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Combining 4D seismic and reservoir simulation: key to effective reservoir management

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Introduction

The recent advances in the field of reservoir management in terms of improved visualization, increased computing power and increases in the quality and quantity of data collected can often be offset by the key problem of integration and communication between the varied members of an asset team. For example, reservoir engineers work with rock and petrophysical properties such as porosity, fluid saturation, fault transmissibility etc., whereas geophysicists use parameters such as velocity, acoustic impedance, Poisson's ratio etc. Lack of a common ground can prevent successful integration of the disciplines and hence each user essentially derives his/her own version of an earth model, instead of working and updating one shared model that is currently consistent with all the data.

The main objective of this current study is to promote an idea of "common ground" for reservoir specialists and demonstrate an example of its successful application. We believe that the common ground adopted should be the reservoir fluid-flow model – this is the approach described in this study. From this, the main challenge therefore, is to provide a method for the domains of the other asset team members to be linked directly to the reservoir model. This may be carried out via existing physical/petrophysical modeling techniques in combination with new research prototypes.

In this study, we present one possible example towards the implementation of this idea in combination with one of the necessary software pieces. This research prototype is called the Seismic Property Modeller (SPM) and this enables the user to incorporate their 3D, 3C and/or 4D seismic data into the reservoir characterization and monitoring processes. We will discuss the key concepts behind the tool and illustrate some uses of this tool through presentation of a case study for the Foinaven field of BP Amoco. This will highlight the basic capabilities of the software and potential benefits of the tool for reservoir management.

Although the idea of common ground and one earth model sounds a simple and attractive proposition, there are numerous technical and implementation challenges to be overcome during the development of this process. The process and software illustrated in this current study is merely one of the initial steps into providing a truly 'shared earth model' (SEM).

As a result, we believe that it is very important to learn from the issues resulting from the application of this concept to various case studies in order to understand what needs to be done to ensure that we incorporate all significant physical effects in our models, and we have enough measurements to properly calibrate existing models.

We will address some of these issues and demonstrate that new physical measurements are required to enhance the potential of 4D seismic for use in reservoir management. Within 5-10 years, the oil industry will ideally have specialized suites of logging/borehole/surface measurements that will significantly enhance the process of direct SEM calibration. This is a new way of working that will be necessary if we desire to make use of the SEM for fully quantitative 4D monitoring of reservoir properties and conditions.

2. The Seismic Property Modeller (SPM)

The SPM is based on a very simple idea to link the reservoir fluid-flow model to the seismic domain or vice versa. This is by no means a new idea (Koster *et al*. 2000), but it has been described more often than it has actually been put into practice. To carry out this process successfully, we concentrated on overcoming 4 major technical challenges:

1) The SPM should be linked to the reservoir simulator and understand its language.
2) The elastic properties of the rock frame should be supplied independently.
3) The petrophysical transformations should be implemented to derive time-variant elastic properties from the rock frame and fluid properties.
4) The output of elastic properties to some form of interpretation software should be provided to enable comparison and matching with seismically inverted properties. Additionally, output to some forward modeling package might be provided for computing synthetic seismic.

Although some of the challenges (such as the petrophysical transformations) are addressed by existing software on the market, the most critical path we identified was the clean and successful integration of SPM into the chain of preceding and succeeding software. Only seamless integration will allow the reservoir engineer to make relevant use of the 4D seismic data. Indeed, for this process, the structure of the software assumes that the end user might be any type of an asset team member, so a strong geophysical background should not be a pre-requisite. Of course, fine-tuning or troubleshooting of the models and transformations should ideally be performed by a geophysicist or petrophysicist when required.

In this study, the SPM is linked to a commercial reservoir simulator (Schlumberger GeoQuest's Eclipse). The results of coarse-gridded, fluid-flow simulations from this simulator form an input to the petrophysical transformations mostly for definition of "fluid" properties. Reservoir simulators can provide time-varying grids of pressure, temperature, gas-to-oil ratio, oil saturation, gas saturation, water saturation as well as properties of individual fluid phases.

To make another input from the "rock frame" side to the petrophysical transformations we have to use both the simulator data and outside-derived information. Reservoir simulators typically provide an upscaled coarse-gridded, geocellular model which defines geometry of the individual cells, their lithology type and some petrophysical parameters needed for fluid-flow modeling. Ideally, we would like to capture the fine-gridded, highly detailed geological models available from commercial stochastic or deterministic property model generators for combination with our coarse-gridded fluid-frame. In the simplest scenarios, the geological model can be reduced to a net-to-gross (NTG) model where only two lithological types are defined: net (reservoir rock with hydrocarbons) and gross (non-reservoir rock). This approach can easily be extended to any number of mixing lithologies. Apart from the geometrical co-ordinates, each cell contains the required information about volume fractions of net and gross as well as porosity and permeability of the net. Obviously this is not enough information to compute the elastic properties of a rock frame. It is assumed therefore, that the user provides the relevant properties of the dry frame for each lithotype from either well-log or core information.

Having both rock and fluid frame inputs, the petrophysical transformations are straightforward. Various possible routes are extensively discussed by Mavko *et al.* (1998). Although we can use a variety of effective medium theories for calculation of mineral (solid material) moduli, for the saturated moduli, we apply only Gassman equations. The use of Gassman equations for rocks with a composite frame is complicated and we attack this problem by applying the so-called generalized Gassman equation for composite porous media (Berryman & Milton, 1991). The final output of the SPM will be grids of acoustic properties such as *P*- and *S*-wave velocities, density, and other parameters.

3. Foinaven case study

3.1. Example of an SPM workflow

A SPM working prototype was designed and applied to an interpretation of 4D seismic data for one structural fault block (called Panel 4) of the Tertiary deep-marine Foinaven field of BP. Petrophysical transformations for siliciclastic rocks were incorporated into this first version. Firstly, the elastic properties of the composite rock frame were obtained by applying the average of Hashin-Shtrikman bounds to grids of the geological model (for net-to-gross (NTG) and porosity in this example, net corresponds to pure sandstone and gross to shale). As porosity of the net was almost constant for the whole reservoir (26 %), then NTG was the main factor defining heterogeneity of the rock frame properties. Grids of the bulk and shear modulus of dry composite frame consisting of porous sandstone (net) and shale (gross) were computed using generalized Gassman equations (Berryman & Milton, 1991).

After 10 months of oil production the effective pressure drops by approximately 1000 psi and gas starts to come out of solution as the pressure drops below bubble point. A few percent increase of gas saturation significantly reduced the acoustic velocity of gas-oil-water mixture from 1100 m/s to 300 m/s.

Computing velocities of elastic waves using generalized Gassman equations, we can perform more detailed analysis of derived elastic properties following two routes:

1) Add the velocity model of the overburden and simulate the synthetic seismic response for each of the time steps. Then we can perform comparison of either waveforms or particular attributes from synthetic and real seismic cubes for each time step.
2) Directly compare simulator-derived elastic properties with those inverted from seismic.

Mismatches between synthetic and real seismic attributes or properties indicate that there is a lack of consistency between the fluid-flow and seismic models.

For the Foinaven case study, we followed the first route and computed synthetic seismograms using a convolutional method and assuming a constant velocity model for the overburden. Thus, for each surface location, we used the acoustic impedances as if it were a simple 1D model. Repeating this process for each location (using a local 1D model), we produced a map of amplitudes of the first peak, which was the seismic attribute of interest for BP. Comparison of the predicted and experimental maps for the 1995 survey (Figure 1) shows a relatively good match. However, if we look at the same comparison for the 1998 survey (Figure 2) we immediately see that although the prediction around the eastern horizontal producer works well, the prediction around the western producer is less good. This indicates that our fluid-flow model needs some adjustment in this area.

A good match for the baseline survey and yet a poor match for the monitoring survey might seem disappointing at first. However, after further thought, we conclude that this in fact confirms that the 4D-aspect of the seismic can sense properties not originally detected in the original 3D. In fact it is most likely that permeability of the grid blocks and transmissibilities of the block interfaces are the properties that need to be adjusted to get a better match. An initial incorrect input into the baseline survey has gone unnoticed because low-frequency seismic waves are not sensitive to permeability and interfaces where it changes (Dutta & Ode, 1983). However, transport properties control the fluid distribution over time and this is sensed by seismic waves. Hence, as a result, the addition of the time variable offers us the unique possibility to sense a parameter which is normally non-detectable, and thus emphasizing one more strong reason for the importance of 4D seismic data.

The Foinaven asset team has used the information from the amplitude maps computed by the SPM to update their fluid-flow model in those regions where the mismatch with the seismic-derived maps was significant. Overall, the project directly linked geophysical results to reservoir engineering production models. We believe that qualitative use of SPM is just one important step at the beginning of the process and further implementation of the steps discussed below may enable a move to full quantitative interpretation and updating of the reservoir model.

3.2. Qualitative versus quantitative 4D interpretation

If we want a quantitative interpretation of a 4D response, then we need to address the following issues:

1) The geological model:
   A) Is it realistic enough to allow a quantitative interpretation? The net-to-gross model is obviously a large simplification of a very complex geological system. This model is likely to work optimally for fluid-flow modeling rather than for modeling elastic properties. Assuming that the elastic properties of net and gross remain constant and only the concentrations for each reservoir cell have changed is not realistic.
   B) What confidence (resolution) do we have in the realizations of the geologic model? The common current practice of deriving a geological model from seismic data and logs using geostatistical techniques to fill in the interwell volumes provides a poorly constrained picture with several uncertainties. The typical size of the cells used in the simulation models (typically ~100 m x 100 m x 2 m) is too large to justify constant properties derived from well logs and too small to obtain a reliable estimate from low resolution seismic data. The best possibility to improve our knowledge (and hence our reservoir characterization process) is to incorporate downhole seismic measurements with much higher frequencies and resultant improvements in resolution.

2) Rock frame modeling:
   A) Do we currently have the proper tools for modeling rock frame? Assuming a simple net-to-gross value for any particular cell is insufficient to compute effective resultant elastic properties. In many examples, the layered structure present in the actual distribution of net and gross would require Backus averaging, poroelastic averaging (Bakulin, 1997) or other techniques to accounting for spatial distribution details and anisotropy.
   B) How do we know that rock frame properties stay constant with time? For the Foinaven case study, we assumed that rock frame elastic moduli do not change with time. In many cases, this is not realistic and changes in rock frame due to changes in effective stress can override the fluid effect and provide a wrong estimate of the time-lapse seismic response (Pennington, 2000). The real challenge is to measure the correct parameters controlling velocity versus behavior stress (or other reservoir conditions changing with time) and to account properly for these effects.

3) Forward seismic modeling:

How confident are we in the synthetic seismic results (assuming that the reservoir properties are predicted correctly)? For the Foinaven case study, we have used a 1D convolutional method assuming constant velocity in the overburden. This worked very well in Foinaven due to the favorable reservoir and overburden geometry and rock properties. In the majority of cases this will not be realistic and we ideally require a good velocity model of overburden as well as more sophisticated 2D/3D computations. This would require merging a seismic-derived velocity model for overburden and an SPM-derived velocity model for the reservoir. Currently, there is no software to support such a workflow.

One alternative to avoid such a process is to invert the seismic data for elastic parameters and perform the comparison in the domain of reservoir elastic properties. In this case, all the complexity is moved into the seismic inversion domain. However, properties derived from standard surface seismic have low vertical and lateral resolution. Therefore to compare them with smaller scale predictions computed by the SPM would require proper up- and downscaling. To be meaningful, this kind of quantitative route requires the introduction of uncertainty by seismic inversion.

4. The road ahead

To make a quantitative link between the flow simulator and the seismic data, we are obliged to address the issues listed above as well as several others. We will try to resolve the most important of them but at this stage of our research, some will remain unanswered.

4.1. Initial characterization (Geological and rock-frame model)

As a result of this work, we propose that the best way to build reliable, high-resolution geological and rock-frame models is to:

1) Instrument the boreholes with acoustic sensors. To make this process cheap it is worth installing permanent sensors for the duration of the reservoir's life.
2) Perform an extensive single-well, cross-hole high-resolution characterization combined with traditional VSP and log program.
3) Combine this information with surface seismic data (3D, 3C and 4D) and build unified geological and rock-frame models.

A more radical approach for the future would be to drill above the reservoir, a network of horizontal side-tracks from existing production, appraisal or injection wells. These could be used to perform localized reflection surveys in a similar way to surface or ocean-bottom seismic surveys, thus characterizing the reservoir body in high resolution. These side-tracks wells could be further used ***for in-situ 4D seismic*** (see below).

4.2. In-situ 4D seismic

It seems natural to include the borehole permanent measurements into the SPM workflow, as it is essentially the same measurement as surface 4D seismic but with the added advantages of being carried out at higher frequencies with acquisition directed at the reservoir. In addition, such time-lapse borehole measurements are superior to surface seismic because they are almost free of the overburden effects and have higher resolution. Drilling several horizontal side-tracks above the reservoir exclusively for putting their permanent seismic sources and receiver is an exciting possibility for the future. It is possible that 4D single-well or well-to well reflection measurements using these side-tracks might in fact replace surface 4D monitoring with its typical problems of low frequency, low resolution, strong multiples, complex overburden etc. This development however is obviously strongly tied to drilling technology and cost. In the meantime, we foresee a well-balanced mix of both surface and in-situ 4D seismic.

4.3. Stress-dependence of the rock frame properties

The importance of this effect is difficult to overestimate. Pore pressure drop during production leads to "stiffening" of the rock frame because the effective stress is increasing. This effect is not of primary interest to us, however, as it competes with fluid response like "weakening" of elastic properties due to gas coming out of solution. If we account for stress effects ("noise") then we are left only with a "fluid" or "saturation" response which is in fact the "signal" in time-lapse studies.

One possibility is to use input from time-lapse logging techniques (see *Guerra et al.*, this volume). Another possibility is to acquire ***in-situ 4D seismic*** or VSP while testing (pressurizing) a well. This has an advantage of averaging the reservoir properties at a range of seismic wavelengths and therefore is less sensitive to local variation in conditions existing in the borehole. However, it takes significant time for pressure or the fluid front to propagate a significant distance away from the borehole so that changes can occur in a volume big enough to be detected by borehole seismic wavelengths. The technical challenge for the VSP survey is to have sensors installed and measurements performed in a production well. Another challenge is to be sure that we independently measure the properties we want to sense by seismic - either form the well itself or from local side-tracks, 3-10 m long, with sensors installed inside.

In the future we foresee a use for all these types of measurements complementing each other because of the inherently different scale and volume sensed. For example, using logging techniques gives us a "local" answer in real time while the well is drilled and logged, whereas time-lapse VSP will deliver its "more global" answer but with inherent time gaps. A VSP experiment may be considered also as a feasibility survey for time-lapse. If good results are obtained, it enables the decision to utilize either surface or ***in-situ 4D seismic.***

5. Conclusions

The methodology for seismic monitoring is still in the early stage of design, although some interesting, relevant technology is starting to become commercially available. We describe in detail one of the possible approaches for integrating the fluid-flow and geological models with the seismic data. Prototype software, called the Seismic Property Modeller, was built to demonstrate an example of the application of the technology. The Foinaven case study, using this new software, revealed the areas of the reservoir that could require an adjustment to the fluid-flow model. The results proved to be valuable for the asset team and particularly for the asset reservoir engineer.

We address several important challenges that have arisen on the implementation of this approach. In particular, we emphasize the importance of initial reservoir characterization for building a confident geological and rock-frame model. To successfully achieve this, we strongly advocate the use of high-resolution borehole or even in-situ reflection surveys from a network of horizontal side-tracks. Additionally, we advocate the use of special measurements exclusively designed for calibrating the 4D response. As an important example of such measurements, we propose determining stress sensitivities of rock frame by either specialized logs, VSP or in-situ seismic.

Finally, we foresee the use of new technique **“**in-situ 4D seismic**”** which uses a network of horizontal side-tracks to perform the measurements directly above (or inside) the reservoir. This technique for the future completely eliminates the problems typical for surface seismic such as statics, strong ground-roll and multiples, attenuation of higher frequencies.

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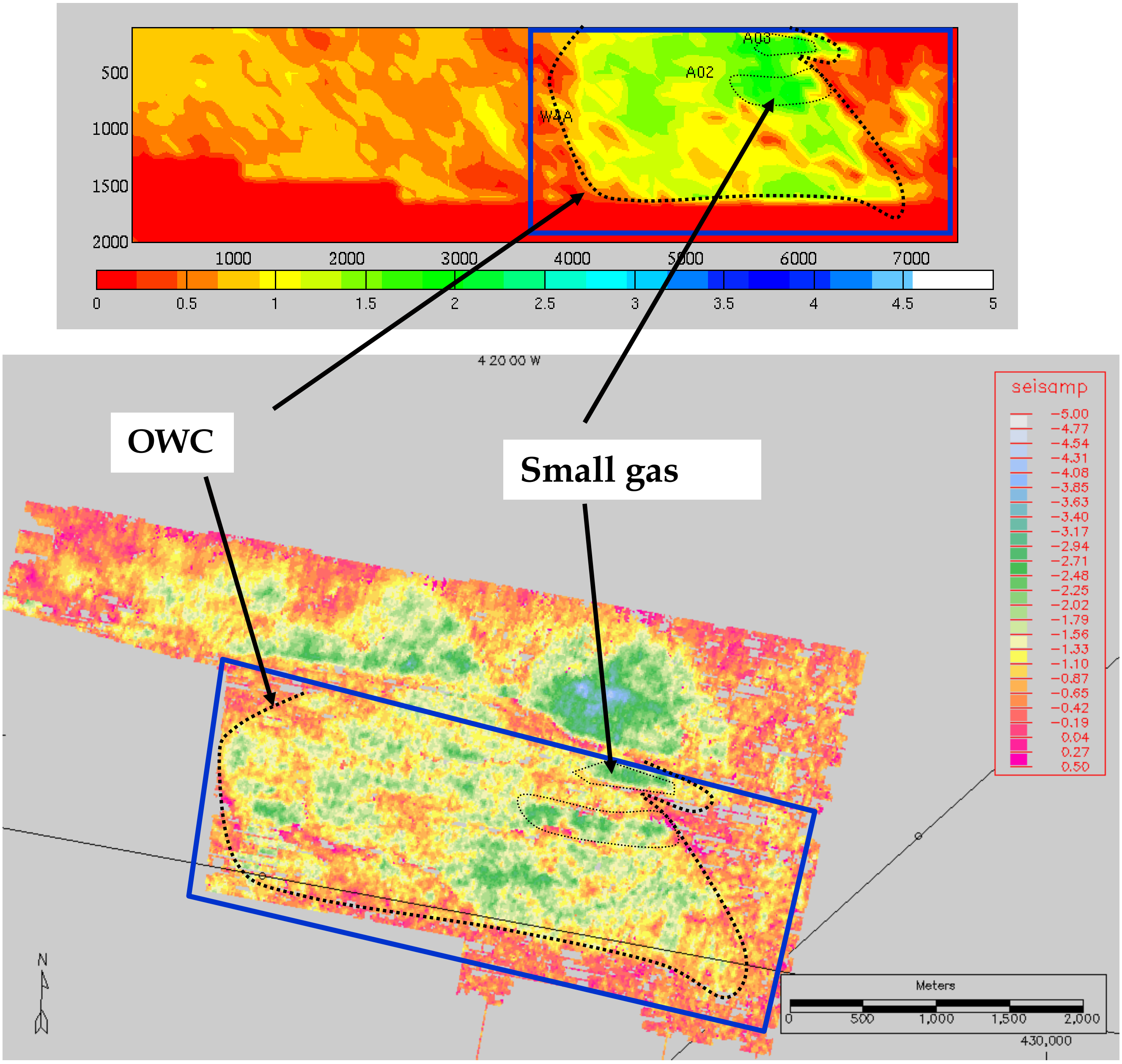

Figure 1. Comparison of amplitude maps for the top reservoir of the Panel 4 fault block of the Foinaven field computed using the SPM from the Eclipse model (top) and the same from real seismic data for the 1995 baseline survey (bottom).

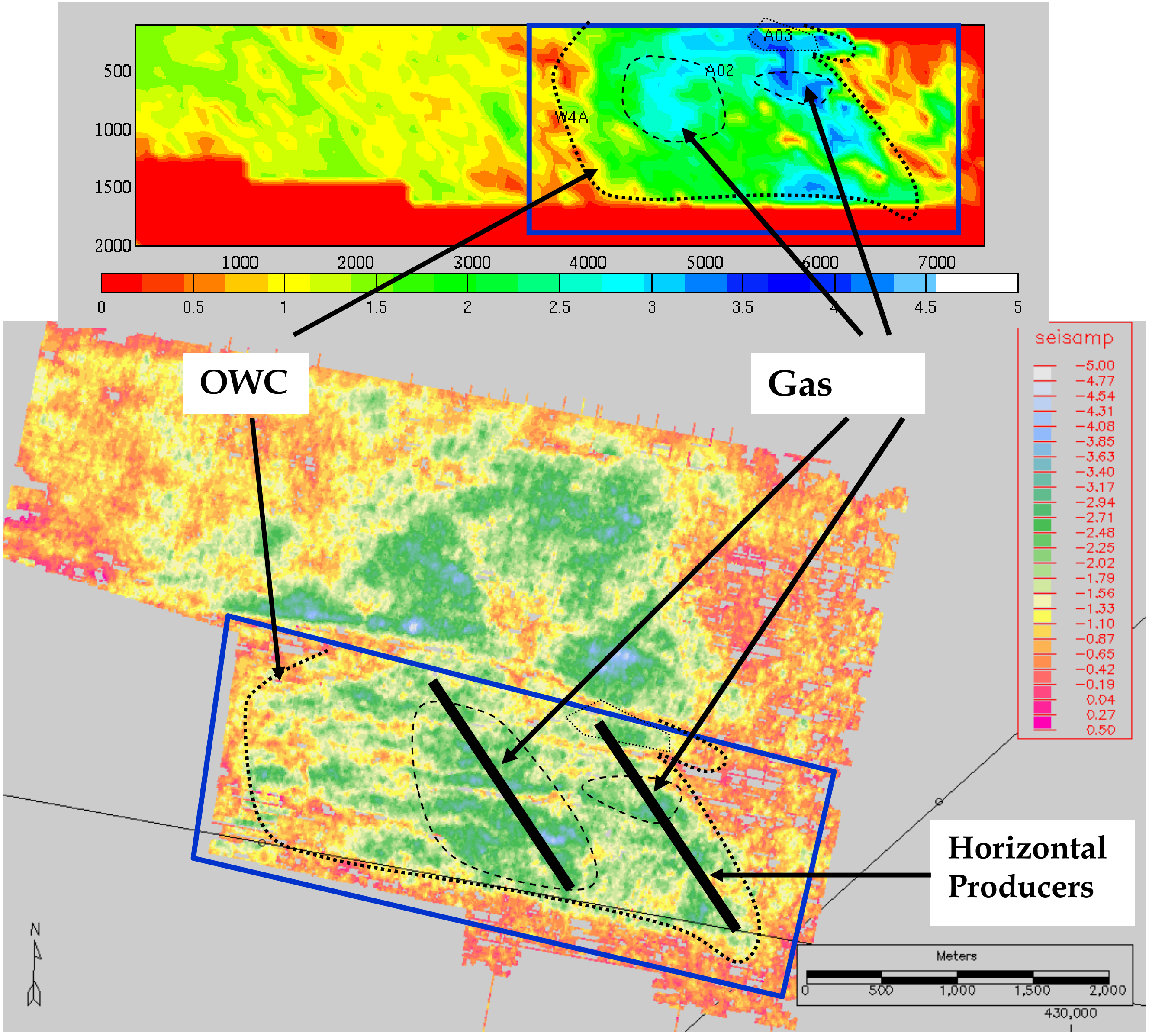

Figure 2. Comparison of amplitude maps for the top reservoir of the Panel 4 fault block of the Foinaven field computed using the SPM from the Eclipse model (top) and the same from real seismic data from the repeat 1998 survey (bottom).