The Effect of Faults and Fractures on Fluid Flow during CO_2-EOR at Wellington Field in South Kansas

Yevhen Holubnyak[1], Eric Mackay[2], Oleg Ishkov[2], and Willard Watney[1]

[1]Kansas Geological Survey

[2]Heriot-Watt University

Abstract

Approximately 20,000 metric tons of CO_2 were injected in the top sequence of the Mississippian age carbonate reservoir to evaluate potential for CO_2 Enhanced Oil Recovery (EOR) and to estimate potential of transitioning to geologic CO_2 storage through EOR.

Many Mississippian age reservoirs in Kansas are currently undergoing final stages of secondary recovery and are suitable for CO_2 EOR. It has been previously estimated that recoverable potential for Mississippian Formation reservoirs in Kansas with CO_2 EOR is 250-350 million barrels of oil (REF). The Wellington field is situated in South-Central Kansas near the town of Wellington, Sumner County, and it is a typical carbonate reservoir of Mississippian age that has produced 20 MMBO since discovery in 1929. This field was converted to waterflood after1957 and is delivering steady secondary production, but is nearing the end of a cycle with average daily production per well of ~2.6 bbls using 49 active producing wells and 15 injectors out of more than 290 total drilled wells (KGS, 2017).

The Mississippian group of formations consists of interlayers of limestone and chert that can be divided into older, shallow marine limestone, chert, and cherty limestones, with interbeds of shale, and younger marine and nonmarine shales and sandstones with minor limestones (Newell et al., 1987; Watney et al., 2002; Evans and Newell, 2013). The Upper Mississippian sequence is a limestone and dolostone with interbedded sandstone and shale, as well as some deposits of chert (Goebel, 1966; Goebel, 1968; Zeller, 1968). KGS 1-32 core from Upper Mississippian was described as a moderately argillaceous, fine peloidal limestone to micritic lime mudstone with massive chert (Scheffer, 2012). The Upper Mississippian is composed by the underlying Meramecian and overlying Chesterian stages (Goebel, 1966; Goebel, 1968; Zeller, 1968). The unconformity bounds the Chesterian stage and hosts oil reservoirs.

Baseline geologic characterization, geologic model development, studies of oil composition and properties, miscibility pressure estimations, geochemical characterization, and reservoir modelling were performed. In March 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. Based on geological characterization efforts it was estimated that the average reservoir porosity around KGS 2-32 well is ~25%, and the average permeability is 15-25 mD. The reservoir is located in the upper Chesterian stage and high permeability and porosity zones with oil saturations are observed in the upper ~35 m (115 ft). The perforations for the injection well were selected in the upper 16 m (50 ft) of the reservoir and ~7 m (25 ft) were perforated. Due to oil and gas production in the region, and the local Wellington field oil production, the pore fluid pressure of the Mississippian reservoir was measured at ~7 MPa (1015 psi). Also, it is known that the pore fluid pressure in Mississippian reservoirs is below hydrostatic (Bradley, 1975; Puckette and Al Shaieb, 2003; Sorenson, 2005). The average temperature in the reservoir is ~ 43 °C (~110 °F). The minimum miscibility pressure (MMP) was estimated at ~11.4 MPa (~1,650 psi).

Based on core observations, Formation Micro Imaging (FMI), dipole-dipole sonic logs, and regional earthquake focal mechanism analysis, the fracture intensity for a selected upper 35 m (115 ft) of Mississippian reservoir was present but estimated as low. Additional well test analysis and 3D seismic analysis reveal at least 12 vertical faults with NNE orientation in the Wellington Field reservoir and adjacent Anson Bates Field (Bidgoli, Schwab, Bidgoli, & Taylor, 2017). Moreover, using Amplitude Variation with Azimuth (AVAZ) pre-stack method for mapping of subsurface seismic anisotropy, which is linked to the subsurface stress field, it was possible to map fracture density and orientation in the Mississippian reservoir (Fig. 1) (Graham et al., 2017). The effect of these well-studied structural elements and fractures on fluid flow in the reservoir is discussed in this paper.

For the EOR test, a total of 1,101 truckloads (19,803 metric tons at an average of 120 tonnes per day) were delivered over the course of injection that lasted from January 9 to June 21, 2016. After cessation of CO_2 injection, KGS 2-32 well was converted to a water injector and it currently continues to operate as such. CO_2 EOR progression in the field was monitored weekly with fluid level, temperature, and production recording, and formation fluid geochemical composition sampling. As a result of CO_2 injection, the observed incremental average oil production increase was ~68%, with only ~18% of injected CO_2 produced back. (Holubnyak et al., 2017).

Continuous geochemical monitoring showed that the alkalinity has noticeably increased and pH has decreased in most (17) of the continuously monitored wells and some randomly sampled wells around the CO_2 injector. However, the CO_2 gas production registered by gas separating units was recorded at only 5 wells. Well proximity also did not assure CO_2 breakthrough: wells to the west of the injector and to the west of the described fault produced CO_2 and experienced oil production improvement within weeks since the start of injection. Wells to the west of the injector and across the mapped fault experienced CO_2 breakthrough only several months after the start of injection and oil production improvements were marginal. Therefore, it is hypothesized that CO_2 movement in the reservoir was affected by (1) major structural elements and associated depositional and other changes in reservoir properties, and (2) fluid movement in the fracture network. The first phenomenon explains fluid delivery across the fault and the second phenomenon explains the discrepancy between actual CO_2 production and observed elevated alkalinity and decreased pH in the produced brine (Fig. 2).

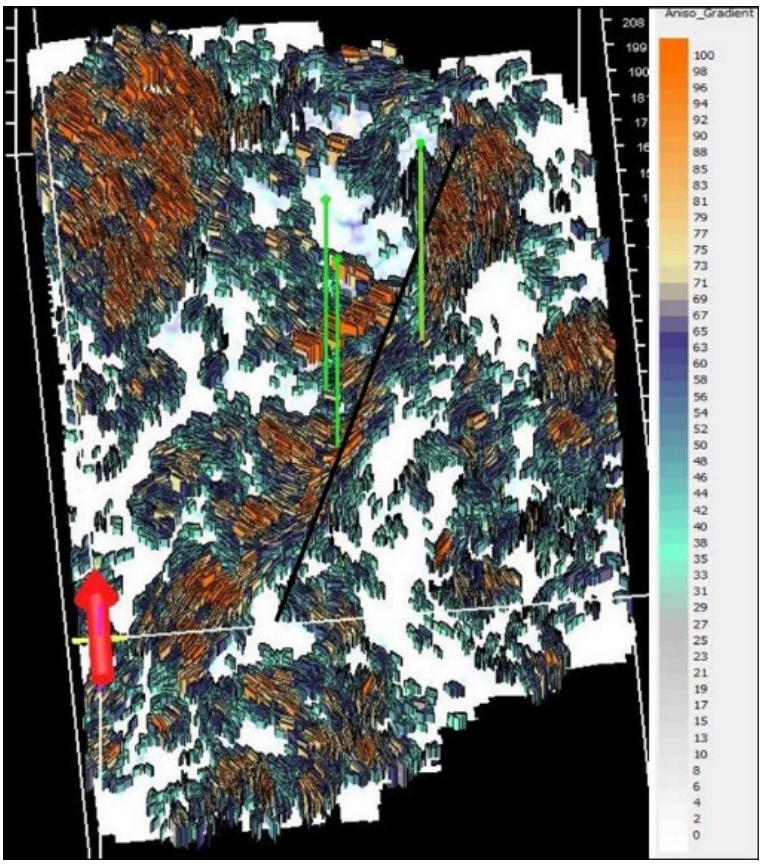

Figure 1. Tilted perspective of the azimuthal planes of isotropy at the Mississippian reservoir (anisotropy gradient 33%-100% in color). The orientation can be interpreted as fractures and stress direction, and the size and color is the degree of anisotropy. The black line delineates a fault mapped in the 3D seismic. Wells KGS# 1-32, 2-32 and 1-28 are sown in green (from left to right).

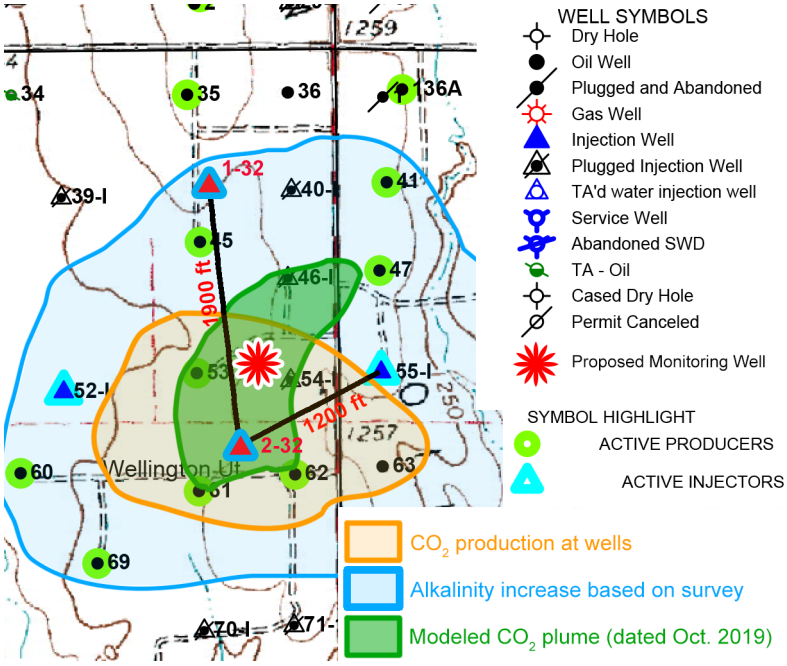

Figure 2. Wellington field map showing well locations and the extent of the CO_2 plume (orange outline) versus observed alkalinity increase versus predicted by simulations CO_2 plume (green outline)

References

Bradley, J. S. (1975). Abnormal formation pressure. AAPG Bulletin, 59(6), 957-973.

Crabtree, B., Christensen, J., (2012). CO_2-EOR Potential in the MGA Region, Great Plains Institute for Sustainable Development Report

Goebel, E. D. (1968). Mississippian rocks of western Kansas. AAPG Bulletin, 52(9), 1732-1778.

Graham, B. L., Haga, L. N., Nolte, K. A., Tsoflias, G. P., and W. L. Watney (2017), Fracture Mapping and Feasibility of Monitoring CO_2 in situ From Seismic Data at the Mississippian Carbonate Reservoir, Wellington Oil Field, South-Central Kansas, in DOE NETL Mastering the Subsurface Through Technology Innovation, Partnerships and Collaboration: Carbon Storage and Oil and Natural Gas Technologies Review Meeting, Pittsburgh, PA, August 1-3, 2017.

Holubnyak, Y., Watney, W., Birdie, T., Rush, J., Fazelalavi, M., Wreath, D., (2017). Pilot Scale CO_2 EOR in Mississippian Carbonate Reservoir at Wellington Field in South-Central Kansas, Energy Procedia, EGYPRO30710.

KGS oil and gas wells database, Kansas Geological Survey, http://www.kgs.ku.edu/Magellan/Qualified/, (accessed 12/1/2017).

Lugn, A. L. (1935). The Pleistocene Geology of Nebraska: Nebraska Geol. Survey, Bull. 10, pp. 1-223.

Lee, W., and Merriam, D. F. (1954). Preliminary Study of the Structure of Western Kansas. State Geological Survey of Kansas, University of Kansas.

Newell, K. D., Watney, W. L., Cheng, W. L., and Brownrigg, R. L. (1987). Stratigraphic and spatial distribution of oil and gas production in Kansas.

Scheffer, A. (2012). Geochemical and Microbiological Characterization of the Arbuckle Saline Aquifer, a Potential CO_2 Storage Reservoir; Implications for Hydraulic Separation and Caprock Integrity (Doctoral dissertation, University of Kansas).

Schwab, D.R., Bidgoli, T.S., Taylor, M. H., (2017) Characterizing the potential for injection-induced fault reactivation through subsurface structural mapping and stress field analysis, Wellington Field, Sumner County, Journal of Geophysical Research: Solid Earth

Sorenson, R. P. (2005). A dynamic model for the Permian Panhandle and Hugoton fields, western Anadarko basin. AAPG bulletin, 89(7), 921-938.

Watney, W. L., Guy, W. J., and Byrnes, A. P. (2002). Characterization of the Mississippian Osage chat in south-central Kansas: Kansas Geological Survey, Open-file Report 2002-50.

Zeller, D. E. (1968). Stratigraphic succession in Kansas. Kansas Geological Survey Bulletin, 189. http://www.kgs.ku.edu/Publications/Bulletins/189/ (accessed 12/12/2017)