Combining BroadSeis 3D HD-WAZ data in a reservoir-driven processing approach for field development

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The advent and integration of new technologies in seismic acquisition, processing and reservoir characterization are allowing for a better understanding of the geologic processes playing a part in the creation of hydrocarbon reservoirs in the subsurface. Extended seismic bandwidths provided by broadband acquisitions (BroadSeis), improved illumination from wide-azimuth (WAZ) configurations and high spatial resolution made possible by dense acquisition techniques are all new technologies producing visually compelling imaging and reservoir results. In addition, application of the latest reservoir characterization tools and workflows on these data are bringing greater insight into the inner workings of petroleum reservoirs.

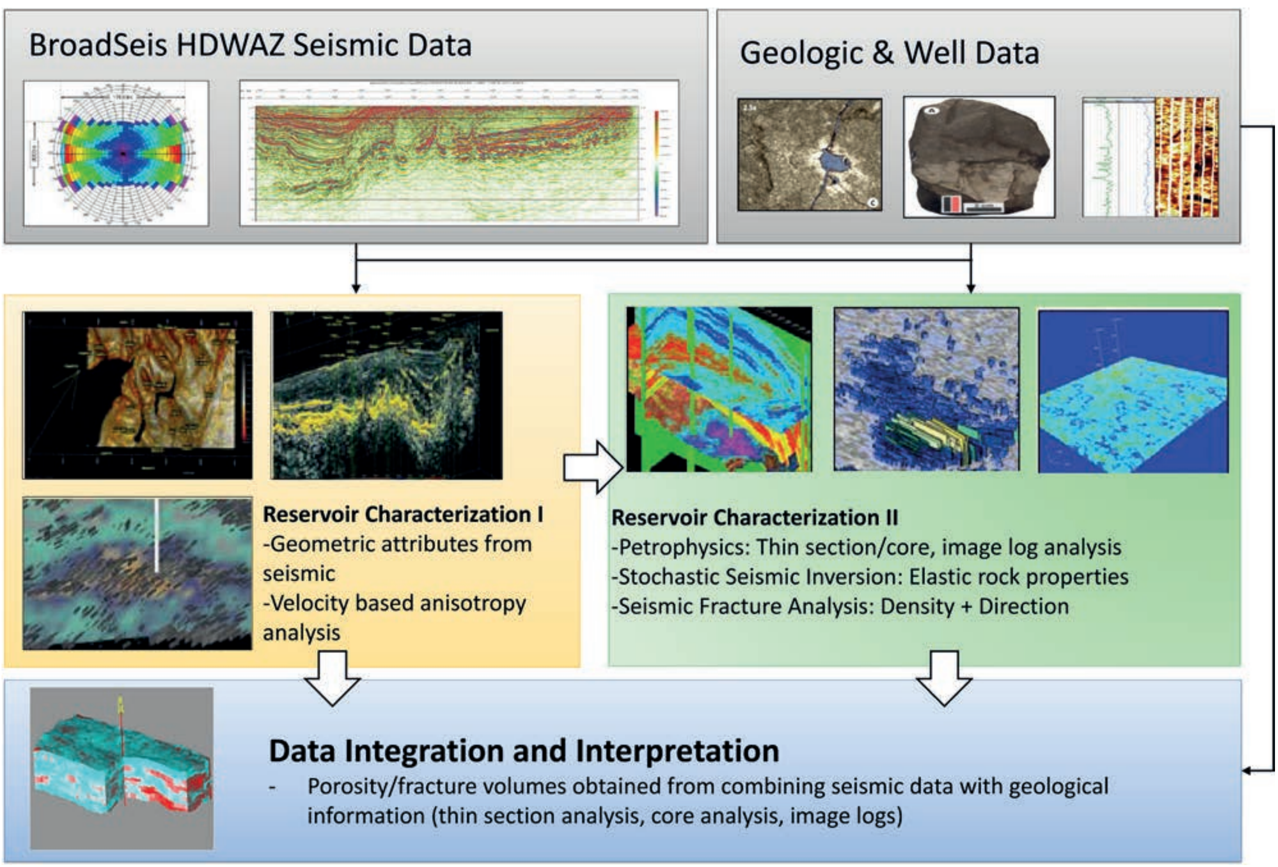

***Figure 1** A tailored acquisition, processing and reservoir characterization workflow.*

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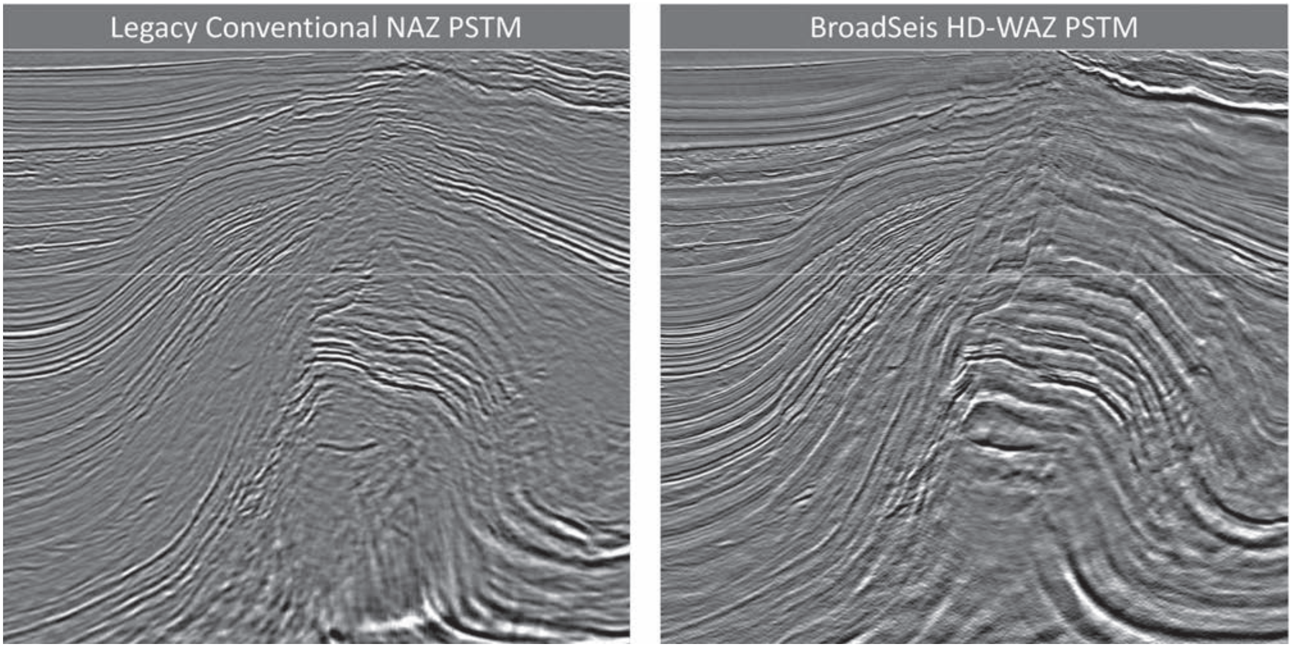

***Figure 2** Legacy conventionally acquired Narrow-Azimuth (NAZ) data (left) compared to High-Density Wide-Azimuth (HD-WAZ) data (right) showing improved illumination and resolution for structural and stratigraphic interpretations.*

Seismic acquisition and processing

In order to gain a detailed quantitative understanding of the reservoir, a team of geoscientists conceived a survey design and reservoir-driven processing flow to meet the reservoir characterization objectives. The resulting broadband high-density wide-azimuth (HD-WAZ) survey was acquired for Pemex targeting a shallow-water Gulf of Mexico reservoir. On this survey, four sources and 24 streamers were deployed in a multi-vessel arrangement using CGG's BroadSeis seismic acquisition methodology, delivering detailed high-resolution images that are ideal for both structural interpretation and reservoir characterization. High temporal resolution was provided by variable-depth streamer acquisition, enabling broadband imaging from 2.5 to 150 Hz. High spatial resolution was required in both inline and crossline directions, necessitating a dense shot grid and interleaved sail lines. Continuous recording was employed to maximize record length despite the close shotpoint interval.

A fully integrated reservoir-oriented processing sequence was applied to the data to facilitate a detailed reservoir characterization study. Key processing steps included demultiple, velocity analysis, deghosting (Soubaras, 2010) and Kirchhoff migration. The shallow water depth resulted in strong multiples throughout the dataset, necessitating a multi-step 3D prediction and subtraction flow to uncover the underlying primaries. Geology-based rock property models yielded a series of synthetic seismic forward models that were utilized for amplitude and phase preservation and refinement of the pre-stack migration velocity model. Broadband deghosting and pre-stack Kirchhoff migration yielded an image with substantial improvements over the legacy conventional narrow-azimuth (NAZ) data, including higher definition in the shallow section, sharper fault plane imaging and

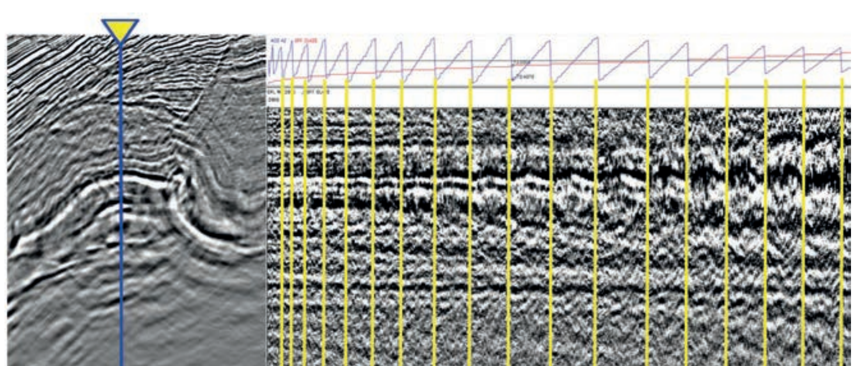

***Figure 3** A single prestack-migrated gather (right) from the HD-WAZ data. The yellow vertical lines in the gather group traces have the same offset, yet different azimuths from 0 to 180 degrees. The angle-dependent time differences are caused by azimuthal anisotropy and highly related to fracture orientation and density.*

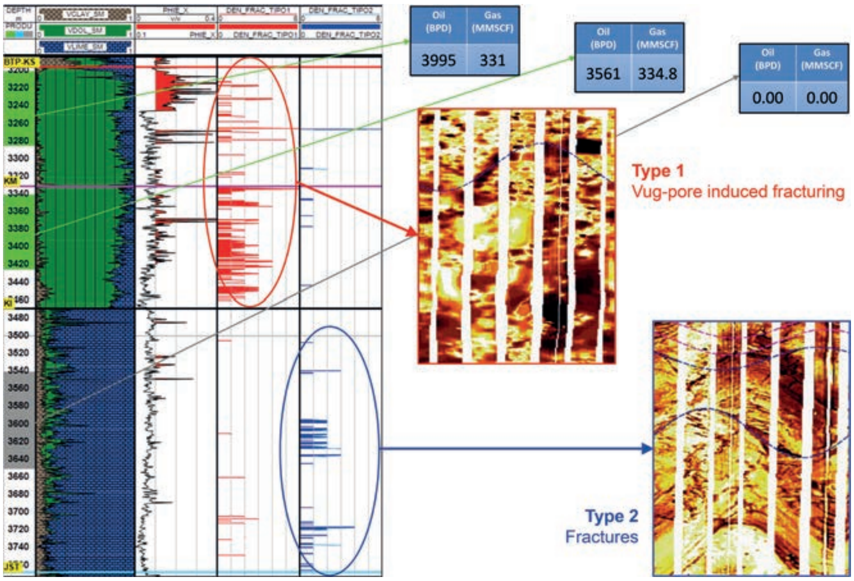

Figure 4 *Type 1 fractures, associated with vuggy porosity, correspond to high total porosity areas and producing intervals. Type 2 fractures are associated with low-porosity intervals and poor or no hydrocarbon production.*

superior definition of deep structures as shown in Figure 2. However, the benefits of the new dataset for the purposes of the reservoir characterization study were even more apparent in the pre-stack domain. Figure 3 shows a pre-stack time-migrated gather near one of the well locations. The high fold and azimuthal sampling of the high-density WAZ data yields a dense sampling of azimuths within each offset class. In the displayed location, azimuthal anisotropy effects appear in the timing variations within each offset class, providing valuable information for fracture characterization.

Reservoir characterization

The primary objective of the reservoir characterization was to identify and quantify the generation of secondary porosity within the carbonate reservoir. In the target reservoir, porosity has been enhanced as a combined result of fractures, dissolution voids (causing vuggy to cavernous porosity) and dolomitization of the original limestone. The geological processes responsible for this porosity enhancement are complex and include both regional and local tectonics together with a complex diagenetic history. Understanding the significance of the altered seismic data response associated with the effects of these geological processes is critical to the understanding of the geological model.

Upon completion of the acquisition and reservoir-driven seismic processing stages, the reservoir characterization study was initiated and divided into three phases, as shown in Figure 1. The first phase focused on the generation of geometrical attributes, spectral decomposition and initial fracture analysis based on Horizontal Transverse Isotropy (HTI). During phase two, geological and petrophysical analyses were carried out on well data to identify reservoir properties such as porosity, lithology and fracturing. This information, combined with the subsequent rock physics analysis, allowed for the calibration of well data to seismic attribute volumes derived from elastic and azimuthal inversion processes. The last phase integrated and analysed geological, petrophysical and seismic data to identify prospective areas and high-grade locations for new wells.

Petrophysical and geological analysis

The objectives for this phase were as follows:

- QC and edit logs to perform petrophysical evaluations and rock physics analysis.
- Conduct petrophysical evaluations to characterize the reservoir, using the selected wells and integrating all available information to calibrate with reservoir properties.
- Identify the best elastic properties to characterize the lithological end-members in the field.
- Find the best correlations between petrophysical and elastic properties.

Seismic-based predictions of lithofacies and fracture density were challenging to obtain due to the complex nature of the secondary porosity. Significant effort was made to constrain these predictions using geologic interpretations from wireline and image logs, thin sections and core data analysis. Based on this analysis, the reservoir was subdivided into two basic classes:

Type 1: Fractures associated with vuggy porosity, within a high-porosity dolostone.

Type 2: Non-vuggy fracturing associated with low-porosity limestone.

Figure 4 shows well-log examples of these end members (limestone/dolostone) and highlights the significant differences in effective porosity (track 2). Type 1 fractures are associated with the presence of dolostone and are high-porosity reservoirs, whereas type 2 fractures are associated with the presence of limestone, low porosities, and are non-producing intervals.

The improved reservoir properties in the type 1 intervals result from the presence of large, vugular pores in which pore connectivity is significantly enhanced by the presence of fractures. This not only accounts for the higher log porosities, but also has implications for improved permeability relative to type 2 intervals.

Seismic azimuthal anisotropy shows a clear difference in areas characterized by type 2 vertically oriented stress fractures. Attributes from this anisotropy can be compared with image logs to determine the relationship between the two data types in order to predict fracture density away from the wells.

The distribution of the type 1 vuggy porosity appears to be less regular and predictable than the type 2 stress fractures, showing less noticeable seismic azimuthal anisotropy. An alternative methodology was therefore required to characterize the fractures and vugs, and predict the orientation, magnitude and secondary porosity effect. To identify these prospective areas, porosity discretization was carried out based on petrophysical information. The discretization process involved the separation of the different components that contribute to the total porosity calculated within any interval in the reservoir (matrix, vugs, micro-fractures, fractures) and, as a result, it was determined that type 1 fracturing contributed to reservoirs where total porosity values are in excess of 10%. Pore size was also determined to have had an effect on overall reservoir quality; samples with large vuggy or cavernous porosity >16 mm in diameter ('megapores') (Flügel, 2013) correspond to the best producing intervals. Additionally, rock physics analysis identified a good separation of these high-porosity areas from background values based on elastic parameters. Figure 5 shows an example of the final porosity discretization carried out for one of the control wells, as well as the observed relationship between calculated total porosity and acoustic impedance (upper right), and acoustic vs. elastic impedance (lower right).

Seismic attributes

The seismic characterization phase of this project focused on obtaining elastic impedances (P-impedance, S-Impedance) and anisotropy-based seismic attributes (Castillo and Van de Coevering, 2013). With judicious geologic constraints, fracture information can be inferred from these anisotropy-based attributes. Pre-stack azimuthal velocity analysis and azimuthal seismic inversion yield fracture-based attributes including: normal and tangential weakness, anisotropic gradient, fracture strike, Vfast, Vslow and the orientation of Vfast.

Rock physics analysis indicated that high-porosity intervals could be identified with a good deal of certainty on the basis of elastic parameters. However, in order to separate the end-member lithologies into their discrete porosity units, the uncertainty associated with lithology identification and porosity calculation needed to be reduced to a minimum. Elastic attributes obtained from deterministic and stochastic inversion analysis, as well as anisotropic parameters obtained by means of the azimuthal inversion process, were used as inputs for a multi-attribute analysis designed to improve lithology and porosity calculations.

Prestack seismic inversion is required to extract the P-impedance and S-impedance volumes from the seismic data. As the earth has filtered both high and low frequencies from the original seismic source, the low-frequency band must be recovered from geologic constraints. As a development project with sufficient well control, a low frequency model was constructed with seismically-guided interpolation of filtered impedances from the well logs.

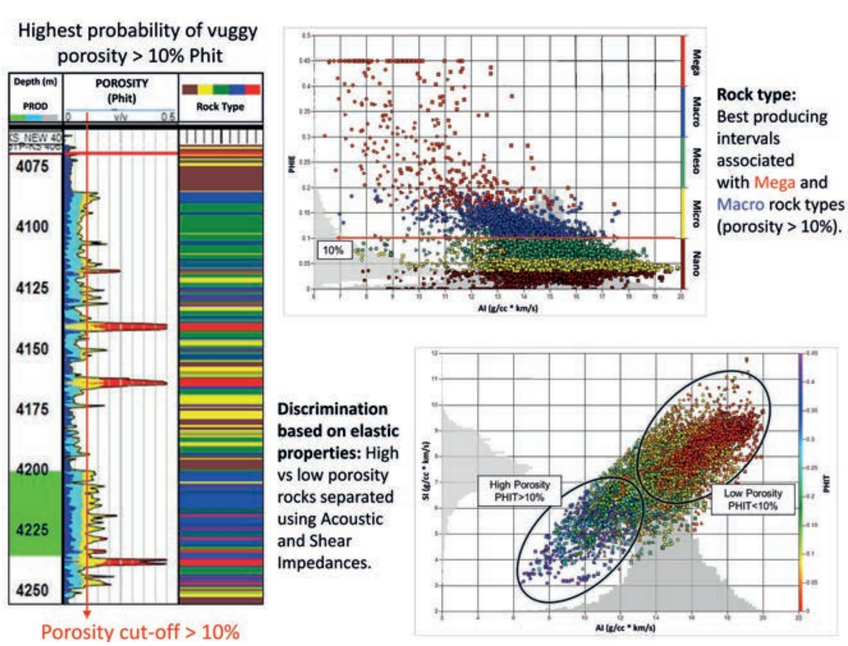

***Figure 5** The image on the left shows the resulting porosity discretization, in which most producing intervals are associated with porosity values in excess of 10%. The top cross plot shows the discretized porosity groups vs. Acoustic impedance. The cross plot at bottom right shows P-Impedance values plotted against S-Impedance and coloured by total porosity. Note how points associated with high porosity separate in the bottom left corner of the plot.*

The broader frequency spectrum obtained as a result of broadband acquisition and processing proved valuable in the creation of reservoir property volumes such as porosity and lithology. Specifically, the improvement in the low-frequency component reduced the reliance on the pre-stack inversion low frequency model, leading to higher confidence in the multi-attribute seismic analysis prediction of rock property volumes.

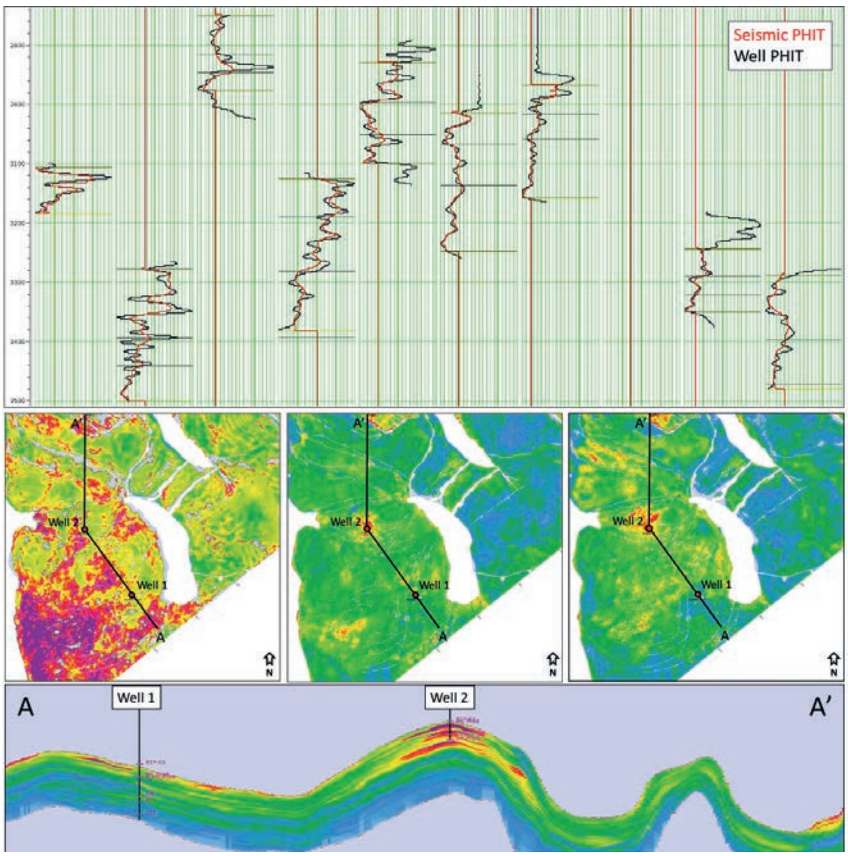

Figure 6 *Porosity estimation from seismic data compared to calculated porosity from well data (top). The resulting porosity volume allows for the extraction of the maps shown, which are helpful in identifying the highest porosity areas at different stratigraphic intervals.*

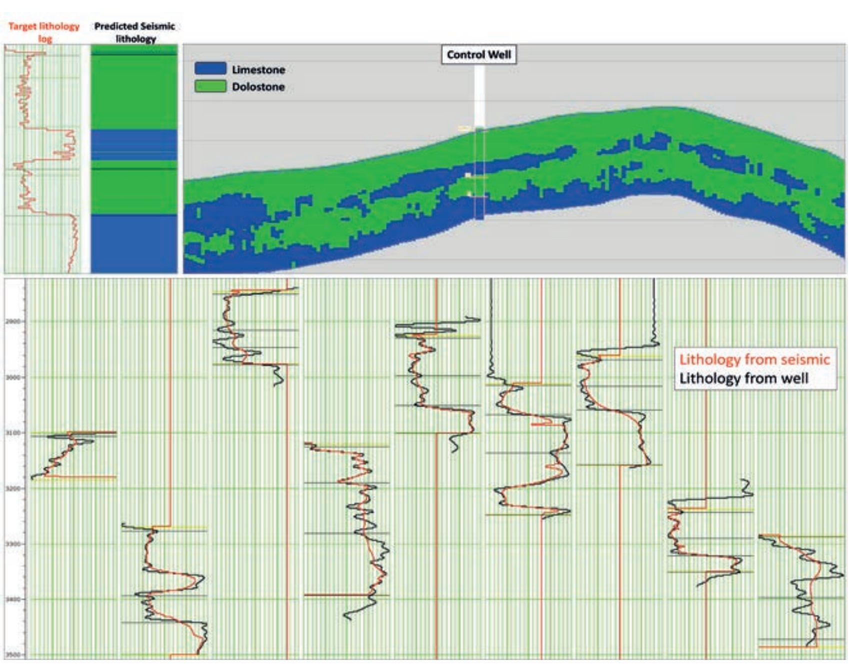

Figure 7 *Top image shows a classified lithology cross-section as a result of multi-attribute analysis/ prediction techniques. The bottom image shows lithology estimation at the well locations from seismic data (red trace) compared to calculated lithology from well data (black trace).*

Figure 6 shows the results of the multi-attribute porosity calculation based on seismic inputs at various control wells (top image). The estimated total porosity values from seismic are shown in red, while the total porosity curves from petrophysical analysis are shown in black. Correlation between well data and estimated seismic values is high; it is this type of detail that allowed for a more thorough analysis during the interpretation phase. The maps shown correspond to multiple horizon slices within the reservoir, and show the extent of the high-porosity areas.

The discrimination of high-porosity areas was made possible using elastic parameters. In the absence of high porosity, discrimination between limestone and dolostone

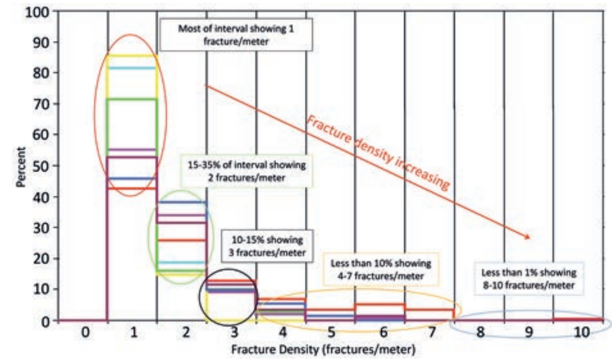

Figure 8 *Image log data showed that only a small percentage of the reservoir was highly fractured (>7 fractures/meter).*

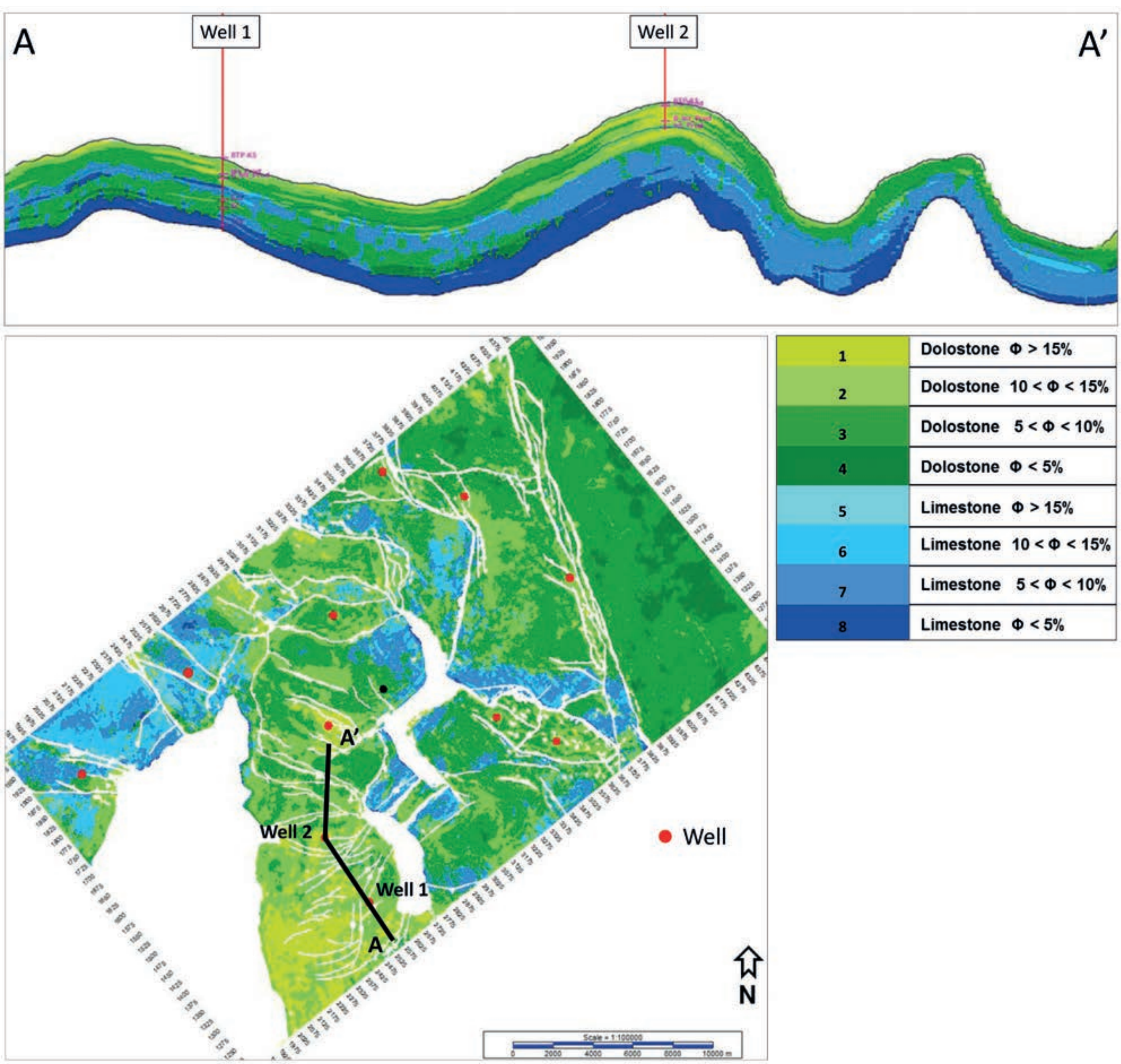

Figure 9 *For interpretation purposes, the two end-member lithologies, limestone and dolostone, were sub-divided into discrete porosity ranges. The resulting volume allows for the identification and mapping of the most prospective groups. In this case, high-porosity dolostones are associated with the best producing intervals.*

becomes complicated due to the similarity between density and velocity values observed for both lithologies. To produce a reliable seismic lithology volume that would allow for the discrimination between the two end-members (limestone, dolostone), a similar multi-attribute workflow was applied using seismic attributes derived from the different inversion processes (Russell et al., 1997). Figure 7 shows a cross-section of the resulting lithology volume, including lithology information from one of the control wells (top left). Limestone sections are shown in blue, while dolostone sections are shown in green. As can be observed, a high correlation exists between the calculated lithologies at the well location and the estimated lithologies from seismic data.

Integration and interpretation

The inclusion of geological information into the interpretation phase, along with petrophysical and seismic information, significantly enhanced the results. Information obtained from geological studies, including sedimentological core description, petrographic and diagenetic analysis, and structural and fracture studies, provided considerable insight into the reservoir and became an important tool for interpretation of seismic attributes.

Key points to consider for the integration and interpretation phase were as follows:

- Rocks with greater storage and flow capacity show porosity values in excess of 10% and are associated with the presence of vuggy porosity and interconnected fracture systems; they predominantly have dolomitic lithologies.
- Rock physics analysis established that low impedance values, both P and S, are associated with the presence of high porosity (more than 10%).
- The greatest contribution to secondary porosity and improved reservoir quality was dissolution resulting in the creation of vugular porosity. Dolomitization appears widely in the survey area and has a high correlation to improved reservoir performance.
- The integration of fracture information identified by image logs, as seen in Figure 8, was calibrated to the seismic through the use of key attributes such as seismic anisotropy and geometrical attributes. An accurate seismic-based prediction of fracture density greatly assisted in the final classification / ranking approach.

A reservoir classification scheme was selected utilizing seismic lithology and porosity volumes. A single volume was created to assist in the creation of an integrated geological model and used to support field development. Two end-member lithologies, limestone and dolostone, were subdivided into discrete porosity ranges (Figure 9). The map shown is derived from a horizon slice within the reservoir and displays the level of detail that was achieved, allowing for the identification and mapping of the most prospective areas in the field.

Conclusions

New technologies in seismic acquisition, processing and reservoir characterization are resulting in a better understanding of hydrocarbon reservoirs. The broadband acquisition and processing improved the imaging and seismic reservoir characterization compared to legacy conventionally acquired data.

The primary objective to improve the identification of the highest hydrocarbon-producing intervals was achieved with the creation of a classification volume incorporating lithological and porosity-predicted attributes.

Further work on understanding the nature and paragenesis of the limestone, dolomite and vuggy porosity will improve understanding of the properties and distribution of reservoir quality, in particular, permeability characteristics.

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