Use of Seismic Inversion to Constrain the Heterogeneity of Reservoir Models in a Carbonate Environment – a Case Study from Al Shaheen Field Qatar*

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Abstract

The Al Shaheen Field is a giant field located offshore Qatar in Block 5 and Block 5 extension (Figure 1). It produces from a series of stacked reservoirs consisting mainly of carbonates including the Kharaib. The Kharaib reservoir is mature, with over 100 producers and injectors having been drilled since 1994, making it the most extensively drilled reservoir in Block 5. It is also the reservoir with most core and well log data, which allow the quantitative interpretation of the seismic data over the reservoir, including derivation of a porosity volume.

The dynamic behaviour of the reservoir is controlled by the permeability, with matrix behaviour being the most significant component. Development is increasingly being directed at areas of lower oil viscosity, which makes the prediction of permeability in target areas particularly important. Experience to date shows that permeability is largely dependent on porosity, and so estimation of porosity, including the range of uncertainties, plays a key role in developing an accurate dynamic model of the reservoir. A small number of wells are affected by local fractures.

Reservoir Stratigraphy

Rock types found in the upper part of the Kharaib B range from mudstones and wackestone at the base to packstones and grainstones. A number of breaks in the deposition resulted in thin (~1.5 m) laterally continuous hardgrounds of lower permeability. The reservoir therefore consists of alternating softer (primary reservoir zones) and harder layers, with a total thickness varying between 20 and 30m. Well log correlations and core samples suggest a laterally continuous stratigraphic model, but reservoir variability does exist, both vertically and laterally at shorter scale lengths, and it is these heterogeneities that must be understood in order to ensure an optimal field development. The spatial distribution of and variability in oil APIs provide another level of heterogeneity that is not discussed here.

Reservoir Porosity Models

Reservoir porosity models are commonly built using well log data from vertical wells. However, since such wells are relatively sparse, even in this densely drilled field, the expected variability will not be properly represented. The true reservoir porosity would be better represented by a more heterogeneous model based on data from the entire reservoir, and not just the well locations. Porosity derived from seismic data offers the possibility to investigate the heterogeneity in areas without well control. The seismic data were inverted for absolute acoustic impedance using proprietary geostatistical inversion software called Jigsaw (Cherrett et al, 2011). Well log data from clean water-saturated carbonates in the Kharaib B reservoir show a strong correlation between porosity and impedance (Figure 2). This correlation may in principle be perturbed by differences in rock frame stiffness resulting from facies changes, but in the relatively homogeneous Kharaib one may expect that this effect is minimal. Figure 2 shows the relationship between P-impedance and porosity for the Kharaib B rocks from the wells used in the seismic inversion prior model. The relationship between impedance and porosity is shown to be linear and may be confidently used to estimate porosity from an impedance volume with an accuracy of approximately +/- 2pu.

Methodology

A seismic inversion typically produces a result that is sampled in time, and has limited vertical resolution compared with that required for characterisation in a reservoir model. In addition, it usually has a regular horizontal sampling which may be finer than the reservoir model grid sampling. If the seismic products are to be of use during the reservoir modelling process, a method must be devised which resamples the seismic results into the geometry of the reservoir model.

As a first step, the seismic porosities are upscaled horizontally from the seismic to model grid size. The value of the upscaled property within a reservoir model grid cell is the average of the properties from the seismic traces falling within that grid cell, with appropriate weighting for traces falling close to the boundary of the cell.

The second step requires that the seismic data in time be converted to model grid data in depth. In principle, this could be accomplished using a velocity model, but in practice it is difficult to produce a velocity model that is sufficiently detailed and accurate to perform this conversion without significant errors and inconsistencies. Another approach is to map the seismic horizons interpreted in time onto the corresponding model surfaces in depth. In this case, we had four seismic horizons available – top and base reservoir and two intermediate horizons. Between these horizons, the layer proportions were assigned according to the inverted porosity, which is possible here because porosity has a strong relationship to velocity. (This approach ignores minor variations in mineral density within the Kharaib B.) As a final stage, a curve is fitted to the seismic porosity in depth and the result resampled into the reservoir model grid layers. This process is illustrated in Figure 3.

Discussion and Results

The result of this rescaling process is a reservoir model populated with porosities obtained from seismic inversion. Unlike a well data derived model, it is a property that is based on data from the whole field, rather than at a few locations. However, the seismic data may be noisy, which gives a result that can appear excessively variable when compared with expectations based on areas with dense well spacing or outcrop

analogues. It is therefore desirable to investigate the extent to which the seismic derived porosity is overly heterogeneous, and if necessary to correct for this effect.

The heterogeneity of the reservoir was characterised by calculating horizontal variograms of porosity for the reservoir layer for which most data were available. These data were used to populate a 2D grid, and a 2D plane fitted to them and used to detrend the data. The variograms were computed in the FFT domain using the method of Marcotte (1996). A similar procedure was used to calculate the variogram of the seismically derived porosity. The results are shown in Figure 4.

In Figure 4, the red curve shows the variogram of the horizontal well porosity data. This may be compared with the variogram of the seismically derived porosity data shown in dark blue. These seismically derived data show a much higher variability than the well data. However, the well data do not provide a representative estimate of the variability over the whole block area, and if the variogram is calculated for seismic porosity data resampled at the wells, to provide a fair comparison with the well porosity data, that variability is considerably reduced (green curve), and is comparable to the variability of the well data. At this stage, a spectral matching operator can be calculated and applied to the seismically derived porosities in order to give a dataset, which is populated over the whole field and matches the observed variability of the well data (cyan curve). The effects of applying this filter are shown in Figure 5. Casual inspection does not reveal large changes during this process, but there are areas of significant modification, such as the one circled.

A further calibration is applied to the porosities in which a smoothly varying adjustment is applied on a reservoir layer by reservoir layer basis. This adjustment is calculated by fitting a smooth surface to the residuals between the seismically derived porosity and the well porosity. The result of this process is to add a fine scale layering to the porosity model.

Summary

Such an approach may appear to be an unwarranted manipulation of the data, but the justification lies in the fact that the reservoir units in this area are very laterally extensive and highly correlatable. We observed that the shape of the porosity well log curve remains relatively unchanged, although the absolute values of the porosities vary laterally. Because of the calibration, the seismic porosities match observed well trends, and the effects of limited seismic bandwidth and residual noise are somewhat compensated, while local variations in porosity are preserved. Finally, local adjustments are made in order to match the well data for QC purposes.

Figure 6 shows a comparison between a porosity model built using vertical wells and the seismically derived porosity volume. Clearly, the level of heterogeneity in the seismic porosity is greater, and this has been shown to be more representative by comparison with horizontal wells. Comparison with the horizontal well data also shows that the absolute values of porosity are more realistic in the seismic porosity, as is the connectivity, which has implications for estimation of both in-place volumes and reserves. The seismic porosity volume was therefore useful in investigating the resource estimation in undeveloped areas of the field, helping to unlock remaining potential in this mature reservoir.

Acknowledgements

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References Cited

Cherrett, A.J., I. Escobar, and H.P. Hansen, 2011, Fast deterministic geostatistical inversion: 73rd EAGE Conference and Exhibition.

Marcotte, D., 1996, Fast variogram computation with FFT: Computers and Geosciences, v. 22/10, p. 1175-1186.

Figure 1. Location of Block 5 and Extension area, offshore Qatar.

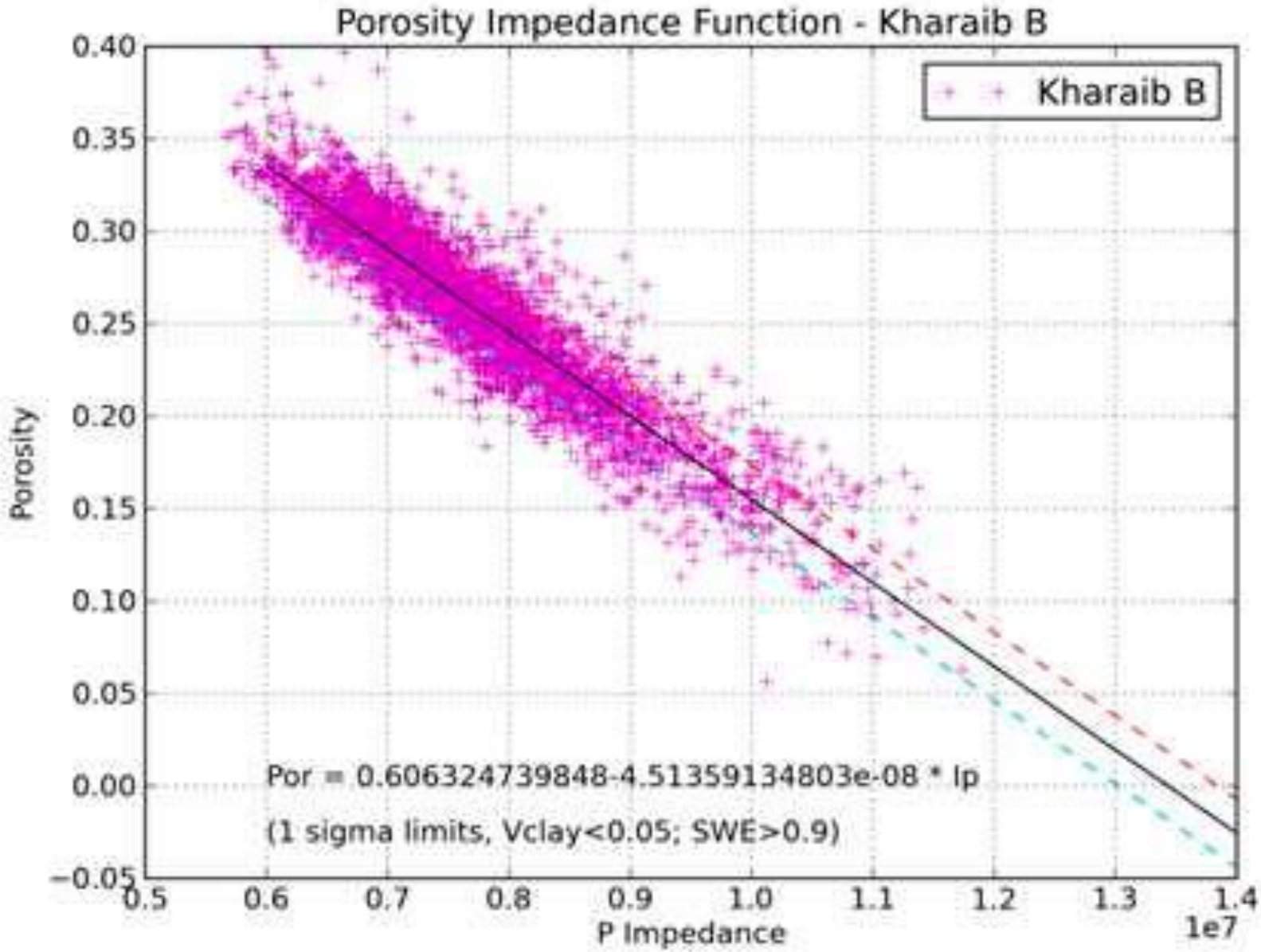

Figure 2. Relationship porosity vs. acoustic impedance (Ip) for Kharaib B carbonates. The points plotted correspond to low clay content (Vclay <5%) and high water saturation (Sw>90%).

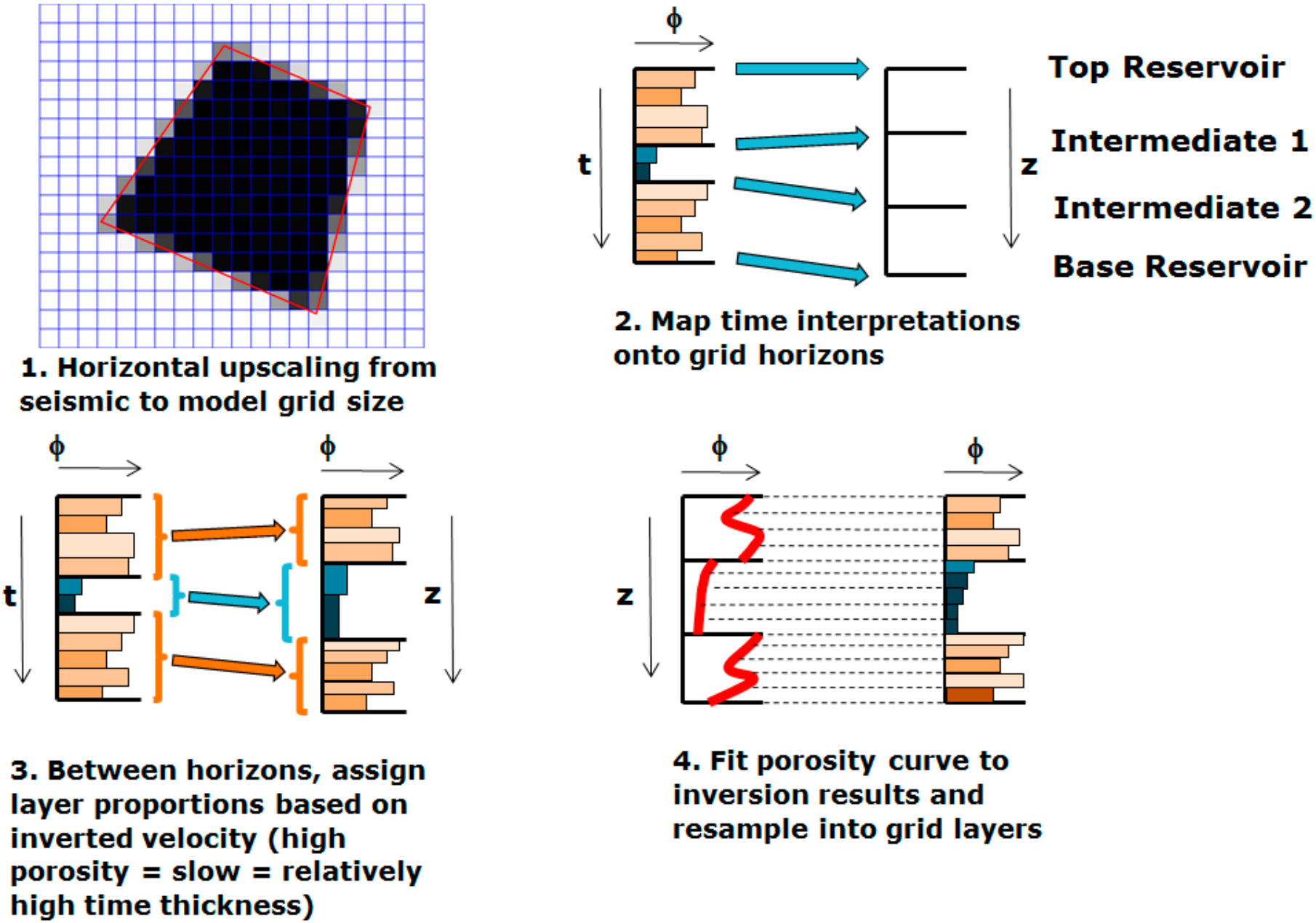

Figure 3. Steps in upscaling seismic porosity to reservoir model porosity.

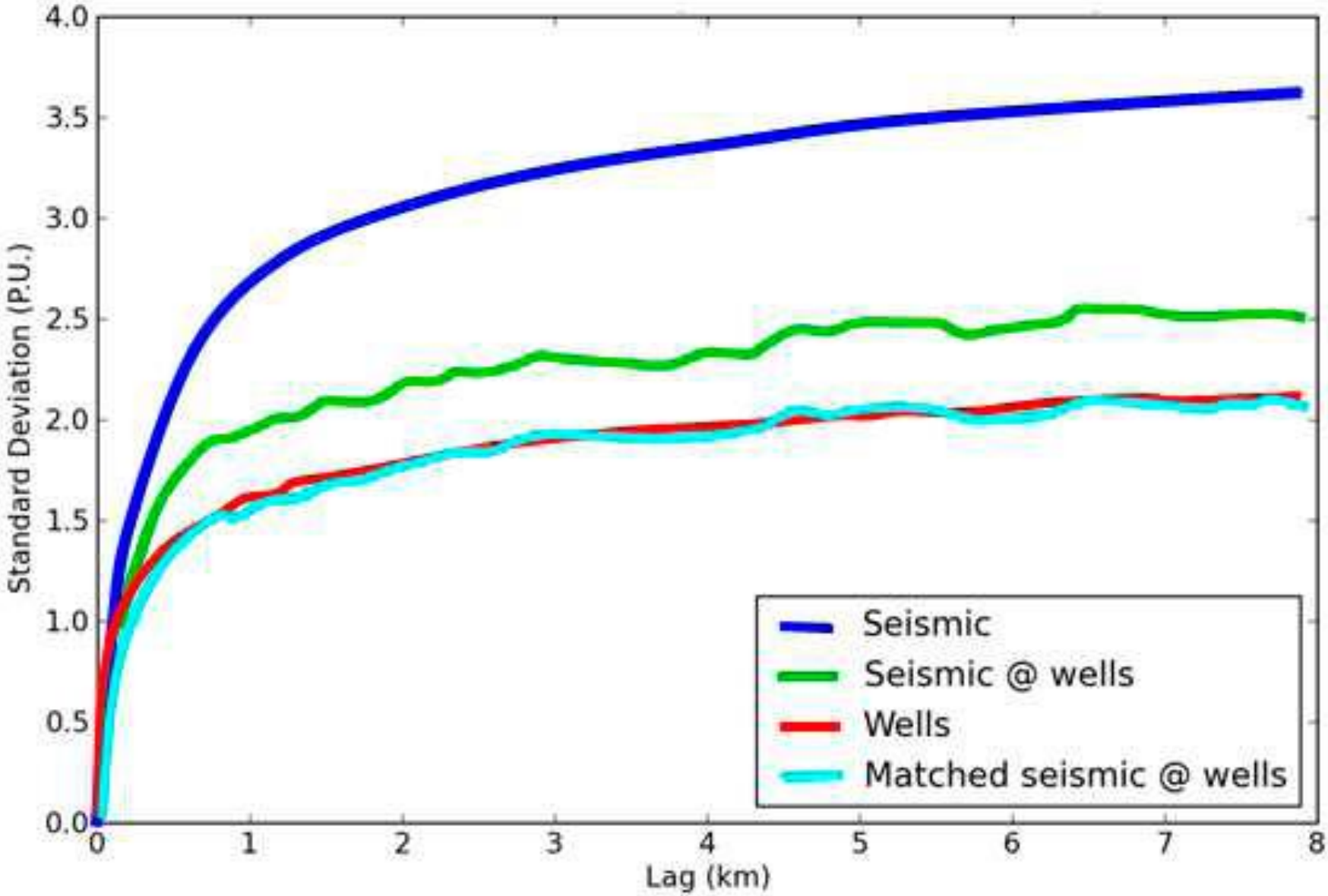

Figure 4. Variograms of porosity showing the difference between well and seismic-derived porosity heterogeneity.

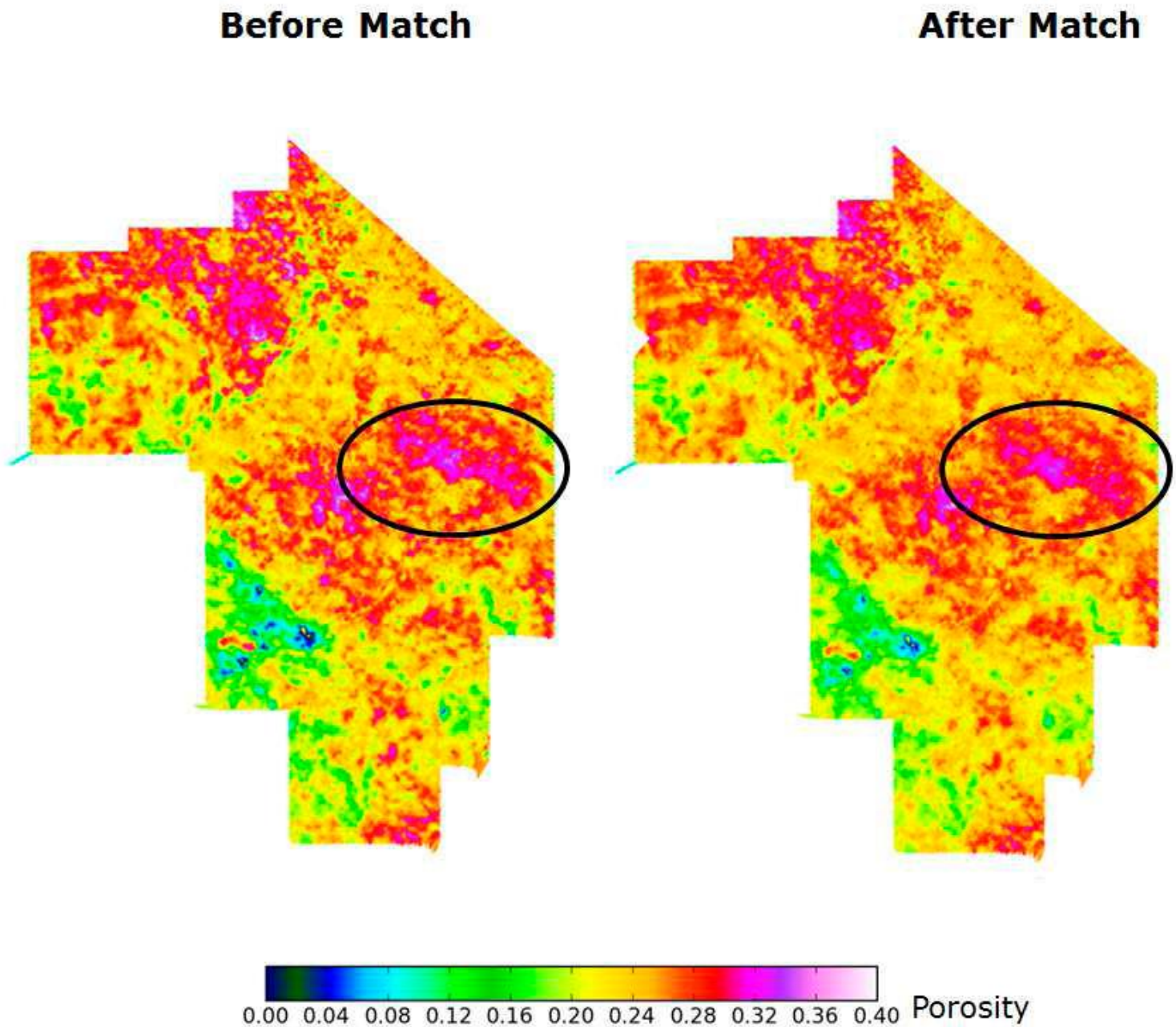

Figure 5. Effect of applying spectral matching filter to layer.

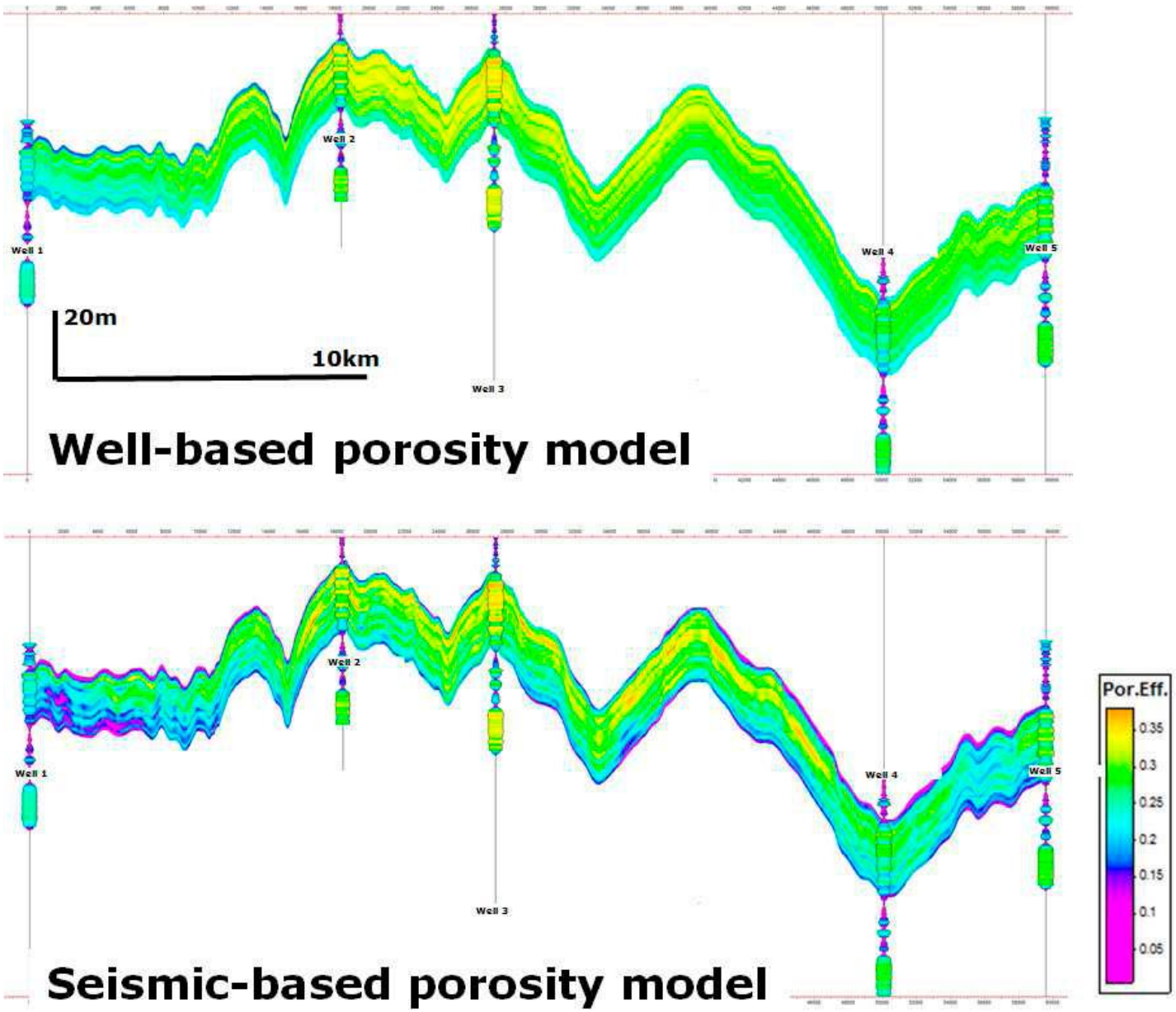

Figure 6. Sections through well-based and seismic-based porosity models showing the increased heterogeneity achieved using seismic data input, with significant differences away from the wells.