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Reservoir Characterization of Morichal Member in the Cerro Negro Field. Challenges and Opportunities in an Extra Heavy Oil Field in the Orinoco Oil Belt, Venezuela

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ABSTRACT

The Cerro Negro field (Petromonagas joint venture) has had more than 16 years of production history representing one of the most prolific fields in the Orinoco Oil Belt of Venezuela. The Oficina formation is the most important in the Eastern Venezuela Basin and represents the main objective of this study.

A new and more detailed static and dynamic model was carried out, in order to explain the main geological and dynamic issues that affect the production performance of more than 320 horizontal wells and the lessons learned. Therefore one of the main aims of this study is to identify the importance of the static variables on the dynamic behavior of the extra heavy crude oil and the relationship of the solution gas drive mechanism and its influence, in both the good performance of the reservoir at the beginning, which wasn’t expected in the original conceptualization of this project. Moreover, the analysis of vertical stratigraphic barriers, sand thickness, the geological structure, high permeability values and well location are factors that helps the generation of local gas caps which affect the production performance of existing wells and optimize the placements of new wells along the field. On the other hand, the updating of 3D seismic interpretation, the static and dynamic modeling of water zones (perched water), a regional sequence stratigraphic framework based on the regional geology in the Carabobo Block and the evaluation of different strategies to incorporate horizontal wells in a stochastic model, allowed to improve the characterization of this field. In conclusion, the integration and modeling of static and dynamic properties have shown to be efficient to reproduce a history matched model in full field scale, which could quantify the remaining oil reserves, the impact of water and gas production and the optimization of the developing plans for this extra heavy oil reservoir.

KEY WORDS

Reservoir Characterization, Cerro Negro field, Oficina Formation, static, dynamic modeling, Orinoco Oil Belt, Extra Heavy Oil, Petromonagas.

INTRODUCTION

The Cerro Negro oil field is located in the Carabobo Block of the Orinoco Oil Belt, at the southern flank of the Eastern Venezuelan Basin, specifically in the Maturin sub-basin (Figure 1). The Orinoco Oil Belt contains the world's largest accumulation of heavy and extra-heavy crude oil. Currently, the field is operated through a joint venture between PDVSA (60%) and Rosneft Oil Company (40%), under the name of Petromonagas. The field production comes from unconsolidated sand deposits of Morichal Member (Oficina Formation) at depths from 2000 to 3700 ft (TVD), containing extra heavy crude oil of 8.5° API and excellent rock properties with porosities and permeabilities of around 32% and 12 Darcies respectively.

This paper aims to describe the case of study of the Cerro Negro Oil Field where a new high-resolution static and dynamic model were built updating the stratigraphical, sedimentological, structural and reservoir engineering models of Morichal reservoirs, in order to respond several issues that the field is experiencing currently, such as high gas production and water production reservoir management and also how the geological features are directly related to the dynamic properties which affect the production performance of the horizontal wells.

In the first instance, the stratigraphical model was updated based on regional studies carried out recently by PDVSA Exploration (Santiago et al., 2015). The integration of new core information for sedimentological analysis and the reinterpretation of the structural model, where major structural accidents and faults were integrated, give a more accurate vision of how these variables can affect the distribution of fluids in the reservoir. Futhermore, from a petrophysical point of view, a more robust model was carried out taking into account the new available information, focusing on generating a permeability model that allow to reproduce the behavior of producer wells in the field, especially in wells with higher cumulative oil production. Therefore, all models were used to generate a high-resolution geocellular model integrating different methodologies to incorporate data from more than 320 producer horizontal wells in the field.

In a second instance, the dynamic variables were modeled taking into account the initial reservoir conditions, the rock/fluid properties changes along the reservoir in order to initialize and estimate the dynamic STOIIP of the Field. Afterwards, the history match of the reservoir was conducted considering the geocellular model and the geological heterogeneities of the formation, including thickness, permeability changes, and water accumulations, among others. After several simulation runs, various examples of horizontal producing wells were analyzed, showing how changes in geometry, thickness, distribution of rock types along the wells, the local seals of shale, and identification of zones with free water levels allowed reproducing the wells production more accurately.

Finally, based on this integrated approach, it was possible to understand the reasons why certain wells produce higher water cut than others, how the gas irruption develop faster in certain wells and in other cases the reason why some wells do not reach the estimated potential depending on the formational member where they were completed. As a result, it cleared out how the geological variables directly affect the performance of wells and field production in general.

STRATIGRAPHY AND SEDIMENTOLOGY

The lithostratigraphic column of the study area (Figure 2) is described from bottom to top by sediments of the Oficina Formation (early to middle Miocene) composed of unconsolidated sandstones and shales laying on the igneous-metamorphic basement and in some cases, on a sedimentary remnant which could represent Cretaceous sediments, known informally as "weathered basement". Afterwards, the sediments of the Freites Formation (Late Miocene) were deposited, finishing toward the top with the sediments of Mesa - Las Piedras Formations (Plio-Pleistocene).

The tectono-stratigraphic evolution of the basin is framed within a first order stratigraphic sequence, which has been called tectonosequence, defined as the sequence of sediments deposited in a cycle of continental opening, where each tectonic phase generates particular type of basin (Santiago et al., 2015). At this tectonosequence, second-order cycles were identified, which correspond to depositional units defined as a sequence of sediments deposited under different changes in the basin, as a consequence of different tectonic pulses within a tectonic phase. In this sense, considering this tectono-stratigraphic regional framework, this study is framed in one of these second-order depositional units, limited by subaerial unconformities associated with the evolution of foredeep of Monagas (Santiago et al., 2015).

In order to define the lines of correlative time and the markers in this field framed within the regional analysis mentioned above, the stratigraphic correlation was based on sequence stratigraphic analysis using the model of transgressive-regressive sequences proposed by Embry and Johannessen, (1992).

The interpretation of the stratigraphic surfaces is based on the available biostratigraphic information and six core data in the area of study, where two are located in the neighboring areas near to Petromonagas and the seismic response of them in the 3D seismic survey (Figure 3). The main surfaces defined in the sequence stratigraphic analysis are represented by the following sequence boundaries: SB1 corresponding to the top of the igneous-metamorphic basement; SB2 corresponding to the top of the weathered basement (± 23 m.y.); and the SB3 sequence boundary corresponding to the overlying depositional boundary at the top of second order unit of about ± 8 m.y. Between the sequence boundaries SB2 and SB3, certain some maximum flooding surfaces (MFS) and maximum regression surfaces (MRS) were identified, which correspond to the Lower Morichal top (MFS1 ± 20 to 23 m.y.), Middle Morichal (MRS1), Yabo (MFS2 ± 15.5 m.y.), Jobo (MRS2) and MFS3 representing the maximum surface of this depositional unit (± 13.6 m.y.), completing the third-order sequences within the transgressive cycle system of the main second order unit, where is possible to identify the oil reservoir of interest within the Oficina Formation. Consequently, the sequence of petroliferous interest in the Cerro Negro oil field is represented by sediments of Morichal Member of the Oficina Formation as mentioned before, and it is divided into three informal members: Lower Morichal, Middle Morichal and Upper Morichal.

The sedimentological model is based on the core description and cartography, which allows interpreting that the sediments of Morichal Member were deposited under different environmental settings strongly influenced by a transgressive phase (Figure 4). Towards the base, is possible to find fluvial deposits (Lower Morichal) characterized by large thickness of stacked channels (120 to 280 ft) and upward change to more transitional (estuarine) environments (Middle Morichal) with high tidal influence defining a lower lateral and vertical continuity of the sand bodies, degrading the reservoir properties. Towards the top, the marine influence increase (Upper Morichal), closing with internal neritic environments represented by the Yabo Member (Marine shales) overlying the Morichal Member.

Base on the mentioned above, the river deposits and fluvial-estuarine environments depict the different stages of development of The Orinoco River, which is established as a modern analogue for the distribution of the facies model.

STRUCTURAL GEOLOGY

The study area is placed in a foreland basin platform and forms a monocline dipping 3° toward the northwest. The structural model is based upon the detailed interpretation of 3D seismic that allowed distinguishing the following geological structures in the study area: three fault systems, structural depressions (pull-apart) and drag folds of extensive origin (Salazar, Rodriguez and Gonzalez, 2015).

The structural interpretation, characterization and definition of 56 faults on time and other structural features of interest, such as dip and strike of the horizons, were possible using as supports the attributes of curvature and semblance. Thereafter, seven (7) seismic horizons were interpreted in time: SB2 (Basement), Lower Morichal, Middle Morichal, Upper Morichal, Jobo, Pilon and SB3. In addition, the seismic volume used reaches a vertical seismic resolution between 25-70 feet with a maximum frequency range between 85-125 Hz, which increases from bottom to top within the interval of interest. Nevertheless, due to the low acoustic impedance contrast between sand and shale common in the Orinoco Oil Belt is not possible to image the internal structure of the fluvial reservoir directly on the existing 3D seismic. Therefore, the stratigraphic framework was defined based on the well correlations.

It was evidenced that the occurrence of different structures as master faults with obvious vertical movement in lateral east-west direction, leads to the generation of transverse faults that form transfer areas, oblique faults that form a system in *échelon* confined in a shear band, extensional depressions forming small pull-apart basins, horts and grabens, which are common in this reservoir (Figure 5). Besides, the normal and reverse drag folds, has been established that the Cerro Negro field is possibly located in a transtensive framework within a dextral strike-slip zone.

Beyond the optimization of drilling trajectories and reducing the structural uncertainty by integrating into the model a greater number of faults and folds, the detailed description of the geometry and structures allowed to define water and gas traps which affect the production performance, as well as its influence on the compartmentalization of the reservoir.

PETROPHYSICAL MODELLING

The petrophysical model is focused on define the rock quality, the storage and flow capacity of the Morichal reservoirs. Therefore, the model included the validation, edition and normalization of 108 vertical, 254 horizontal and 48 slant wells.

Based on deterministic models the following properties were estimated: shale volume, porosity, absolute permeability, irreducible water saturation, rock type, and total water saturation. As mentioned before, the reservoir rock is formed by unconsolidated sands interbedded with shales where kaolinite is the predominantly clay mineral. Due to the radioactive characteristics in the clay mineral, it has been necessary to employ a model for estimating shale volume which includes gamma-ray, neutron and density curves in order to correct the clayey areas. Additionally, it was necessary to correct the shale volume, using resistivity logs (RD), specifically in areas where very thin laminations shales (heterolithic areas) are presents, which are not clearly identifiable in gamma ray, density and neutron logs. Moreover, from the core-log calibration it was established a porosity model which represents the best fit on porosity estimation. Therefore, a cross plot of neutron density was built using the Bateman Konen method.

In general, the main challenge in petrophysical reservoir characterization of the Orinoco Oil Belt has been the determination of absolute permeability. In this sense information from cores, logs, pressure tests and historical production was integrated to achieve a model that is able to estimate this property. Furthermore, it was identified that factors such as sorting, grain size and clay content are the main textural features in the sandstones that dominate the distribution of absolute permeability, for instance, this was identified from the results of conventional core analysis (porosity and permeability) and the relationship with the dominant facies. Consequently, the permeability in this type of reservoir is direct function of the porosity and shale volume. Besides, the rock quality index (RQI) was calculated with the values of porosity and permeability measured in wells with cores, after that, the irreducible water saturation was calculated using the correlation derived in this study considering the analysis of capillary pressure and its relationship with RQI. As a result, and considering the correlation generated between the irreducible water saturation and the RQI values for all plugs available in the core wells, four drastic changes were observed in the slope of the curve, which can be considered to establish ranges of RQI values and irreducible water saturation representing the four main rock types of the reservoir that were modeled (Figure 6).

The main achievement of the petrophysical model was to estimate a detailed shale volume, which allowed to differentiate more accurately, clayey areas of low thickness, which influence the estimation of permeability, irreducible water saturation and the mobile water saturation, fundamental for characterization of this type of reservoir.

GEOCELLULAR MODEL

The objective of the geocellular model was to represent in a high resolution 3D grid (Figure 7), the integration of geological and petrophysical properties that works as input in the simulation model. The model was designed to cover the following assumptions:

- Identify possible vertical and lateral barriers (stratigraphic and structural) which affect the production performance of the wells.
- Predict the behavior of water, oil and gas production of the field in a more reliable estimation.
- Construct a detailed model that helps the guidance and optimization of the drilling and making decisions processes.
- Define potential areas with risk of water production in the field (Perched water, aquifers, among others)
- Build a model with the enough resolution to evaluate and simulate EOR processes and IOR methods.

The total area of the geocellular model was limited to 216 km^2 covering the area of the original seismic survey. The initial area was defined to avoid border effects and including selected information from the neighboring blocks. The grid cell model is corner point type with 195 (i) x 163 x (j) x 179 (k) cells dimensions, for a total of 5,689,515 grid cells with a dimension of 100 x 100 meters and an average of vertical thickness of 4.75-5 feet for each cell. The final reservoir grid was cut considering the area of the Petromonagas block (184.84 km^2) maintaining an external interval of about 500 meters in each areal direction to avoid border effects on the dynamic simulation.

Considering the density of wells drilled per unit area, the quality of existing data and the available knowledge of the field, it was decided to select the pixel modeling method Simulation Sequential Indicators (SIS), since is possible to guide the discrete property of facies with defined geometries in maps of probability of sand, vertical proportion curves and variograms, among others (Figure 8). During the stochastic simulation runs it was proved for this type of deposits that the SIS method was more predictive than others, such as object modeling and computationally less demanding than Multipoint techniques.

The facies modeling in the geocellular model started from the relationship between the rock type and depositional facies defined in the sedimentological model. In order to make a more accurate reservoir model, beyond to include the data of vertical and slant wells, the information of horizontal wells was included indirectly, making local runs of facies in these wells trying to avoid effects on the overall statistics which come from the vertical and slants wells logs. As a consequence, the information included from horizontal wells directly can cause overestimation of the statistics and volume of the reservoir.

Furthermore, the geocellular model is capable of represent the shale and heterolithic facies present in the reservoir in a more realistic way, defining the reservoir architecture and geometry of deposits honoring the sedimentological model.

The distribution of petrophysical properties in the geocellular model was controlled by the rock type defined in the petrophysical analysis. The method of simulation Gaussian Random function simulation (GRFS) was selected to extrapolate the petrophysical properties (porosity, water saturation and shale volume) across the grid model, where the data analysis included the standardization and generation of variograms faster than SGS. The GRFS is an interpolation method based on kriging. This algorithm assumes that data have normal (mean zero and standard deviation one) distribution and having stationarity requiring a consistent spatial variogram model. These properties were also adjusted to the trends of petrophysical properties observed on the isoproperties maps and based on the production information of the field. Permeability property is considered to be a function of porosity and shale volume as it was defined in the petrophysical model. These sets of equations were adjusted from well test interpretation (Figure 9) to populate the 3D grid. In fact, this method gave satisfactory results in the simulation model compared to the simple kriging of the well data.

WATER ZONES MODELING

In this study the potential areas of water production related to rock type, accumulations of trapped water (Perched water) and aquifers (Figure 7) were modeled in order to identify the impact in the water production. The analysis began by determining the wells that shows identified water in the well logs. Afterwards, the behavior of water production in producer wells and water analysis available was reviewed. It is noteworthy that trapped water areas generally have high salinity values, greater than 20,000 ppm, while the associated aquifers located at the northern part of the reservoir; gives lower values of around 10,000 ppm. This allowed giving more support to the interpretation of perched water zones for modeling. Therefore, the modeling strategy was based on determining the geometric relationship of entrapment perched water regarding close faults, structural depressions formed by the folds of drag folds described in the structural interpretation and the influence of the impermeable igneous-metamorphic basement. Subsequently, the 3D volumes of water areas were modeled in the geocellular model. The last step was determining the more real dimensions of trapped water was conducted in the dynamic model, simulating the behavior of water production in the horizontal wells close to these areas. In the final water saturation grid, the 3D water zones were replaced in order to determine the impact of these areas in the STOIIP volume estimation.

RESERVOIR AND SIMULATION MODEL

The first step in the dynamic model was the initialization process, which included: pressure and temperature distribution analysis, construction of rock/fluid model from available PVT and SCAL data in the Field. Therefore, the fluid model was based fundamentally on reproduce changes of viscosity, solution gas and Bo with pressure and temperature. Rock/fluid model involved the generation of average relative permeability curves and capillary pressure by rock types. In addition, several build up tested wells were interpreted in order to estimate, confirm and adjust the permeability model generated in the petrophysical model. Once the initialization of the dynamic model is done it delivered the dynamic estimation of STOIIP, which compared to the static model estimation gave an error less than 5%.

The second step of the Dynamic model is to review the static and dynamic properties in order to reproduce the production and pressure history of the Field, which included the reevaluation of general geological properties such as: permeability changes, channel dimensions (thickness, aereal and vertical connectivity) and a sensitivity analysis of critical gas saturation, relative permeability end points and rock compressibility to reproduce the best production history of the field in a general framework. Once the static and dynamic properties that affect the production in a Field scale are estimated and fixed, the third step is to modify local properties that affect the production behavior of the wells, which include: small vertical shale barriers, thickness, water pots size and contacts depths, transition zones size and permeability adjustment when needed. In the next part of this article will be exampled the static variables affected the local production in some wells of the field.

INFLUENCE OFGEOLOGY FEATURES IN WELL PRODUCTION PERFORMANCE

Case of study 1: Water production

Water zones are well identified mainly at the north of the field by a water oil contact located at 3320 feet of depth (TVDSS) according to well logs. Figure 10 depicts an E-W well F section showing water saturation property in the end of the simulation. Water channelization is reproduced in the reservoir model with a vertical movement of water in the connected body located at the heel of the well. In figure 10 water cut and oil production rate is reported registering a water breakthrough, achieving more than 20% of watercut, in the end of 2013 (early to the well production history). As a consequence well drawdown was adjusted and oil production rate fall in the first quarter of 2014 from 500 BPD to 200 BPD during 2014 and declining below to 100 BPD during 2015. It is demonstrated that in this case, vertical facies changes control the water coning to the producer well, therefore the presence of vertical connections from the water contact and the well affect the production performance.

Case of study 2: Gas production

In the second case (Figure 11) is shown an arrangement of five horizontal wells, drilled in parallel, two of them (A and E), are located at the bottom of the reservoir (Lower Morichal) and the other three (B, D y C) at the top and center of geological structure, in this case a faulted monocline. The wells A and E shown a production performance characterized by a stable initial gas oil ratio after ten years of production although the gas has been released due to the pressure drop. On the other hand, the wells B and D have shown a progressive increment of gas production after six years. Afterwards, both wells present a breakthrough achieving high GOR values (6000 ft3/bbl). Even though all wells are approximately 250 psi below the bubble pressure (1400 psi) only wells that are at the top of the structure show a significant increase in GOR over time.

In this example it is clearly demonstrated that the geological structure and well placement control the trapping of a local gas cap formed during the production period evaluated. It could be inferred that due to vertical connections and the high thickness (140 ft), commonly found in the stacking channels deposits of Lower Morichal Member (Figure 12) generating a production impact in wells located at the top of the geological structure. However, is important to mention that this condition could change from an area to another of the field in just in few hundred meters.

CHALLENGES AND OPPORTUNITIES

Evaluation of infill drilling, new wells placement optimization and production optimization of existing wells are the main challenges which could be seen as opportunities to improve the reservoir management based on the static and dynamic model can undoubtedly increase the oil production and value of the active. Besides, dynamic modeling will help the screening to evaluate and help the decision making to implement EOR technology projects to increase the recovery factor of the field.

CONCLUSIONS

Static and Dynamic models where successfully generated in order to identify possible vertical and lateral barriers (stratigraphic and structural) which affect the production performance of the wells, predict the behavior of water, oil and gas production of the field in a more reliable estimation. A detailed model was built to guide and optimize the drilling and making decision processes, defining potential areas with risk of water production in the field (Perched water, aquifers, among others).

The sediments of the Morichal Member (Oficina Formation) are framed in the transgressive phase of a mayor second order depositional units limited by subaerial unconformities associated with the evolution of the foredeep of Monagas.

The stratigraphic surfaces defined in this study could be correlated through the Cerro Negro field and extended to other fields in the Carabobo Block.

The reservoir properties are affected toward the top of the Morichal Member, because of the increase of shale volume, and vertical and lateral barriers which are associated with the increment of marine conditions of deposition.

The 3D modeling of trapped water (Perched water) according to the structural and stratigraphical interpretation, helped to identify the source of water which justifies the water production in some wells far the northern WOC.

Gas and water coning was modeled in order to reproduce historical production profiles, giving a more reliable evaluation of the well performance which requires monitoring and well optimization to avoid suddenly gas and water breakthrough.

Building a 3D geological model of a complex heavy oil field, with more than 320 producing wells and able to reproduce historical production and pressure is a tremendous task that requires a multi-disciplinary approach, where the key for success is to work as an integrated team at each stage of the process.

RECOMENDATIONS

It is recommended to drill more slant and vertical wells to improve and guide the placement of new horizontal wells in order to minimize the impact of water accumulations is mandatory for this field considering the influence of shale barriers and thickness in the productivity of the wells.

Moreover, it is important to drill the wells far from the top of the sands in order to avoid the fast gas irruption due to its accumulation on the top of the structure.

Evaluate technologies to avoid water coning in existing wells and improve the placement of new wells near water zones.

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TABLES

Table A-1. Reservoir properties of Morichal Member.

Reservoir Property	Morichal Member
Porosity	32%
Permeability	12000 mD
Water saturation	19 %
Temperature	120 - 135 °F
Bo	1,078
Viscosity	2000 cp
Datum	2750 ft
Initial Pressure	1280 psi

FIGURES

Figure 1. Location map

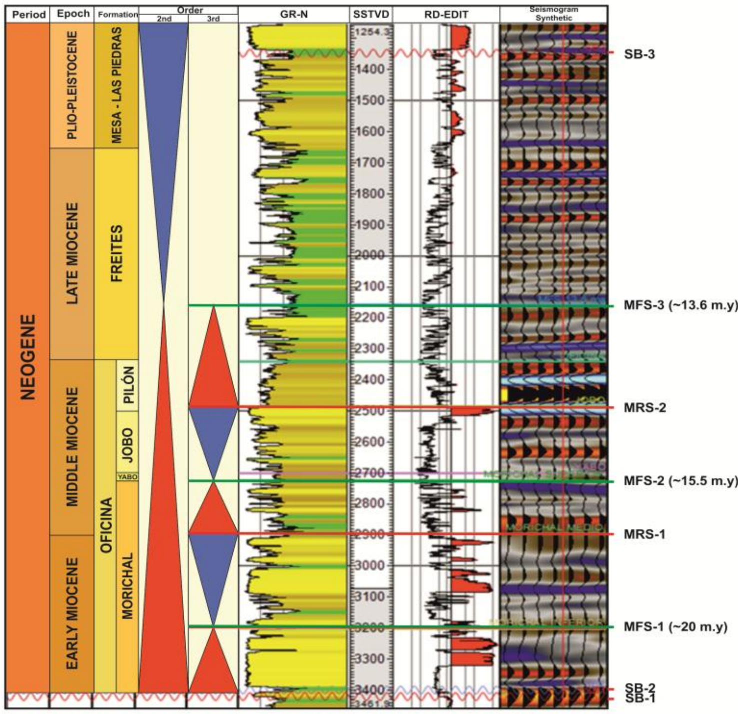


Figure 2. Stratigraphic column showing the main markers interpreted and the sequence stratigraphy analysis

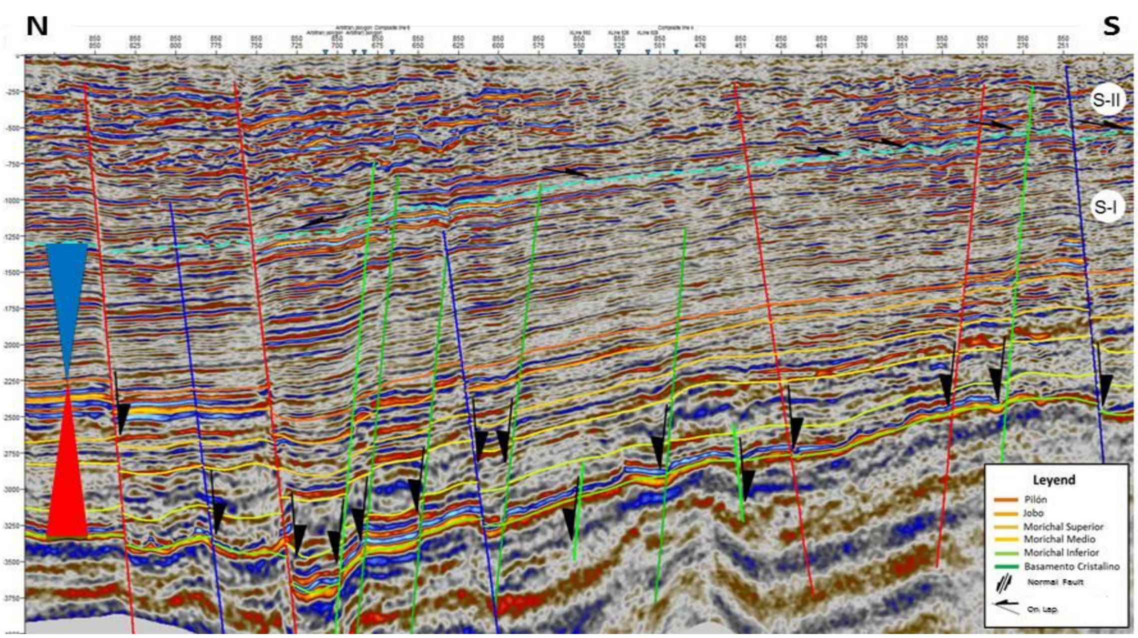


Figure 3. Seismic stratigraphy analysis showing the 2nd order sequence (SI) and the main surfaces interpreted

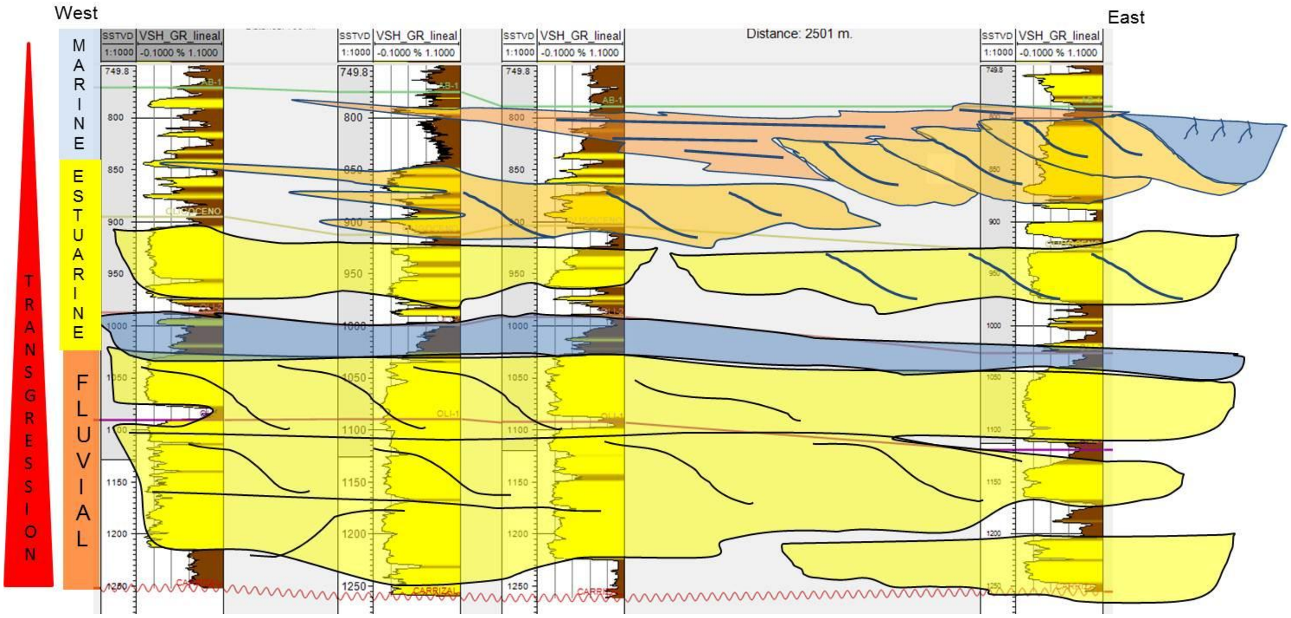


Figure 4. Schematic distribution of sedimentary bodies in Morichal Member

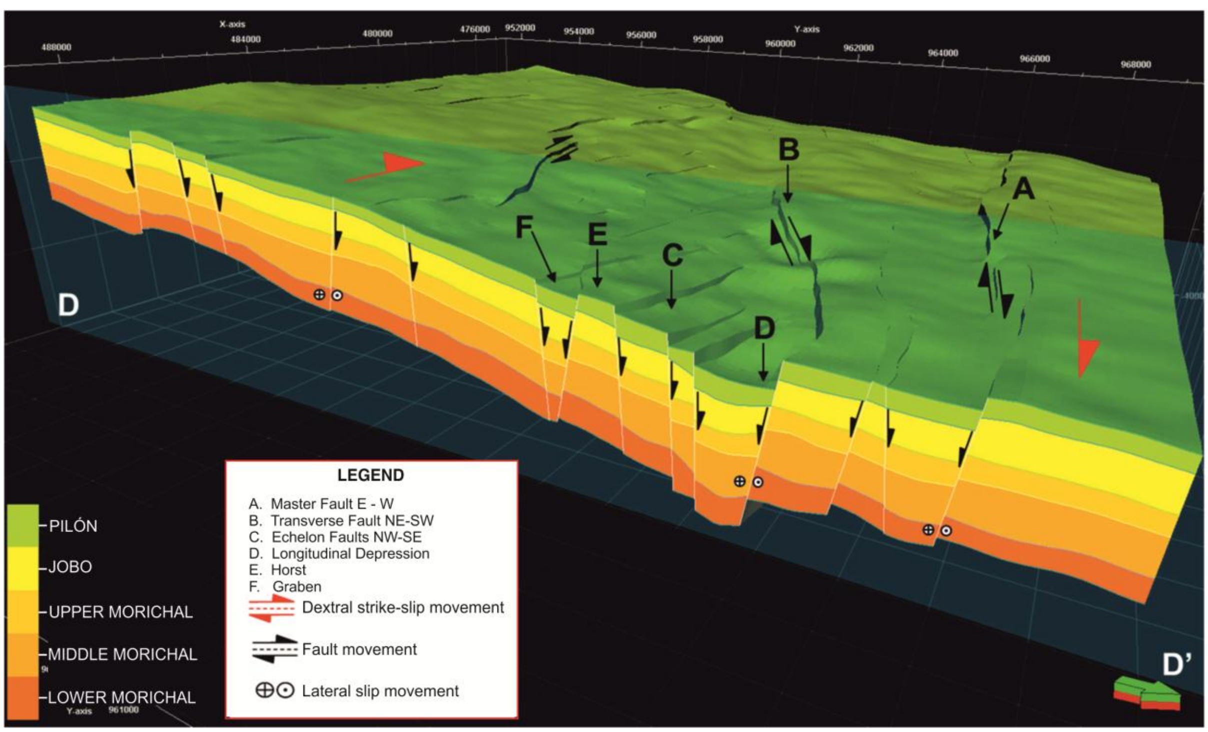


Figure 5. Three dimensional structural model shows the internal configuration of the Cerro Negro Field (Petromonagas joint venture)

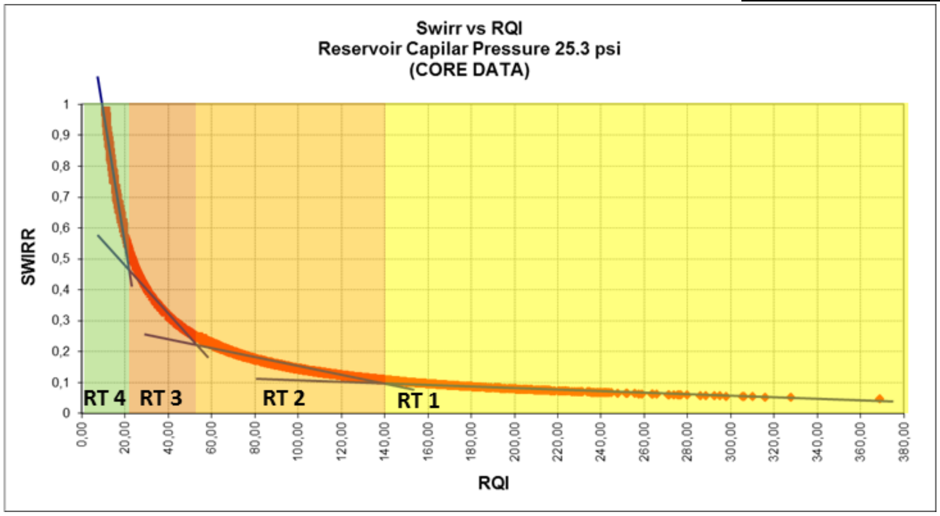


Figure 6. Ranges of RQI values and irreducible water saturation representing the main four rock types modeled in the reservoir

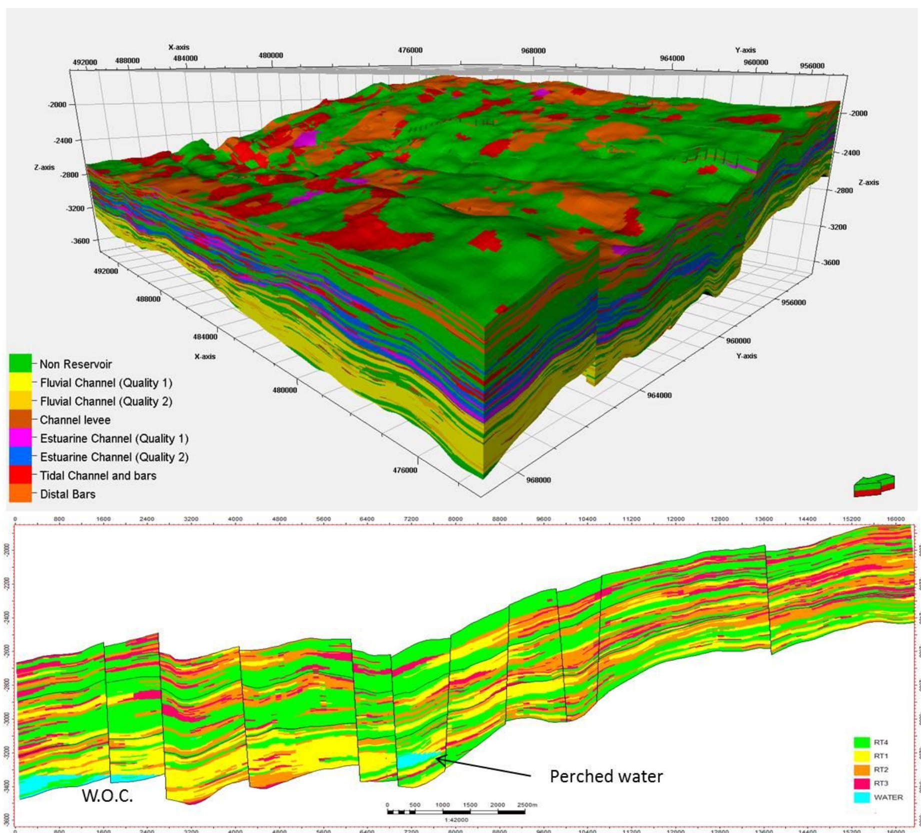


Figure 7. 3D geocellular model views and cross section showing water source

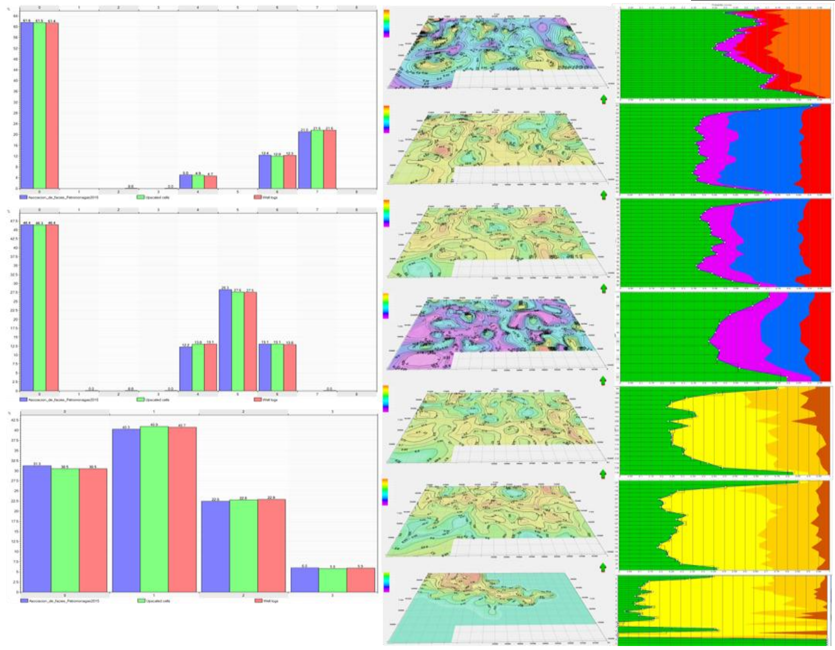


Figure 8. Proportion of Rock type in 3D modeling in each informal member of Morichal, maps of probability of sand and vertical proportion curves used in the geostatistical modeling

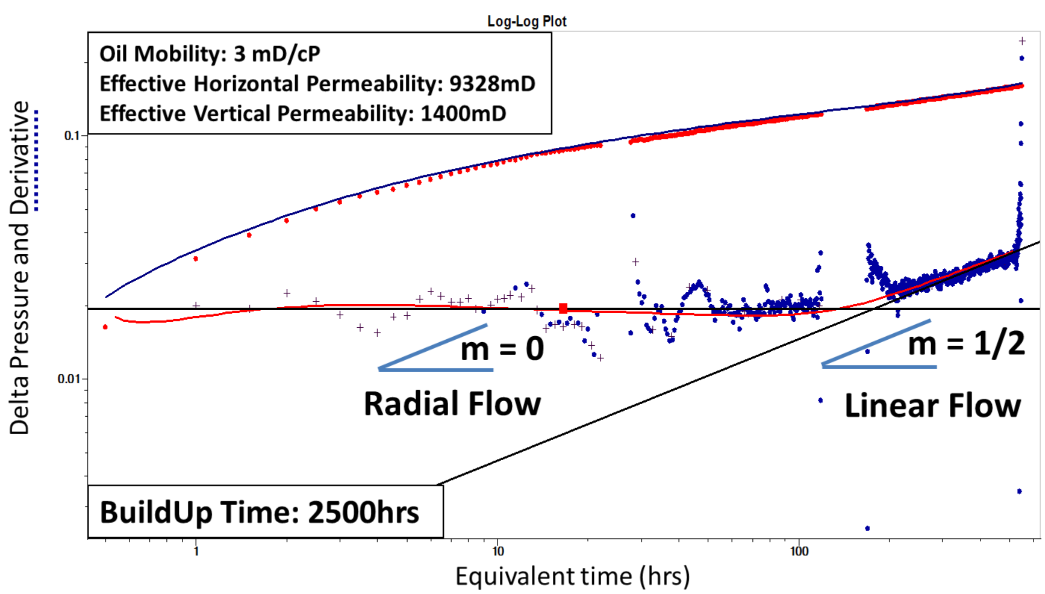
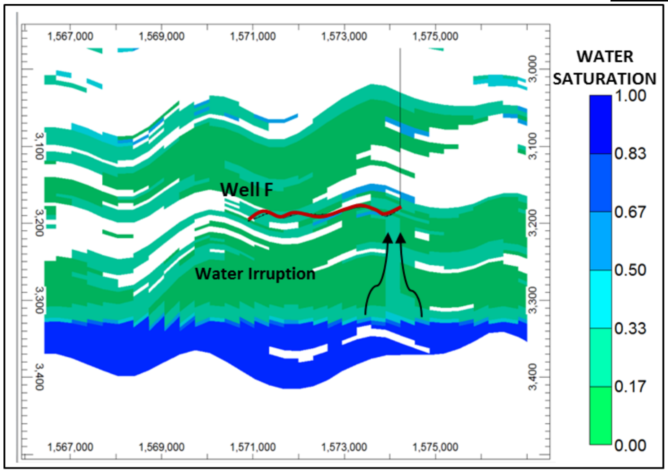


Figure 9. Built up Test Interpretation from Petromonagas Morichal Reservoir



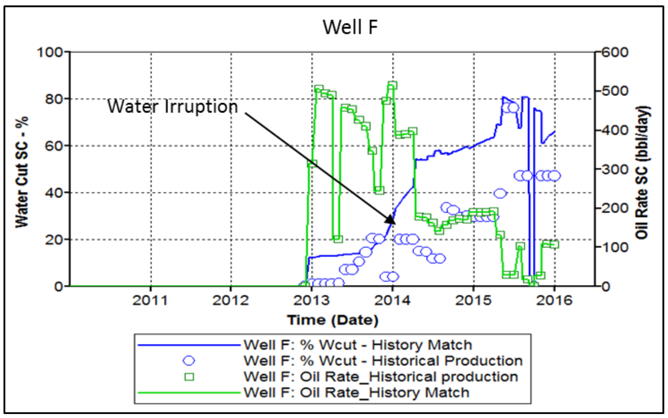


Figure 10. Water production case

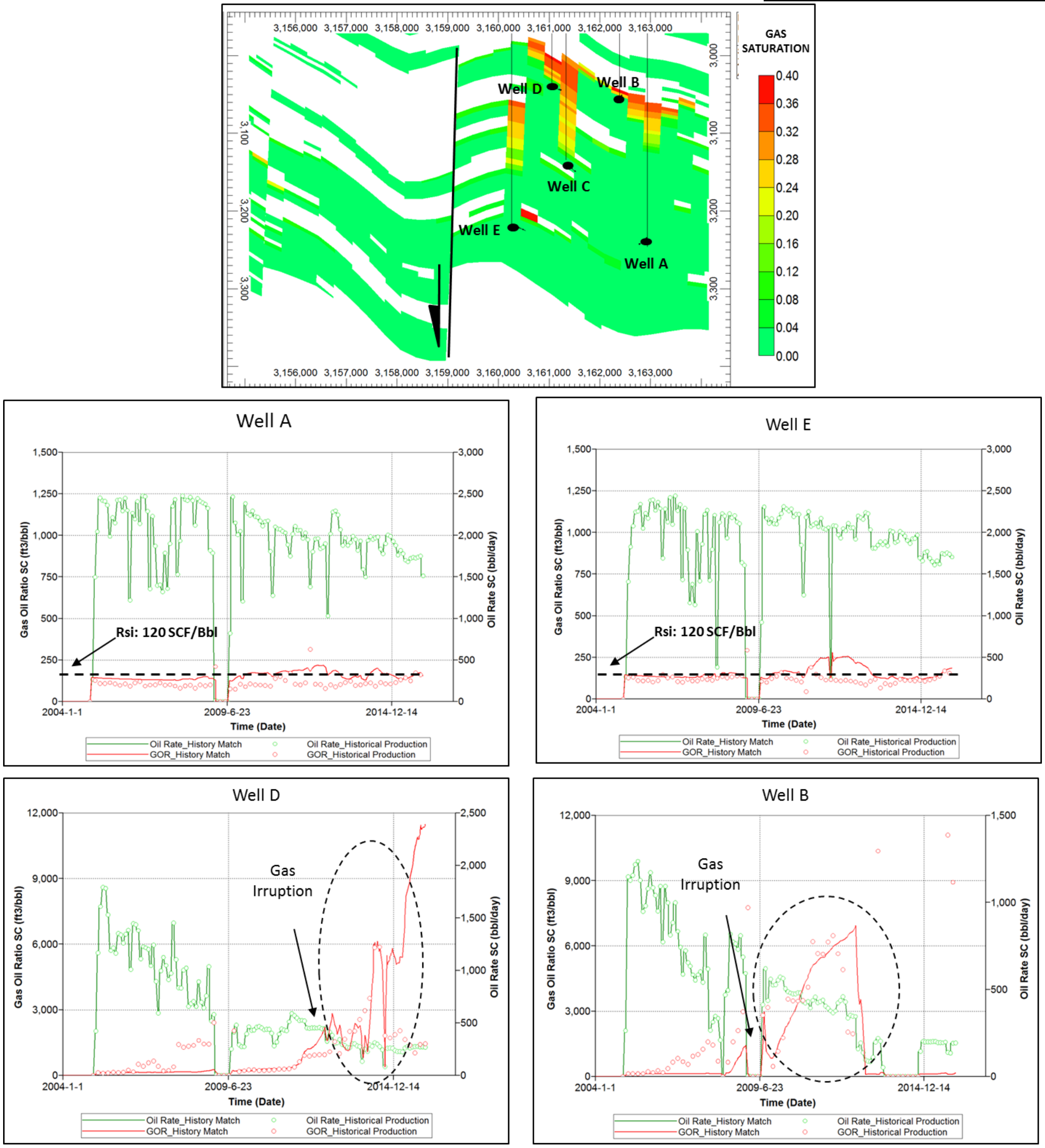


Figure 11. Gas production case

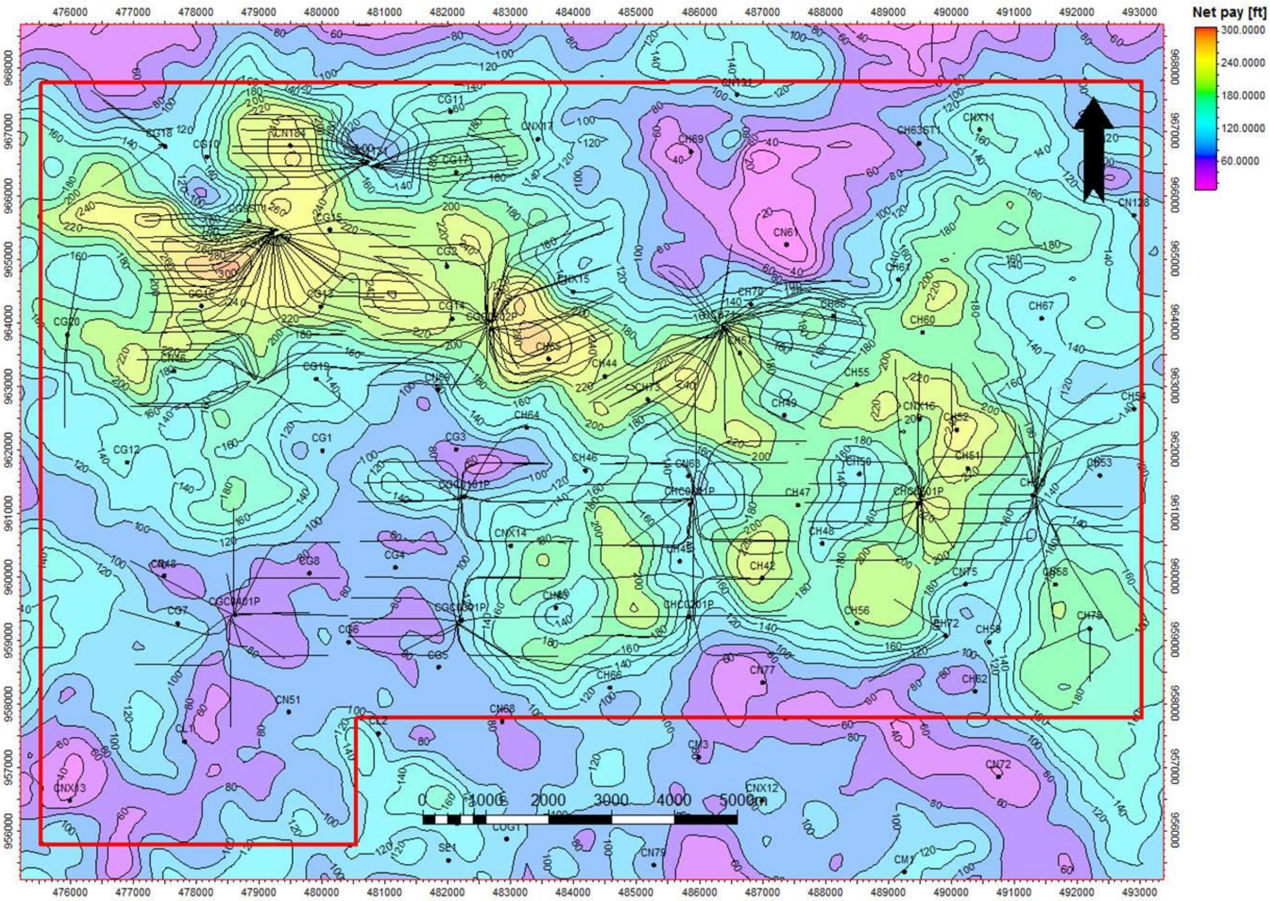


Figure 12. Lower Morichal net pay map