Seismic monitoring of oil production: A feasibility study

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SUMMARY

We perform a feasibility study on the likelihood of seismically detecting and interpreting the time-varying changes in a North Sea reservoir during solution-gas-drive oil production from a horizontal well. This study integrates reservoir engineering fluid-flow simulations, rock physics measurements and transformations, and prestack seismic modeling and migration on a real but anonymous North Sea reservoir model. Our hydrocarbon recovery monitoring analysis includes:

- Integrating reservoir fluid-flow simulation results (pore pressure; temperature; and oil, gas and water saturations) as provided by Norsk Hydro.
- Integrating reservoir geology information on relevant rock properties (porosity, dry elastic constants and density) measured from core data.
- Computing spatial distributions of compressional and shear wave velocities in the reservoir using Gassmann's formula and the fluid-flow simulation results of oil production.
- Simulating multi-offset surface seismic monitor surveys over the reservoir during oil production using a Kirchhoff elastic modeling algorithm.
- Mapping the differences between seismic responses as a function of reservoir production time using prestack seismic imaging methods.

We calculate spatial distributions of reservoir rock properties from the fluid-flow simulation data, and map the associated seismic responses at three production-time snapshots: prior to any oil production (Base Survey), after 56 days (Monitor 1), and

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after 113 days (Monitor 2) of oil production. Multi-offset seismic surveys are simulated for each of these three production times. Using realistic seismic acquisition parameters, we are able to successfully detect and monitor dynamic gascap expansion in the reservoir during the fluid-flow simulation of the oil production process. Evidence of gas coning is clearly visible in the prestack-migrated difference sections at realistic seismic noise levels and frequency bandwidth.

INTRODUCTION

Hydrocarbon reservoirs are increasingly recognized as spatially heterogeneous entities, in terms of pore-fluid content, pore-fluid saturation, porosity, permeability, lithology, and structural control. Knowledge of these reservoir parameters and their spatial variation is critical in the evaluation of the total volume of hydrocarbon reserves in place, in understanding and predicting physical processes in the reservoir such as fluid flow and heat transfer, and in projecting and monitoring reservoir fluid production and recovery as a function of time.

A new diagnostic role for seismic has recently been proposed, in which several repeat seismic surveys are acquired in time-lapse mode to monitor reservoir production fluid-flow processes (e.g., Nur, 1989). This concept offers a method for better characterization of reservoir complexity by monitoring the flow of fluids with time in a producing reservoir. Additionally, 3-D seismic monitoring may provide a full reservoir volume analysis of production sweep efficiency, early breakthrough prediction, and location of bypassed (unproduced) hydrocarbons. Seismic monitoring of reservoir production processes potentially offers a new dimension to the manner in which hydrocarbon reservoirs are currently developed and produced.

Although the concept of time-lapse seismic reservoir monitoring is relatively recent, a few notable pilot projects have been attempted. Pullin et al. (1987) collected two 3-D seismic surveys before and after a steam pilot at an Athabasca tar sands reservoir site. By comparing time delay and amplitude attenuation maps between the two stacked surveys, they seemed to be able to qualitatively map the location of steamed versus unsteamed zones. Their observed vertical time delays and amplitude attenuations through steamed sections of the reservoir compared reasonable well with prior rock physics laboratory studies of the predicted thermal effects on seismic data.

Greaves and Fulp (1987) designed and analyzed a 3-D seismic monitoring experiment of an in situ combustion (fireflood) EOR process. They collected three 3-D surface seismic datasets: one pre-combustion, and two during combustion. They made stacked sections from each survey and computed traveltime and amplitude difference maps comparing each fireflood data set to the pre-fire base survey. They were able to monitor the volume of combustion burn accurately, as well as the sweep efficiency, with confirmation by borehole measurements.

More recently, Graebner (1993) presented results of a 3-D marine seismic monitoring survey in the Oseberg field offshore Norway. The objective was to monitor the movement of the gascap during production over time. They compared reservoir fluid-flow simulation predictions of the gas-oil contact to the actual seismic observations, and found a weak seismic amplitude anomaly in the difference section which correlated somewhat with the zone of change predicted by the fluid-flow simulator. They state that their results were inconclusive due to significant noise in the final seismic difference sections, and concerns about relative and absolute survey positioning errors from one survey to the next.

In this paper, we present what we believe to be a major step forward in establishing the petrophysical basis for seismic reservoir monitoring, by conducting a comprehensive physical modeling study that integrates fluid-flow simulation and rock physics with seismic modeling and migration. We demonstrate the potential feasibility of performing seismic reservoir monitoring with a North Sea reservoir case study. Fluid-flow simulations were computed by Norsk Hydro for the case of solution-gas-drive oil production from a horizontal well in the reservoir after 56 and 113 days of production. Reservoir geology and core data measurements were combined to make rock physics transformations of the fluid-flow saturation, pressure and temperature data to seismic velocities and densities. Multi-offset elastic reflection seismogram surveys were simulated at each production phase. Prestack migration images clearly show gas coning during production in reasonable seismic noise levels and frequency bandwidth.

FLUID-FLOW SIMULATION

The reservoir in this study is located within a large oil and gas field located in the North Sea. The oil zone is located at a depth of approximately 1500 meters, and it varies in thickness from a few meters to more than 20 meters. Horizontal drilling technology makes it possible to commercially produce oil from this thin oil zone. Norsk Hydro provided fluid-flow simulations of primary oil production from a horizontal well in the reservoir. The timeframe of the two simulation datasets was 56 and 113 days into production.

The productive interval of the reservoir consists of loosely consolidated sands with porosities ranging from 23% to 35%. All three fluid phases of gas, oil and water are simultaneously present. The reservoir oil is fairly heavy with a low gas-to-oil ratio of about 60. Typical values for the oil at reservoir conditions are: density 0.8 g/cc, bulk modulus 1020 MPa, viscosity 1.5 to 2.0 cp. The temperature in the reservoir is approximately uniform and constant at 60 $^\circ$C. The overburden pressure is approximately 34 MPa and the pore pressure is about 16 MPa.

The reservoir grid consisted of 312 individual blocks, as schematically diagrammed in Figure 1. At both production times of 56 and 113 days, each grid cell was given with a fluid-flow simulation data value of porosity, pore pressure, gas saturation, oil saturation, and water saturation. As an example of the simulation data, Figure 2 shows the *change* in oil saturation after 113 days of production. The thin oil zone is clearly compressed due to gascap expansion from above and upward water coning from below.

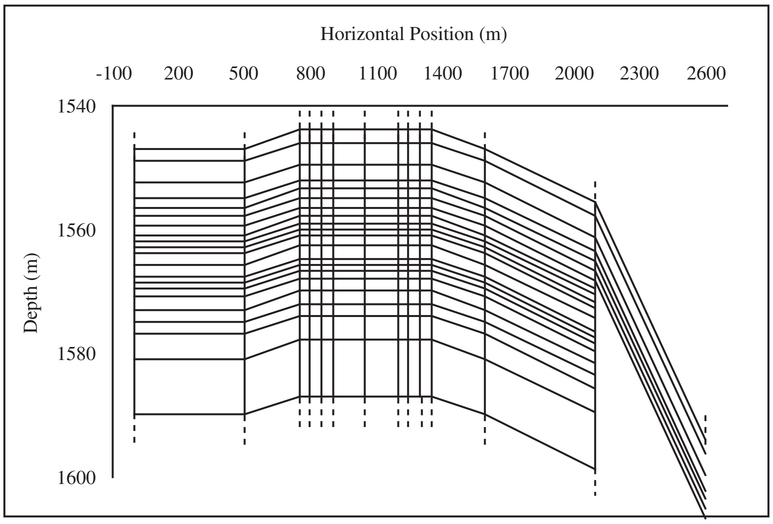

Figure 1: An expanded section of the reservoir fluid-flow simulation grid.

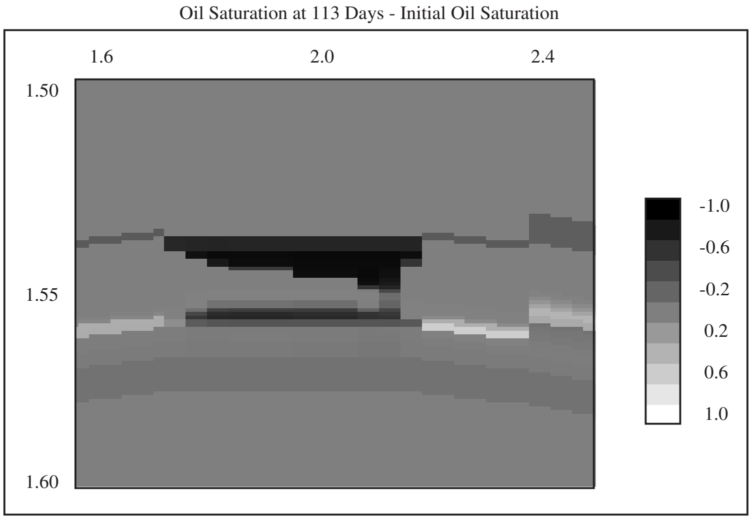

Figure 2: The change in oil saturation after 113 days of production.

ROCK PHYSICS

Given the fluid-flow simulation data and reservoir geology, we use rock physics analysis to transform pressure, temperature and saturation data into Vp, Vs and density distributions within the reservoir. Our estimates of dry rock properties in the reservoir are based on the results in a similar reservoir reported by Blangy and Strandenes (1991) and Blangy (1992), which involved laboratory experiments conducted on 38 core samples. In the reservoir sand, quartz is the dominant constituent, with volumetric content between 50% and 80%, feldspar content is almost constant at 20%, and mica volumetric content varies between 0% and 25%. Ultrasonic compressional and shear wave velocities (Vp and Vs) were measured at varying differential hydrostatic stress from 5 to 30 MPa. Overburden pressure is approximately 34 MPa and pore pressure varies close to 16 MPa with differential pressure close to 18 MPa. Thus we have chosen to rely on the core lab data set measured at a differential pressure of 20 MPa. Figure 3 shows an example of the Vp core measurements made as a function of reservoir sand porosity at 20 MPa differential pressure.

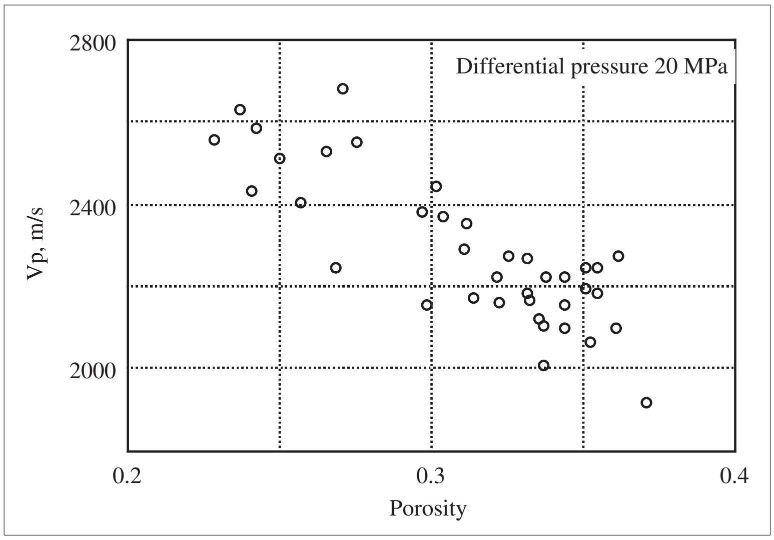

Figure 3: Vp measured versus porosity at 20 MPa differential pressure.

The velocity effect of saturation can be calculated at seismic frequencies by using Gassmann's formulas (e.g., Bourbié et al., 1987). This formula relates the effective elastic moduli of a dry rock to the effective moduli of the same rock containing fluid. Gassmann's relations require knowledge of the effective shear and bulk moduli of the dry rock, the shear and bulk moduli of the mineral material making up rock, the effective bulk modulus of the saturating pore fluid, and the porosity.

For partially saturated rocks at sufficiently low frequencies, we use an effective modulus for the pore fluid that is an isostress average of the moduli of the liquid and gaseous phases. This requires knowledge of the bulk modulus of the liquid phase, the bulk modulus of the gas phase, and the saturation values. In general, if the pore fluid includes more than two phases, we calculate the mixture's effective bulk modulus based on the the number of fluid components, their volumetric concentrations, and their bulk moduli. We assume the following typical values for the reservoir water: a density of 1.0 g/cc and a bulk modulus of 2250 MPa. This process allows us to calculate fluid properties that depend on fluid-flow saturation values. These properties will depend on pressure and temperature because the bulk modulus and density of the reservoir gas are affected by these two parameters. We calculate pressure- and temperature-dependent gas properties as in Batzle and Wang (1992), and assume that the reservoir gas is primarily methane with a specific gravity 0.55.

This rock physics analysis allows us to calculate seismic velocities in saturated reservoir rock as a function of mineralogy, fluid type and saturation value, pore pressure and temperature. Therefore, we can map P-wave and S-wave velocity and density as a function of the reservoir grid directly from the fluid-flow simulation values of pressure, temperature, and oil, gas and water saturation. Fig 4 shows an example of the change in P impedance mapped from the fluid-flow simulation at 113 days of oil production compared to the the initial reservoir state prior to production. There is a significant decrease in P impedance above the oil zone where the gascap has expanded downward, and a smaller increase in P impedance below the oil zone where the aquifer has coned upward during production. The maximum relative decrease in P impedance is about 15% which is strong enough to cause a significant seismic reflection.

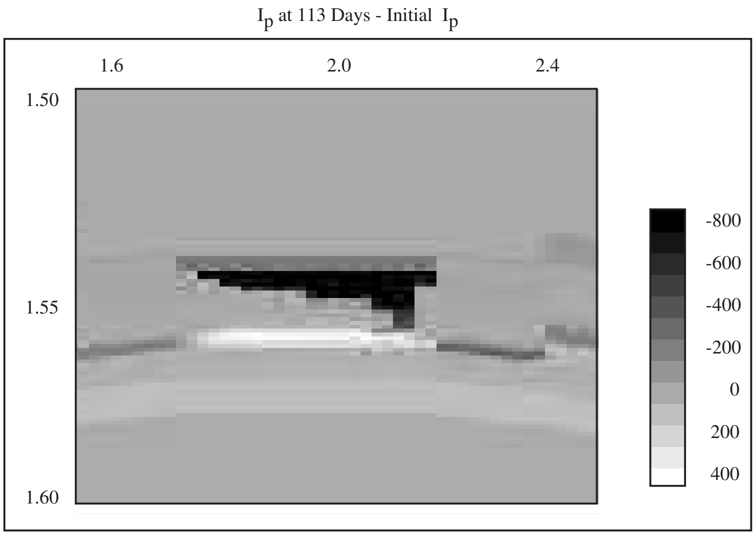

Figure 4: The change in P impedance after 113 days of production.

SEISMIC ANALYSIS

Given the Vp, Vs and density distributions in the reservoir corresponding to the fluid-flow simulation data and rock physics transformations, we simulated a multi-offset surface seismic survey at each of three separate monitoring phases of oil production. These three prestack datasets were then processed in a conventional manner to produce stacked and prestack-migrated reflectivity images. Difference images obtained by subtracting combinations of stacked and migrated sections clearly show that reservoir fluid production is visible in the seismic data and can be monitored in the presence of reasonable levels of seismic noise.

A global seismic model of P- and S-wave velocity and density was constructed based on information provided by Norsk Hydro, and consisted of a 1-D "overburden" macro-model merged with a 2-D fine-scale reservoir model. The macro-layers of the overburden model were chosen to approximate the position and relative reflection amplitude of reflectors seen in the Norsk Hydro stacked section at the well location, which penetrates the reservoir horizontally at about 1.55 km depth at the 1.5-2.0 km midpoint distance.

The fine-scale seismic properties were mapped from reservoir pressure, temperature, relative saturation values of oil, water and gas, and porosity as described in the previous rock physics section. An issue of upscaling arises because in situ reservoir properties measured at very small spatial scales are not necessarily the same properties that a seismic wavefield samples at larger seismic wavelength scales. We computed an "equivalent medium" sampled on a coarser mesh that propagates seismic wavefields which are dynamically equivalent to the waves that would have propagated in the true fine-layered medium. This equivalent medium can be obtained by a spatially weighted average of elastic compliance and density that conserves the stress-strain energy of elastic waves and the mass of the medium (Schoenberg and Muir, 1989; Muir et al., 1992).

Given the global elastic models during each of the three phases of oil production, synthetic surface reflection seismic data was generated for each time snapshot of production. The synthetic seismograms are calculated based on the generalized Kirchhoff body force scattering theory of Lumley and Beydoun (1993). Three prestack marine surveys were simulated to monitor the oil production in the reservoir. Each survey consisted of 161 60-fold CMP gathers with a typical marine acquisition geometry of a 25 m midpoint spacing, a near offset of 250 m and a 3 km cable length. The bandwidth of the seismic data have corner frequencies of 5, 10, 60 and 80 Hz. Random spatially-uncorrelated Gaussian noise was filtered to the same bandwidth and added to make "noisy" seismic traces. The S/N amplitude ratio is about 3:1 at the strongest reservoir reflection at 1.6 seconds. Amplitude effects of geometrical spreading, transmission loss, and source-receiver directivity were modeled in the data.

The three prestack datasets were analyzed with prestack migration. A true-amplitude Kirchhoff prestack migration code was used that includes operator anti-aliasing (Lumley, 1993; Lumley and Claerbout, 1993). Figure 5 shows the difference section obtained by a simple subtraction of the Base Survey prestack migration from the Monitor 2 prestack migration. The gas coning clearly stands out from the background seismic noise as a bright spot at 2 km and 1.6 s, and accurately defines the spatial extent of the true impedance model anomaly.

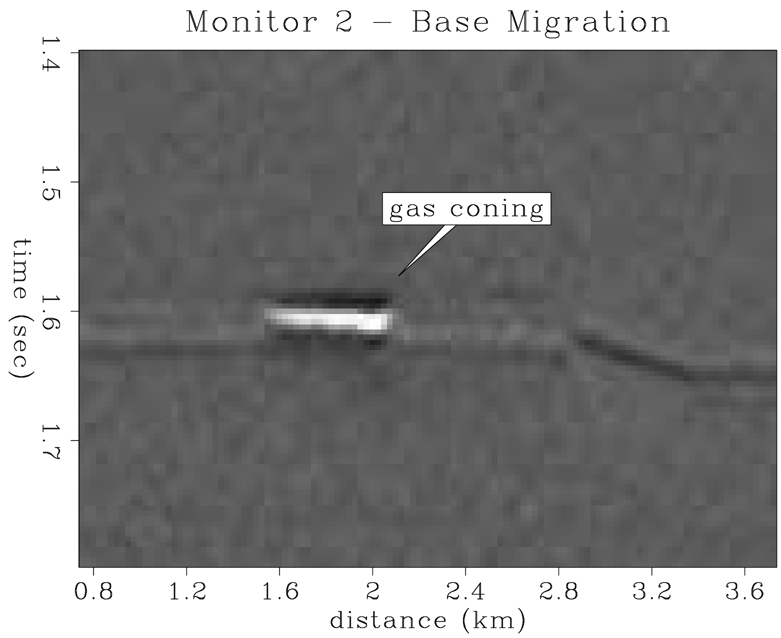

Figure 5: A difference section of the Base Survey prestack migration subtracted from the Monitor 2 prestack migration.

CONCLUSIONS

We conducted a feasibility study concerned with the likelihood of seismically detecting and monitoring the fluid-flow changes in a North Sea reservoir during solution-gas-drive oil production from a horizontal well. We conducted this hydrocarbon recovery monitoring analysis by: (1) using flow simulation results (pore pressure, and oil, gas and water saturations) and information about the relevant rock properties (dry elastic constants); (2) using rock physics to compute compressional and shear wave impedances in the reservoir from the flow simulation results; (3) conducting elastic modeling to simulate seismic surveys of the recovery process; and (4) mapping the differences between seismic responses at production intervals of 56 and 113 days, and the base seismic survey. Using realistic marine seismic recording geometry parameters and noise levels, we were able to successfully detect and monitor dynamic gascap coning and expansion in the reservoir from seismic monitor data during the fluid-flow simulation of oil production.

ACKNOWLEDGMENTS

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