Devonian Naturally Fractured Reservoirs, Tarija Basin, South America*

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Search and Discovery Article #10883 (2016)**
Posted November 14, 2016

*Adapted from extended abstract prepared in conjunction with oral presentation given at AAPG 2016 International Conference and Exhibition, Cancun, Mexico, September 6-9, 2016.

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Abstract

This paper evaluates the naturally fractured reservoirs (NFR) that produce most of the gas in southern Bolivia and northwest Argentina in order to find tools and models that could lead the exploration efforts to new discoveries. These reservoirs of the Tarija Basin are known as Huamampampa and Santa Rosa formations dated as early Devonian.

A reasonable amount of public information related to geosciences and engineering, published in both countries, has been reviewed and evaluated. Field trips have also been done to describe the outcrops in the vicinity of the producing fields, observe the fracture patterns, and measured their frequency and orientation. Electric logs, wellbore images, core analysis, pressure and production data from some key wells have been obtained, analyzed, and integrated into this study.

Gas production comes from tight sands broken in two main set of fractures, oriented N10°E and N80°W, as well as several others that convert the reservoir into polyhedrical pieces which resemble a box of matches. The open fractures communicate vertically sandstone and shale layers in such a way that they constitute a single reservoir.

Several geological factors have made these tight sands the main reservoirs in the Subandean belt: thick layers with some primary porosity and abnormal high pressure, interbedded or encapsulated in a moderately rich source rock. Total Organic Content from wells drilled in the studied area varies from 0.4% to 1.9 % in the Silurian Kirusillas as well as the Devonian Icla and Los Monos formations which have fed the reservoirs. Fractures and abnormal pressure explain the reservoir connectivity and high initial production rates, ranging from 30 to 200 MMscf/day per well. Total combined ultimate recovery of six fields adds up to 14 TCFs, 55% of the original gas in place.

Modern seismic on this high relief mountainous terrain has been proven effective to image synclines and limbs of these narrow faulted structures, but must be improved to map better the fold axial plane of the deep target reservoir where most of the fracturing has occurred.

Integrating seismic, surface geology, fracture orientation, logs, and core data into the model is required to reduce the risk of 5,000+ meter deep wells. Investments in large 3D seismic sound too high, but will be paid off since infrastructure and natural gas markets are in place.

Introduction

The Tarija Basin tested commercial oil production in the early 1920's in several small fields, less than 10 MMstb oil ultimate recovery, on both sides on the Argentinean – Bolivian border. Surface geology was used then as an effective exploration tool to drill wells for shallow reservoirs. Figure 1 shows the location of the Tarija Basin in South America.

Fifty years later, commercial production from the Huamampampa Formation was tested in the Caigua oil field for the first time. Even though the ultimate recovery was only 6.3 MMstb, the production rate was about 1,000 bop/day/well on natural flow. Soon, the early Devonian sandstones became the deep target in many structures in Bolivia and Argentina.

For location purposes, Figure 2 shows the Huamampampa main fields in dark color, shallower fields are in light color, and the crosses the main sets of fractures, dominantly oriented N10°E and N80°W. The Huamampampa wildcats were located using maps derived from detailed surface geology mapping and shallow wells.

In Bolivia, initially the results were frustrating since the more promising prospects were either dry, marginal, or the wells did not reach the target at the programmed depths. Most of the wells were drilled in the vicinity of the Caigua Field.

In Argentina however in 1974 was discovered Ramos, the first giant gas field, with an ultimate recovery of about 3.7 TCFs of gas and 50 MMstb of condensate. Ramos was then a mature oil field that had produced from Carboniferous sands.

The Ramos Field was put on stream almost immediately through the existing international main gas line from the Rio Grande hub in Bolivia to Buenos Aires. The following important Huamampampa discovery in Argentina was Aguaragüe in 1979 with an ultimate recovery of 1.0 TCFs of gas and 26 MMstb of condensate.

Legal barriers and lack of markets limited the exploration of dip targets in Bolivia until 1990. That year, the San Alberto gas field was discovered by YPFB, the Bolivian state oil company, on the Ramos productive trend. San Alberto was also at that time a marginal oil field discovered in 1967, which had produced from Carboniferous sands.

The San Alberto discovery accelerated many years of negotiations between Bolivia and Brazil to build a 3,000 km-long gas line to feed the San Pablo industry energy needs. This new gas market opened in turn more exploration wells and the discovery of Sábalo and Margarita giant gas fields in 1998.

Data and Bolivian Gas Production

A reasonable amount of public information related to geosciences and engineering, published in Argentina and particularly in Bolivia, has been reviewed and evaluated to write this article. References are listed alphabetically at the end of the paper.

In Argentina the main studies are on the Ramos and Aguaragüe fields, both are currently depleted or produce marginally.

In Bolivia the most important documents are the Field Development Plans (FDP), approved by the government, and the web pages published by YPFB and the Bolivian Ministry of Hydrocarbons and Energy.

Special attention was paid to the dip seismic lines, electric logs, wellbore images and core analysis focused on the detection and interpretation of fractures incorporated in the FDP documents.

Finally, field trips have also been done to describe the outcrops in the vicinity of the producing fields, observe the fracture patterns, and measured their frequency and orientation. A couple of photographs are inserted in this paper.

In order to show the importance of the naturally fractured reservoirs, Figure 3 shows the Bolivia historical gas production in millions of cubic meter per day (MMm^3/day) from 2000 to 2015. The upper curve shows the total production; the lower dashed curve shows that most of the current production, about 70%, comes from NFR reservoirs of the San Alberto, Sábalo, and Margarita fields.

Geology

Fracturing is the result of the interaction of multiple geologic factors that end in many fractures that make a difference from a productive stand point. The rock type must be brittle enough to break in multiple pieces when supporting tectonics stress. The minimum percentage of fracturing occurs in shales (20%) and the maximum in sandstones (75%) and limestones (80%).

The stratigraphic column of Figure 4 shows that the Huamampampa and Santa Rosa sandstones, brittle and prone to fracturing, are encapsulated in plastic shales.

Los Monos, Icla, and Kirusillas formations are the oil and gas source rocks in the basin. Particularly important is the thickness and distribution of Los Monos shale, that seals the Huamampampa reservoir allowing gas accumulations down to the spill point of the structures.

The Kirusillas Formation of Silurian age (>409 mya) and the other Devonian formations (>363 mya), in addition to the compaction, cementation, dissolution and recrystallization, have had several orogenic processes that resulted in extensive fracturing.

Definition and Recognition of a NFR

In a Naturally Fracture Reservoir (NFR) fracturing has increased the primary permeability of an otherwise very low productivity zone improving the recovery efficiency. NFR have been deposited as any other sediment, but its geological history has determined that its primary porosity and permeability have less importance compared to the fracture network that drives production.

The NFR may be of three types: a) porous, where the pore space contains connate water and hydrocarbons but the flow occurred mainly through the fractures, b) non-porous, where both fluids are located only in the fractures, and c) a combination of both.

When the fractures, because of their extension and quantity, have an impact on the production, the reservoirs must be handled as fractured. Figure 5 shows a porosity vs. permeability plot of decreasing quality reservoirs to the low left corner of the diagram, with a blue circle on the upper right that represents the NFR of the Tarija Basin with total porosities, matrix and fracture, in the 5% range and high permeability, derived from formation tests.

The early recognition of the Huamampampa as a NFR has had an impact on the Field Development Plans (FDP). The few wells are located on the anticline axes at a distance that they do not interfere one to another because of the high permeability corridors.

Decreasing shale density, gas shows, well kicks are some indications of fractures when drilling the lower section of Los Monos shales cap rock. When these indicators are present a drill break is expected at the very top of the Huamampampa Sandstone, where the intermediate casing is set to secure the well.

In the producing fields, due to the high risk involved in the operation, few oriented conventional cores have been obtained to describe the fractures and measure their inclination. Figure 6 shows a core photograph of the Huamampampa reservoir in well Margarita - 3 (MGR-3) and an outcrop. Even small fractures, not seen on the core, have a tremendous impact on the permeability.

The presence of fractures does not affect the sandstone's matrix description. The fracture's porosity contribution to the matrix porosity is very small, usually less than 5% of the total. Fractures themselves tend to close up due to pressure depletion affecting the reservoir productivity. Later on well tests can confirm the presence of fractures through the detection of double porosity, high production rates across poor quality reservoir zones, and hydraulic connection between wells.

Another method of identifying a NFR is during the interpretation of pressure build up tests (PBU), where the development of 2 stages of radial flow, first the fractures, then the matrix, are evident.

Heterogeneity is typical of NFR and it can be shown building bubble maps whose radii depends on the initial rate, productivity index, cumulative production, transmissibility, or any parameter that prove that few wells that intersect most of the factures, are responsible for most of the field production.

Figure 7 shows the gas production rate in millions of cubic meter per day (MMm^3/d) of seven wells of the Margarita Field, where the rate is much higher in heavily fractured wells. The production record is held by MGR-6 with 6.0 MMm^3/day (210 MMscf/day), equal to the daily volume exported from Bolivia to Argentina from 1970 through 1990.

In the studied area, connectivity in the Huamampampa NFR is excellent along the anticline axes due to fracturing. In the Margarita Field, for instance, an interference test carried out back in 2009, proved the pressure connection between two wells, MGR – 3 and HUA -x1, which are almost 20 kilometers apart. During the interference test the other wells completed in the same reservoir were shut-in.

Outcrops

Since the cores, logs, and tests come from few wells located on the crest of the structure, the reservoir model was enriched with the description of outcrops observable on creeks and roads. The Devonian formations can be observed 60 km to the west of the producing fields, particularly on roads in the Tarija city vicinity, like Yesera and Serranía del Condor. Figure 8 shows, from left to right, the Santa Rosa sands, Icla shales, and Huamampampa sands at the hilltop.

The Huamampampa is made of fairly continuous sand packages, 10 to 20 meters thick, interbedded with thin black shale, that were deposited in a shallow marine and deltaic environment. The sands are light gray, fine to very fine grain, quartzite, well compacted, siliceous cement, occasionally calcareous cement, micaceous, including heavy minerals, piled up in strata usually 30 cm. thick.

Both places, Yesera and El Condor, have been visited to better understand the fracture pattern and frequency. Figure 9 shows a photograph of several sand layers with multiple vertical fractures; Figure 10 shows the same fractures on the top of a stratum where the joints have facilitated the weathering, where the pieces resembles a box of matches.

The two main set of fractures are oriented north – south and east - west, matching with the subsurface data, like the Schlumberger FMS log of the Ramos 1003 well of Figure 11, or the fracture model of the Margarita field, derived from several wells. In outcrops, there are other fractures that convert the rock into polyhedral vertical pieces that explain the high permeability. Notice also that the GR curve shows clean sands.

Production rates indicate that fracturing is more intense on the apex of the structure, acting as permeability corridors oriented north south as proven in the connectivity test between wells MGR-x3 and HCY-x1.

Fracturing determines the vertical communication through the shale layers. Shales are also fractured as shown in the fracture diagram of the Margarita Field (Figure 12) or the fact that the Huamampampa, Icla, and Santa Rosa formations share a common gas water contact in Ramos, San Alberto, Sábalo, and Margarita fields.

All these fields and others that produce from the Huamampampa reservoir, have consistent values of matrix porosity (~5%), fracture porosity (~1%) as well as permeability's measured in formation tests of tens or hundreds of milidarcy. These values combined with abnormal reservoir pressure explain the high initial production rates, up to 200 MMscf/day, when a well intersects several fractures.

Exploration

Considering the five geological conditions that control the probability of success (POS) the risk to explore the Huamampampa reservoir can be consider moderate. Proven source rocks of the Tarija Basin encapsulate the reservoir and production is everywhere, so the migration risk from source to the trap is also low. The reservoir has a regional distribution, as shown in Figure 13 Huamampampa Gross Sand Isopach, that has been updated in the Incahuasi Field development plan. The Santa Rosa sand have a similar areal extension.

The probability of being fractured is very high, as indicated by the production rates registered is distant fields. Wells of all the above-mentioned fields yielded high production gas rates, so the reservoir risk is also low.

Los Monos Formation is several hundred meters thick and constitutes an excellent seal. Furthermore, this integral cap that has allowed filling the reservoir to the spill point having four giant gas fields so far.

However, the risk of having the traps present at the time of migration is high on the both borders of the producing belt. Structures on the west are older than the ones on the east, like the Aguaragüe trend. On the west, there is a high risk that the source rock is over cooked. So the most prospective exploration prospects are in the central structural trends.

To illustrate these comments, Figure 14 shows a regional cross section at a latitude of 23° South after the Ramos Field development plan. On the same Ramos productive trend, further north, are located the San Alberto and Sábalo fields in Bolivia; Margarita is immediately to the west.

The latest Huamampampa discovery in the studied area was the Incahuasi in 2004. Since then, four Huamampampa exploration wells have been drilled, all of them dry. If the exploration risk is moderate, why have these four wells been unsuccessful? The main reason is the difficulty of defining the core of Huamampampa structure with the existing geological and geophysical data.

The next trend to the west of Margarita is even more complex, as can be seen in the west – east section based on two wells, surface geology and 3D seismic shown of Figure 14 taken from the Incahuasi Field Development Plan. Incahuasi will start production this year, with two wells and a combined rate of 4.5 MMmcd and 4,000 bpd of condensate.

Figure 15 shows a West East geological section through the ICS -x1 well in order to illustrate the complexity of the Incahuasi structure. Notice the Los Monos shale, shown in gray color on the cross section, has increased its thickness several times making it even more difficult to image the western overturned side of this 100 kilometers long anticline.

In order to delineate the major gas fields, some operators acquired 3D seismic whose main challenge was the abrupt change in topography, hundreds of meters in altitude variations to calculate static corrections, and weathering thickness with accuracy.

Strike lines have minimal value, but dip lines do have structural relevance since they have good resolutions, especially the synclines and lateral reflectors. Notice that quality of seismic quality shown in Figure 16 on the Margarita Field, obtained on a high relief terrain, is poor. It shows the synclines on both sides of the structure, but does not image the core of the structure where the wells have to be drilled.

However, this information that was unimaginable few years ago, but it still can be improved with current acquisition and processing technologies available in the market. The good news is that almost all the appraisal and development wells drilled on the main gas fields have been productive, proving that the key for success is the integration of the data, which means the best 3D seismic, wells, and surface geology.

Conclusions

The Huamampampa is a NFR of the very low porosity and high permeability due to a fracture network that reach its maximum expression at the apex of the structure.

It is possible to reduce the exploration risk, improving the quality of the seismic data, and integrating all the geological data to image the structure underlying the Los Monos shales.

The production infra structure is in place and market for gas is unlimited in the region, taking into account the contract with Brazil and Argentina. It is expected that exploration activities will increase again in the studied area.

Acknowledgments

To Víctor Hugo Hamdan for his support on reservoir engineering of fracture reservoirs; to Asterio Ayaviri and Carlos Cherroni for their comments on regional geology.

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Figure 1. Tarija Basin and Studied Area.

Figure 2. Huamampampa Fields Index Map.

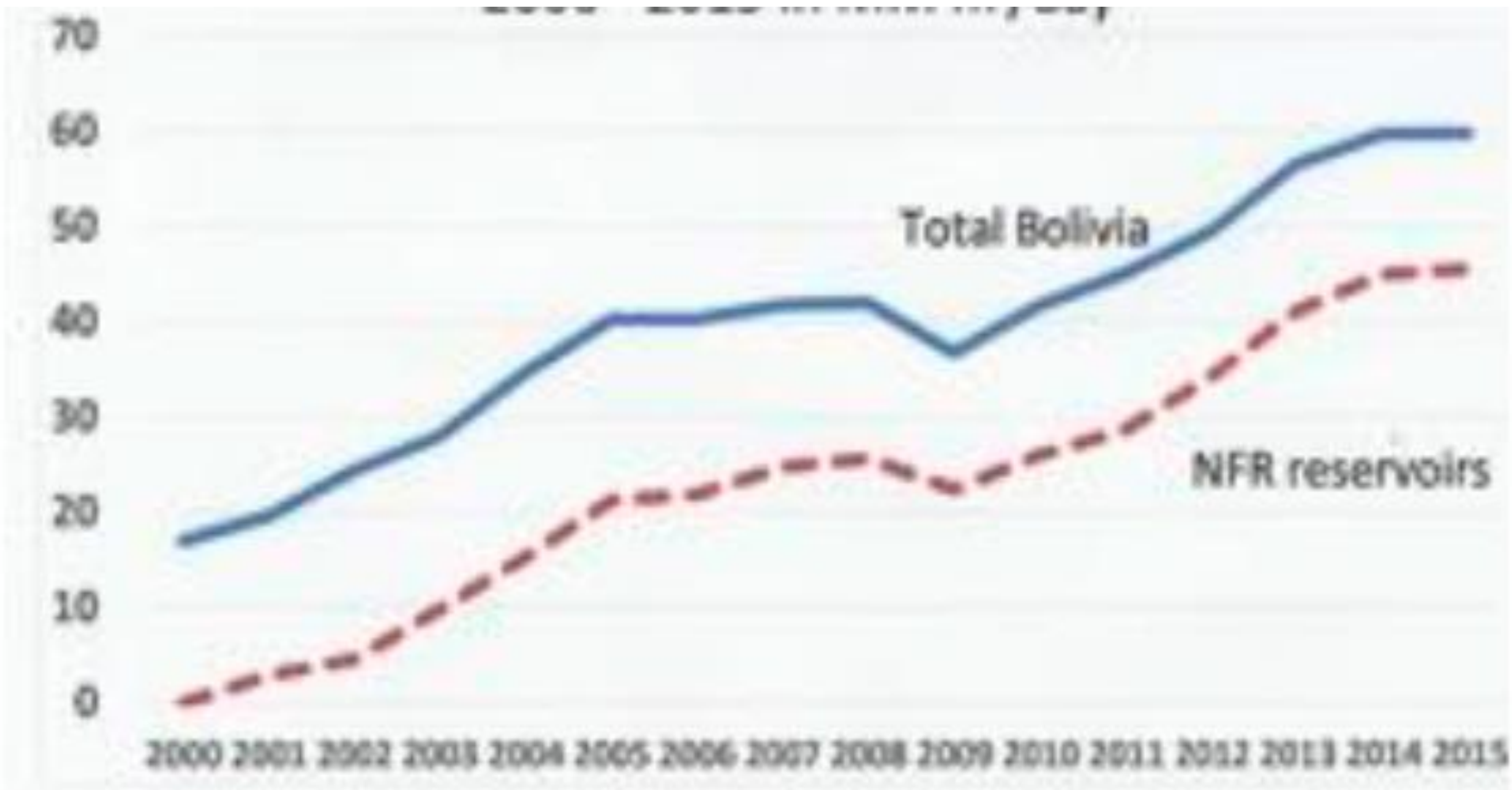

Figure 3. Bolivia – Total and NFR Gas Production: 2000-2015 in MM m³/day.

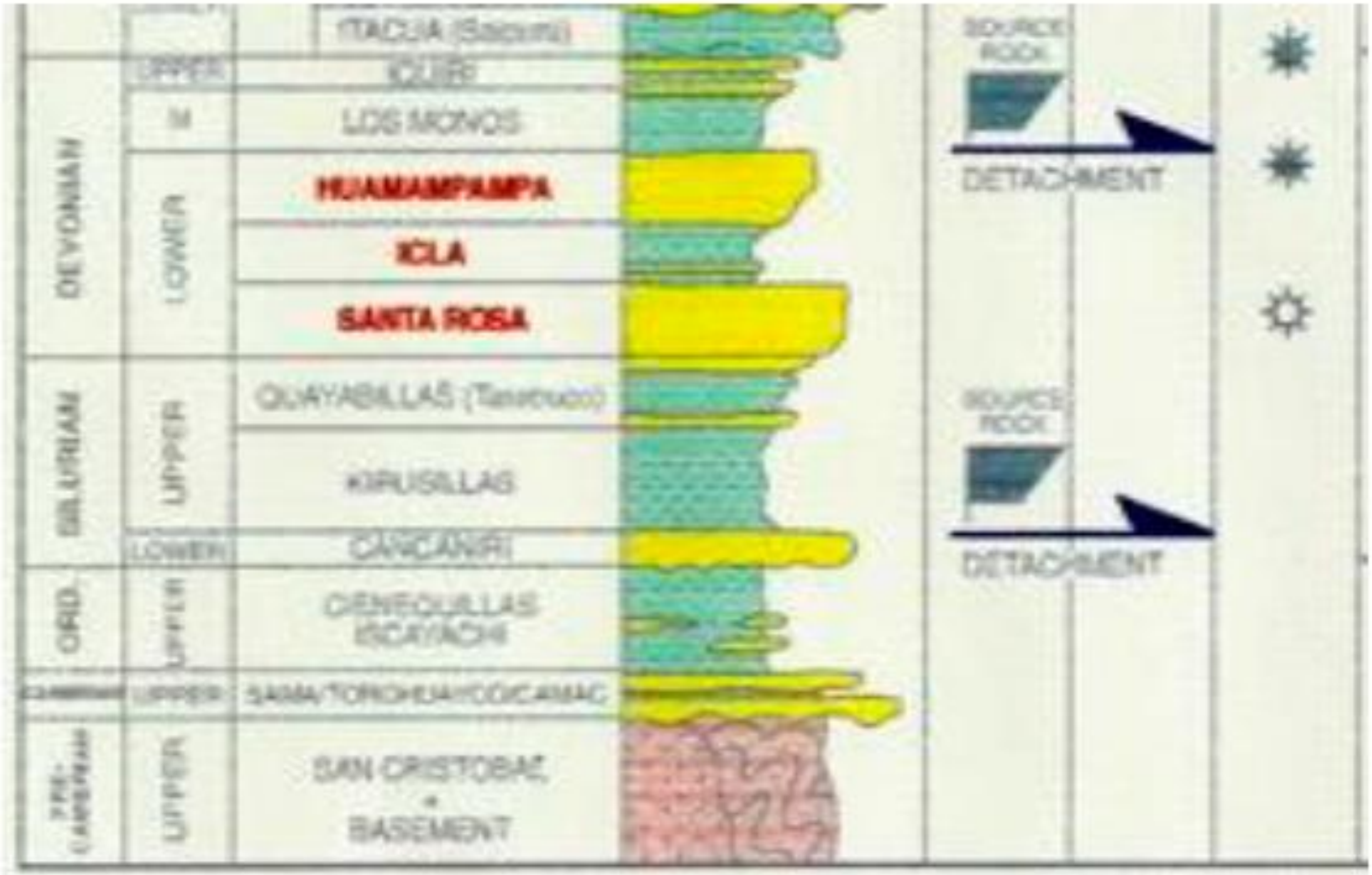

Figure 4. Paleozoic Stratigraphic Column.

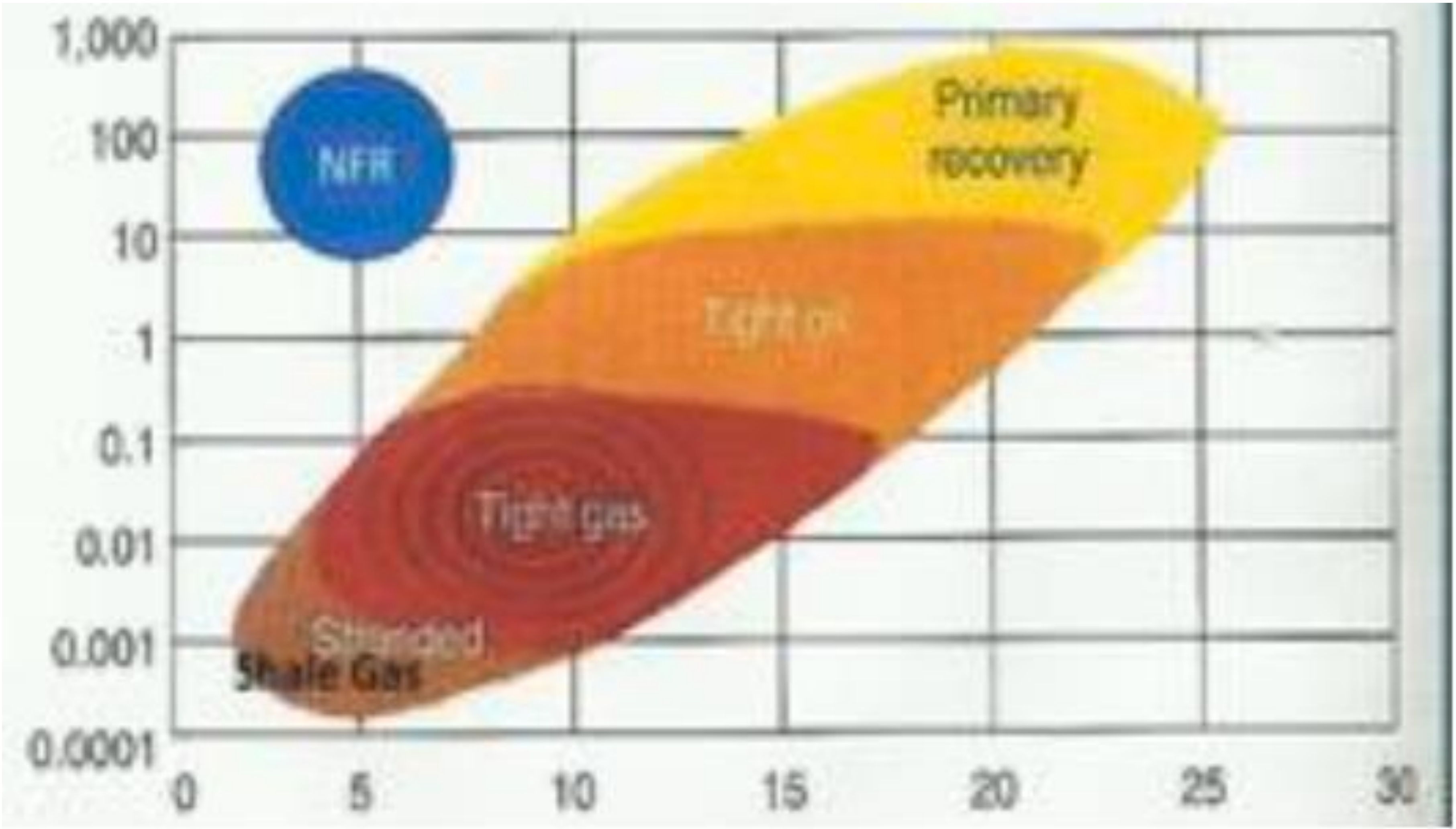

Figure 5. Porosity (%) Permeability (mD) Plot.

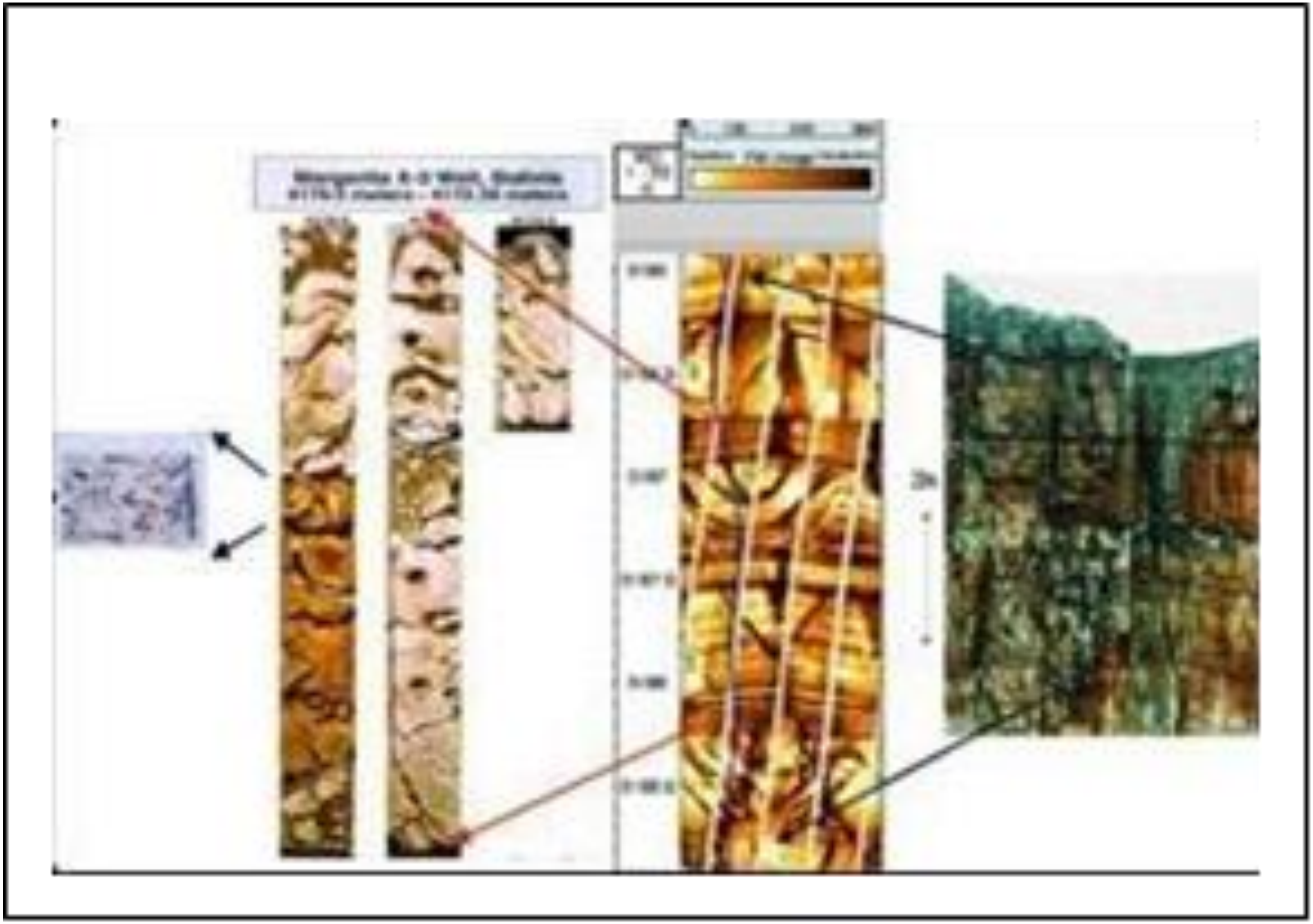

Figure 6. MGR – 3 Core and FMS Log.

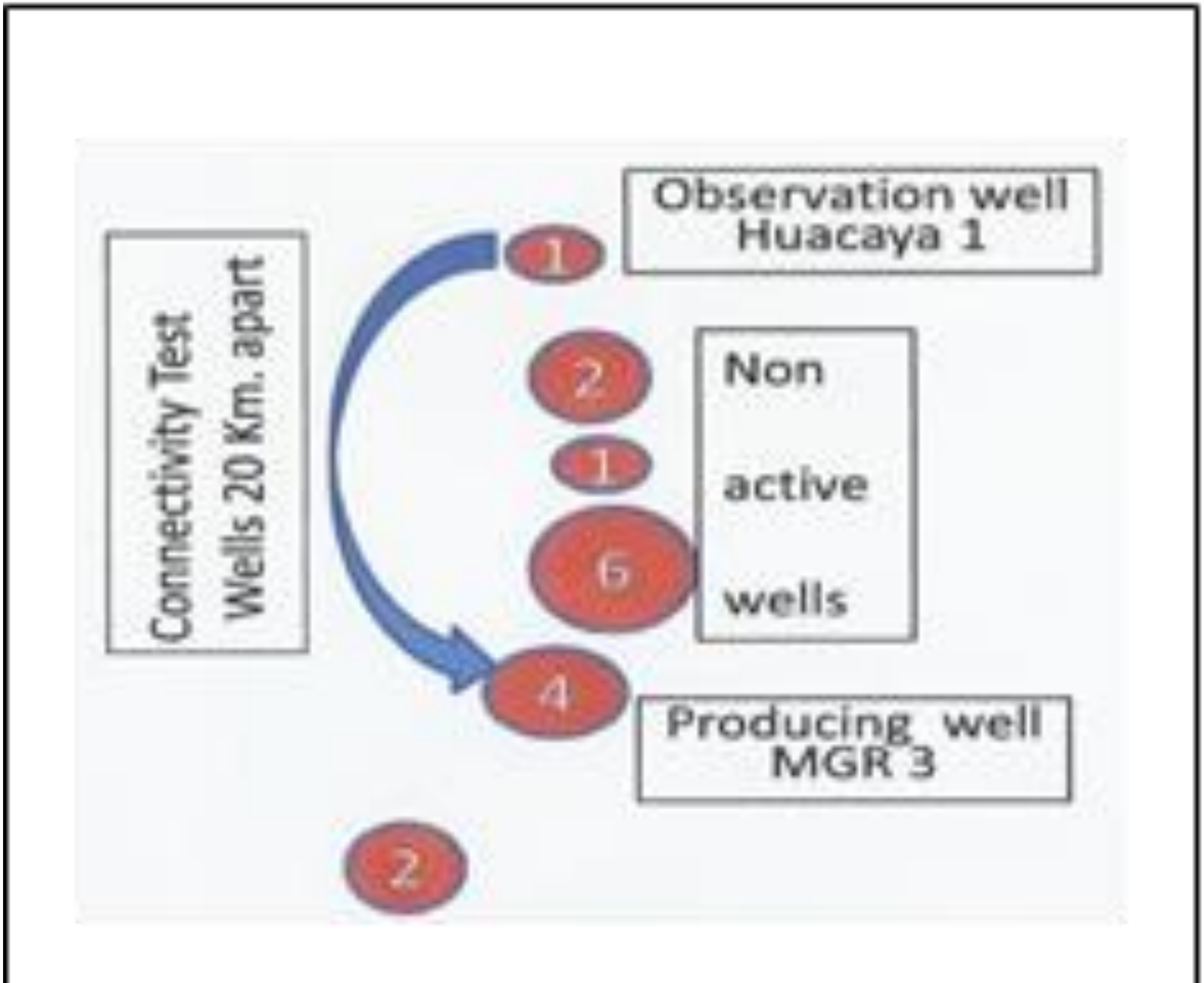

Figure 7. Bubble Map in MM m³/day.

Figure 8. Serranía del Condor Outcrop.

Figure 9. Vertical fractures on sand layers.

Figure 10. Fractures on top layer.

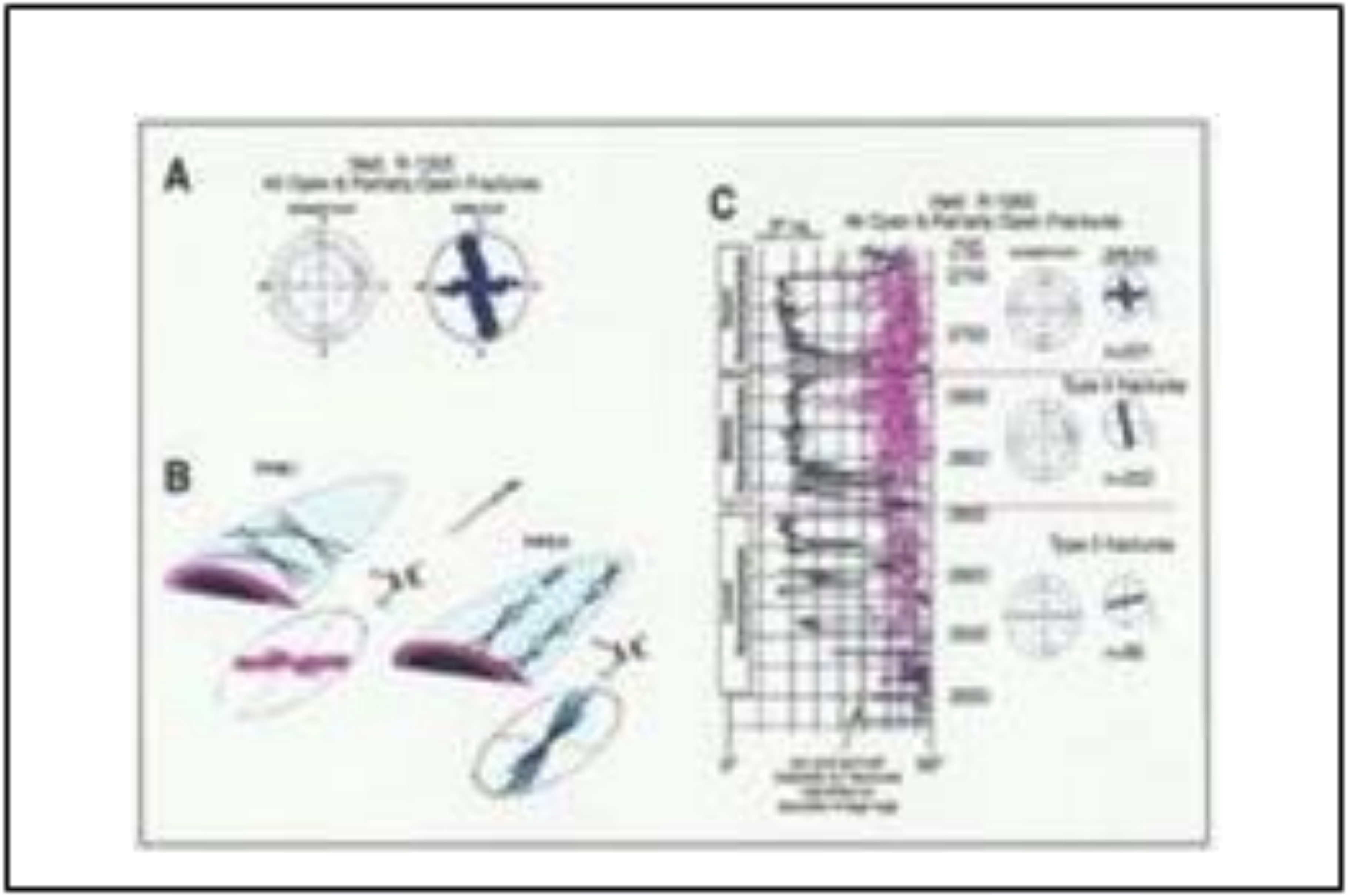

Figure 11. Well RMS 1003.

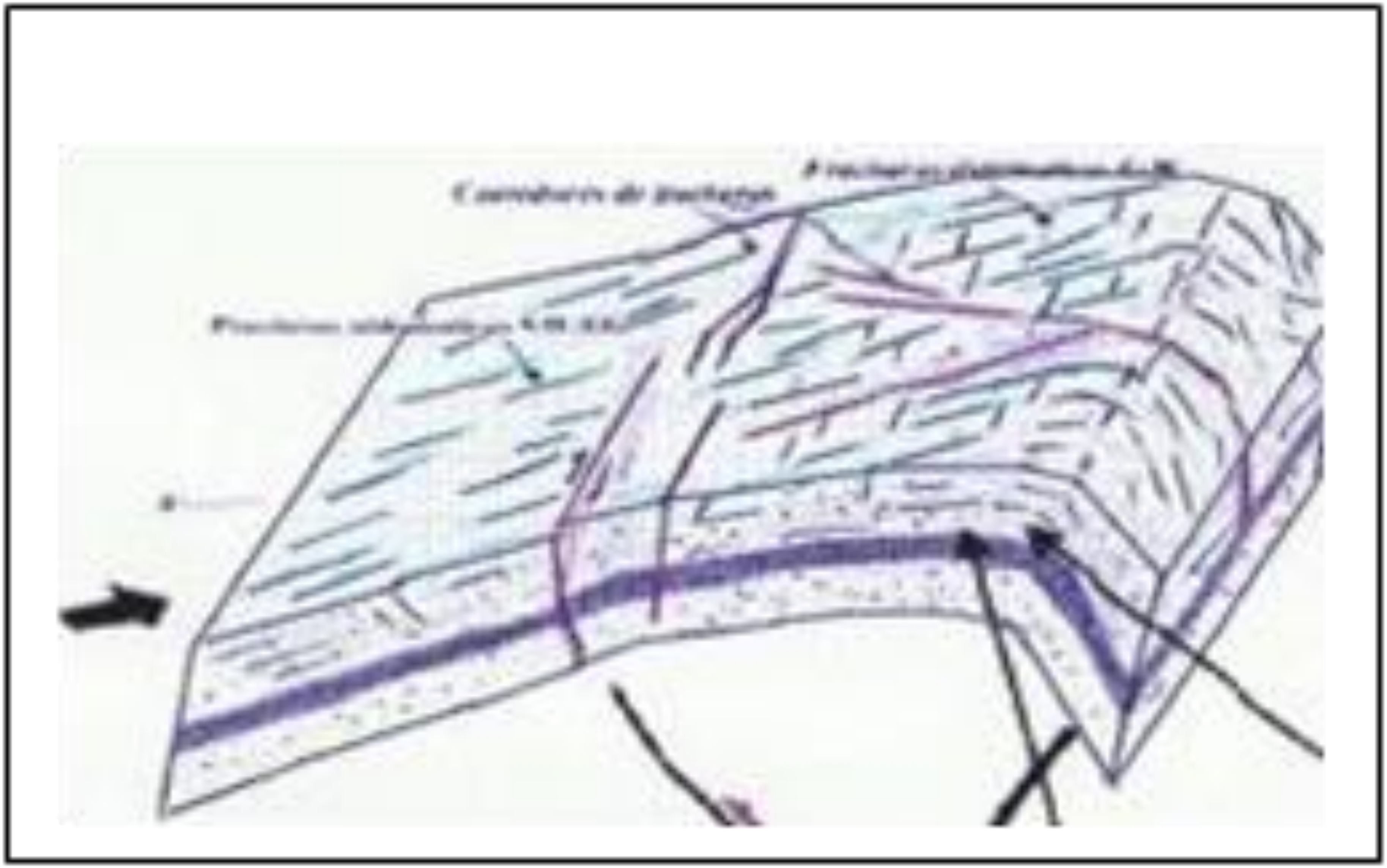

Figure 12. Fractures in Margarita Field.

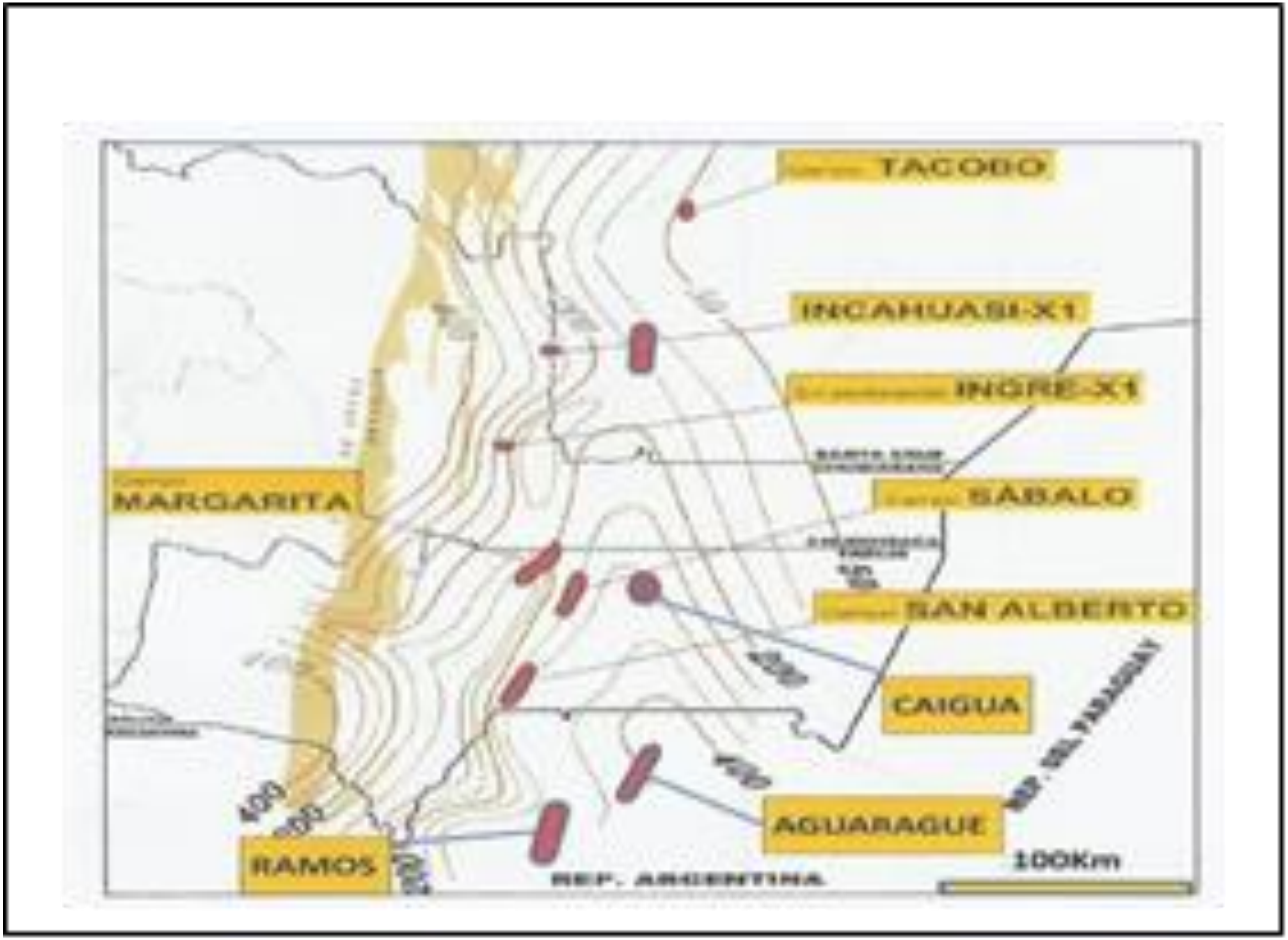

Figure 13. Huamampampa Isopach (CI 50 m).

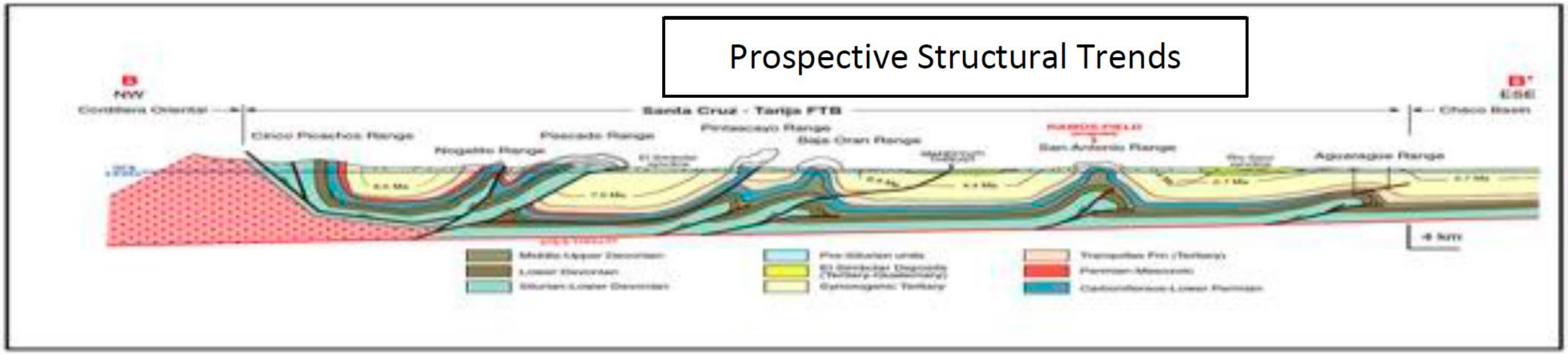

Figure 14. WNW – ESE Geological Section at 23 degrees’ latitude (after Ramos Field Evaluation Report).

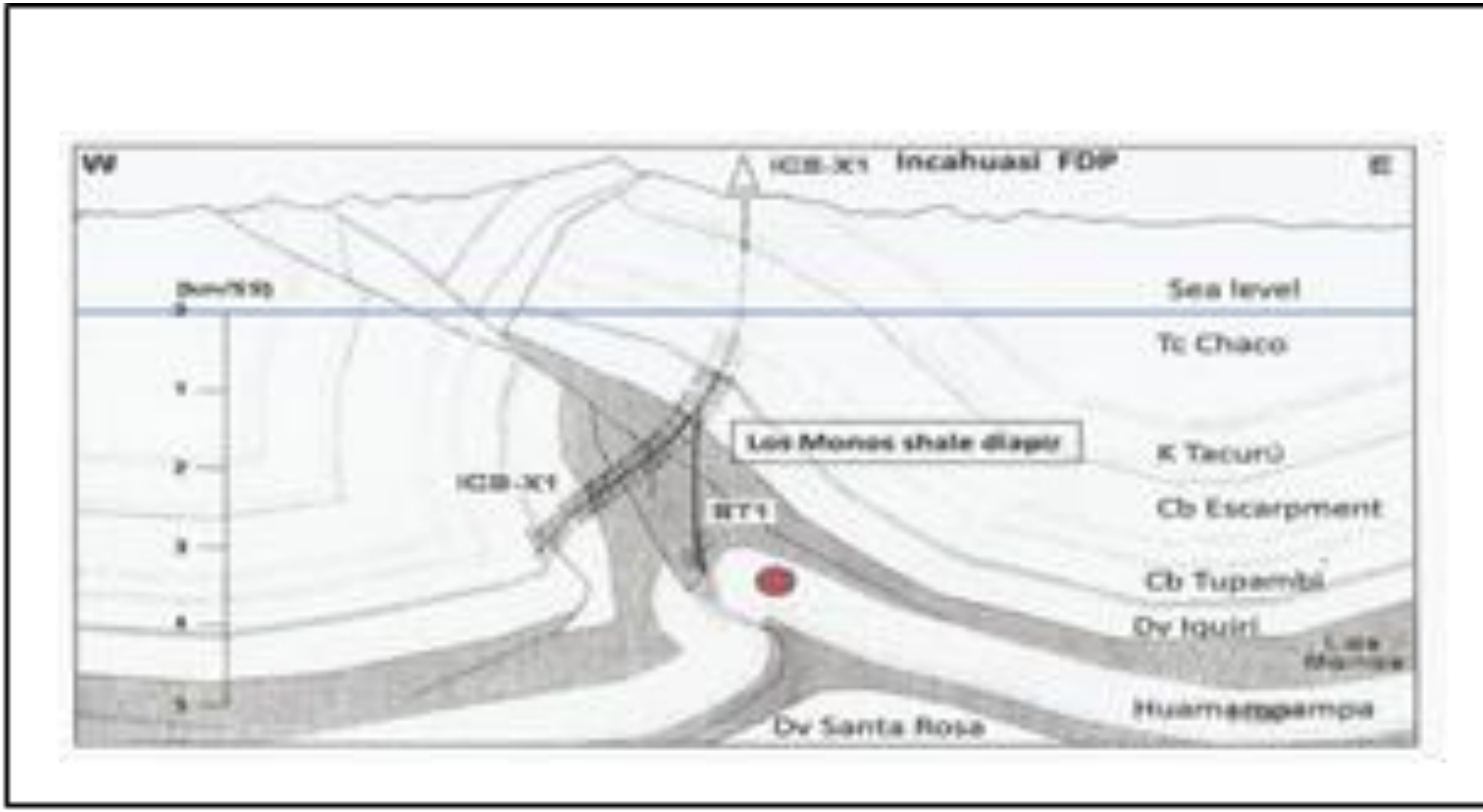

Figure 15. West East Section Incahuasi Field.

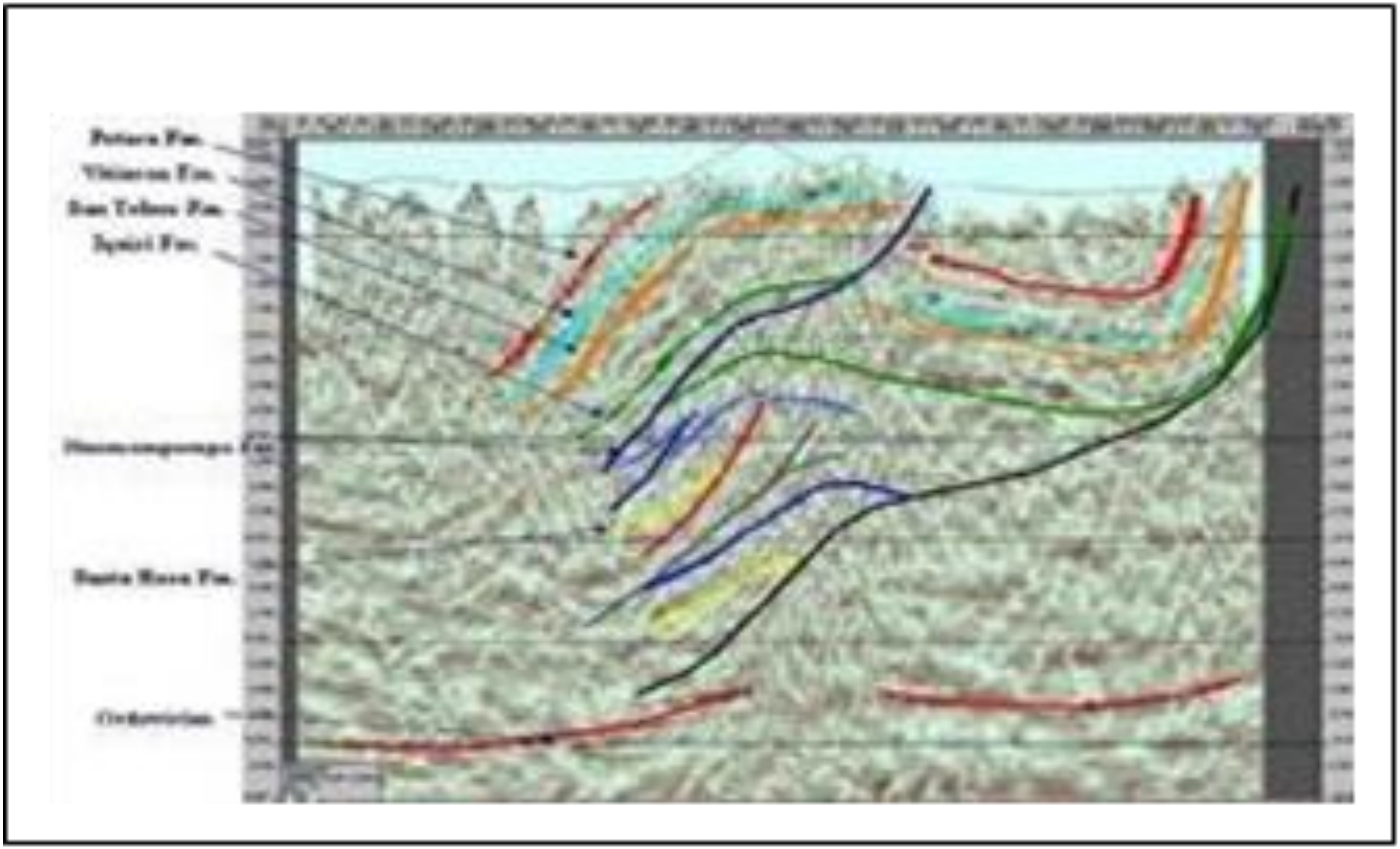

Figure 16. West East Seismic Line on the Margarita Field.