Mitigating Water Encroachment in a Fractured and Faulted Carbonate Gas Field: An Uncertainty Management and Field Optimization Study Using Unstructured Discrete Fracture Models*

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Abstract

The reservoir of interest is early Triassic bedded dolostone and limestone, located at a depth of more than 3 km. The depositional environment is carbonate platform and ramp with oolitic shoals. Gas is trapped in different pools in thrust-related anticlinal structures and seals comprise tight limestones and anhydrites. There is well-based data suggesting the existence of effective natural fractures: well productivity indicates substantially higher permeability than expected from matrix, and natural fractures are commonly seen in core and image logs. Several major faults also exist in the reservoir and are thought to be sealing. Because high-permeability fractures have been known to result in significant downside risks to gas production (rapid water breakthrough), it is important to assess their impact on fluid flow for effective development planning. In this work, we will describe a study to evaluate the effects of natural fractures on gas and water production for this field. The focus was to address the chief field-development-plan concerns around aquifer-water mitigation and well-pattern optimization. An experimental design (ED) approach that entails multiple unstructured discrete fracture models (DFMs) for a large sector of the field was applied.

Introduction

Our workflow begins with reservoir characterization. Two fracture sets are present, striking roughly parallel and perpendicular to the fold axis, and dipping perpendicular to bedding. Observations of fractures that intersect wellbores are converted to logs of fracture density. We then use a non-linear, multiple-regression technique to generate a relative spatial distribution of fracture density throughout the reservoir model, using empirically determined distributed predictor properties like matrix porosity and volume illite, as well as structural curvature as secondary control. We next employ this distribution as a highly correlated soft data and the well fracture-density frequency distribution as a constraint in the geostatistical procedure of sequential Gaussian simulation collocated cokriging to generate the final model fracture-density distribution. By further specifying the distributions of fracture dimensions (height, length, and aperture) and orientations, a network of fractures can be stochastically generated. In our DFMs, faults and fractures are modeled explicitly as thin vertical planes (triangles and rectangles) while matrix is represented as polyhedral blocks (tetrahedra, prisms, pyramids, and hexahedra) – see Figure 1. We next compute the parameters required for our finite-difference flow simulator using a control-volume, finite-difference discretization scheme with a two-point-flux approximation. These include the bulk volumes and porosities of the cells as well as the cell-to-cell connection list and transmissibilities. Fracture-fracture, matrix-fracture, and matrix-matrix connections are all accounted for.

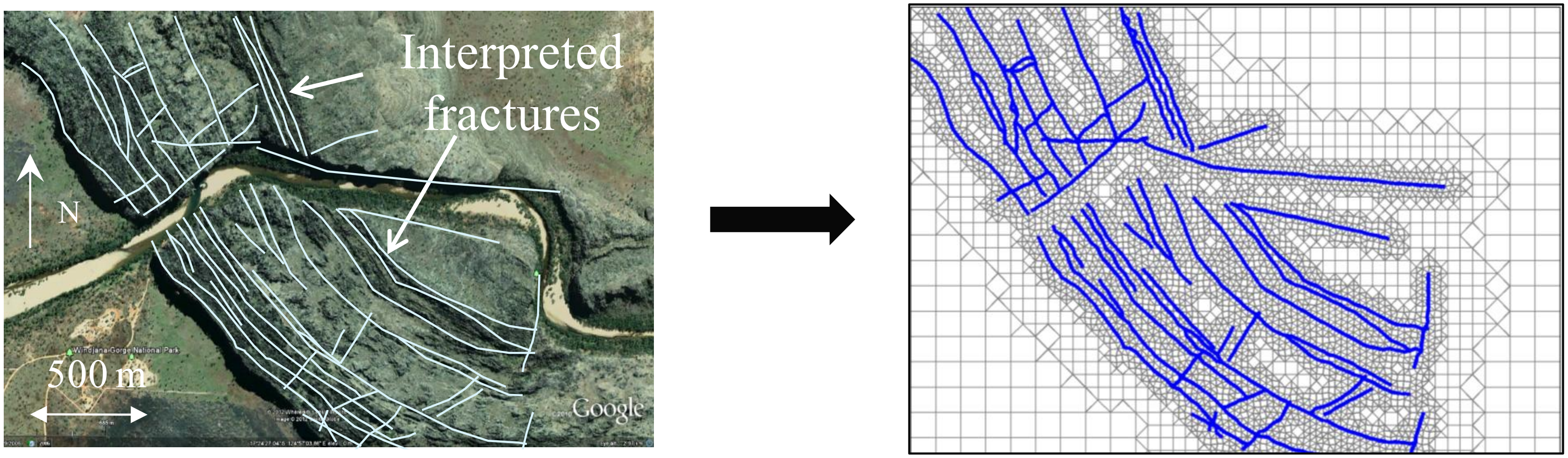
Discussion

In our experimental design, we evaluated the impact of five parameters: fracture density, fracture length, fracture conductivity, matrix permeability, and original-gas-in-place (OGIP) - on several field responses under a 20-year pressure-depletion scenario. Each parameter was assigned three possible values (low, mid, and high) to capture its range of uncertainty. Different fracture-density values led to different stochastic realizations of discrete fracture networks with varying connectivity. The field response variables evaluated are cumulative gas production (GPC), cumulative water production (WPC), and water-gas ratio (WGR). Apart from assessing the effects of geological uncertainties, we also wanted to select the optimal well pattern between two alternatives that are designed to mitigate water encroachment and reservoir compartmentalization respectively. We used a d-optimal design that entailed 200 simulations of unstructured DFMs representing different combinations of uncertain parameters and well patterns. We employed ED techniques like response surfaces, Monte-Carlo simulations, and pseudo-Pareto charts to analyze the field responses from the DFM simulations. WPC was used as the basis to rank the level of optimism/pessimism of the outcomes, thus the P10-P50-P90 cases are in a decreasing order of WPC values. The pseudo-Pareto charts indicate that original-gas-in-place (OGIP) impacts GPC strongly while WPC is controlled by both OGIP and matrix (reservoir rock) permeability. On the other hand, the WGR is mainly controlled by matrix permeability and fracture density.

At first glance, these observations might lead one to think that natural fractures do not impact fluid flow for the problem in question. However, a more thorough analysis of the results yields some non-intuitive conclusions in regards to the role of fractures in controlling water movement in the field as a function of other uncertainties (matrix properties) and different well patterns. By cross plotting the field responses for the two well patterns considered and color-coding the impactful parameters, we showed that the water-mitigation well pattern is more optimal (led to lower water production) than the compartmentalization-mitigation pattern for mid and high matrix permeabilities but the converse is true for low matrix permeability. It was also observed that a lower fracture density actually leads to higher water production for tight matrix rock whereas a denser fracture network decreases water production when matrix permeability is higher. These trends can be explained as follows. Natural fractures were expected to cause early water breakthrough from encroaching aquifer at the reservoir. However, it was found that, for mid to high matrix permeability, the relatively tall fractures actually act as high-permeability vertical separators for water to slump down to the aquifer instead of migrating upslope towards the gas producers, thus actually reducing water breakthrough. In contrast, when matrix permeability is low, the overall viscous pressure drop across the system becomes greater and the well drawdown needs to be greater in order to meet the target field gas rate. This brings about a larger pressure drop between the aquifer and the wells, which beyond a point, becomes large enough to overcome gravity and the fracture system instead acts to channel water to the wells, to the detriment of gas production (Figure 2). In other words, while the water-mitigation well pattern is generally more optimal, it will be prudent to implement measures to handle any additional water production that might occur in more pessimistic outcomes.

Summary

These findings highlight the situation-dependent and unexpected consequences of natural fractures in a gas field that has an adjacent aquifer. Apart from the assessment of geological uncertainties, this study illustrates a framework for optimizing the field development plan in the face of uncertainty. This work underscores the need to employ detailed DFMs to complement any conventional (e.g., dual-porosity) flow simulations for carbonate gas fields with a risk of water production from natural fractures. It also underscores the importance of reducing geological uncertainty (e.g., fracture and rock characteristics) through a sound surveillance plan for effective field development.



Fracture outcrop (areal view)

Discrete fracture model

Figure 1. The realistic representation of natural fractures seen in an outcrop using an unstructured discrete fracture model (DFM) grid that represents fractures explicitly as planar features sandwiched between polyhedral matrix cells.

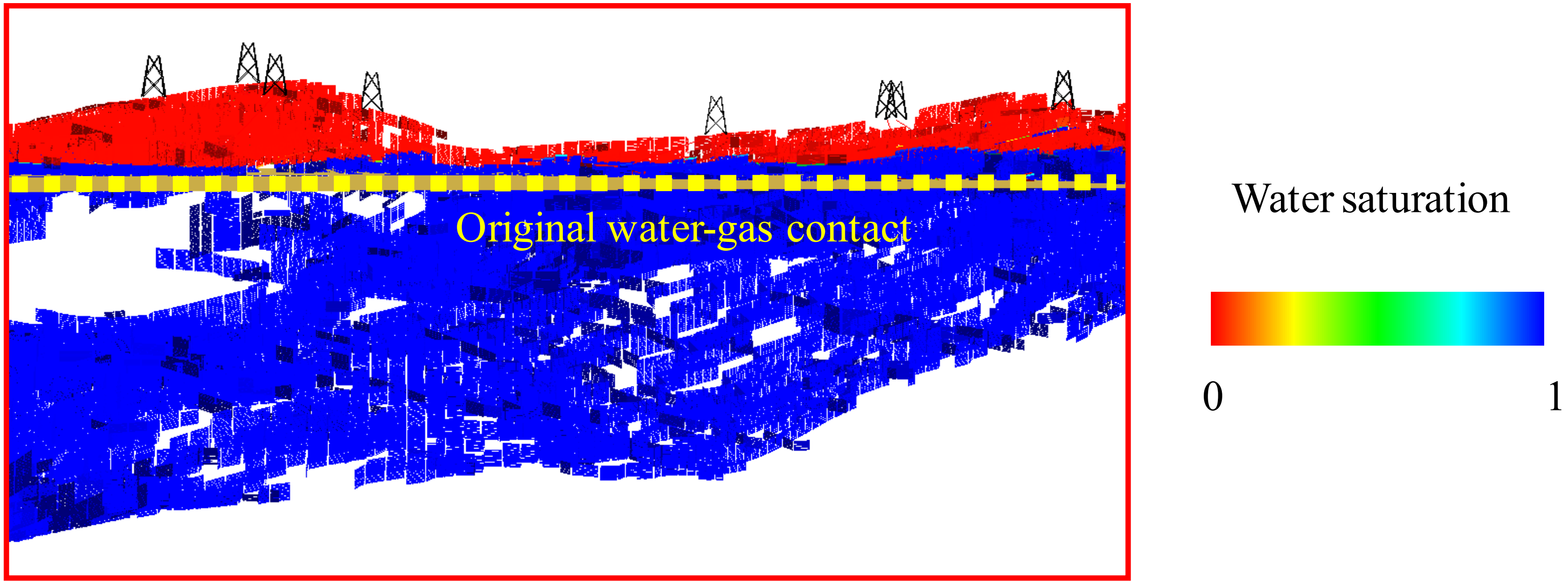


Figure 2. Perspective view of field sector showing late-time water saturation in fracture simulation cells for the most pessimistic ED case (highest final WPC); note the relative upward movement of aquifer water in relation to the original water/gas contact.