Multi-physics inversion for reservoir modeling including transient-EM data

M. Commer[1], G.M. Hoversten[2], S. Finsterle[1], Y. Zhang[1]
[1]Earth and Environmental Sciences Area, Lawrence Berkeley National Laboratory, California, USA
[2]Chevron Energy Technology Company, California, USA

Summary

We investigate the potential of transient EM data for fluid saturation and flow path prediction in an enhanced oil recovery scenario with water and CO_2 flood of a tight unconventional reservoir. Characterization of the subsurface permeability (here referring to the ability to transmit fluids) is achieved by sequential Gaussian simulation in a geostatistical modeling framework, thus capturing the underlying 3D complexity with a few categorical parameters. Our hydrogeophysical joint inversion method combines time-lapse pressure and flow rate data with transient EM data to estimate permeability modifiers at predefined pilot points. Preliminary imaging results highlight the potential benefit of surface EM data to aid this type of parametric inversion for time-lapse fluid monitoring.

Keywords: Time-domain EM, Joint inversion, Enhanced oil recovery, Reservoir monitoring, Hydrogeophysics

Introduction

After cessation of primary production at new oil fields, a considerable hydrocarbon percentage typically remains in place. Enhanced oil recovery (EOR) is a means of releasing this residuum from the formation through fluid injection. During the secondary production phase, water is usually injected to repressurize the formation and sweep oil to producing wells. During the tertiary or post-conventional phase, CO_2 gas is often used to further modify hydrocarbon flow properties, aiming at oil separation from the host rock. Time-lapse observations in the reservoir, such as injection pressure and production rates, are essential for monitoring the fluid flow loop, also for decisions on new injection well placement or well conversion (from production to injection).

EOR management potentially benefits when adding the resolution properties of geophysical observations to traditional reservoir monitoring and history matching approaches. Given its generally high sensitivity to fluids and favorable depth resolution, we consider the inclusion of transient EM (TEM) measurements in a hydrogeophysical joint inversion approach. Joint inversion of disparate data types is a complicated process due to several aspects such as proper data weighting, differing sensitivities, coupling between hydrological state and attribute variables with their geophysical counterparts, computational demands, etc.; some aspects are discussed by Kowalsky et al. (2004). With each of these issues calling for separate rigorous in-depth studies, the main objective of this report is to demonstrate the resolution enhancement that TEM data may add to complex reservoir characterization problems.

Methodology

The main methodology is based on the parallel flow and transport simulator MPiTOUGH2, which includes optimization drivers and a 3D TEM simulator for the combined inverse modeling of hydrological and EM data (Commer et al., 2014; Finsterle et al., 2016). Our hydrogeophysical model resembles conditions at the Vacuum Field, a major producing reservoir located in the upper San Andres formation (New Mexico). Middle Permian dolomites with minor anhydrite portray the reservoir's main geology, with an average porosity of ≈7.4% and permeability (referring to the hydrological attribute related to fluid transmissivity) varying from 1-100 milliDarcy (Dutton et al., 2005). We invert for the reservoir's 3D permeability distribution (Fig. 1) in order to ultimately map water and CO_2 saturation in a time-lapse manner. Saturations are calculated using a parallel version of the multi-phase flow and transport simulator TOUGH2 (Pruess et al., 2012), which is embedded into the MPiTOUGH2 driver.

Hydrological and geophysical attributes are fully coupled using a simple Archie form for the bulk electrical resistivity ϱ (in units of $\Omega\,\mathrm{m}$),

$$\varrho = \varrho_f\, \Phi^{-2} S_w^{-1.7}, \;\; \varrho_f = 0.035\,\Omega\,\mathrm{m},$$

where ϱ_f, Φ and S_w refer to the pore fluid electrical resistivity, rock porosity and pore fluid (water) saturation, respectively. We further use a porosity-permeability relationship of the form

$$\Phi = (k/\alpha)^{\beta}; \quad \alpha = 3500,\ \beta = 0.385,$$

with k representing the permeability in units of milliDarcy (1 Darcy $\approx 10^{-12}\mathrm{m}^2$). Such relationships can be derived from core samples.

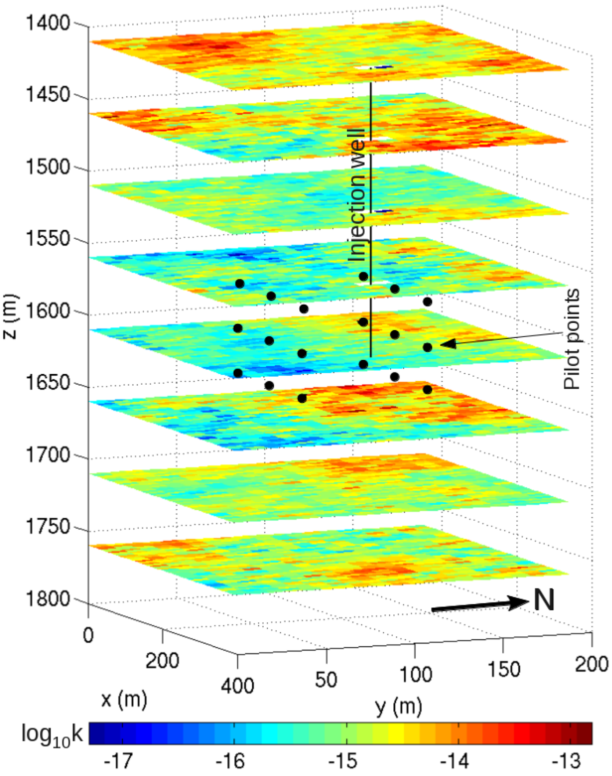

Figure 1: Actual 3D permeability distribution over the reservoir volume. Black circles indicate the locations of pilot-point inversion parameters.

Inverse modeling parameterization

Fig. 2a shows the model of electrical resistivity with the embedded reservoir model, its top located at 1.4 km depth. Following the method of Finsterle and Kowalsky (2008), we employ a semivariogram-based geostatistical model for the generation of the reservoir's actual heterogeneous permeability field over a 3D Cartesian finite-volume mesh of size (x,y,z) 400m × 200m × 400m, discretized by 40 × 20 × 20 elements. Sequential Gaussian simulation then generates realizations of spatially correlated permeability fields that are consistent with a pre-defined semivariogram model. These realizations are further conditioned on permeability values estimated at a mesh of 18 pilot points distributed over the reservoir volume (Figs 1 and 2c).

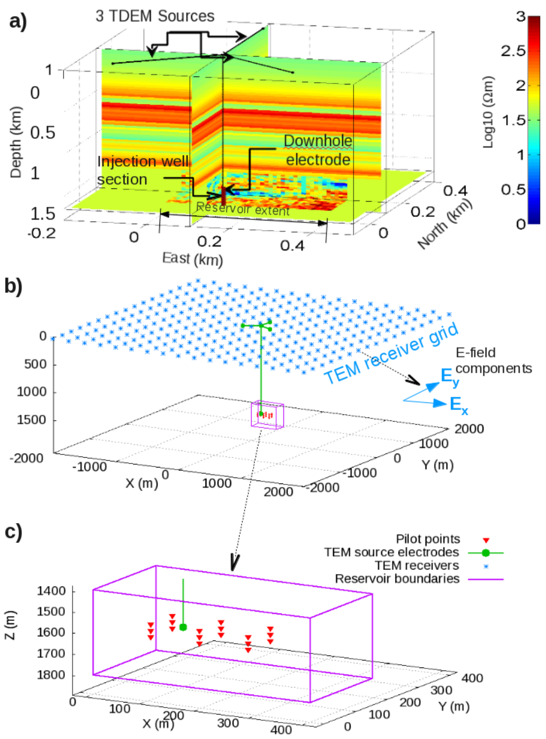

Figure 2: (a) 3D distribution of electrical resistivity over the background model and the embedded reservoir model calculated from the initial hydrological state of the true model. Water and CO_2 are injected over the well section z=1400-1600 m, with the downhole electrode of a 4-segment dipole transmitter located at its bottom. (b) TEM transmitter-receiver layout and reservoir region and (c) close-up view.

The inverse problem is thus given by estimating permeability modifiers at these pilot points for use as conditioning points in the sequential Gaussian simulation process. Note that this process uses different seed numbers for the random component of the spatial permeability field, as opposed to the seed used for creation of the true model (Fig. 1), thus always avoiding trivial realizations as starting models.

Synthetic hydrogeophysical data set

The simulated injection period extends over 9.07 years (3311 days). Water injection with a rate of 0.7 kg/s starts at time 0 and stops at time 2737.5 days, succeeded by a CO_2 injection rate of 0.5 kg/s. Hydrological data is sampled over the injection period 1575-3311 days, with 89 equidistant samples of pressure and flow rates. Injection pressure is measured at the center of the injection well section (z=1600 m), water and oil flow rates are measured at an eastern production well segment at (in meters) (x,y,z1-z2)=(300,100,1400-1600). The inversion procedure joins these 267 hydrological data samples with a surface TEM data set that is laid out in Fig. 2b. A multi-electrode transmitter with four connected dipole segments generates TEM fields that are measured over a grid of 288 receivers, where both E_x and E_y components are recorded at each station. Further, 21 transient decay times are sampled at each receiver. This TEM survey is conducted at the injection times 1642.5 days and 2737.5 days, leading to a total of 24192 TEM data points. Pressure and water production data are shown by the upper panels of Fig. 3, and E_x-field amplitudes from TEM transients over the central profile are exemplified in the lower panel.

Results

We have carried out multiple inversion realizations, characterized by different randomness in the initiation of the permeability fields serving as starting models. Comparative analysis of all (joint versus hydrological only) results revealed the joint inversion's potential to approximate the true permeability field. Fig. 4 exemplifies one successful realization. Horizontal (upper) and vertical (lower) sections of the 3D water saturation (S_w) distribution after 6.7 years of water injection, followed by 1.2 years of CO_2 injection, are plotted. Comparing the maps of S_w between joint inversion result (left), true case (middle), and hydrological (pressure and flow rate) data inversion (right), highlights the potential resolution improvement achieved by the TEM data. Black contour lines outline the volume where S_w exceeds 70 volume percent, indicating the improved prediction of the preferential flow path in the northern imaging volume. The northern region of elevated permeability (red colors) in the depth region around z =1600 m explains this flow path evolution (Fig. 1). In addition to saturation contours, the joint inversion result also produces a better image of the saturation magnitude.

Conclusions

The presented hydrogeophysical imaging study of a water-CO_2 flood into a deep reservoir for EOR highlights the potential resolution enhancement owing to a typically high sensitivity of time-domain EM data to contrasting fluid saturations. The shown results are preliminary and call for further investigation of potential pit falls that apply to joint inversion of disparate data types. While none of the hydrological data inversion realizations achieved the degree of model reproduction as obtained by the joint inversion instance in Fig. 4, a large number of joint inversion approaches were less successful. Nevertheless, the improved replication of both preferential flow path and saturation magnitude in the shown success motivates further development in this complex application area.

Acknowledgments

The authors thank Chevron Energy Technology Company for permission to present this work.

REFERENCES

Commer, M., Kowalsky, M. B., Doetsch, J., Newman, G. A., & Finsterle, S. (2014). MPiTOUGH2: A parallel parameter estimation framework for hydrological and hydrogeophysical applications. *Computers and Geosciences*, *65*, 127-135.

Dutton, S., Kim, E., Broadhead, R., Raatz, W., Breton, C., Ruppel, S., et al. (2005). Play analysis and leading-edge oil-reservoir development methods in the permian basin; increased recovery through advanced technologies. *AAPG Bulletin*, *89*, 553-576.

Finsterle, S., Commer, M., Edmiston, J., Jung, Y., Kowalsky, M. B., Pau, G. S. H., et al. (2016). iTOUGH2: A simulation-optimization framework for analyzing multiphysics subsurface systems. *Computers and Geosciences*, doi:10.1016/j.cageo.2016.09.005 (in press).

Finsterle, S., & Kowalsky, M. B. (2008). Joint hydrological-geophysical inversion for soil structure identification. *Vadose Zone J.*, *7*, 287-293.

Kowalsky, M., Finsterle, S., & Rubin, Y. (2004). Estimating flow parameter distributions using ground-penetrating radar and hydrological measurements during transient flow in the vadose zone. *Adv. Water Resour.*, *27*, 583-599.

Pruess, K., Oldenburg, C., & Moridis, G. (2012). TOUGH2 user's guide version 2.1. *LBNL-Report No. 43134*, *Lawrence Berkeley National Laboratory*, 204pp.

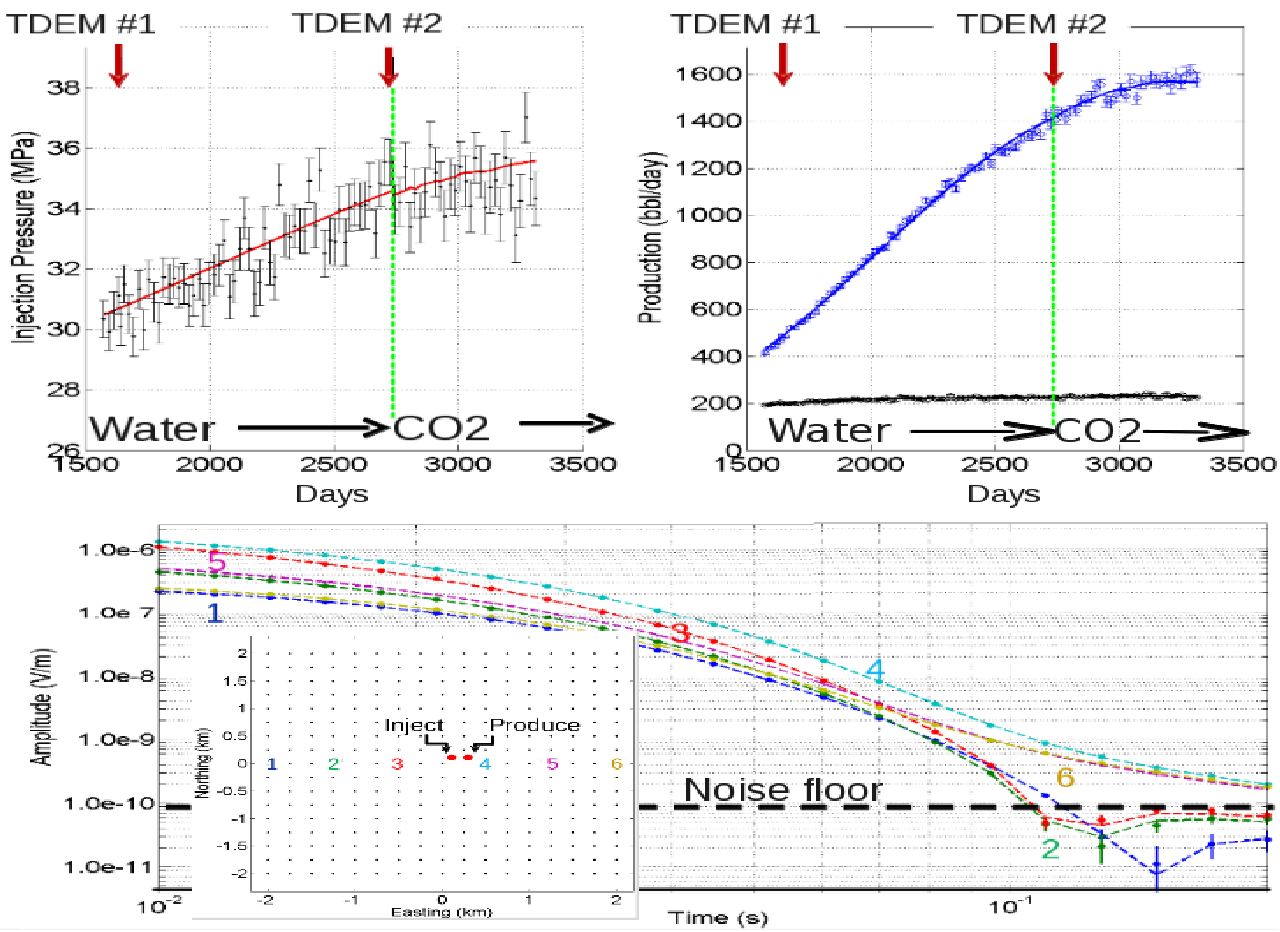

Figure 3: Synthetic hydrological and TEM data. Gaussian noise of zero mean and 2 % standard deviation is applied. The TEM data noise floor is 10^{-10}V/m.

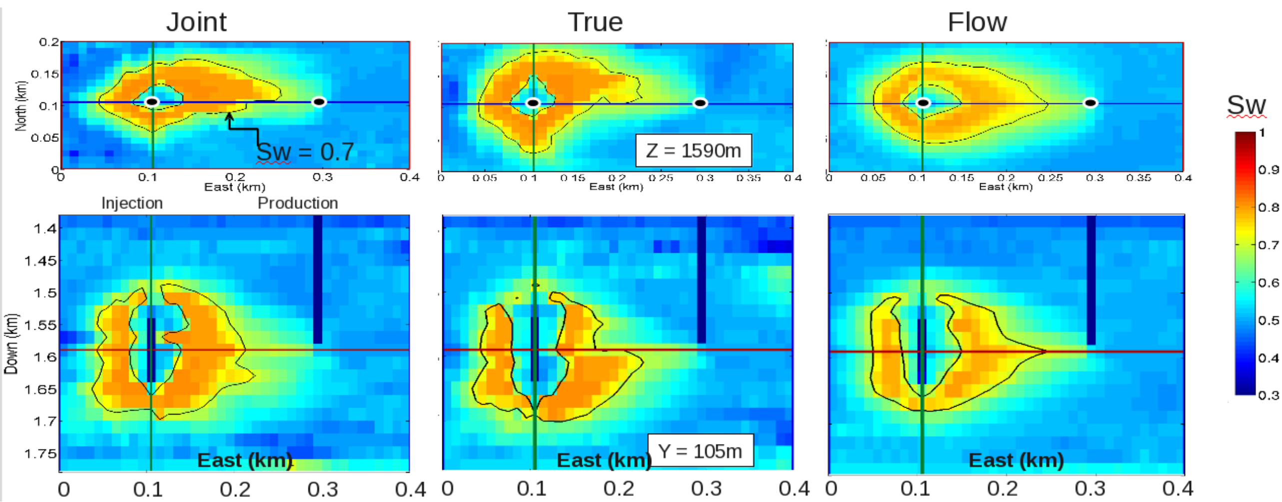

Figure 4: Water saturation from joint inversion, true hydrological state, and hydrological data inversion.