V019 RESERVOIR MONITORING — A MULTI-DISCIPLINARY FEASIBILITY STUDY IN 3D

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INTRODUCTION

Monitoring reservoir changes with time-lapse seismic holds the promise to significantly improve reservoir characterization and reservoir management. Relating time-dependent changes in seismic to the underlying flow processes requires inputs from: (1) geological modeling/geostatistics, (2) flow simulation, (3) rock physics, and (4) seismic imaging. This paper documents the results from a project that brings these disciplines together. In this study we have considered the forward problem for a 3-D reservoir monitoring problem: creating a detailed geological model, performing flow simulation, relating the dynamic rock properties to seismic properties, and, finally, imaging the reservoir at multiple times.

FORWARD MODELING OF THE SEISMIC MONITORING PROCESS

The starting point of our project was building a reservoir model whose lithology and structure resembles a North Sea reservoir, shown in Figure 1. We built a geological model of a braided stream fluvial reservoir with three distinct geological strata. The distribution of channel complexes versus overbank deposits within each strata, the distribution of individual channels within each channel complex, and the channel sand distribution in each layer were modeled through a hierarchical object-based procedure. Within the channel sands, porosity was assigned with sequential Gaussian simulation (SGS). The SGS algorithm constructs a stochastic porosity model constrained to a histogram of porosity, a model of spatial correlation, and well data. Two vertical faults are present in the reservoir unit; one of the faults is leaking while the other is sealing. Fault permeability is one of the reservoir characteristics that are better defined by repeated seismic experiments than by traditional geophysical measurements.

The next step was to up-scale the lithological properties to a coarser grid that could be handled by a fluid-flow simulation program. The flow simulation blocks for the 250,000 block model are approximately 1000 times larger than the geological model. The details in the geological model provide the ground truth petrophysical properties and are transferred to flow simulation as effective block properties. The scaled-up porosity was taken as the arithmetic average of the constituent porosity values, the scaled-up horizontal permeability was taken as the arithmetic average of the constituent permeability values, and the scaled-up vertical permeability was taken as a power average of the constituent permeability values. This power average for the vertical permeability takes into account that the flow paths are more tortuous in the vertical direction because of lateral continuity.

All fluid-flow simulations were done using the 1996A parallel version of Eclipse, a three-phase, three-dimensional, general purpose black-oil simulator from GeoQuest, running on a 16 processors SGI Power Challenge. The reservoir was produced under primary production for the first 6 months using 24 production wells producing at 5000 m³/day and a minimum bottom-hole pressure constraint of 200 bars. After 6 months of primary production, 17 injection wells

were added injecting water at 5000 m³/day with a maximum bottom-hole pressure constraint of 400 bars.

Rock physics provided the link between reservoir properties and the seismic properties that can be observed with a seismic survey. The reservoir parameters of importance are lithology, porosity, permeability, pore fluid types and saturations, temperature, reservoir effective stress, and pore fluid pressure. The related bulk properties that most impact seismic wave propagation are bulk density, and P- and S-wave velocities.

Seismic modeling of the reservoir required a technique that could handle an Earth model that is both elastic and heterogeneous; this suggested a ray-based scattering approach, such as the first order Born approximation. We modeled two multi-offset surveys assuming a marine-like acquisition geometry. The first survey was recorded at the beginning of production, while the second one after 3 years of production. Cubes of seismic impedance were obtained by imaging the data using a 3-D Kirchhoff prestack depth migration. Comparing the images obtained from the two surveys clearly show the effects of non-uniform depletion of the primary gas cap caused by water injection, and the formation of a secondary gas cap on the side of the sealing fault.

The results of the seismic imaging and modeling process suggest that fluid-flow patterns and variations of fluid properties within the reservoir can be detected using 3-D seismic surveys. However, conclusions should be drawn cautiously from these results since they were not affected by all the factors that in a real case would contribute to degrade the results of seismic imaging; such as: noise, acquisition constraints and variability, and uncertain knowledge of the overburden parameters.

Figure 1: Perspective view of the reservoir model, showing structure and faults. Production wells are indicated in white, and water injection wells are indicated in black.