

COAL-SEQ PROJECT UPDATE: FIELD STUDIES OF ECBM RECOVERY/CO₂ SEQUESTRATION IN COALSEAMS

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ABSTRACT

In October 2000, a three-year government-industry project known as the Coal-Seq project was launched in the United States. The project is studying the feasibility of CO₂ sequestration in deep, unmineable coalseams using enhanced coalbed recovery technology. The Coal-Seq project is specifically focused on understanding the results of actual field experiments via reservoir modeling, with laboratory studies filling a supporting, not primary, role. The fields being studied are both in the San Juan basin. The sites are the Allison Unit, operated by Burlington Resources and the Tiffany Unit, operated by BP America. These two sites are the only two in existence today, worldwide, where long-term, multi-well injection of CO₂ or N₂ is being performed. In addition to the field studies, supporting analytic work in the areas of multi-component sorption behavior, and coal swelling with CO₂ adsorption, are being performed.

INTRODUCTION

The Coal-Seq project, funded by the U.S. Department of Energy and being performed by Advanced Resources International (ARI), is investigating the feasibility of CO₂ sequestration in deep, unmineable coalseams, by performing detailed reservoir studies of two enhanced coalbed methane recovery (ECBM) field projects in the San Juan basin which are undergoing CO₂ and N₂ injection. The interest in understanding the N₂-ECBM process has important implications for CO₂ sequestration via flue-gas injection. The project is also conducting supporting studies into the effects and modeling of multi-component sorption and coal swelling. This paper describes the results and findings from the project through mid-2002.

Field Results

The field R&D sites are located in Colorado and New Mexico (Figure 1). At Allison, CO₂ is being injected, and the CO₂ is sourced from a nearby pipeline that transports CO₂ from the Cortez area of New Mexico to West Texas for CO₂ flooding of oil reservoirs. The Tiffany project, into which N₂ is being injected, the N₂ is sourced from an air separation plant located at BP's Florida River gas processing facility.

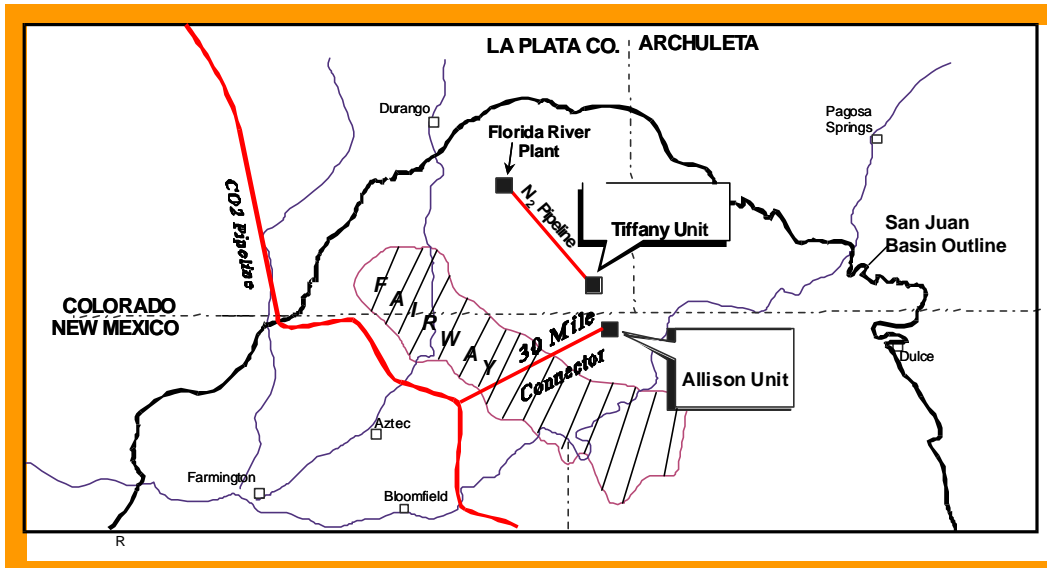


Figure 1: Location of Field Sites, San Juan Basin

Allison Unit

The Allison Unit study area consists of 4 CO₂ injector wells and 9 methane producers (Figure 2). The field originally began production in 1989, with CO₂ injection beginning in 1995. CO₂ injection operations were suspended in mid-2001 to evaluate its' impact on field methane recovery. The production/injection history for the field is illustrated in Figure 3. Note that for a period following the commencement of injection operations, other production enhancement activities were also performed, such as recavitations, well reconfigurations and the installation of dewatering pumps, line pressure reductions, and the implementation of on-site compression.

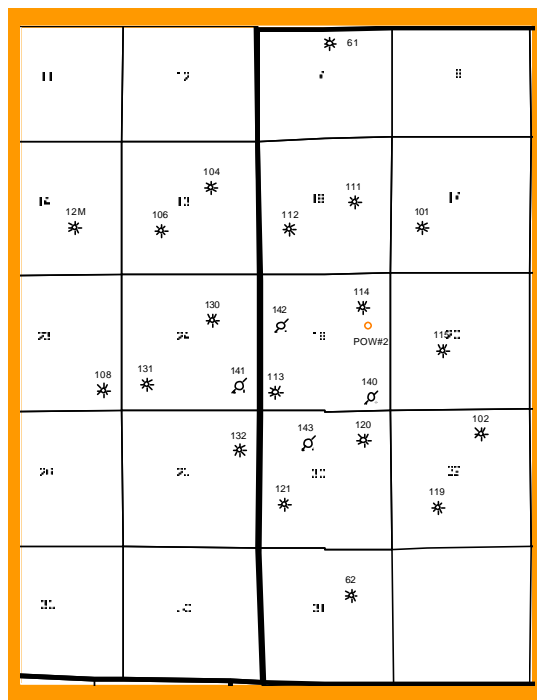


Figure 2: Producer/Injector Well Pattern, Allison Unit

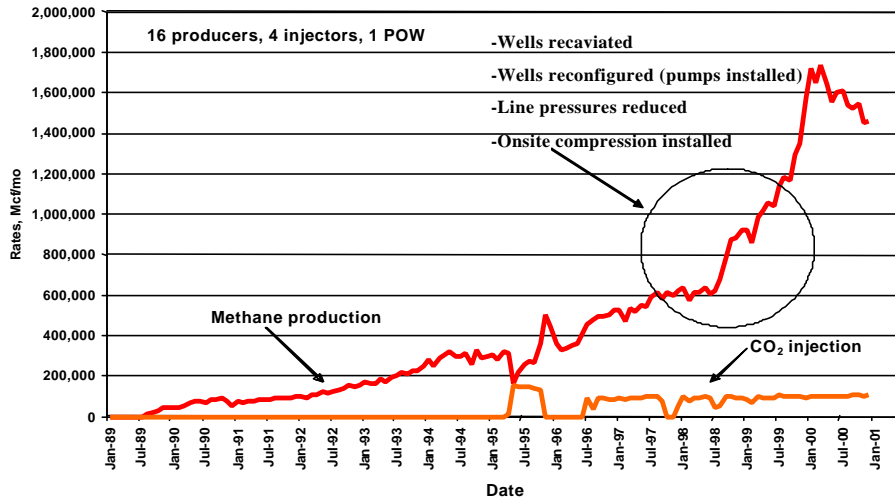


Figure 3: Production/Injection History, Allison Unit

To understand the field results, particularly with the operational complexity that exists, the field was simulated and matched with a three-layer reservoir model, and using ARI's COMET2 simulator. Individual well matches were achieved for gas rate, gas composition, water rate, producing pressures, and reservoir pressures (where available).

Using the calibrated model, an analysis of incremental methane recovery due to CO₂ injection was performed. The results indicated that approximately 2.0 Bcf of incremental methane will be recovered as a result of injecting 6.3 Bcf of CO₂. This yields CO₂/CH₄ ratio of 3.2; this ratio is consistent with the CO₂/CH₄ sorptive capacity ratio based on the isotherms at the abandonment pressure of about 50 psi. Process economic and optimization studies for the field are currently underway.

Tiffany Unit

The Tiffany Unit study area consists of 12 N₂ injector wells (10 of which are directional) and 34 methane producers (Figure 4). The field originally began production in 1983, with intermittent N₂ injection beginning in 1997. The production/injection history for the field is illustrated in Figure 5.

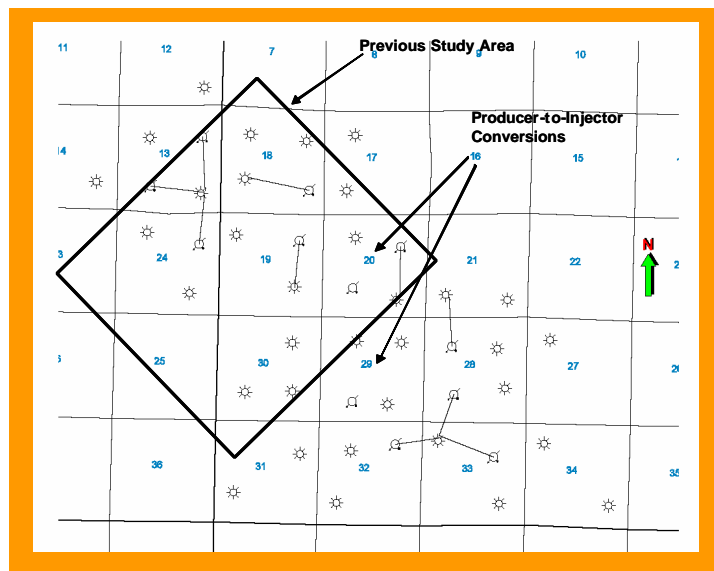


Figure 4: Producer/Injector Well Pattern, Tiffany Unit

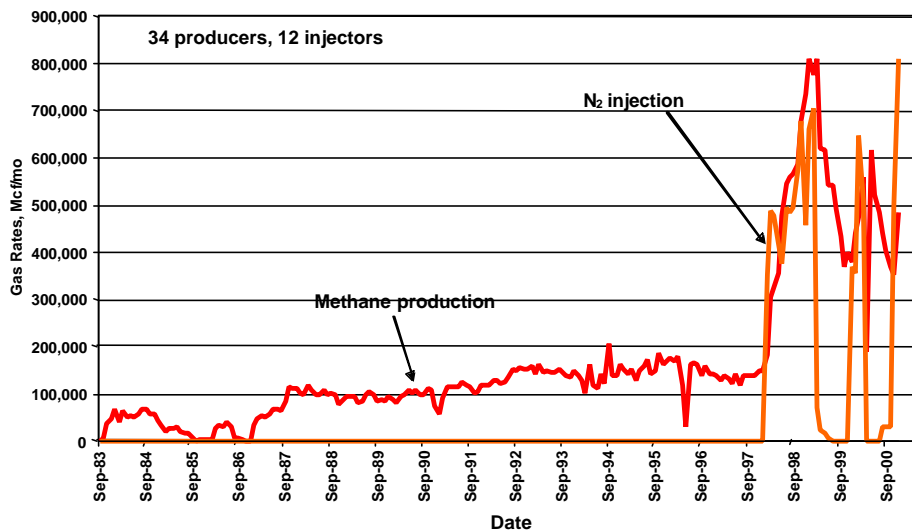


Figure 5: Production/Injection History, Tiffany Unit

To understand the field results, the field is being simulated and matched with a four-layer reservoir model, and using ARI's COMET2 simulator. Individual well matches are being achieved for gas rate, gas composition, water rate, producing pressures, and reservoir pressures (where available). Once complete, incremental recovery and process optimization and economic analyses will be performed.

RESERVOIR MECHANISM STUDIES

In addition to the field modeling work, studies of coal sorption behavior and coal swelling are also being performed to understand their impact, as well as how to appropriately model them.

Multi-Component Isotherm Behavior

In the mid-1990's some researchers published results of isotherm measurements for CH₄, N₂, and CO₂ on San Juan basin coal [1]. The results indicated an abnormal increase in sportive capacity for CO₂ around the CO₂ critical pressure. Several different theories on the cause for the abnormal behavior have been proposed, the most common of which is multi-layer adsorption. Importantly, the consequence of this behavior is that the Langmuir equation is not valid for describing this response, which is the most common method used in reservoir simulators.

To evaluate this phenomena further, a new set of isotherm measurements were performed on a coal sample from the Tiffany Unit. Sorption measurements were taken at pressures well above the CO₂ critical pressure such that the abnormal behavior, if it exists, could be replicated. Results of the study, performed by the same investigators that originally performed and reported the abnormal behavior, did not show the abnormal behavior. It was discovered that an error in reducing the measured data to absolute sorption units, magnified by the closeness of the density in the gas and adsorbed phases near the critical point, was the source of the "abnormal" behavior. (The investigators had identified the problem prior to this effort, but the absence of the behavior was clearly established as a laboratory finding with this work.)

Another, and perhaps just as important finding, was that while sorption models such as Langmuir can adequately describe sorption behavior, no known model, Langmuir or otherwise, can

accurately predict multi-component sorption behavior based on single-component data. In general, the error is larger the greater the difference in adsorptive capacities for the gases, and is larger for the less-adsorptive gas.

Coal Swelling Behavior

It is a well-established that as gas is released from a coal reservoir, the coal matrix shrinks, and cleats open, creating a significant improvement in coal (cleat) permeability. There has been considerable speculation and some laboratory evidence that the process also works in reverse; that is, as gas is adsorbed onto coal, the matrix swells, cleats close, and permeability is reduced. Since CO₂ is much more adsorptive on coal than methane (by 2-3 times), the problem is exacerbated with CO₂ injection.

To examine this effect, as well as how to model it, the injection histories of the four CO₂ injector wells at the Allison Unit were studied. Pressure transient test results for the wells were also available. Figure 6 presents the CO₂ injection rate and computed bottomhole pressure for one of those wells. Initially, injectivity declined significantly. Subsequent to that, injectivity began a long period of improvement, which has continued through the last available data. These trends are consistent for all four of the injection wells.

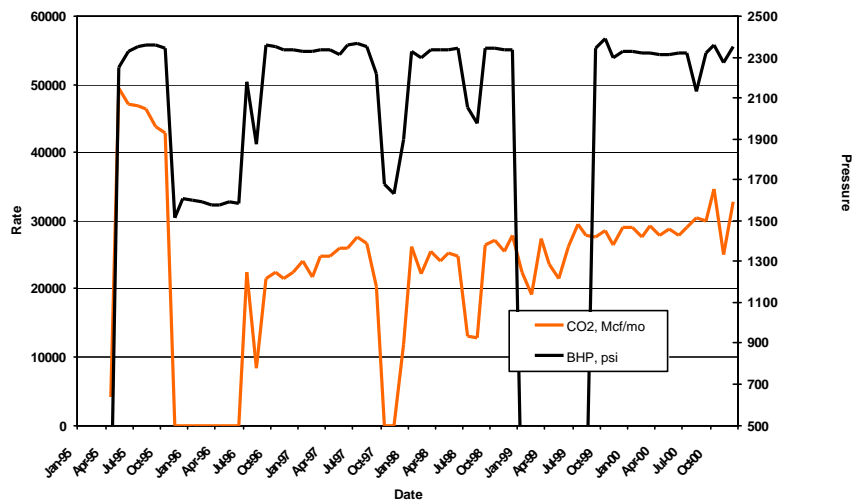


Figure 6: Injection/Pressure History for CO₂ Injection Well, Allison Unit

Pressure transient data from several producing wells in the field in the vicinity of the four injector wells had been collected in May, 2000. The results of their analysis suggested that in-situ coal permeability for the area was in the 100 – 130 md range. In August, 2001, the four injector wells were temporarily shut-in, and bottomhole pressure data collected. Results of analyzing these data suggested coal permeabilities in the >1 md range, two orders of magnitude less than the implied initial values, a reduction of 99%. These data provide our first insight into the potential magnitude of coal permeability reduction with CO₂ injection on a field-level basis.

Using the ARI permeability function model [2], the permeability history of the injector wells was rationalized. This is illustrated in Figure 7. First, coal permeability at the injection well locations declined with a reduction in pore pressure. When the injection wells were drilled and injection

commenced, a rapid reduction in permeability occurred as the permeability trend shifted from the methane to the CO₂ curve. Later in injection well history, as the area under injection became further depleted and reservoir pressures declined, matrix shrinkage began to occur, leading to a continuous and gradual improvement in the injectivity. While somewhat subjective, this explanation is entirely consistent with field data, the results of reservoir simulation studies, and the predicted response based on the permeability function model.

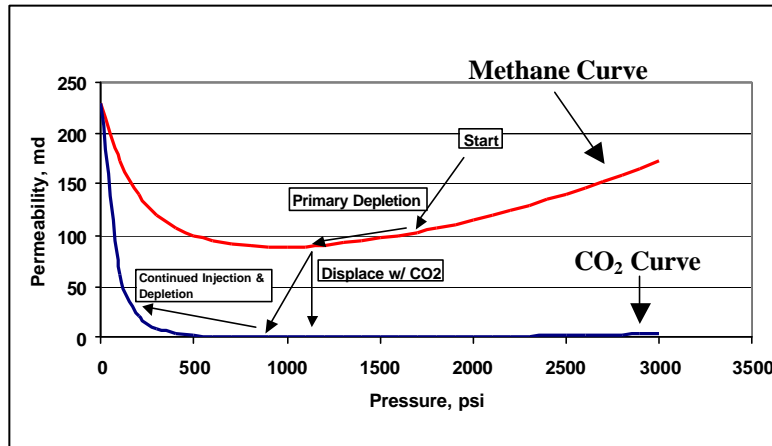


Figure 7: Permeability History for CO₂ Injection Well

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