Seismic inversion and AVO analysis applied to predictive-modeling gas-condensate sands for exploration and early production in the Lower Magdalena Basin, Colombia

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Abstract

The Plato Depression in the Lower Magdalena Basin is a Miocene depocenter where a thick, shale-prone marine sequence known as the Porquero Formation was laid down in basin-floor conditions. Seismic inversion carried out on new and existing 2D seismic data helped to focus early exploration on a shallow stratigraphic gas-sand play associated with what seemed to be isolated shale diapirs with shallow roots. A subsequent land 3D survey helped to locate the first exploratory well, which resulted in the discovery of the Guama gas-condensate field. The main reservoir consists of laminar, low-permeability sands in a relatively thick shale-prone sequence of Early and Middle Miocene age. Sequential application of acoustic and elastic inversion and AVO analysis was used to build an evolving 3D predictive model of gas sands, extracted from an otherwise featureless seismic cube. Workflows were based on careful rock-physics analysis, simultaneous seismic inversion, and AVO analysis supported by custom well-log and seismic-gather conditioning. Work routines carried out in parallel became essential to applying quality control and fine-tuning the model, which supported three additional successful wells, early reservoir planning, and key volumetrics.

Introduction

The Plato Depression is a deep Miocene depocenter in the eastern Lower Magdalena Basin, in northwest Colombia. Previous exploration was aimed at deep turbiditic sands in the thick Porquero sequence of massive shales and muds in large fault blocks defined from conventional 2D seismic lines of various vintages. In 1975–1980, two wildcat wells flowed gas and condensate at rates that were considered noncommercial for the depths involved (more than 10,000 ft).

In 2008, 256 km of 2D seismic was acquired to better define the play. A first acoustic inversion was carried in 2010 on five of the new 2D lines, where the Poisson’s ratio–based shaliness showed that the deep sands had limited extension. In 2010, a 3D survey was acquired over 100 km². Interpretation of this survey improved the maps of the deeper targets and showed an additional sand play at shallower depths (less than 7000 ft), making exploration more attractive. However, the new seismic image was still insufficient to define individual targets because the sands are dispersed in more than 4000 ft of shales. Therefore, reservoir presence continued to be the main geologic uncertainty of the play.

AVA analysis indicated gas prospectivity for the shallow play. The first well was drilled in 2010 on the flank of one
of two shale diapirs interpreted from the new data. The well resulted in the first gas-condensate discovery in the shallow Porquero play. Cores showed that the reservoir was made of laminar, thin to medium lithic sands with fair porosity but low permeabilities.

Production tests in the different wells of the area have been done in intervals with a high percentage of laminated sandstone (1 to 4 cm). The aim of this work is to present a workflow to characterize the reservoir considering the high heterogeneity and wide range of petrophysical properties in the Porquero Formation. Seismic resolution is not enough to resolve these thin laminated sandstone intervals. However, the play can be defined by an important number of layers arranged in thick intervals interbedded in the massive shales of the Porquero Formation. The seismic data have enough resolution power to resolve the thick intervals.

The data set used in analysis of the study area consists of a 3D seismic cube and log data from five wells, as shown in Figure 1.

**Geologic framework**

The Miocene Porquero Formation in the Plato region exceeds 10,000 ft of total thickness of massive shales and silty shales with subordinated laminated shaley sands and silts. This massive shale-prone marine sequence represents slope and basin-floor settings (Arminio et al., 2011; Ghosh, 2013).

The sandstones show individual laminated bed thickness ranging from 1 to 4 cm, grouped in multiple cycles. For practical purposes, the Porquero Formation has been subdivided into informal units defined between unconformities. The prospective sand cycles are contained mostly in the Porquero “C” and “D” units with a joint thickness of 2000 to 3000 ft.

The sands range in grain size from fine to medium and show complex mineralogy with abundant clay minerals (Leyva et al., 2012). Low sand permeabilities were estimated from production tests and were measured in core samples, with values ranging from 1 mD to as low as a few nanodarcies. Figure 2 shows a well core and a thin section taken from Well P-1 at target level.

The dominant structural style is high-angle normal faults, some of which show moderate tectonic inversion. The presence of at least one shale diapir was first interpreted from 2D seismic by previous explorers (Arminio et al., 2011), and two of them were mapped on the 2010 3D cube. Initially considered as incipient features, they are now interpreted as Miocene to Early Pliocene features, fossilized under the thin Quaternary alluvium, lacking observable surface expression.

Figure 3 shows a well-log type at the study area and a section that illustrates the seismic expression of the mud diapirs and the different unconformity levels. Both images highlight the main target section.

It must be emphasized here that gas charge is pervasive in the whole Porquero section, even at shallow depths.
AVA and elastic inversion

As previously mentioned, the seismic resolution was not enough to resolve individual sand beds, and the elastic-inversion workflow was designed to spot multisand intervals embedded in the massive shales.

Basic tools used in the exploration phases of this play were

- amplitude-variation-with-angle (AVA) analysis
- seismic-inversion analysis supported by a rock-physics framework

Given the presence of gas, the apparent decrease in acoustic impedance and density values at the target level afford an opportunity to map sweet spots based on changes in seismic-attribute responses by an integrated rock-physics interpretation approach.

The fundamental interpretation strategy was the use of seismic attributes from AVA analysis to confirm the results of the simultaneous inversion. In case of discrepancies, detailed revisiting of well-log analysis was performed, along with a careful evaluation of seismic gathers to explain and reconcile the differences. Sometimes subtle editing of sonic logs based on rock-physics models enhanced the consistency of seismic attributes significantly.

In Figure 4, we can see the AVO effect of one of these target intervals and the graphical petrophysical evaluation of the P-1 well.

Data conditioning

Seismic data. Two-dimensional and three-dimensional seismic followed a standard processing sequence up to prestack time migration (PSTM) constrained by relative amplitude-preserving requirements. However, reservoir characterization based on quantitative seismic interpretation requires the data (seismic and well log) to fulfill quality-control standards. Before any attempt to perform inversion, the PSTM seismic gathers went into an additional sequence of data-conditioning steps to enhance signal-to-noise ratio, recover offset-dependent frequency loss caused by NMO stretch, and align reflections with a static-based technique (Singleton, 2009).

Figures 5 and 6 show some results of seismic data conditioning at the gather and stack levels. This approach results in more stable seismic wavelets and consistently lower levels of seismic-inversion residuals, as shown in Figure 7.

Well-log data. Along with seismic data, well logs were also conditioned. Normally, well-log analysis focuses on the target level of interest. However, for inversion purposes, the whole column needs to be conditioned to edit and reconstruct a complete and reliable set of well logs. Sonic logs in particular are used to generate synthetic seismograms in the seismic well-calibration process. This conditioning workflow includes volumetric estimation, rock-physics analysis, fluid substitution, multiwell analysis, prestack synthetic seismograms, and well-log AVO analysis.

Rock-physics analysis results in a theoretical model that best explains the behavior of the measured well-log data. This model is the link
between reservoir properties — such as mineralogy, porosity, pore geometry, and fluids — and elastic rock properties \( (V_p, V_s, \text{ and density}) \). Once the model is selected and calibrated, it is used to estimate log intervals with very low quality or with no data at all. The “soft rock-physics model” was selected for this study area (Dvorkin and Nur, 1996).

Figure 8 shows a crossplot of \( V_p \) versus density from the M-1 well, where the data fit the soft-sediment model. Differentiation of rocks with greater gas content from the background trend is evident.

The shear sonic-log estimation used the Greenberg and Castagna (1992) rock-physics model. Figure 9 shows the scheme used in the well-log data conditioning and its different phases.

**Simultaneous seismic inversion and AVA analysis**

Seismic inversion aims at estimating model parameters \( (V_p, V_s, \text{ and density}) \) based on observed data: PSTM seismic gathers and rock-property well logs. The inversion technique applied on the Porquero shale-sand geology used synthetic multipartial-angle stacks in the PSTM domain that are compared with multipartial-angle stack data to update model parameters. This deterministic inversion scheme minimizes the sum of two cost functions,

\[
J = J_g + J_s,
\]

where \( J_g \) corresponds to geologic constraints given by a priori information associated with interpreted horizon and stratigraphy, and \( J_s \) measures differences between the modeled data and the actual recorded angle stacks. Synthetic angle stacks for a particular elastic-parameter model were estimated by convolving Aki and Richards (1980) reflectivities with an angle wavelet extracted during well-to-seismic calibration.

Simultaneous elastic inversion following Tonellot et al. (2001, 2002) (Figure 10) required three main inputs:

\[
V_p \text{ vs. Density - color-coded by } S_w.
\]

**Figure 7.** (a and b) Wavelet extraction for angle ranges of 0° to 43°, 10° to 23°, 20° to 33°, and 30° to 43°, associated with whole-stack, near, medium and far partial-angle stacks, respectively. (c) Superimposed color-coded wavelets and their amplitude spectra.

**Figure 8.** Crossplot of \( V_p \) versus density in the M-1 well. Colored curves represent soft-sand-model boundaries. Colored bar scales are for (a) \( V_{clay} \) and (b) water saturation (\( S_w \)).
• elastic-property initial models ($V_p$, $V_s$, and density)
• partial incident-angle stacks
• extracted seismic wavelets

The model parameters are based on well logs from five wells and on seismic markers interpreted at different stratigraphic levels. The initial model structure for the elastic parameters was low-pass-filtered to obtain a 3D regional trend for the much higher-frequency inversion outcome.

The ranges of the selected partial-angle stacks were 0° to 13°, 10° to 23°, and 20° to 33°, associated with near, medium, and far offsets, respectively. Figure 11 shows an input partial stack, a modeled stack, and an inversion residual section for an angle range of 10° to 23°.

Quantitative interpretation — Rock-physics analysis

Crossplots were generated from log-derived elastic properties. From them, elastic facies were interpreted in the wells. Figure 12 shows two of the crossplots obtained from this analysis, with a large overlap in the impedance axis. Because of the overlap, discriminating lithology and fluid proved to be difficult. In the Poisson’s ratio axis, however, we found that over the target section (higher IP), the cleanest rocks (lower $V_{clay}$ values) show lower Poisson values.

Figure 9. Well-log data-conditioning workflow: volumetric estimation, rock-physics analysis, fluid substitution, multwell analysis, prestack synthetic seismogram, and well-log AVO analysis.

Figure 10. Simultaneous elastic-seismic workflow applied on the Porquero succession of massive shale and thin sand.

Figure 11. Seismic-inversion quality control: (a) observed partial-angle stack; (b) modeled partial-angle stack; (c) inversion residual section for angle range of 10° to 23°.

Figure 12. Crossplot of Poisson’s ratio versus IP for the M-1 well. Sample points are color-coded for (a) $V_{sh}$ and (b) $S_w$. In part (a), black and gray represent higher $V_{sh}$ values, in contrast with brown and orange, which represent lower $V_{sh}$ values. In part (b), blues represents higher $S_w$ values and red lower $S_w$. Cleaner sands tend to show lower Poisson’s ratio values.
Similarly, Figure 13 shows a crossplot of $V_P$ versus $V_S$ for the M-1 well, in which we can see that higher values of $V_P$ and $V_S$ are associated with target intervals.

The next step was a fluid-substitution model, using the Biot-Gassmann equations (Mavko et al., 1998). Because of limitations in log data in the older well, the analysis was done on only four wells.

The fluid-substitution study incorporated the in situ state and cases with water saturations of 40%, 60%, and 100%. All the scenarios used fluid parameters as measured on the wells: gas gravity 0.62, condensate API gravity 50°, and water salinity 25,000 ppm.

Figure 14 shows a profile of density, $V_P$ and $V_S$ logs, P-impedance, and Poisson’s ratio for the indicated values of fluid substitution in the K-1 well. Black curves represent the in situ base case. In Figure 15, analysis of the crossplot of Poisson’s ratio versus IP from the K-1 well shows a clear separation between samples from partially gas-saturated and 100% water-saturated rocks. There is, however, no significant separation between samples with water saturation of 40% and 60%.

**Reservoir identification and lithologic maps**

The crossplot of P-impedance (IP) versus Poisson’s ratio was chosen as the parameter that best discriminates gas-sand-prone sections. Figure 16 shows four crossplots based on well-log data that illustrate values of IP and Poisson’s ratio that represent good reservoir properties. The four crossplots were used to define prospective zones (indeed, 3D geobody renderings, rather than individual reservoir layers that are impossible to discriminate) and their associated porosity, gas saturation, and clay content.

By combining the crossplots with calibration of seismic inversion obtained from the 3D seismic cube, it was possible to define the most prospective sections in the 3D seismic area by defining distributed
geobodies in the seismic cube. Figure 17 illustrates the calibration procedure of the reservoir’s properties as a function of the cutoff set in the crossplot domain.

**Ongoing analysis.** As indicated before, the inversion model was not a one-off effort; rather, an early model was updated with new well data, thus helping to locate new wells and contributing to the robustness of the model. Figure 18 illustrates with an isometric view the current state of the predictive geobody model after four new wells.

The total geobody spatial definition was done over eight stratigraphic intervals within a relatively thick section (more than 2000 ft) of Porquero target. This created a 3D geobody framework. The aggregate of geobody properties, used to create total gas-pay maps, for example, was obtained by collapsing the total geobody volume into a single volume.

The reasons for this interval stepwise analysis are:

- This allows better control of the input of each sublevel to the total geobody. This flexibility allows identification of the levels that provide more pay from all the target section.
- Poisson’s ratio is sensitive to rock compressibility, which is related to reservoir depth. Indeed, when crossplot analysis and geobody selection are done on different intervals, selection is more accurate, and there is more confidence in the results (Figures 16 and 17). After each geobody is obtained, a quality-control protocol can benefit one particular interval, and this facilitates the result that four control points correctly match the geobody rendering.

At the end of the process, we obtained a set of geobodies that

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**Figure 16.** Crossplot of P impedance versus Poisson’s ratio using well information. Color scales help to discriminate (a) depth, (b) porosity, (c) gas saturation, and (d) clay content.

**Figure 17.** Reservoir-property calibration, based on cutoff values derived from rock-physics analysis.
represents the higher probability of gas-bearing sand. The geo-
body from the crossplot selection is generated in time, and
then a time-depth velocity model is used to obtain a geobody
thickness of each interval. As an example, Figure 19 shows the
aggregate of inversion-derived total gas pay for one of eight
stratigraphic subdivisions of the Porquero prospective section.

Conclusions

The case history presented here shows the simultaneous
application of AVA and elastic inversion to predict sand pre-

sence and gas saturation in massive shales, in this case, a very
thick Miocene section where 3D seismic images are insuffi-
cient to discriminate individual reservoir horizons.

On finishing a first exploration in the area, several ele-
ments can be deemed relevant to four successful wells:

- Definition of several stratigraphic work subunits helped
to focus analysis of the otherwise thick and massive suc-
cession.
- Acquisition of log suites for each well, including dipolar
and borehole imaging, helped to build an early, robust
rock-physics model that could be updated as new wells
were finished and tested.
- Dedicated well and seismic data conditioning helped to
improve signal-to-noise ratio and enhanced accuracy and
stability of results. **TLE**

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