CO_2 production during venting operation.

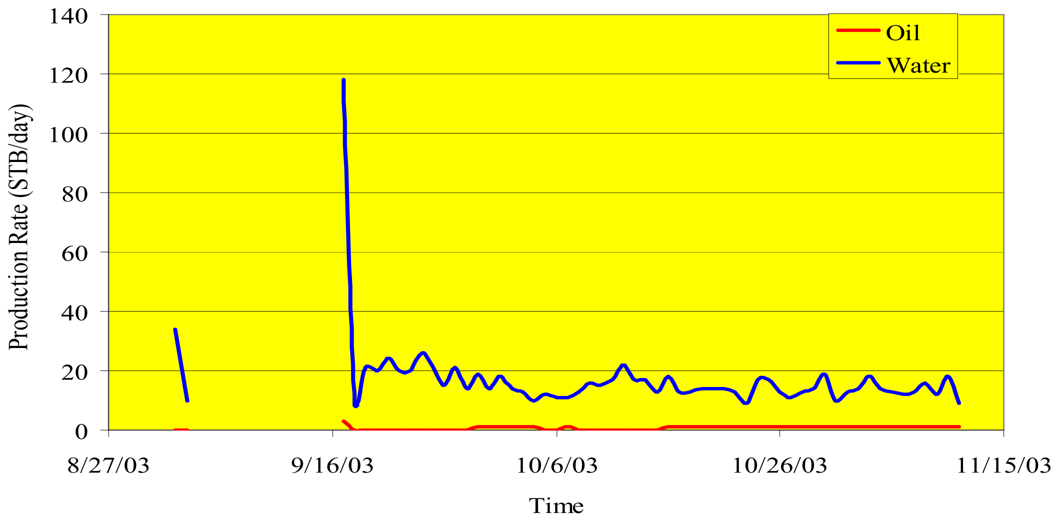

Figure 11. Daily rates of liquid production during CO2 venting operation.

Only a fraction of the CO_2 injected was produced during venting. The observed production rates were significantly lower than the expected rates based on the injection data. The production data indicate possible reservoir damage near the wellbore, though further analysis is still in progress. The production data is currently being used to develop and validate numerical models for the reservoir.

During the venting operation periodic samples of reservoir oil, water and gases were collected for compositional analysis. Figure 12 is a plot of all the separator gas data gathered to late October 2003. The dates on the legend represent the dates of sample collection. The pre-CO_2 injection composition of the gas indicated in black had less than 1 % CO_2, while the produced gas after the six month soaking period was in the 95-99% range. There is a trend of increasing methane in the produced gas from August 21, 2003 to October 14, 2003. The increase is from a few tenths of a per cent to a few per cent. The increase is of an order of magnitude though small in every case. The other hydrocarbon components did not show any trend. Because all the readings are near or below background levels (less than 1 %), the detection of no trend is not surprising. Figure 13 shows the gas composition of the gas obtained from the oil sample when pressure on the separator oil was reduced to atmospheric pressure and temperature. As would be expected this has higher amounts of the ethane and heavier gaseous hydrocarbons. The system is still 80-95 mole % CO_2 after CO_2 injection. The volume of the gas in the separator was less than 2 scf/bbl and thus insignificant compared to total gas in solution at reservoir conditions estimated to be about 410 scf/bbl. Figure 14 shows the cumulative weight percentage of the oil versus gas chromatograph column retention time for the oil at ambient conditions (dead oil). Retention time is indicative of the boiling temperature and thus related to the molecular weight of system. Several oils were available: one was taken just before CO_2 injection started (December 19, 2002) and three samples taken at near the start of the project in September 2000. The three 2000 samples came from oil: stored at ambient conditions (91400), stored at separator pressures (91400-o), and oil skimmed off a water sample (091400-w). Figures 15 and 16 compare the post- and pre-flood compositions for the oil. Figure 15 are samples collected at separator pressure and Figure 16 shows results of samples skimmed off the water samples taken during the same period of time. More water samples were taken, thus it was thought that they might be a more representative cross section and thus are compared. In each case the black curve is for the average pre-injection value. In both Figures 15 and 16 the early time oil compositions show lighter oil (steeper curve when plotting cumulative % versus composition). This is an indication that more of the produced oil is dissolved in the CO_2 (stripped from the formation oil) versus being pushed in front of the advancing CO_2 or in a miscible bank. In Figure 15, at later times, the values approached that of the

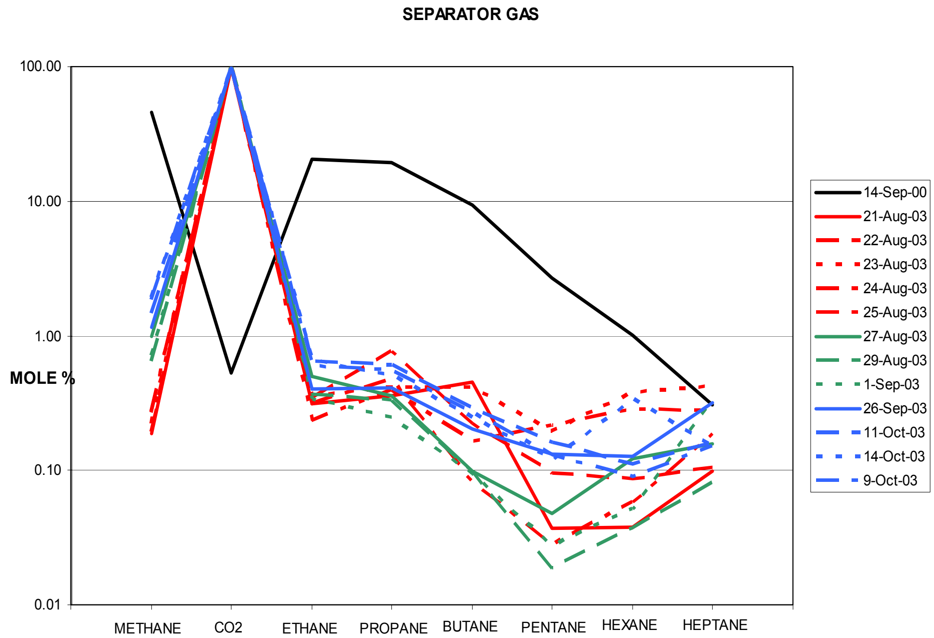

Figure 12. Compositions of separator gas samples collected during venting operation.

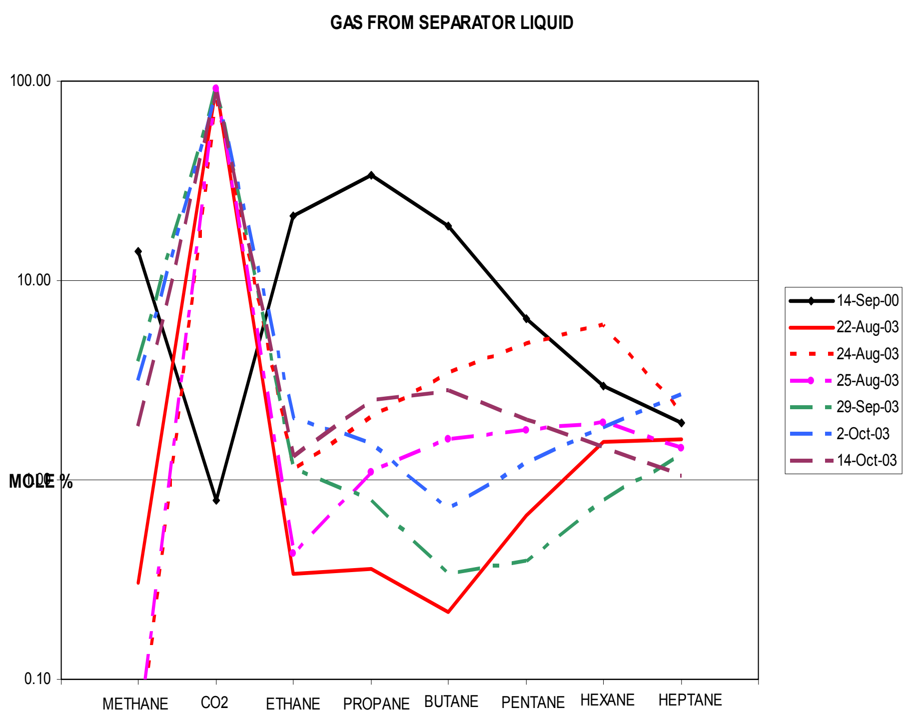

Figure 13. Compositions of the flashed gas from the separator oil collected during venting operation.

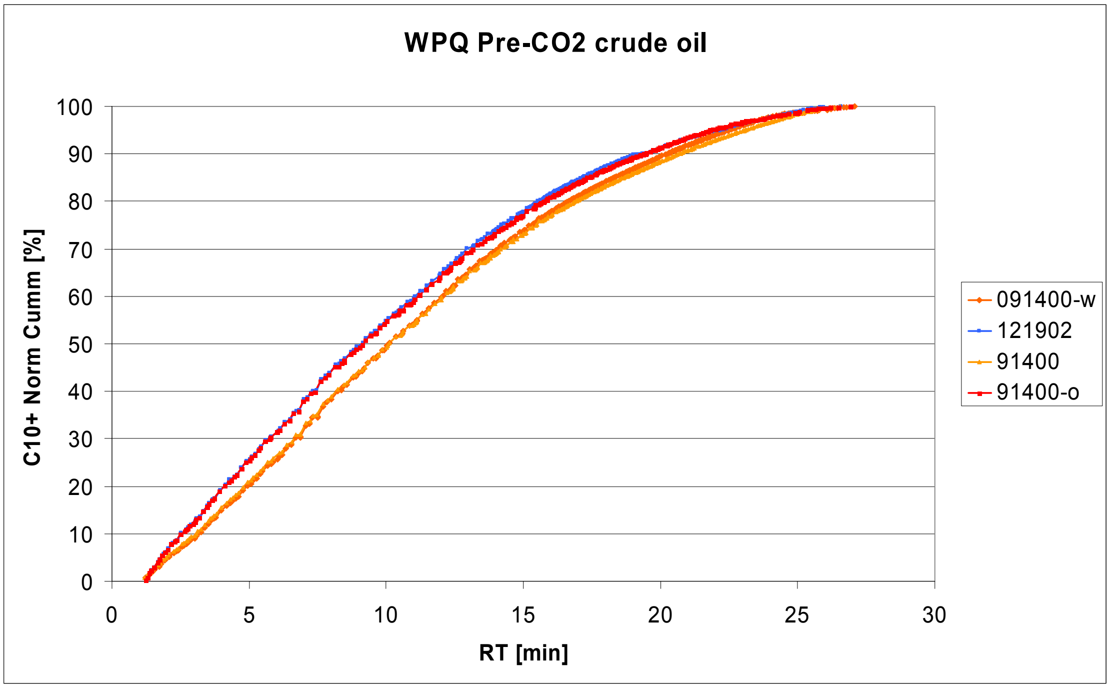

Figure 14. Pre-flood oil compositions.

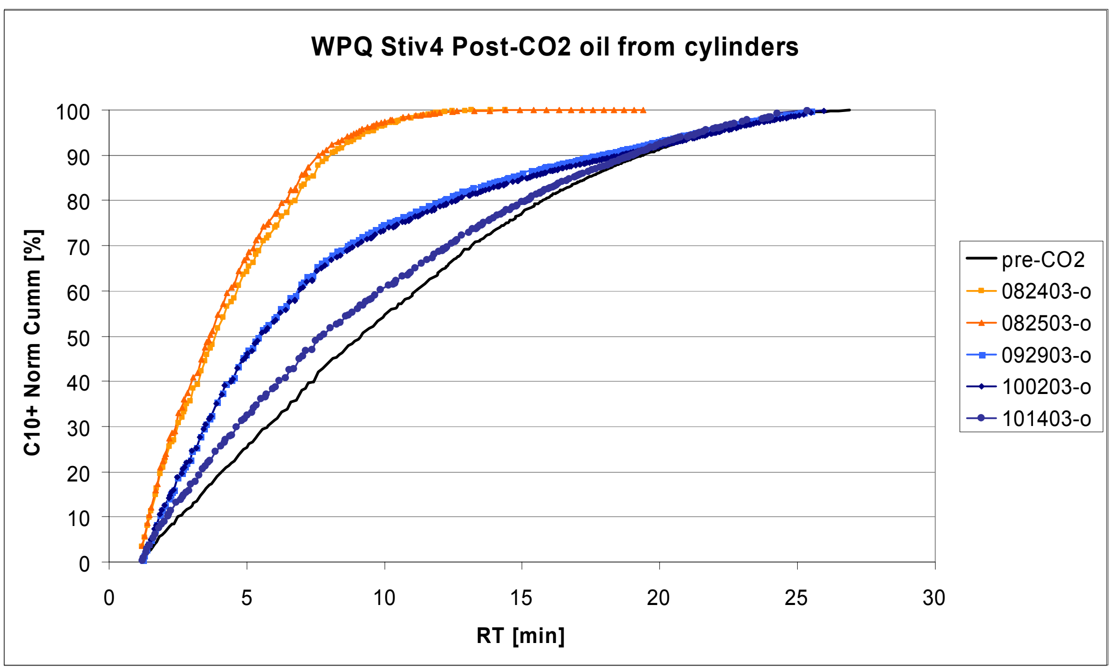

Figure 15. Composition of oil samples after CO_2 injection.

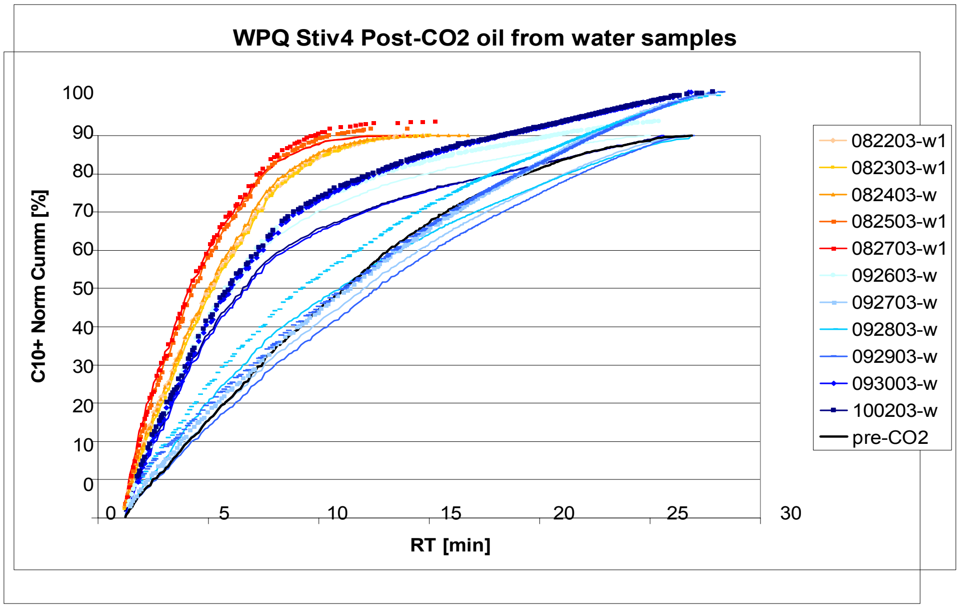

Figure 16. Compositions from oil skimmed off water samples after CO_2 injection.

original oil, indicating production of the reservoir fluid as a bank. In the samples from the water there are results in the mid-time range that have compositions that are near that of the original or heavier oil (curve to the right of the original oil). This could be oil that was stripped of lighter components by CO_2 and then produced or it could be the samples were weathered. Weathering is when the sample is left open to the atmosphere and lighter components evaporate. Since we did not have much control over the water samples before we received them they are the less reliable samples. Also on September 29, 2003 there are samples from both the water and pressure cylinder and the one from the cylinder was much lighter, indicating weathering of the water sample. Similar to oil and gas samples water samples were also collected. Compositional analysis of water sample is currently under progress and will be utilized in the ultimate analysis of the field data.

SUMMARY AND CONCLUSIONS

A field test of CO_2 sequestration was conducted in the West Pearl Queen reservoir near Hobbs, NM. About 2100 tons of CO_2 was injected into a 40-ft-thick, depleted-oil, sandstone reservoir at a depth of 4500 ft. Prior to injection, a 3D/ 9C surface seismic survey along with other geophysical surveys was conducted. CO_2 was allowed to soak for about six months. During the soak period the reservoir pressure was monitored intermittently. A second 3D/9C surface seismic survey was conducted prior to venting of CO_2. The interpreted data from the two surveys are currently being compared. Preliminary interpretations indicate an anomaly near the injection well, which could be due to the CO_2 plume. Further analyses of the seismic data are in progress. Additional information provided by shear wave data is being utilized in the interpretation. The reservoir pressure response during the soak period indicates that a steady state was achieved during which CO_2 did not migrate away from the injected plume. Compositional analyses of the samples collected during venting operation indicate that CO_2 had interacted with the reservoir oil in place. Only a fraction of total CO_2 injected was recovered during venting operation and the production rates were significantly lower than expected, indicating possible reservoir damage due to presence of CO_2 near the wellbore.

Future work includes continued processing of the surface seismic surveys to further verify presence of CO_2 and to get information on spatial extent of the plume. Additional laboratory tests will be conducted to characterize the brine and oil compositions taken during continued sampling. Modeling of the measured injection behavior and integration of data will then commence in order to assemble a detailed picture of reservoir behavior.

The end result of this project should be a demonstration of the suitability of such reservoirs for storing carbon dioxide, a verification of our ability to model and predict the performance of the reservoir in which sequestration is attempted, an assessment of our ability to monitor the injection plume using available geophysics, and a test of our understanding of the geochemical processes that will occur as a result of geologic sequestration.

REFERENCES

1. Warpinski N. R., Pawar R. J., Grigg, R. B. and Stubbs, B.; "Geologic Sequestration of CO_2 in a Depleted Oil Reservoir", Proceedings of the Second National Conference on Carbon Sequestration, May 5-8, 2003, Alexandria, VA.