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ANALYSIS OF PINDA RESERVOIRS IN THE MOTOBA FIELD: METHODOLOGY, LITHOLOGICAL CHARACTERISTICS, AND POTENTIAL ZONES FOR WATER INJECTION

Marlin Agolo Monza[1 *]
Joël Etshekodi Lohadje [1, 6]
Louis Lungu Malutshi [3, 4]
Jean Manteke Kabay [3, 5]
Franck Tondozi Keto [2, 5]
Dan Tshimini Mutelu [1]

[1] Exploration-Production Department, Faculty of Oil, Gas and Renewable Energies, University of Kinshasa, D.R. Congo
[2] Physics Department, Faculty of Science, University of Kinshasa, D.R. Congo
[3] Directorate of Water Resources, Ministry of Environment and Sustainable Development, D.R. Congo
[4] African Institute of Foresight Studies, D.R. Congo
[5] Geophysical Research Center, D.R. Congo
[6] National Geological Service of Congo, D.R. Congo
* email (corresponding author): marlinagolo123@gmail.com

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ABSTRACT

The paper presents a comprehensive study of the Pinda reservoirs in the Motoba field, Democratic Republic of Congo (DRC), highlighting the methodology adopted to collect and process geological and petrophysical data. The analysis focuses on the LP1, LP2, and LP3 layers, with the primary objective of locating suitable areas for the establishment of injector and producer wells. The analysis includes data collection and processing, followed by result interpretation to create maps of isobaths and iso-values of hydrocarbons in place. Tools such as Grapher and ArcGIS were used to visualize this information. The history of the Motoba field, discovered in 1975, is also discussed, illustrating the challenges and successes of production, particularly the water injection initiated in 1998 and resumed in 2011. The regional geology and stratigraphy of the Pinda formation are described, emphasizing the lithological complexity and diagenetic processes that have influenced reservoir quality.

The study reveals that the Lower Pinda reservoir is divided into sub-units, each exhibiting distinct petrophysical characteristics. Data on porosity, saturation, and clay content were analyzed to establish a dynamic model for evaluating hydrocarbons in place. The results from the isobath maps show significant depth variation, identifying favorable areas for well implantations, particularly in the Northwest, East, and Southeast. Recovery factor analyses and GOR indicate opportunities for resource optimization, with regions identified as suitable for water injection. In conclusion, this paper underscores the importance of a methodical approach in reservoir evaluation and strategic planning of injection operations in the Motoba field.

Keywords: Reservoirs, Injection, Petrophysical, Hydrocarbons, Optimization

INTRODUCTION

The oil-rich Democratic Republic of Congo sees the Motoba field as a major opportunity for hydrocarbon development. The study of the Pinda reservoirs, in particular the LP1, LP2 and LP3 layers, [19] is crucial to maximize production. This manuscript aims to present a rigorous analysis of these reservoirs, relying on geological and petrophysical data to identify strategic zones for water injection [17]. Through a combination of advanced technologies and detailed data interpretation, this study aims to contribute to the optimization of petroleum operations and the sustainability of resources in the region [12].

The scope of the paper is to offer an integrated approach to hydrocarbon reservoir evaluation, highlighting the importance of water injection as a recovery enhancement method. A significant gap covered by this study lies in the lack of previous research into specific aspects of Motoba field reservoirs, particularly with regard to interactions between the different layers. The novelty of the proposed study lies in the use of advanced geostatistical models, enabling a better understanding of reservoir characteristics and thus optimizing exploitation strategies.

METHODOLOGY

In addition to documenting water injection and the LP1, LP2 and LP3 layers, we used the following methods and techniques to identify potential water injection zones in each layer of the Upper Pinda reservoir.

Data collection: This phase involved an exhaustive collection of relevant data concerning the layers making up the Upper Pinda reservoir. This included, but was not limited to:

- Geological data: Formation summits, fault interpretations, stratigraphic markers, core and log data.
- Petrophysical data: Porosity, permeability, water saturation, clay volume and net-to-gross ratio derived from log analysis.
- Reservoir fluid data: PVT (Pressure-Volume-Temperature) data, including dissolved gas/oil ratio (GOR) and bubble pressure.
- Production data: Historical production rates (oil, gas and water) for individual wells and the reservoir as a whole, wellhead pressures and downhole pressures.

Data processing: This stage involved rigorous processing and analysis of the collected data to generate key maps of reservoir properties. This included: maps of isobaths and iso-values of hydrocarbon volume in place, recovery factor, mobility, pressure, and GOR.

Log Analysis: Calibration of logs with core data, environmental corrections, and calculation of petrophysical properties.

- Seismic Interpretation: Structural interpretation of seismic data to define reservoir boundaries, fault locations, and horizons.
- Reservoir Modeling: Construction of a static reservoir model integrating geological structure, petrophysical properties, and fluid contacts.
- Upscaling: Upscaling petrophysical properties from fine-scale logs to grid blocks of the reservoir model.
- Map Generation: Development of isobath maps (structural maps) and iso-value maps of key reservoir properties.
- Geostatistical Analysis: Use of geostatistical techniques (e.g., kriging, sequential Gaussian simulation) to interpolate and extrapolate petrophysical properties between wells, respecting geological trends and seismic data.
- Fluid Flow Simulation: Use of reservoir simulation software to model fluid flow in the reservoir under different water injection scenarios.

Interpretation Phase: This critical phase involved analyzing the generated maps and simulation results to identify potential water injection zones in each layer of the Upper Pinda reservoir. This included:

- Identification of High-Potential Zones: Identifying areas with high hydrocarbon saturation, good permeability, and low pressure that would benefit from water injection.
- Injectivity Assessment: Assessing the injectivity of potential injection wells based on permeability, skin factor, and reservoir pressure.
- Consideration of Sweep Efficiency: Analyzing the potential sweep efficiency of water injection based on reservoir heterogeneity, fault patterns, and well positioning.
- Water Compatibility Assessment: Evaluating the compatibility of injected water with reservoir fluids and rocks to prevent formation damage.
- Risk Assessment: Identifying potential risks associated with water injection, such as premature water breakthrough, fault reactivation, and formation damage

Data processing, which enabled us to obtain isovalue maps of the properties studied, was carried out on a laptop equipped with software such as:

- **PETREL:** Comprehensive modeling software used to build static and dynamic reservoir models, perform petrophysical analysis and simulate fluid flow.
- **GRAPHER:** Mapping and modeling software used to create isovalue maps of the properties studied. It allows visualization and analysis of spatial data. Specific functionalities used probably included contouring, gridding and data transformation.
- **ArcGIS-10.8:** This software enabled us to create maps relating to the study area, including base maps, well locations and reservoir boundaries. It was used for spatial data management, analysis and visualization. Specific functionalities used probably included georeferencing, digitizing and spatial analysis.

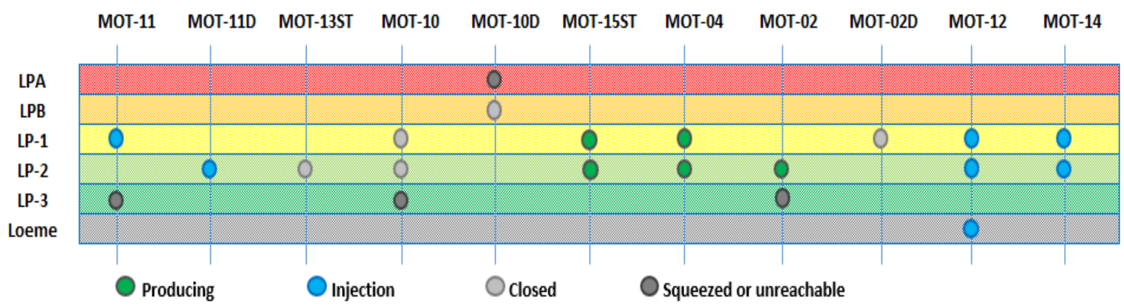
HISTORY OF THE MOTOBA FIELD

The Motoba field was discovered in 1975 with the drilling of well MOT-01X targeting the Upper Pinda reservoir, and in 1986 with well MOT-02X reaching the lower reservoir [20]. This field represents the sixth oil discovery made offshore in the DRC, with the first signs of oil from the Lower Pinda reservoir noted in July 1986 [13].

Following the drilling of five additional producers in the Lower Pinda (MOT-02, -04, -10, -11, -12, and -13ST), water injection was implemented in 1998 with well MOT-14, but stopped in 2004 due to a shortage of injection water. At that time, Perenco acquired a 50% stake in the field and took over operations from Chevron [15]. Water injection was resumed in 2011 and improved a year later with the conversion of MOT-11 from an oil producer to a water injector [5].

Current operations by the subsidiary include optimizing the injection system and the quality of the injected water [18]. Despite the loss of water injection in MOT-14 from 2004 to 2011, the Lower Pinda reservoirs still maintained some pressure support from aquifers, alongside natural injection in MOT-12. Initially perforated at the oil levels LP1 and LP2, well MOT-12 received additional perforations in 2006 in an intra-salt layer (Loeme) [19]. This reservoir was, however, water-bearing, leading to the closure of well MOT-12, which allowed water to flow transversely into the drilling well from the Loeme into the LP1 and LP2 reservoirs, a phenomenon referenced in various reports as "discharge flooding" [17]. A well status in the Motoba field is presented in Table 1.

Table 1. *Well status* [17]



Recent years have seen a decline in production despite a significant increase in reservoir pressure, primarily due to mechanical issues and difficulties in optimizing gas lift systems (e.g., MOT-04) [19]. Well MOT-15 has barely produced since 2007 due to a blockage obstructing the lower perforations (base LPB and LP3) and the observation in 2010 of tubing restrictions and loss of access to closed sliding sleeves (LPA), despite a fishing operation since February 2013 [18].

First oil production at Motoba occurred in 1981, six years after the initial discovery, peaking in February 1990 at approximately 9,000 BOPD [19]. Current production (June 2019) is around 2,600 BOPD with four wells producing from the Upper Pinda reservoir, three producer wells, and three injector wells from the Lower Pinda reservoir [16]. Cumulative production from the field stands at 41 MMstb, with the majority attributed to the Lower Pinda reservoir (30 MMstb; 21% RF), and a smaller contribution from the Upper Pinda formation (11 MMstb; 6% RF) [19].

Perenco acquired a 67% interest in the offshore DRC license (including Motoba) in several stages starting in 2004, with the remaining 33% held by INPEX. A 20-year license extension was negotiated and finalized with the DRC government towards the end of 2017, meaning the license now expires in 2043 [8],[16].

REGIONAL GEOLOGY AND STRATIGRAPHY

The Pinda formation, dating from the Albian period in the Congolese offshore, is characterized by extreme lithological complexity, ranging from carbonates to siliciclastic rocks, largely associated with depositional environments [13],[20],[27]. This formation overlies the Aptian salt horizon of Loeme and is topped by the Kinkasi layer of the Iabe formation, which consists of shales (Figure 1).

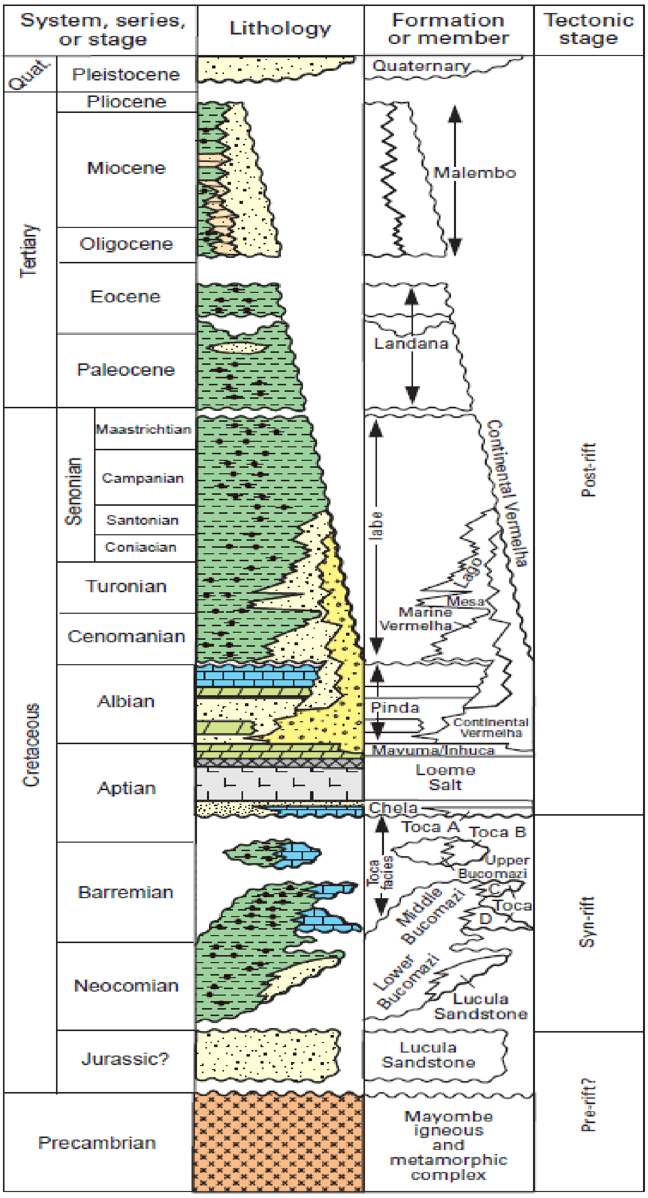


Figure 1. *Generalized stratigraphic column of the coastal basin* [20].

The entire depositional sequence of the Pinda formation is regarded as a reference for marine deposits linked to the opening of the sea, established under marginal and/or lagoonal conditions in a tidal environment over various depositional times [19]. In addition to deposition, the intensity of tectonic activities has significantly influenced the formation during its deposition. The halokinesis of the salt formation beneath the Pinda formation, coupled with faulting during deposition, has largely affected its stratigraphy, causing it to thicken or thin [18]. The Pinda formation is primarily characterized by an alternation of carbonate and siliciclastic layers, which are considered to represent a "rhythmic or cyclical sequence". However, for a better understanding of the stratigraphic scale of the coastal basin, Chevron divided the Pinda formation into eight major sequences numbered P1 to P8, starting from the oldest to the most recent [19],[24].

The Upper Pinda reservoir consists of three major lithofacies. The upper section is mainly composed of limestones and sandy limestones, with small beds of sandstone [28],[29]. These rocks cover a dolomite-dominant facies, also interbedded with minor sandstones. The basal section comprises sandstones and dolomitic sandstones with intercalated dolomites and minor limestone layers [19]. Diagenesis is a major controlling factor for the quality of reservoir rocks in the Upper Pinda reservoir [15],[19]. Chevron, the previous operator, conducted a detailed analysis of the reservoirs concerning diagenetic characteristics, although references to this study are minimal, and the location of the original documents is unknown [14],[25]. The main conclusions of this work include:

- The dolomite facies shows local diagenetic heterogeneities on a scale of inches permeable zones with vuggy and intercrystalline porosity are visible in the same thin section, alongside narrow zones devoid of any porosity.
- Predicting diagenetic fabric in the subsurface is extremely difficult without knowledge of certain intangible elements: fluid migration pathways, fluid composition, temperatures, and pressures.
- The "ghost" allochem fabrics recognized in the fine sections of dolomites indicate that the dolomites of the Upper Pinda formed by replacement of limestones. Their diagenetic history is interpreted as beginning with preferential dolomitization of certain carbonate grains, followed by the dissolution of unaltered calcite grains, producing vuggy and moldic porosity.
- Dolomitization appears to be selective of fabric; porosity and permeability are definitely fabric-selective, increasing in grain-rich areas.
- Facies and depositional textures in carbonate environments generally vary significantly over small vertical and lateral distances, thus influencing the selective diagenesis of facies and restricting the surface distribution of dolomite and associated permeable zones.

Additional complications arise from the non-conformable nature of dolomitization and geological deposits; dolomite cuts across different geological zones and layers [4],[20]. This increases uncertainty when attempting to map the facies of dolomite reservoirs far from well control points. However, successfully predicting the distribution of dolomite in the geological model is likely crucial for achieving an accurate historical concordance due to the marked differences in reservoir and flow characteristics between dolomite and surrounding limestone facies. This marked difference is evident in core plug porosity-permeability measurements, well test/DST results, and flowmeter/PLT data, all indicating a minimal contribution of liquid (gas flows easily) from the limestone facies to overall production from the Motoba field reservoir.

The main lithological complexities and uncertainties of the reservoir are noted above, but they must also be considered alongside the poor distribution of well control points present at Motoba, where, as in many Pinda fields in the DRC, most wells tend to be located along structural ridges [4],[20]. This inherent lack of downhole data further complicates the prediction and distribution of facies and petrophysical properties.

These eight major sequences are regionally correlated across the offshore fields of the DRC, and this correlation is based on "Mean Sea Level" markers [11],[20]. These sequences can be grouped into two main cycles: the Upper Pinda, which includes sequences P6, P7, and P8, and the Lower Pinda, which includes sequences P1 to P5. Among these eight sequences, the roof of the Upper Pinda (P8) represents the top part of the Pinda formation, while the summit of P5 is the top of the Lower Pinda.

In the Motoba field, the Lower Pinda Formation is subdivided into subunits. In this study, this nomenclature will be applied and these sub-units are defined as LPA, LPB, LP-1, LP-2 and LP-3 (Figure 2). The Lower Pinda formation in the Motoba field is a carbonate deposit associated with siliciclastic facies. The depositional environment of this formation is characterized by the carbonate deposition of shallow seas, consisting of "wackestone to grainstone" limestones, claystones, siltstones, and dolomites interbedded with sandstones. The quality of these facies significantly influences reservoir quality. When comparing the Lower Pinda reservoirs of the Motoba field to those in the southern offshore fields of the DRC, notable differences arise.

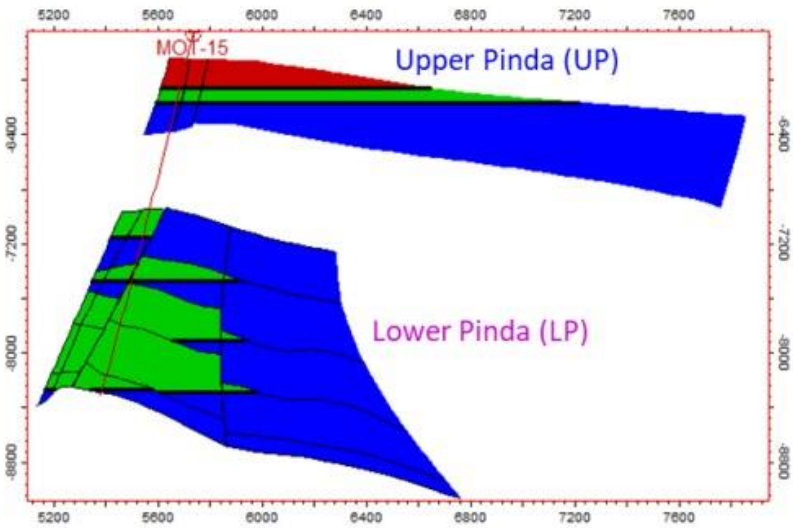


Figure 2. *Stratigraphic correlation between Chevron (1998) sequences and Motoba Field sub-units* [13]

In the southwest part of the GCO oil concession, carbonate deposits are dominant, while the central and northern areas are characterized by marginal or lagoonal deposits made up of siliciclastic formations, similar to the Motoba, Tshiala, and Mibale fields. Additionally, the Lower Pinda formation is marked by intercalations of porous and permeable siliciclastic layers, which are associated with channel and lagoon depositional networks. The sandstones and siliceous dolomites within the lagoonal facies are productive zones of the Lower Pinda formation in the Motoba field.

TECTONIC CONTEXT

The structural evolution of the Bas-Congo is closely linked to the development of the South Atlantic rift, which occurred when Africa and South America separated [20]. The tectonic styles associated with this separation can be simplistically classified into pre-rift, syn-rift block faults, and post-rift tilting and subsidence. The deposition of the Pinda formation took place during the early post-rift phases of structural development. Halokinetic movements and growth faults began to occur during this period, playing a significant role in controlling local and regional sedimentation and the distribution of lithofacies. Furthermore, halokinetically induced faults created structural features that provide effective trapping locations for hydrocarbon migration. The key structural trap type observed in the Pinda formation consists of tilted fault blocks, with hydrocarbon accumulation from the Upper Pinda field situated along the crest of one of these structures.

The Motoba field is one of many post-salt deformation blocks offshore the Democratic Republic of Congo. The deformation blocks of the Motoba field began to form during the Albian period and remained active until the mid-Cenomanian period, in response to gravity sliding over the Loeme salt. The Upper and Lower Pinda formations, which are the main reservoirs of this field, are syn-tectonic formations that thicken from the crest of the fault block.

The Motoba field is an inclined fault block featuring five stacked, non-communicating reservoir zones. The structure is geologically complex with intricate fault geometries and wells in close proximity to fault planes. The highest LP-A reservoir is modeled as a chimney structure, representing a sub-seismic fault segment with limited lateral extent, the full width across the field remains unknown. In the Lower Pinda formation, potential fractures have been observed in the dolomitic limestones (also supported by drilling data). Figure 3 illustrates the structure of this reservoir.

The bounding faults of the main block tend to dip northwest-southeast and southwest. These are listric faults found within the Loeme salt. The western bounding faults exhibit complex relay ramp geometries and are segmented into several splays. A number of other intra-block faults intersect the Lower Pinda reservoir section but do not appear to cut through the top surface of the Upper Pinda. The model illustrates the faults intersecting the lower surface of Unit 5. These faults were active during the deposition of Units 1-5 when the thickness of these units varied across the faults.

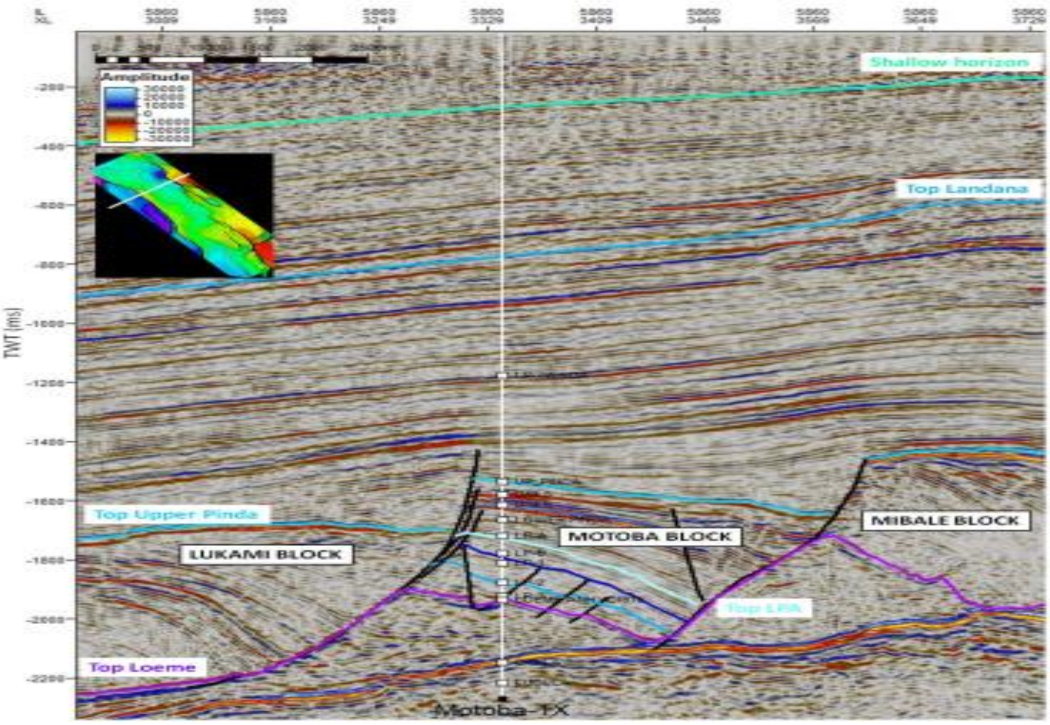


Figure 3. *Structural cross-section of the Motoba field*

RESERVOIRS

The Lower Pinda reservoir of the Motoba field in the Congolese offshore is a producing reservoir divided into five sequences, as mentioned in previous paragraphs: LP-3, LP-2, LP-1, LPB, and LPA [20],[22].

– **LP-3**

This sequence is the lowest in the Lower Pinda reservoir and is considered to have been deposited in a marine environment. It represents a transition between evaporitic deposits and those related to ocean opening. The lithology of this sequence is primarily composed of dolomites and dolomitic limestones.

In the Motoba field, layers of sandstone or indurated limestone are occasionally interbedded within the dolomites. Some horizons of anhydrite are also visible in this sequence. The quality of the reservoir improves with the development of pores in the dolomites and in the associated sandstone horizons, which can be observed in several wells such as MOT-04, MOT-10, MOT-11, and MOT-15, with an average thickness of 120 ft (36.576 m).

In the Motoba field's Lower Pinda reservoir, the LP-3 sequence was the first tested, specifically in the dolomitic formation of well MOT-03, resulting in the presence of water without hydrocarbons. The second test was conducted in the highly porous dolomitic formations with karst features of MOT-04, yielding hydrocarbons without water. Future wells drilled in this field indicated that the productive layer in the LP-3 sequence is the interbedded dolomitic formation with sandstones (Figure 4).

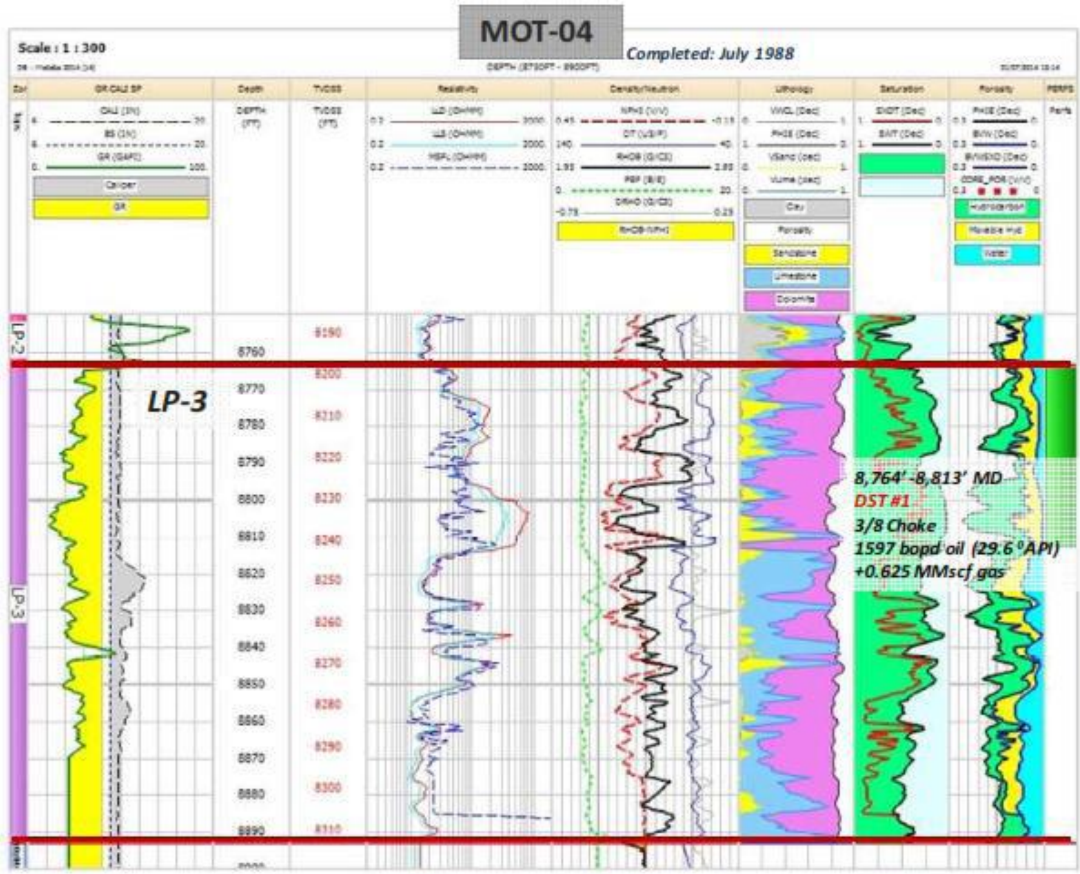


Figure 4. *Log of the LP-3 sequence in the Motoba field (MOT-04).*

The pay thickness of LP-3 measures 100 ft (30.48 m) with porosity at 20% and water saturation at 20% (13.5% porosity cut-off and 50% water saturation as cut-off).

Previous studies conducted in the Motoba field indicate the potential for fractures within the dolomitic and dolomitic limestone formations. This is also evidenced by data from well MOT-15, where a loss of 60 bbls of drilling mud was noted while drilling through the dolomites of LP-03. This same phenomenon was observed in similar intervals of wells MOT-10 and MOT-11, identified through density/neutron log interpretation and sonic log data. The PEF log, on the other hand, indicates the presence of limestone.

Conversely, in MOT-04, this fracture zone is not observed; however, the density-neutron log suggests evidence of porosity due to karsts, with a density of 2.3 g/cm³ and porosity of 28%. Notably, the DST test conducted in well MOT-04 at the same intervals showed the presence of hydrocarbons without water. Results from the CBL log reveal a lack of cementing behind the casing, in addition to the existence of communication between the reservoir and the aquifer.

– **LP-2**

Above the base sequence LP-3 lies a cyclic succession of carbonate and clay deposits. The quality of the LP-2 reservoir is notable in the Motoba field, characterized by dolomitic formations and interbedded sandstone layers. Anhydrite layers are rare in the LP-2 sequence.

The development of pores in the dolomite and associated sandstones in the Motoba field (contrasting with the Tshiala field, which exhibits low porosity in the dolomite for the same reservoir) reflects a more proximal deposition zone. The presence of these deposits suggests lagoonal conditions, although they are attributed to the ocean opening with the establishment of carbonates.

According to data from Perenco, the LP-2 sequence was cored in well MOT-3 and has a thickness of 180 ft (54.864 m). This cored interval consists of dolomitic formations with thin interbedded limestone layers. In the lower parts of this cored section, wackestone and packstone-rich clays with poor porosity, altered by diagenesis (cementation) of the dolomite, are present.

In contrast, the upper portion of the core consists of oolitic limestones with dolomitic cement, displaying porosity ranging from 10% to 28% and permeability between 2 and 30 mD (with some values reaching 200 to 300 mD). The LP-2 sequence, comprising dolomitic formations of the Lower Pinda reservoir, represents a superior reservoir characterized by visible karsts in certain wells. Its average thickness is approximately 350 ft (106.68 m), with an average effective porosity of 18% and irreducible water saturation of 24%.

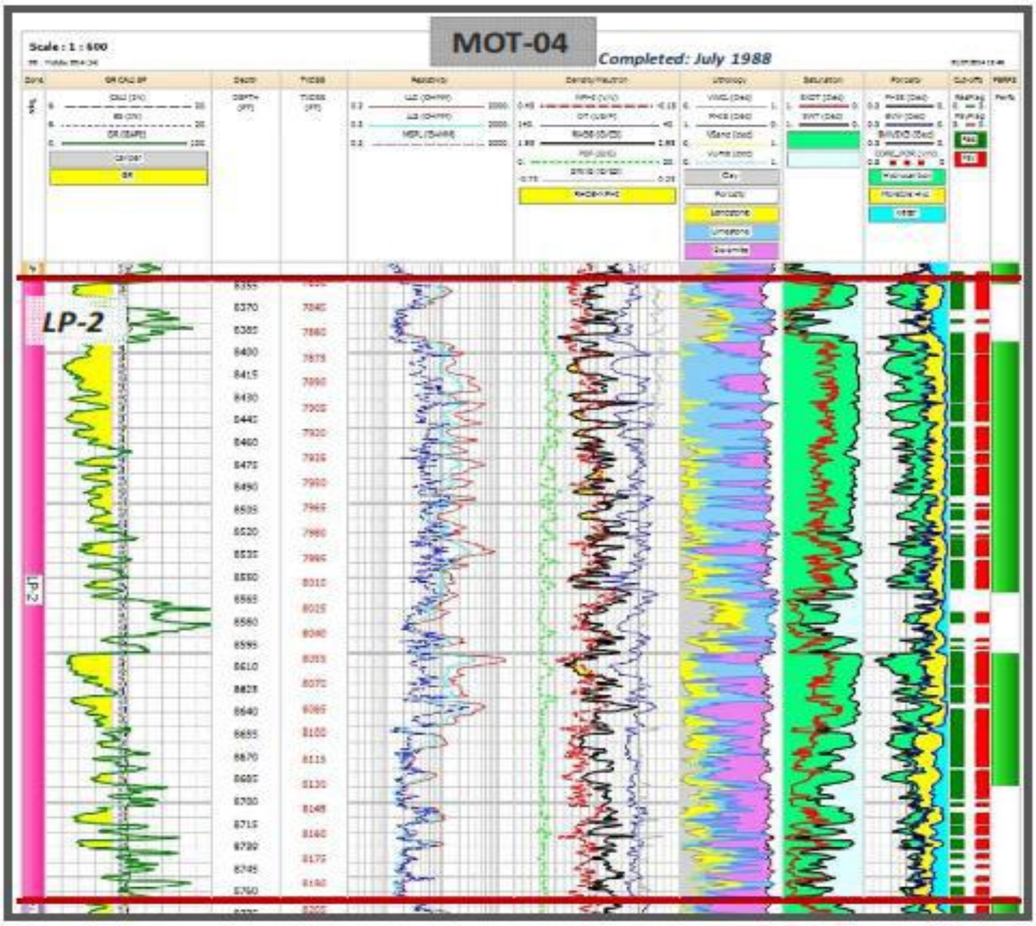


Figure 5. *Log of the LP-2 sequence in the Motoba field (MOT-04).*

– **LP-1**

The LP-1 sequence at the Motoba field is largely composed of carbonate formations deposited in the lagoonal context. As observed in the MOT-03 cores, siltstones and shales predominate, with some anhydrite. Marine opening conditions are visible from the carbonate barriers observed in the drill cores. Lithologically, this sequence consists, apart from carbonate formations, of beds of siltstone, shale, dolomite, sandstone and a small amount of anhydrite.

Good porosity is obtained in the lower parts of the sequence, with non-regular permeability. Good permeability is nevertheless found in the sandstone-rich parts (200 mD). Its average thickness is around 300 ft (91.44 m).

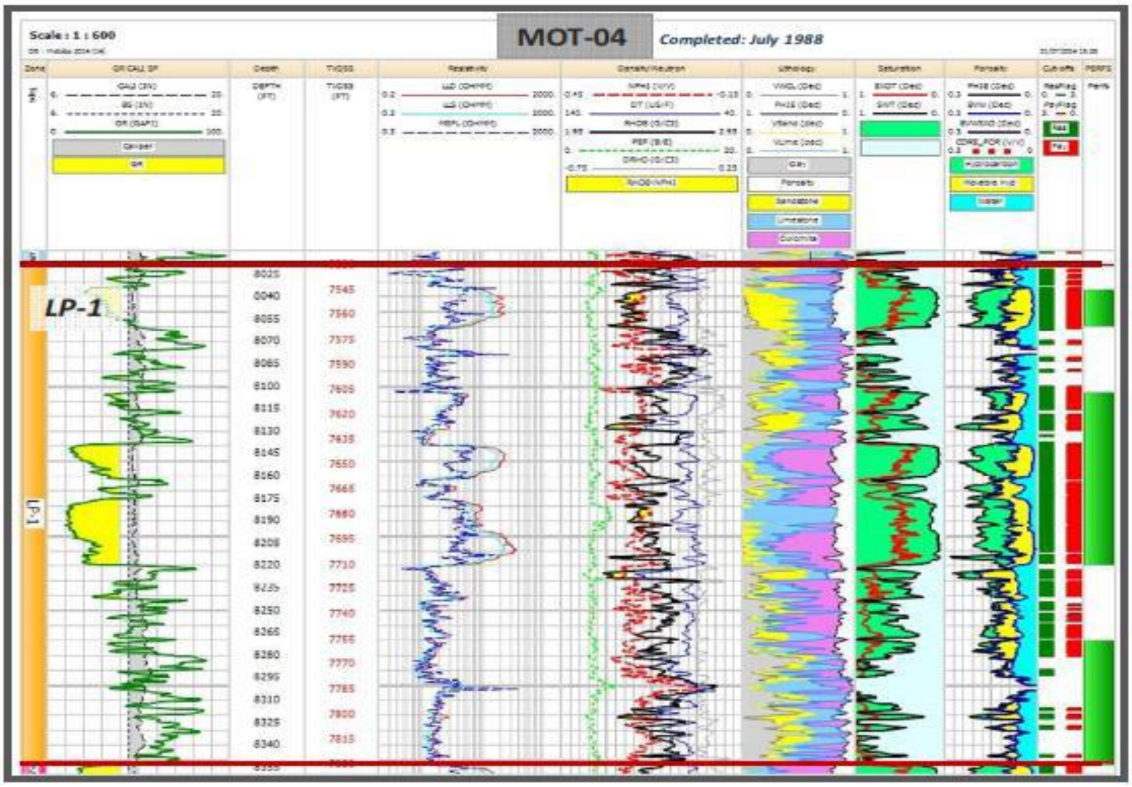


Figure 6*. Log of the LP-1 sequence in the Motoba field (MOT-04).*

– **LPB & LPA**

The LPB and LPA sequences represent the roof of the Lower Pinda reservoir and are characterized by carbonate formations with porosity and permeability linked to silico-clastic layers.

The LPA sequence in the Motoba field is equivalent to the LPB-3A sequence in the Tshiala field. In the Motoba field, LPA consists of porous and permeable sandstone layers.

The total thickness of the LPB sequence is around 225ft (68.58 m) observed in well MOT-11, and its impregnated thickness is between 130ft (39.624 m) and 200ft (60.86), depending on the position of the wells considered. Average impregnated porosity is 20%, with irreducible water saturation of around 32%.

The total thickness of the LPA sequence is approximately 390 ft (118.872 m) observed in wells MOT-10, -11, -13 and -15 and its impregnated thickness is 250 ft (76.2 m) observed in wells MOT-10 and MOT-15. Average impregnated porosity is 20%, with irreducible water saturation of around 33% (see Figure 7).

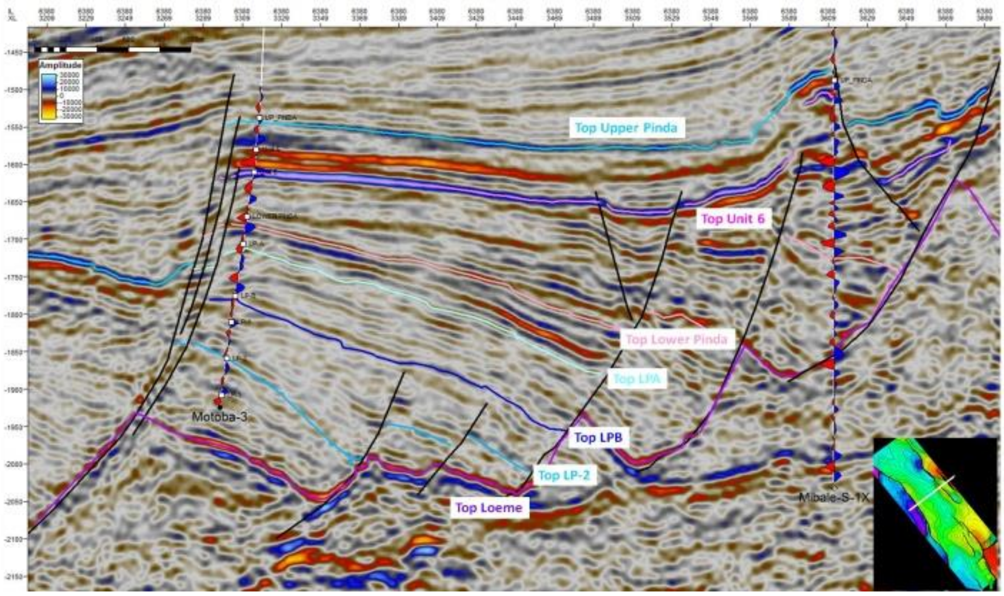


Figure 7. *Seismic section of Pinda reservoir*

The Upper Pinda is composed of three major lithofacies. The upper part primarily consists of limestones and sandy limestones, with minor beds of sandstone. These rocks overlay a dolomite-dominated facies, which is also interbedded with minor sandstones. The basal section comprises sandstones and dolomitic sandstones with intercalated dolomites and minor limestone layers.

Diagenesis is a major controlling factor for the quality of reservoir rocks in the Upper Pinda. Chevron, the previous operator, conducted a detailed analysis of the reservoirs concerning diagenetic characteristics; however, references to this study are limited, and the location of the original documents is unknown [19],[22].

Additional complications arise from the non-conformable nature of dolomitization and geological deposits; dolomite intersects various geological zones and layers. This increases uncertainty when attempting to map the dolomite reservoir facies far from well control points. However, successfully predicting the distribution of dolomite within the geological model is likely crucial for achieving accurate historical concordance due to the marked differences in reservoir and flow characteristics between dolomite and surrounding limestone facies [22].

This significant difference is evident in core plug porosity-permeability measurements, well test/DST results, and flowmeter/PLT data, all indicating a minimal contribution of liquid (gas flows easily) from the limestone facies to the overall production of the Motoba Upper Pinda.

The primary lithological complexities and uncertainties of the reservoir are noted above, but they must also be considered alongside the poor distribution of well control points at

Motoba, where, as in many Pinda fields in the DRC, most wells tend to be located along structural ridges. This inherent lack of downhole data further complicates the prediction and distribution of facies and petrophysical properties.

PETROPHYSICAL CHARACTERISTICS OF THE PINDA RESERVOIR

A series of wells from the Lower Pinda reservoir in the Motoba field have been utilized to define its petrophysical parameters, which will be applied to develop the dynamic model for assessing the volume of hydrocarbons in place. These wells include MOT-01, -02, -03, -04, -10, -11, -12, -13, -14, and -17.

– **Porosity**

The determination of porosity in this reservoir took into account a combination of neutron, density, and sonic log data for the aforementioned wells, with measurements provided in the appendix. This porosity evaluation was conducted using Petrel software. Effective porosities were calculated by applying the clay volume with a cut-off set at 40%.

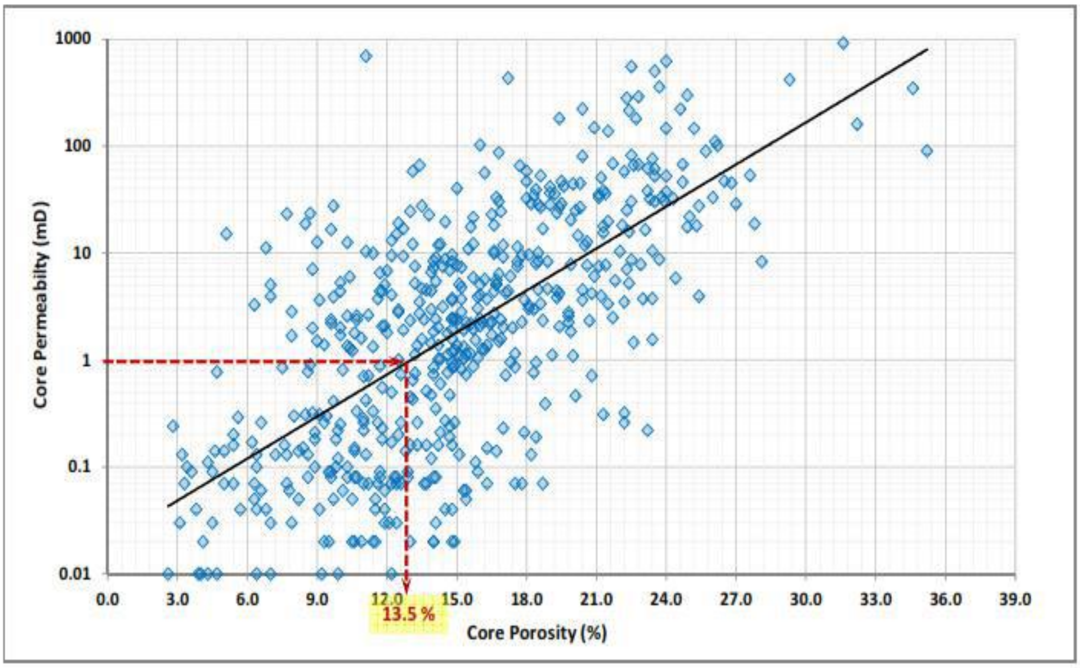


***Figure 8**. Diagram for determining effective porosity*

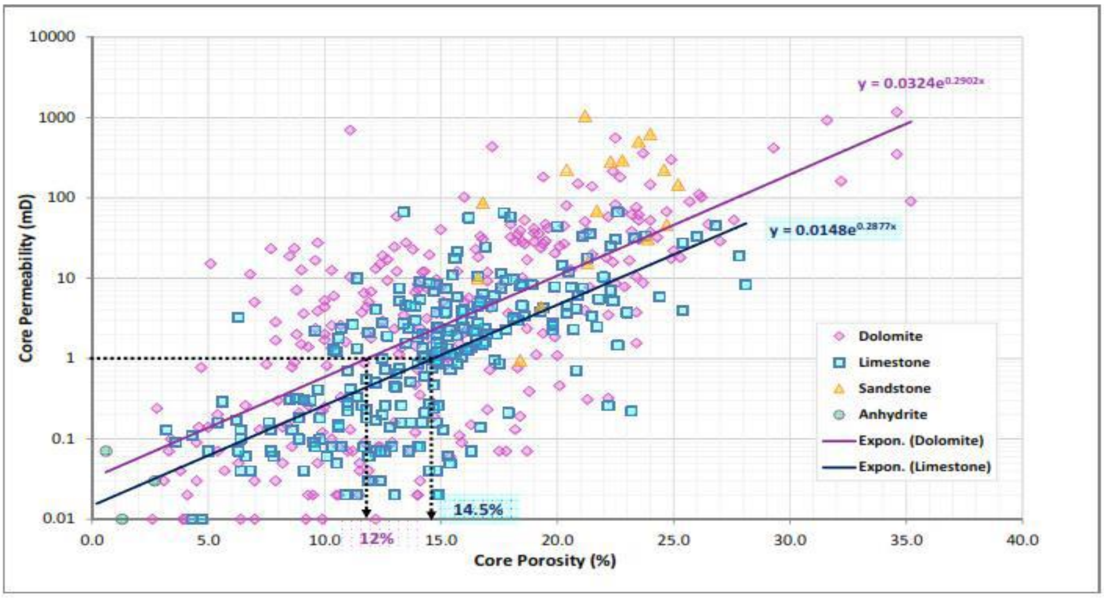


***Figure 9**. Diagram for determining the selective porosity of reservoir rocks*

IRREDUCIBLE WATER SATURATION

Data gathered from the DST tests of wells MOT-01 and MOT-03 allowed for the estimation of Rw at 0.042 Ωm (at 75°F) and the salinity of the reservoir water at 185 Kppm, which will enable us to calculate the irreducible water saturation [2],[4],[26]. We employed the Indonesian formula for calculating water saturation, where a=1, m=2, and n=2. Cut-offs (Threshold Values for Petrophysical Characteristics)

– **Effective Porosity (Φeff):**

The threshold value for effective porosity in this reservoir was defined using core data from well MOT-03. This porosity value was determined by utilizing the permeability and porosity values from the cores in a diagram represented in Figures 8 and 9 [6],[10]. This threshold is set at 13.5% and is used in volume calculations. Additionally, we used another diagram to represent the different facies present in this reservoir, namely limestone, dolomite, and sandstone (Figure 7). The sandstone intervals generally exhibit the best permeabilities (1 mD to 1 D) with good porosities (22%) [6],[9]. The different facies boundaries are shown in Figure 8.

– **Water Saturation (SW):**

Data interpretation from the wells allowed for the determination of the threshold value for irreducible water saturation at 50% [7],[9].

– **Clay Volume (Vcl):**

To define the reservoir horizons, the threshold value for clay volume was set at 40% and used in various calculations. For the reservoir sections, only the threshold values for clay volume and porosity were utilized [6],[9]. The threshold value for SW was added to the calculations for each horizon.

PRODUCTION OF THE MOTOBA FIELD

Production began in January 1990, and Motoba is currently the third highest-producing field, yielding 2,300 BOPD from eight wells, with cumulative production totaling 13 MMbbls, representing about 3% of OOIP. The heterogeneous nature of the reservoir, along with the underdeveloped portion of the field, contributes to the relatively low recovery [21],[23]. In 2005, Perenco's preliminary project revealed that there would be at least 99.5 million barrels of STOIIP in the Lower Pinda, accounting for approximately 45% of the oil reserves for the entire field.

Data Presentation

The data we present are derived from reports from 2017, showing the evolution of the recovery factor and STOOIP, which are displayed in the accompanying tables.

Table 2. *Presentation of STOOIP and RF data in LP1* [15].

Well	***STOOIP***	***RF***
MOT-02	*41,9*	*19,3*
MOT-04	*41,9*	*19,3*
MOT-10	*41,9*	*19,3*
MOT-11	*5,9*	*33,2*
MOT-12	*41,9*	*19,3*
MOT-15	*41,9*	*19,3*

Table 3. *Presentation of STOOIP and RF data in LP2* [15].

Well	***STOOIP***	***RF***
MOT-02	*41,9*	*18,7*
MOT-04	*76,2*	*18,7*
MOT-10	*8*	*6,3*
MOT-11	*6,4*	*23,2*
MOT-12	*76,2*	*18,7*
MOT-13	*6,4*	*23,2*
MOT-13ST	*76,2*	*18,7*
MOT-15	*76,2*	*6,3*

Table 4. *Presentation of STOOIP and RF data in LP3* [15].

Well	***STOOIP***	***RF***
MOT-02	*41,9*	*19,3*
MOT-03	*8*	*6,3*
MOT-04	*8*	*6,3*
MOT-10	*5,9*	*33,2*
MOT-11	*5,9*	*33,2*
MOT-12	*8*	*6,3*
MOT-15	*8*	*6,3*
MOT-13ST	*76,2*	*18,7*

ANALYSIS OF ISOBATH MAPS OF THE LOWER PINDA RESERVOIR HORIZONS

The isobath map of the Upper Pinda reservoir indicates that the depth decreases from east to west. The area with the greatest depth is located in the northwest. Generally, the depth of the LPA layer of the Upper Pinda reservoir ranges from 2,500 feet to 9,000 feet, with a significant peak in depth observed toward the west as one moves north. The Figure 10 show the LPA horizon isobath map of the Upper Pinda reservoir.

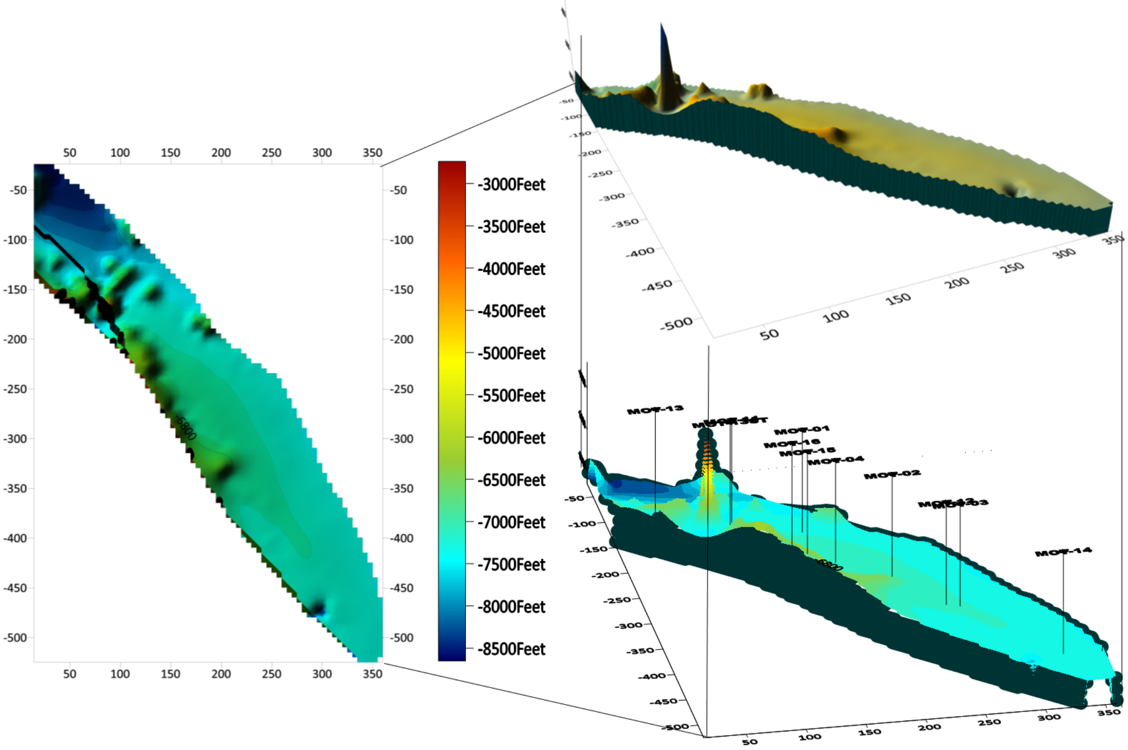


***Figure 10**. LPA horizon isobath map of the Lower PINDA reservoir in Motoba Field*

In order to properly observe the results of the depth variation of the Upper Pinda Reservoir in Motoba Field, we thought it best to proceed by observing several views in order to see the information that may be invisible.

In fact, we will have to observe the appearance of the different layers that make up the Upper Pinda Reservoir in the different views in order to see all the information on the different layers of the Upper Pinda Reservoir.

For us, deep zones are the best locations for identifying candidate injection wells. The view from the east (Figure 11), obtained by superimposing the isobath maps, shows us zones that are favourable for the location of new candidate wells. These are deep zones or synclines.

In view from the South, we can see that there are potential areas for the installation of producer and injector wells. An elevated area in the middle reveals a good location for producing wells. And the two low-lying areas shown on the map in blue are ideal for producing wells (Figure 12).

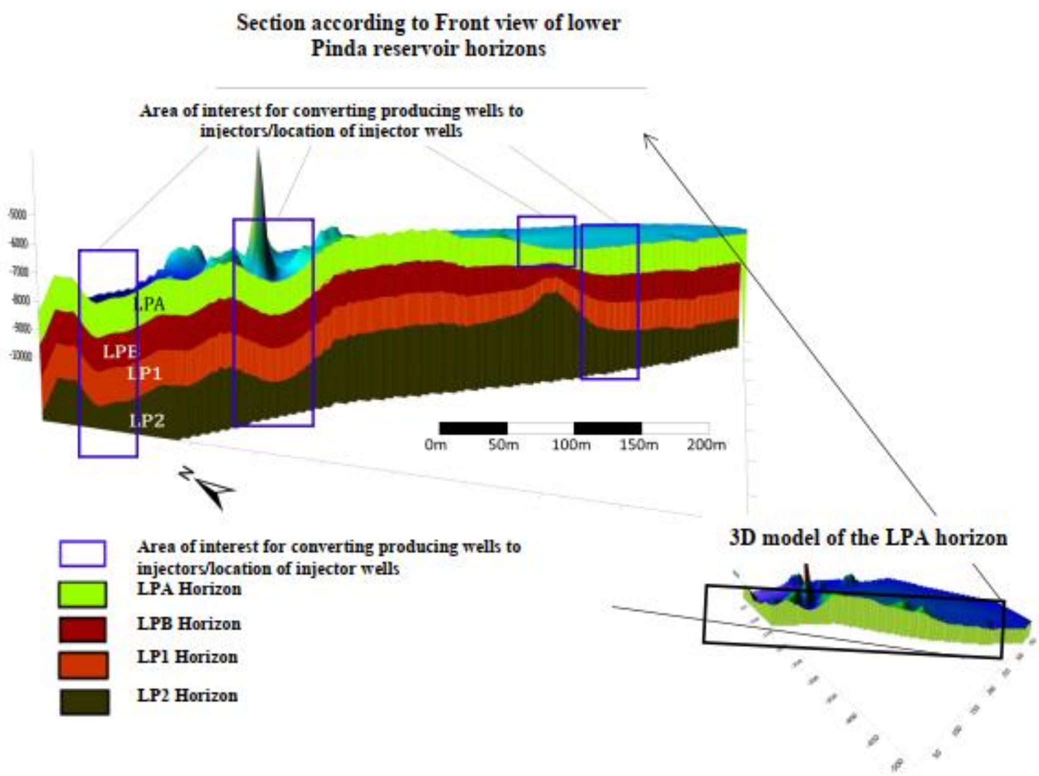


Figure 11. *Eastern view of isobath map of Lower Pinda reservoir horizons*

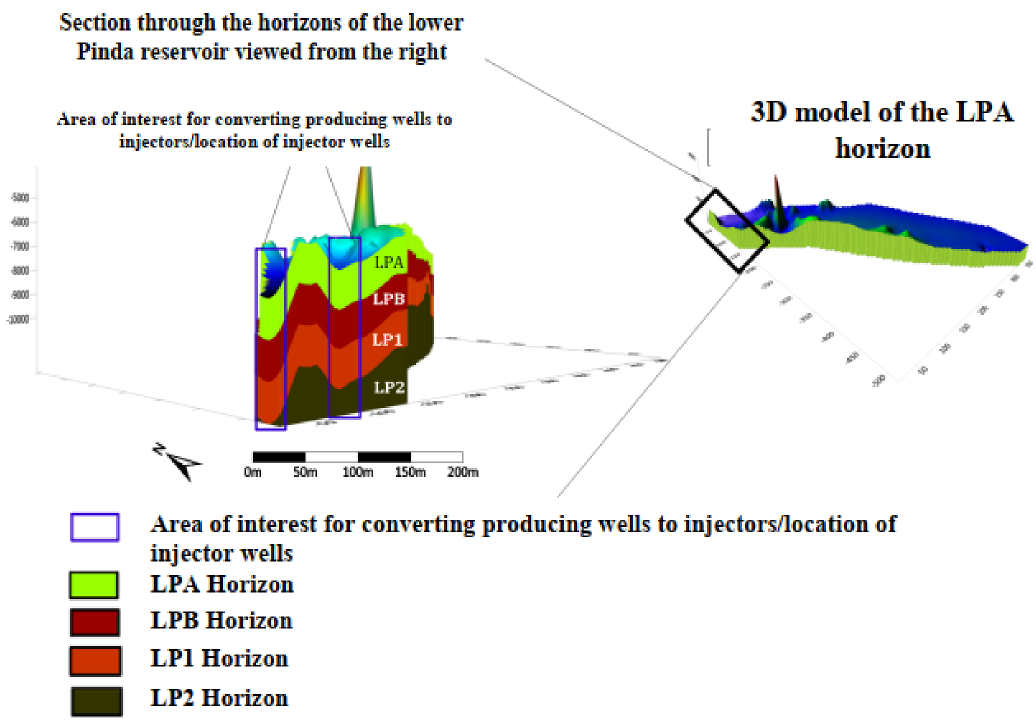


Figure 12. *Right view of isobath map of Lower Pinda reservoir horizons*

In view from the West, the appearance of the LP1, LP2 and LP3 layers shows that they are horizontal and show two raised zones. The areas framed in blue are potential locations for injector wells, as the injected water will be drained by gravity.

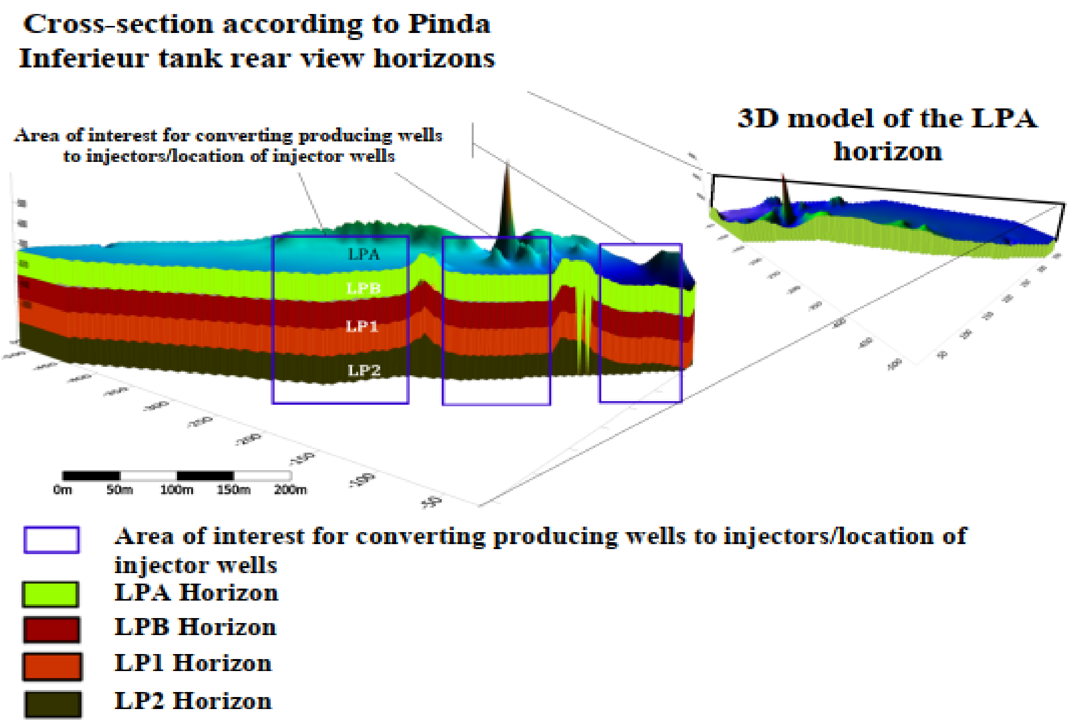


Figure 13. *Section according to Rear view of isobath map of Lower Pinda reservoir horizons*

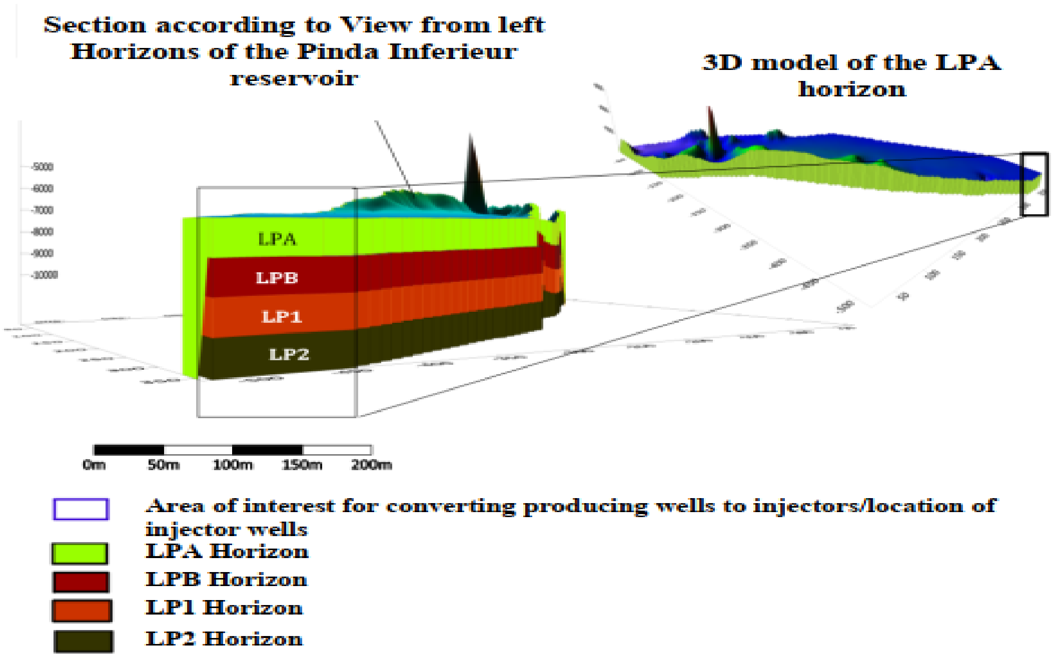


Figure 14. *Right view of isobath map of Lower Pinda reservoir horizons*

CONCLUSIONS

The analysis of the Pinda reservoirs in the Motoba field has revealed crucial information for managing and optimizing hydrocarbon production in the Democratic Republic of Congo. This work has helped identify strategic areas for the placement of injector and producer wells, thereby maximizing the utilization of available resources. The adopted methodology, which includes the collection and processing of geological data, was essential for generating isobath and iso-value maps, providing an overview of the petrophysical conditions of the various layers.

The production history of the Motoba field, since its discovery in 1975, reflects the challenges faced, particularly regarding water injection. Injection, initially implemented in 1998, was resumed in 2011, demonstrating ongoing efforts to maintain reservoir pressure and optimize hydrocarbon recovery. Results indicate that, despite challenges, the field retains significant potential due to the presence of untapped reserves and an improved injection strategy.

The complex geology of the Pinda formation, characterized by an alternation of carbonate and siliciclastic lithofacies, directly impacts reservoir quality. Diagenetic processes influence porosity and permeability, making precise evaluation of these parameters essential. Petrophysical analyses conducted on multiple wells have established threshold values for porosity, water saturation, and clay volume, thus creating a solid foundation for the dynamic model assessing hydrocarbons in place.

Maps generated from the collected data show that deep areas, particularly in the northwest, east, and southeast, are particularly favorable for the installation of new injector wells. Additionally, the analysis of recovery factors and GOR has identified zones with high potential for water injection, which could significantly enhance hydrocarbon recovery.

In summary, this study emphasizes the importance of an integrated and methodical approach to reservoir evaluation. The combination of geological tools and petrophysical analyses paves the way for more efficient exploitation of the Motoba field's oil resources. Future perspectives include ongoing optimization of injection systems and regular monitoring of well performance to ensure sustainable production. This research not only contributes to the management of oil resources in the DRC but also establishes a framework for similar studies in other offshore fields, thereby strengthening the DRC's position in the global oil industry.

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