# Wellington Field — Laboratory in a Field: Lessons Learned

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## Abstract

The original objectives of this project are to understand the processes that occur when a maximum of 70,000 metric tonnes of CO2 are injected into two different formations to evaluate the response in different lithofacies and depositional environments. The evaluation was supposed to be accomplished through the use of both in-situ and indirect MVA (monitoring, verification, and accounting) technologies. To evaluate potential for Enhanced Oil Recovery (EOR) and CO2 geological storage, baseline geologic characterization, geologic model development, studies of oil composition and properties, miscibility pressure estimations, geochemical characterization, reservoir modelling were performed by December, 2013. However, field deployment was delayed due to problems with CO2 supply until early 2015. In March of 2015 the injection well (class II) KGS 2-32 was drilled, cored, and logged through an entire anticipated injection interval. Whole core samples were obtained and tested for porosity and permeability, relative permeability, and capillary pressure. The Drill Stem Test (DST) was also conducted to estimate injection interval permeability and pore-pressure. After the injection well KGS 2-32 was acidized, Step Rate (SRT) and Interference (IT) tests were conducted and analysed for permeability, well pattern communication, and fracture closing pressure. Total of 1,101 truckloads, 19,803 metric tons, average of 120 tonnes per day were delivered over the course of injection that lasted from January 9 to June 21, 2016. CO2 EOR progression in the field was monitored weekly with fluid level, temperature, and production recording, and formation fluid composition sampling. As a result of CO2 injection, observed incremental average oil production increase for EOR pilot area is ~68% with only ~18% of injected CO2 produced back. The second operational phase of this project, where CO2 geological storage potential of Arbuckle Group would be verified and MVA technologies would be tested could not proceed due to several factors that include financial responsibility requirements under US EPA Class VI rule and induced seismicity concerns that became apparent in recent years and associated with increased volumes of fluid disposal in Arbuckle aquifer due to development of Mississippian Lime play and other oil and gas and other industrial disposal activities. Nevertheless, valuable experience was gained by working with US EPA Class VI team and most of the permit requirements were satisfied. As part of requirement for Class VI permit, refined geomodels were developed and reservoir simulation studies mapped the injected $CO_2$ plume. A rapid-response mitigation plan was developed to minimize $CO_2$ leakage and provide comprehensive risk management strategy. Lack of underground sources of drinking water was also established for the pilot area.

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