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Publication Date
2018-08-27

DOI
10.1190/segam2018-2995730.1

Peer reviewed

Using Multiphase Fluid Flow Modeling and Time-Lapse Electromagnetics to Improve 4D Monitoring of CO_2 in an EOR Reservoir

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Summary

Understanding the changes in the saturation within a reservoir undergoing enhanced oil recovery (EOR) is crucial to optimizing production. We debut a novel multi-phase fluid flow modelling code, TOGA, to assist in modeling gas, oil, and water phases within the reservoir, and combine its output with time-lapse Depth to Surface Resistivity data in a case study involving an EOR reservoir. The results show the potential for combining the two methods to improve our understanding of reservoir saturation over an extended period of time.

Introduction

The Hastings Field in southern Texas is currently undergoing enhanced oil recovery (EOR) operations, led by Denbury Onshore LLC (Denbury). Multiple electromagnetic (EM) surveys using the Depth to Surface Resistivity (DSR) method have been carried out there over the past several years to map and monitor the distribution of injected CO_2 within the reservoir (MacLennan et al 2016; Nieuwenhuis et al 2016). The resulting 3D saturation models have increased understanding of the distribution of CO_2 within the reservoir, particularly when combined with existing seismic and other petrophysical data.

However, to maximize production, these 3D models need to be complemented by a more continuous understanding of changes in saturation within the reservoir. Therefore, a natural next step is to combine the EM data with models of fluid flow and transport. Flow models attempt to predict the movement of fluids within the reservoir based on properties such as porosity and hydraulic conductivity, while EM methods detect resistivity contrasts at water and oil/gas interfaces. Combining the output of the two methods can therefore improve evaluation of reservoir saturation changes relative to either method alone. Further, accurate fluid flow models can improve survey planning by identifying areas to target and can produce more robust resistivity models by providing inversion constraints. In turn, resistivity data can help calibrate a fluid flow model and reduce uncertainties in parameter estimates.

Previous work has incorporated flow simulations and EM methods to improve inversion of borehole EM for reservoir simulation (Haber and Holtham 2013), and the two have been combined with seismic data to help obtain estimates of permeability and porosity within a reservoir (Liang et al 2016). However, most prior works have utilized only two-phase flow models which lump together oil and gas phases. In typical EOR operations, a reservoir may have aqueous (water), oil, and gas (CO_2, methane, and a mixture of heavier hydrocarbons) phases that affect the bulk resistivity of the reservoir. By considering the oil and gas phases individually, three-phase flow modeling provides a more accurate model of fluid distribution and motion throughout the reservoir compared to two-phase models. Either a standard Archie's law or a modified version for multiple phases can then relate this more complicated saturation model back to resistivity, to be used in future DSR survey design and time-lapse data inversion.

We utilize a new three-phase fluid modeling code, TOGA (a part of the TOUGH reservoir modeling code suite), to model conditions in the Hastings Field and demonstrate proof of concept. The code performs both history matching and predictive modeling, utilizing a combination of well log data, derived petrophysical parameters, and saturation models from previous GroundMetrics DSR surveys. The results show potential to be used both to advise future survey design and to improve and constrain inversion of time-lapse EM data.

The Hastings Field

The Hastings Field was initially identified in 1933, followed by a discovery well in 1934, and is one of a series of south Texas oil fields

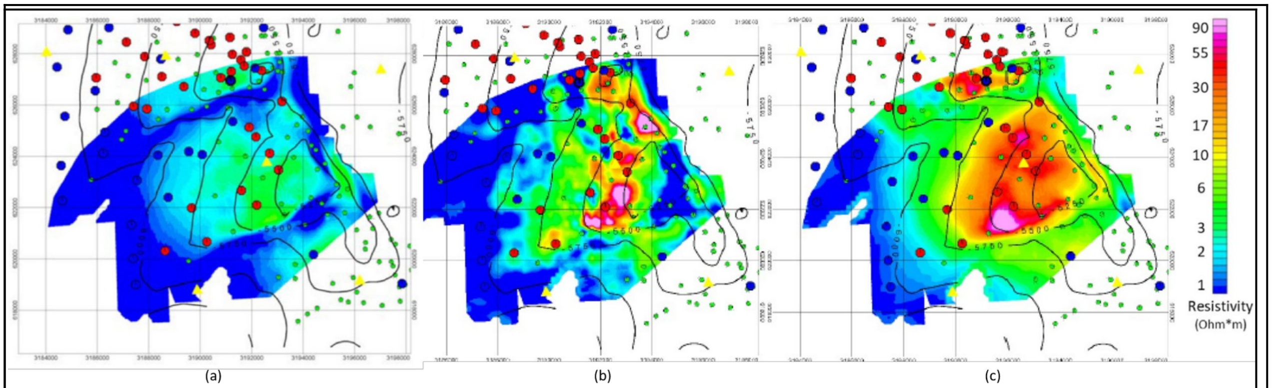

Figure 1: Resistivity distribution along the top of the B and C fault blocks of the Frio Reservoir from (a) well logs prior to CO_2 EOR, (b) 2014 Depth to Surface Resistivity survey data inversion; (c) 2016 Depth to Surface Resistivity survey data inversion. Red dots represent CO_2 injection wells, blue dotes represent water injection wells, and green

formed by underlying salt domes. The 20-square mile field has been on primary production and waterflooding over the past 80 years but has recently been revitalized with a CO_2 EOR program operated by Denbury. The target reservoir lies within a series of sands in the Oligocene Frio formation, divided into fault blocks by natural sealing faults. The EOR program is designed to inject CO_2 and water at the flanks of the fault block and produce from the crest of the main dome. This sweeps oil from the highest part of the structure and pressurizes the sands.

GroundMetrics has performed two Depth to Surface Resistivity surveys over the Hastings Field, one in 2014 and one at the beginning of 2016, with a focus on operations in the B and C fault blocks. In both cases multiple downhole sources were used with a gridded array of receivers at the surface to measure electric fields, and the results were inverted to produce images of resistivity distribution within the reservoir. While differences and challenges in data collection and quality between the two surveys prevented quantitative comparisons, we were able to observe a substantial resistivity increase in the upper parts of the reservoir both with respect to the reservoir prior to injection and during the time difference between surveys (Figure 1).

These surveys, while providing valuable data on a reservoir scale, nevertheless produced only snapshots in time of the resistivity distribution in the Frio sands due to EOR. In contrast, fluid flow models may use data from only a handful of scattered wells, but this dataset is often densely sampled over an extended period. By coupling temporally-dense fluid flow modeling of the Hastings Field with spatially-dense time-lapse EM data, we can improve results of both methods and create a quantitative, dynamic model of the CO_2 saturation within the reservoir during EOR.

Fluid Flow Modeling

TOGA (**T**OUGH **O**il, **G**as, **A**queous) (Pan and Oldenburg 2016) is a new numerical reservoir simulator for modeling non-isothermal flow and transport of water, CO_2, multicomponent oil, and related gas components for a variety of applications, including CO_2-enhanced oil recovery (CO_2-EOR). It is a member of the TOUGH family of numerical modeling codes (Pruess 2004, 2012) developed at Lawrence Berkeley National Laboratory.

TOGA uses an approach based on the Peng-Robinson equation of state (PR-EOS) to calculate the thermophysical properties of the gas and oil phases, including the gas/oil components dissolved in the aqueous phase, and uses a mixing model to estimate the thermophysical properties of the aqueous phase. The phase behavior (e.g., occurrence and disappearance of the three phases, gas + oil + aqueous) and the partitioning of non-aqueous components (e.g., CO_2, CH_4, and *n*-oil components) between coexisting phases are modeled based on the equal-fugacity principle. Models for saturated (water) vapor pressure and water solubility (in the oil phase) are used to calculate the partitioning of the water (H_2O) component between the gas and oil phases. All components (e.g., CO_2, H_2O, and *n* hydrocarbon components) are allowed to be present in all phases (aqueous, gaseous, and oil). TOGA uses a multiphase version of Darcy's Law to model flow and transport through porous media of mixtures with up to three phases over a range of pressures and temperatures appropriate to hydrocarbon recovery and geologic carbon storage systems.

The lateral extent of the numerical model was taken to be the B and C fault block of the Hastings Field, as shown in Figure 2, which displays the depth of the top of the Frio formation. A coarse lateral grid resolution of 500 ft (152.4 m) was chosen for the preliminary model as a reasonable first estimate, with only 216 grid blocks per layer. A factor of three improvement in lateral resolution is planned for later generations of the model, to coincide with the 50 m resolution of the GroundMetrics surveys.

Vertically, the model represents the top six Frio A sands: A1, A2, A3, A4, A4L, and A5. The thicknesses of the layers were judged to be spatially uniform enough to warrant representing them as uniform-thickness layers in the model. Each sand was represented by one layer in the preliminary model, with horizontal permeability representing the sand permeability and vertical permeability representing the permeability of the inter-sand zones. Altogether there were a total of 1296 grid blocks in the model.

The initial conditions for the model represent the state of the system prior to the onset of CO_2 injection. A resistivity distribution taken from well logs was interpolated onto a regular x,y,z grid, with x,y resolution equal to that of the numerical model (500 by 500 feet), and z resolution equal to half that of the original GroundMetrics resistivity data set. Model coordinates of each grid block were identified in the resistivity distribution and the resistivity was converted to an aqueous saturation (the fraction of the pore space containing water) using Archie's Law, and assigned as an initial condition to that grid block. Archie's law is

$$S_a = (\rho_w/\rho)^{1/2}/\phi \qquad (1)$$

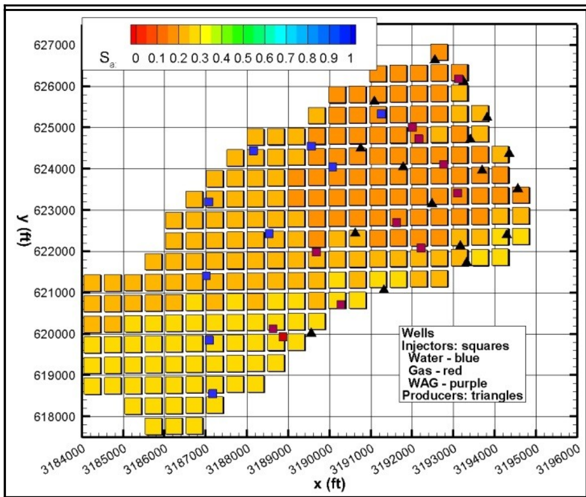

Figure 3: S_a distribution in the TOGA model determined from GroundMetrics' resistivity

where S_a is aqueous-phase saturation, ρ_w is the resistivity of water, ρ is the formation resistivity, and ϕ is the formation porosity. Figure 3 shows the corresponding initial S_a values in the top layer of the model.

The initial pressure distribution was taken to be hydrostatic, but the model was allowed to equilibrate with gravity prior to simulating CO_2 injection. Initial temperature was taken to be uniform and temperature changes are not considered in the model (i.e., no energy equation is solved). Based on initial geologic

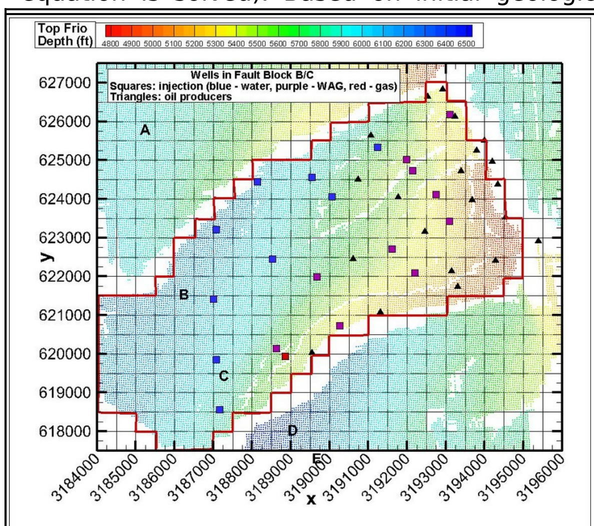

Figure 2: Lateral limits of the TOGA model (red line), grid resolution (black grid), and wells (symbols).

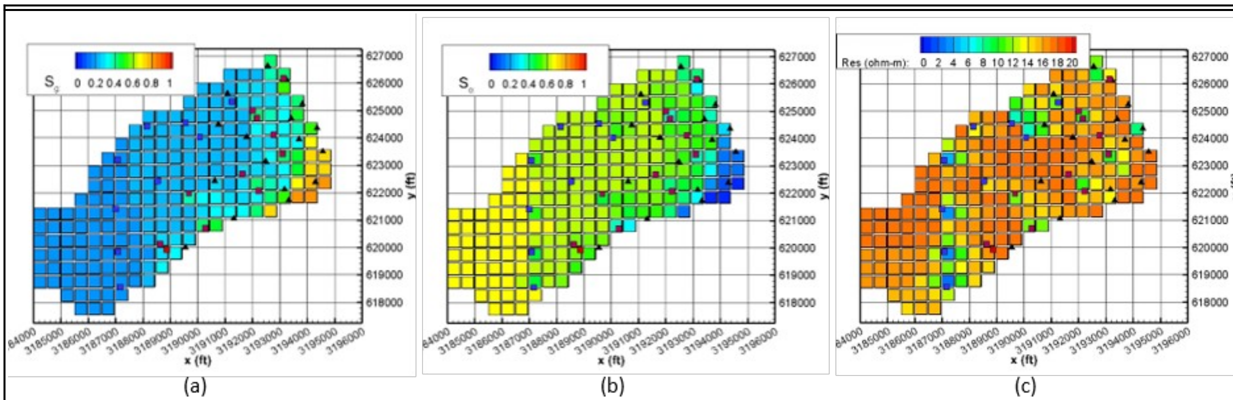

Figure 4: Simulation results after one year for the top layer of the model, for (a) gas saturation (S_g), (b) oil

information, all boundary conditions of the model were closed (no-flow boundaries); it is straight-forward to modify the model to include other boundary conditions (e.g., constant-pressure) if they are determined to be more realistic.

Gas gravity was used to infer the composition of gaseous hydrocarbon components, which for simplicity was assumed to be composed of methane (M=16) and ethane (M=30). Gas-oil ratio (GOR) was used to determine initial values of gas-phase saturation S_g and oil-phase saturation S_o (the fraction of the pore space containing gas and oil, respectively). Since S_a varies spatially, S_g and S_o do as well, as $S_a + S_g + S_o = 1$. For the numerical model initial conditions, mole fractions of oil components were multiplied by gas or oil saturation S_g or S_o to give the actual amount of each component in each grid block.

Porosity and permeability were taken from petrophysical data provided by Denbury, including sand and inter-sand layer permeabilities. No field-relevant information on relative permeability and capillary pressure functions were available, so representative characteristic curves were used instead.

Three types of injection wells were considered in the model: water, gas, and WAG (water alternating with gas). Injection wells are either perforated over the top three sands (A1, A2, A3) or the bottom three sands (A4, A4L, A5), in an alternating pattern moving up dip. For the coarse model representation being used, it would not have made sense to use a wellbore model. Instead, water injection was represented as a mass source in each of the three perforated layers in proportion to the thickness of the layer. Water wells were assumed to inject at a rate of 6000 BWPD, while the CO_2 injection rate was taken to be 15 MMSCFD, For WAG, a two-week water/two-week CO_2 schedule was assumed.

Production wells were assumed to be perforated over the entire sand sequence and to flow at a fixed bottom-hole pressure, P_b. In the absence of knowledge of the actual P_b used in the field, a range of values were used, and the simulated flow rate and composition were compared to field data.

Initial conditions for TOGA are specified as pressure, temperature, S_a, and hydrocarbon component mole fraction. The code then determines phase conditions internally, based on how the hydrocarbon components partition into gas and oil phases. The code takes only a single time step to accomplish this. Next, a pressure/gravity equilibration was run with no sources and sinks, which produced stable initial conditions for the subsequent history match simulations. This equilibration took 302 time steps and simulates 250 years, which required two hours of run time.

The history match simulation began at t = 0, corresponding to November 5, 2014. For this simulation, oil production wells were held at a fixed pressure equal to 70% of the original reservoir pressure. This value is an estimate based on typical oil operations and is not necessarily correct for the Hastings Field. Figure 4 shows snapshots of S_g, S_o, and resistivity after a single year of forward modeling.

In the model, gas saturation (S_g) was generally increased in the up-dip region, while oil saturation (S_o) was generally decreased. Pressure distributions show the expected effect of increased pressure near the injection wells (primarily down dip in the fault block) and decreased pressure near the production wells. The resistivity shows a significant increase compared to the initial condition, which corresponds to a generally lower aqueous phase saturation and an increase in the mole fraction of CO_2.

Conclusions and Future Work

The extreme simplifications of field operating conditions and the coarse spatial resolution used for the present TOGA model precludes using these results to make detailed predictions. However, they indicate that multiphase fluid flow modeling of the Hastings Field is quite feasible and has significant opportunities to assist in refining a future geophysical survey. For example, observing the likely extents of injected fluids within a given layer helps to define locations where additional sources or sensors might be placed in a future DSR survey to maximize detection of changes. To improve the TOGA results to a point where they can be suitable for this purpose, additional refinements and detailed information, such as more accurate representation of wells and injection and production rates, need to be included.

In so far as aqueous saturation S_a decreases when CO_2 content increases, the classic Archie's law is reasonable for predicting resistivity changes arising from CO_2 injection. However, in the present simulations, oil, gas, and aqueous saturations are all changing as CO_2 and water are injected. The three-phase relative permeability functions strongly impact this behavior, and the functions being used need to be carefully evaluated to ensure that the modeled behavior is reasonable. A modified Archie's law that can account for each of these multiple phases may be necessary to most accurately relate the fluid flow modeling back to resistivity.

GroundMetrics is planning to conduct a further DSR survey at the Hastings field in the second quarter of 2018. The results from this survey will be related back to both previous surveys as well as incorporated into an updated TOGA model. Additional modeling will be carried out to determine the sensitivity of various parameters within the flow model and produce a new and more accurate model of fluid flow. Finally, the output of the TOGA model can be used as an inversion constraint for the new data by defining areas within the model that can be weighted to either encourage or discourage changes in resistivity. Ultimately the two methods will combine to generate a highly-accurate 4D saturation model of the Hastings reservoir.

Acknowledgements

The authors would like to thank Denbury for permission to publish this work. This material is based upon work supported by the U.S. Department of Energy, Office of Science, Office of Science under Award Number DE-SC0009709.

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