

Pressure dynamics controlling crude oil migration for reservoir management and exploration in Niger Delta, Nigeria

Abigail T. Olaoluwa^{*1}, Olusegun O. Alabi¹, Bosede T. Ojo², Enock O. Oladimeji¹ and Samuel O. Sedara³

¹Physics Department, Osun State University, Osogbo, Osun State, Nigeria

²Applied Geophysics Department, Federal University of Technology, Akure, Ondo State, Nigeria

³Physics and Electronics Department, Adekunle Ajasin University, Akungba-Akoko, Ondo State, Nigeria

*Corresponding author: abigail.olaoluwa@uniosun.edu.ng

ABSTRACT

Pressure conditions are required in reservoir operations management. This is essential in the adjustment of migration and production strategies. The study investigates the relationship between fluid flux and static pressure across multiple wells in a Niger Delta reservoir using well log and pressure data. Fluid flux and pressure gradients were obtained from modified Darcy's Law, and these were used to generate plots for oil, gas, and oil/water phases. A threshold pressure of approximately 4,899 psi was identified beyond which fluid flux increased sharply, reaching a maximum of 1,400 ft³/day. Below this threshold pressure, fluid mobility was minimal, which indicates an insufficient energy to overcome capillary barriers. The optimal pressure suggests enhanced bulk fluid transmissibility, where both metrics exhibited a sharp decline, stabilizing at lower positive values until approximately 4800 psi. A critical pressure range of 4800 psi to 5050 psi was identified as a pressure range for optimal fluid flux. The major fluid encountered across the entire pressure spectrum was identified as oil, with isolated occurrences of gas and oil/water mixtures. In the present work, we observed that there is existence of a pressure-controlled migration regime and emphasize the importance of maintaining reservoir pressure above threshold values to enhance the oil production. The results obtained would provide insights for designing enhanced oil recovery (EOR) strategies and maintaining long-term reservoir performance above the present traditional concepts of oil production.

Keywords: Threshold Pressure Gradient (TPG), Crude oil migration, Darcy's Law, Seepage velocity, Reservoir management, Niger Delta basin

Nomenclature

Symbol	Description	Units
q	fluid flowing velocity	cm/s
$\emptyset$	Porosity	Fraction or %
k	Permeability	mD
μ	viscosity of the flowing fluid	centipoise
dp/dx	pressure gradient in the direction of flow	atm/cm
x	distance in the direction of flow	Cm
ΔP	total pressure drops	Psi
P_a	initial pressure	Psi
P_b	final pressure	Psi
l_a	initial depth	Ft
l_b	final depth	Ft
q	fluid flux	ft ³ /day
v_s	seepage velocity	m/s

INTRODUCTION

Petrophysics integrates geological, physical, and chemical properties of reservoir rocks to evaluate parameters such as porosity, permeability, volume of shale, and fluid saturation for assessing reservoir productivity (Shah et al., 2021; Shalaby et al., 2023). The well log interpretation, core analysis, and pressure monitoring help petrophysical evaluation to provide critical inputs for reservoir management. When accurate and timely data are provided, petrophysics enables operators to make useful decisions that optimize production rates, reduce operational risks, and improve total reservoir management (Okoro et al., 2022; Esiri et al., 2024; Iriogbe et al., 2024). The significance of

enhanced reservoir management lies in its ability to firstly, improve reservoir understanding and characterization, thereby enabling more accurate estimation of reservoir properties and production potential. This is crucial in mature fields where remaining reservoirs may be complex to quantify using conventional methods. Secondly, advanced monitoring techniques enable real time monitoring of reservoir performance, allowing operators to promptly detect and respond to changes in reservoir situations. This can help to identify issues such as gas coning, water breakthrough, or production anomalies, thus modifying potential production losses and extending the reservoirs life (Satter and Iqbal, 2016; Wu et al., 2023).

Traditional reservoir characterization methods, including core analysis and well logging, have long been used to evaluate reservoir properties. However, core samples are often limited in spatial coverage and may not adequately represent reservoir heterogeneity (Aminzadeh and Dasgupta, 2013; Ganguli and Dimri, 2023; Onita and Ochulor, 2024). Similarly, although well logs provide continuous subsurface information, their interpretation can be affected by clay content and other minerals, leading to uncertainties in porosity and fluid saturation estimates (Bhowmick et al., 2024). These limitations have encouraged the development of more advanced technologies for improved reservoir characterization and management (Ganguli and Dimri, 2023; Onita and Ochulor, 2024).

Enhanced reservoir monitoring supports the implementation of advanced recovery techniques, such as enhanced oil recovery (EOR) methods. By providing comprehensive insight into reservoir behaviour, these techniques can be tailored to the specific conditions of the reservoir, maximizing recovery efficiency and minimizing negative environmental impact (Ahmed, 2024). This could be done by integrating some information from the petrophysical parameter, such as pressure into Machine learning and AI, which are vital tools that can be used to automate data interpretation and optimize reservoir management strategies (Krasnov et al., 2017; Yahya et al., 2025; Singh et al., 2025).

The existing studies have examined generalized reservoir pressure behaviour without quantitatively resolving pressure thresholds governing hydrocarbon mobility under heterogeneous Niger Delta conditions (Vaferi and Eslamloueyan, 2015; Salami and Nton, 2024). The existing literature has not adequately quantified threshold pressure, defined optimum pressure ranges, or established maximum pressure limits required for effective migration of crude oil across capillary barriers and fault zones in Niger Delta. Most prior investigations either focus on generalized pressure regimes without differentiating threshold from maximum migration pressures or constrain their research to specific lithologies and basin conditions (Gao and Flemings, 2016; Satter and Iqbal, 2016; Hong et al., 2018). Present work exposes a critical knowledge gap, particularly in the Niger Delta, where heterogeneity in pore throat sizes, capillary forces, and reservoir connectivity influence the hydrocarbon mobility. It provides a quantitative evaluation of threshold and optimum pressures governing hydrocarbon migration, offering a practical framework for improving reservoir pressure management in heterogeneous basins. It aims to emphasize the significance of pressure in operational petrophysics and its role in enhancing reservoir management,

thereby contributing to more efficient and sustainable oil and gas production practices. The originality of the research is based on three main contributions. First, this paper provides field-specific quantification of pressure thresholds influencing crude oil migration in the Niger Delta's Freeman Field, which has not been done before. Precisely, a threshold pressure of about 4,899 psi, an ideal pressure range of 4,800–5,050 psi, and a maximum pressure of roughly 4,899 psi, are estimated and deduced in light of the local reservoir planning.

In order to identify crucial migration windows throughout the reservoir system, a multi-well, multi-phase pressure-flux design that integrates data from the eight wells spanning oil, gas, and oil/water phases was created. A pressure interval linked to capillary breakthrough or fracture pathway activation has been identified as the crucial transition zone around 4,800–5,050 psi. This finding has significant operational consequences for pressure maintenance and the design of enhanced oil recovery (EOR) strategies. Though often linked to standard recovery methods, EOR plays a broader role here. As pressures drop over time in aging Niger Delta reservoirs, output becomes unstable. Gas begins to cone, water arrives early, and native drive forces weaken - each undermining how much oil can be extracted. These issues also cut short the operational lifespan of wells (Ahmed, 2024). Starting at roughly 4,899 psi, fluids begin moving reliably through the formation, below this level, flow stalls. Maintaining pressures between 4,800 and 5,050 psi, supports efficient movement across the reservoir zone.

FIELD GEOLOGICAL SETTINGS AND CHARACTERISTICS

The field under review is placed inside the offshore portion of the Niger Delta. The Niger Delta is located inside the Gulf of Guinea at the border of West Africa between 3° and 6°N and 5° and 8° E, close to the west coast of Nigeria. The Niger Delta sits on the southern edge of the Benue trough, corresponding to a trapped branch of a triple rift. It is one of the most important and prolific regressive deltas for oil production (Uchegbulam and Ayolabi, 2014; Abiola and Obasuyi, 2019). It has a sub aerial region of approximately 75,000 km², a complete region of 300,000 km² and a sediment fill of 500,000 km² (Reijers, 2011). The Niger Delta basin known as the Niger Delta province, is a vastly productive one and it is of excessive marketable worth to Nigeria. The basin includes merely one petroleum system, identified as the Tertiary Niger Delta (Akata Agbada) petroleum system. The Niger Delta's sedimentary wedge is distributed across five depobelts with the earliest placed offshore and the oldest located furthest away inland (Reijers, 2011; Jonathan and Charles, 2025). These depobelts include,

offshore depobelts, Central Swamp, Northern Delta, Coastal Swamp and Greater Ughelli. Each depobelt is bounded inward by growth faults and seaward by huge counter-confined faults that come after sea-ward depobelt (Reijers, 2011; Jonathan and Charles, 2025). The reservoir units analyzed in this study are predominantly associated with the Agbada Formation, characterized by interbedded sand – shale sequences typical of the Niger Delta. The sand bodies serve as the primary hydrocarbon reservoirs, while the interbedded shales, act as flow barriers and seals. This lithological heterogeneity significantly influences pressure distribution and fluid mobility across the wells.

Stratigraphy of the Niger Delta Basin

The tertiary sequence established in the Niger Delta consists, in increasing order, of the Akata, Agbada, and Benin formations (Figure 1). The strata formed an appraised depth of 8,535 m (28,000ft) near the centre of the deposit in the dominant part of the delta. The Akata is characterized by a

uniform growth of shale, generally dark grey, while in some places, it is silty or sandy, particularly in the upper part of the formation (Schlumberger, 1985), accordingly, the top of the Akata Formation provides an economic base for oil and gas exploration.

However, gas may be present at deeper levels due to high pressures. The Agbada Formation is a succession of interbedded sandstones and shales, containing sandstone reservoirs responsible for gas and oil production in the Niger Delta (Ayuk et al., 2022; Adagunodo et al., 2022). The sandstones are medium to clean, fine-grained, and locally rich in limestone, glauconite, and shells. The shale is medium to dark grey, consolidated, and locally contains glauconitic mud (Doust and Omatsola, 1990). The Benin Formation consists of massive, freshwater bearing, highly porous sandstones with locally thin layers of fluvial shale. The sandstone consists mainly of quartz and potash feldspar with minor amounts of plagioclase (Harry et al., 2022).

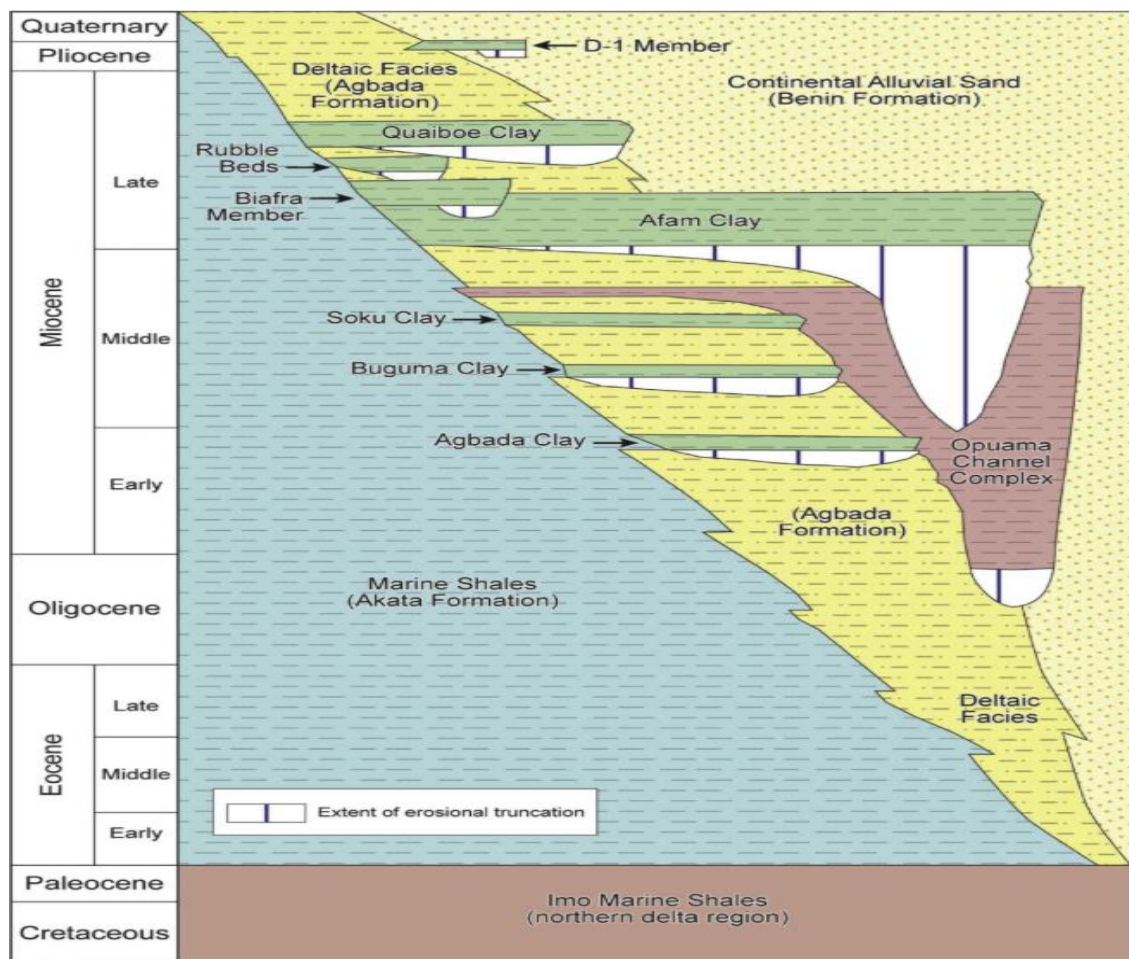


Figure 1. The three formations of the Niger Delta Stratigraphic column (Reijers, 2011)

METHODOLOGY

Data and study area

Eight wells were used in this work, the wells which aligned in a northwest direction towards the study area. Shell Petroleum Development Company of Nigeria Limited, through the Nigeria Upstream Petroleum Regulatory Commission, Lagos, Nigeria, donated the datasets used in this study. The log of the wireline for the wells includes, density, gamma ray, neutron logs, resistivity, sonic logs in LAS format and static pressure data (Table 1). The analysis was implemented in a modular Python script (compatible with IPython/Jupyter). Users can apply the code by inputting their own datasets in the modelled format.

Table 1 shows the wire-log data of all the wells used for this study. The GR log was used for the Well log-based characterization for sand-shale identification, neutron-density cross plot for porosity, and resistivity logs for fluid delineation. The petrophysical parameter was used for the estimating the average porosity of 20%, permeability estimation and fluid saturation. The lithological description of Agbada Formation reservoir sands, correlated across the eight Freeman Field wells but 3D seismic data were not available for this study. This restraint is clearly stated in a new uncertainty subsection, where the RPT analysis cited as a benchmark for future seismic integration work (Datta Gupta et al., 2012)

Theoretical framework

Reservoir Description

The available wireline log suite, which includes gamma ray (GR), resistivity, sonic (DT), neutron porosity (NPHI), and bulk density (RHOB) logs, was used to characterize the Freeman Field reservoir. The productive reservoir zones within the Agbada Formation were identified by using GR logs to separate sand from shale intervals based on deflections toward low API values. Effective porosity was estimated and fluid types were identified using neutron-density cross-plot analysis; gas-bearing intervals were indicated by the crossover between the neutron and density curves. The Archie equation and resistivity logs were utilized to distinguish hydrocarbon-bearing zones from water-saturated intervals. The reservoir sands have an average effective porosity of about 20%, which is in line with values published for the Niger Delta's Agbada Formation sandstones (Kong and Chen, 2018).

Permeability estimations were made using existing porosity-permeability transforms for Niger Delta sandstones. The reservoir sands are medium to fine-grained, reasonably clean (low shale content), and laterally continuous across the eight

Freeman Field wells, as evidenced by GR log correlation. These properties support the use of Darcy's Law as the principal flow model in this investigation (Datta Gupta et al., 2012). It is noted that no 3D seismic data were available for this investigation; this is a restriction because seismic data would further constrain structural geometry and fault connectivity. Future work should include rock physics template (RPT) analysis of seismic and well log data, as part of an effort to provide a more complete reservoir characterisation (Datta Gupta et al., 2012; Chakraborty et al., 2024).

The threshold, optimum, and maximum pressures for crude oil migration were determined by applying Darcy's Law to model fluid flow through porous media. The flow rate was expressed as a function of permeability, fluid viscosity, and pressure gradient. The threshold pressure is the minimum pressure required to overcome capillary forces and initiate flow; the optimum pressure range ensures efficient migration without inducing rock fracturing; maximum pressure is the limit beyond which nonlinear flow and mechanical failure of the reservoir occur. This approach integrates petrophysical properties, static pressure data, and capillary pressure information following some other techniques (Upadhyay et al., 2023; Mkpese et al., 2024; Nabawy, 2025); Fjaer et al., 2021

Darcy's Law describes the flow of fluids through porous media and explains the migration of hydrocarbons in petroleum reservoirs (Kuuskraa, 1982). This law, in its simple differential form is shown in Equation 1:

$$q = -\frac{k}{\mu} \frac{dp}{dx} \quad (1)$$

where q = apparent fluid flowing velocity, cm/s; k = permeability of the porous rock, Darcy;

μ = viscosity of the flowing fluid, centipoise; dp/dx = pressure gradient in the direction of flow, atm/cm; x = distance in the direction of flow, always positive, cm

In this study, the term "modified Darcy's law" does not imply the incorporation of non-Darcy or turbulent flow corrections. Rather, it refers to the practical adaptation of Darcy's equation to field scale reservoir conditions using discrete pressure measurements across well intervals and multiple fluid phases (oil, gas and oil/water systems). The formulation integrates pressure differences, depth variations and fluid properties obtained from well log and pressure datasets to estimate fluid flux under static reservoir conditions. The

negative sign in Darcy's law signifies that the direction of fluid flow is opposite to the direction of increasing pressure (Lyons, 2010; Fanchi, 2010). From an exploration point of view, integrating Darcy's law into basin modeling and reservoir simulations, allows geoscientists to better predict hydrocarbon accumulations and assess reservoir quality (Zhang et al., 2024). It helps identify the most probable migration routes and hydrocarbon traps while also determining whether a seal is effective in preventing further movement of hydrocarbons (Satter and Iqbal, 2016; Sunmonu et al., 2016; Akroun et al., 2021; Zhang et al., 2024).

Equation 2 depicts the total pressure drops under a steady incompressible fluid flow, as

$$\Delta P = \frac{\mu q \Delta L}{k} \quad (2)$$

$$q = \frac{k}{\mu} \left(\frac{P_b}{l_b} - \frac{P_a}{l_a} \right) \quad (3)$$

where q = Fluid flux, k = Permeability of the fluid, μ = Viscosity of the fluid, P_a = Initial pressure, P_b = Final pressure, l_a = Initial Depth, l_b = Final Depth

These expressions formed the basis for calculating pressure gradients and fluid flux for each well and fluid phase (Zhang et al., 2019; Wang et al., 2020). In the context of hydrocarbon exploration and production, it is crucial to understand how oil, gas, and water move through reservoir rocks (Yang et al., 2022). Equation 3 can be broken down to understand its components and their significance in hydrocarbon exploration. The volumetric flow rate (seepage velocity/ fluid

flux), q represents the seepage velocity or the volumetric flow rate of the fluid (oil, gas or water) through a unit cross-sectional area of the porous medium (Wang et al., 2020; Yang et al., 2022; Ahmed et al., 2023; Zhang et al., 2024).

The permeability, k denotes the absolute permeability of the porous medium (Yang et al., 2022). Permeability is directly influenced by the rock's pore structures, including pore size, type, and connectivity, as well as the presence of fractures (Qiao et al., 2021; Yang et al., 2022; Yu et al., 2022; Gao et al., 2024). Similarly, Fluid viscosity, μ represents the dynamic viscosity of the fluid (Yang et al., 2022). Viscosity is a measure of a fluid's resistance to flow (Yang et al., 2022; Gao et al., 2024). The significance of fluid viscosity in hydrocarbon exploration is that, the lower viscosity fluids (light oil, gas) tend to migrate and flow more easily through porous media than highly viscous fluids (heavy oil) (Yang et al., 2022; Gao et al., 2024; Zhang et al., 2024). Fluid properties such as viscosity were assumed based on typical values for Niger Delta reservoir fluids due to the unavailability of detailed PVT data. These assumptions are considered reasonable for comparative analysis of pressure–flux relationships.

$\frac{P_b - P_a}{l_b - l_a}$ represents the pressure gradient across the porous medium, where $P_b - P_a$ is the pressure difference between two points (b and a), and $l_b - l_a$ is the distance between those points.

Table 1. Log data provided for this study

WELLS	WIRE LOGS					
	GR	RES	DT	NPHI	RHOB	PRESSURE
FREEMAN 1	√	√	√	√	√	√
FREEMAN 2	√	√	√	√	√	√
FREEMAN 2ST	√	√	√	√	√	√
FREEMAN 3	√	√	√	√	√	√
FREEMAN 3ST	√	√	√	√	√	√
FREEMAN 4ST	√	√	√	√	√	√
FREEMAN 8	√	√	√	√	√	√
FREEMAN 5	√	√	√	√	√	√

Table 2. Fluid property values used for this study (PVT properties)

Property	Values
Oil viscosity	1.5 cp (at reservoir conditions)
Oil density	0.85 g/cc
API gravity	32°
Gas viscosity	0.018 cp
Water viscosity	0.5 cp
Bo	1.2 RB/STB

RB=Reservoir Barrel, STB=Stock Tank Barrel, Bo=Oil Formation Volume Factor, PVT= Pressure, Volume, Temperature

It signifies the driving force behind fluid flow (Yang et al., 2022; Huang et al., 2023). Fluids tend to flow from areas of high potential to low potential (Huang et al., 2023). This study focuses on pressure – flux relationships and does not explicitly incorporate spatial modeling or well interference effects. However, the wells were analyzed collectively to capture general reservoir behavior. In Table 2, the PVT properties are given, which shows the fluid property values used for this work. The values were estimated from published Niger Delta fluid property correlations (Standing, 1947; Ahmed, 2024) in the absence of laboratory PVT data, and this is explicitly noted in the table caption.

Analytical Workflow

This study adopted a computational and data driven approach to investigate the pressure behaviour and fluid dynamics within the hydrocarbon reservoirs of the Niger Delta. Pressure and flow rate data acquired from multiple wells, were pre-processed to remove incomplete records and standardized for consistency. Key parameters, such as reservoir pressure (P), pressure difference (ΔP), pressure gradient ($\Delta P/\Delta L$), fluid type, and volumetric flow rate (q), were compiled into structured datasets for analysis. The pressure gradient was determined by dividing the pressure difference across reservoir sections by the measured distances between sampling depths. Seepage velocity (v_s) was computed using the relationship $v_s = q/\phi$, where q represents the volumetric flow rate and ϕ is the porosity, which was assumed to be 20% in alignment with reported average porosity values for Niger Delta sandstones (Adagunodo et al., 2017; Kong and Chen, 2018).

Exploratory data analysis was performed to evaluate the relationships between fluid flux and pressure variables. Scatter plots and line plots of q against ΔP , P, and $\Delta P/\Delta L$ were generated both on linear and logarithmic scales for individual wells and for the aggregated dataset comprising all wells. To identify threshold and optimum pressure intervals, pressure data were grouped in 100-psi bins; mean fluid-flux values and their standard deviations were calculated within each bin to reveal pressure zones exhibiting maximum flow rates.

Statistical analysis was employed to quantify reservoir behaviour across fluid types. Summary of the statistics including standard deviation, mean, minimum, and maximum values of seepage velocity and pressure were calculated for water, oil, and gas. Linear regression analysis was performed to describe the relationship between pressure drop and fluid flux. All computations and graphics were produced with Python based libraries including Matplotlib

and Seaborn. The resulting scatter and faceted plots facilitated comparison of flow characteristics among wells and fluid types. The final dataset, enriched with derived parameters and fluid classification codes, was archived for interpretation and validation. All results were exported as high-resolution figures for reporting. It is important to note that this study utilizes static reservoir pressure data, which represents equilibrium conditions within the reservoir. While dynamic pressure (drawdown) is critical during production, static pressure is appropriate for evaluating hydrocarbon migration and pressure-controlled flow behavior. The effect of dynamic pressure conditions is considered a limitation and recommended for future investigation.

Uncertainty Analysis

This study contains a number of inherent sources of uncertainty, which are acknowledged as follows. The first source of input data uncertainty is the variance in static pressure readings among the eight wells, which may be caused by variations in gauge precision, measurement depth, and reservoir compartmentalization, rather than just actual pressure variation. Second, based on published average values for Niger Delta Agbada Formation sandstones, a consistent porosity of 20% was assumed for all wells and reservoir intervals (Kong and Chen, 2018). Seepage velocity was recalculated using porosity values of 15% and 25%, which correspond to the lowest and upper boundaries of reported Niger Delta reservoir porosity, in order to evaluate the sensitivity of this assumption. The resulting seepage velocities differed from the base case by about $\pm 25\%$, which has an impact on the absolute magnitude of computed flux values, but does not change the identification of the threshold pressure range. Third, laminar, single-phase flow over a homogeneous porous media is assumed when applying Darcy's Law. Deviations from this assumption increase model uncertainty that cannot be adequately quantified without core measurements or well test data, especially in fractured or heterogeneous zones and in multi-phase flow situations. Near transition areas like the oil-water contact (OWC) and gas-oil contact (GOC), mixed-phase signals can appear misleading. This happens because logs assign phase types through coded outputs. Pressure-threshold findings rely on data showing large variations across pressure bins, particularly between 4800 and 5050 psi. Such variability reflects both measurement uncertainty and changes in reservoir flow behaviour. Although these fluctuations do not alter the identification of the threshold pressure range, operational application of the threshold values should consider the associated uncertainty.

RESULTS AND DISCUSSION

Determination of maximum pressure ($P_{\max}$), threshold pressure (P_{thrsh}), and pressure range (P_{range}) is required to enhance the migration and volume of hydrocarbon (oil and gas) in complex reservoirs. The exact pressure (not just pressure drop) was identified yielding maximum fluid flux. The data were grouped by pressure, and a threshold pressure (P_{thrsh}) of approximately 4899 psi was identified at a fluid flux value of 1400 ft³/day, as illustrated in Figure 2.

Determination of maximum pressure ($P_{\max}$)

The relationship between reservoir pressure and fluid flux across all wells within the study area was illustrated in Figure 2. The plot depicts fluid flux as a function of reservoir pressure (psi), with each well represented by distinct color-coded markers and lines for clarity. A notable feature in the graph is the red dashed vertical line, which identifies the maximum fluid flux of 1,400 ft³/day occurring at a threshold pressure (P_{thrsh}) of approximately 4899 psi. This critical point is further highlighted with a red marker to emphasize its significance.

The results demonstrate that at pressures below approximately 4,000 psi, fluid flux remains relatively low across most wells, often fluctuating near zero and occasionally showing negative values. These low or negative values may be attributed to insufficient reservoir pressure to

overcome capillary entry pressures, resulting in limited hydrocarbon mobility and, in some cases, potential backflow within certain well sections. As reservoir pressure increases toward the range of 4500 to 4900 psi, fluid flux begins to rise more noticeably, indicating enhanced hydrocarbon migration. The identified threshold pressure (~4899 psi) is interpreted as the capillary entry pressure, required to overcome pore throat resistance within the reservoir. At this pressure, hydrocarbon fluids gain sufficient energy to displace resident fluids and migrate through constricted pore networks. Additionally, this threshold may correspond to localized capillary breakthrough or activation of high-permeability pathways such as micro-fractures.

This trend suggests the presence of a threshold pressure; the minimum pressure required to initiate and sustain effective hydrocarbon flow through the reservoir's pore network. The occurrence of maximum flux at 4899 psi signifies that this threshold was reached or slightly exceeded at this point. Wells such as Freeman-2ST3 and Freeman-4ST1, exhibit pronounced spikes in flux within this critical pressure range, potentially reflecting localized zones of higher permeability or favourable structural features that promote fluid migration (Akrouf et al., 2021; Zhang et al., 2024). They also highlight the importance of maintaining reservoir pressures above critical thresholds to sustain production efficiency in complex reservoirs (Dolson, 2016).

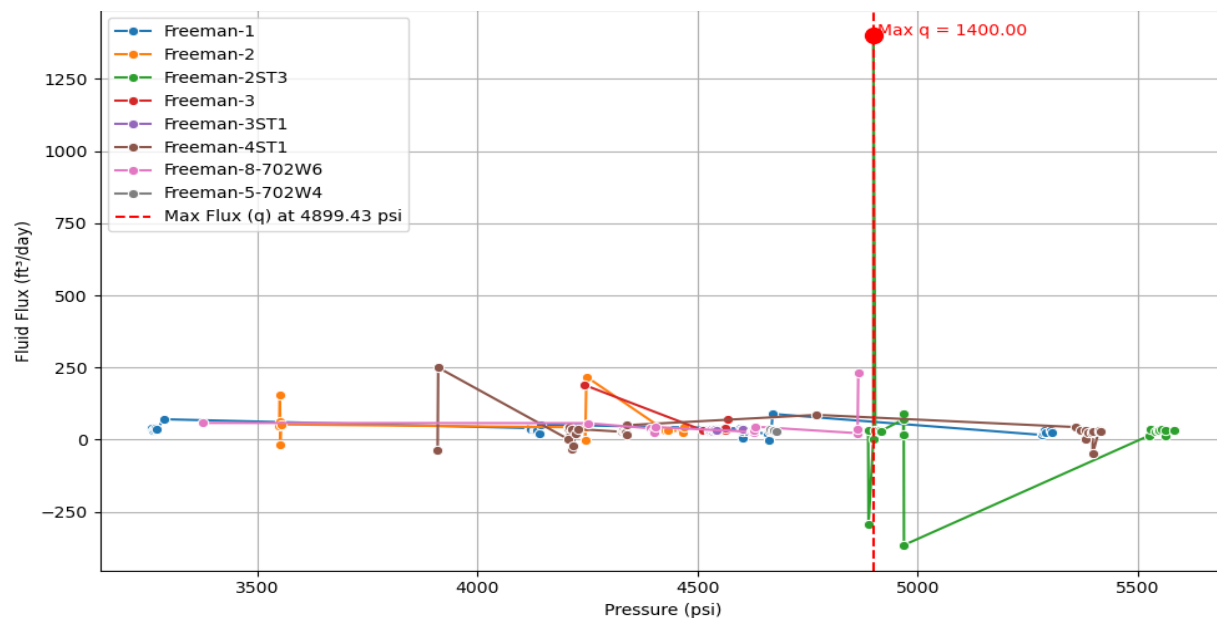


Figure 2. The plot showing relationship between reservoir pressure and fluid flux for all wells showing maximum flux at 4899 psi.

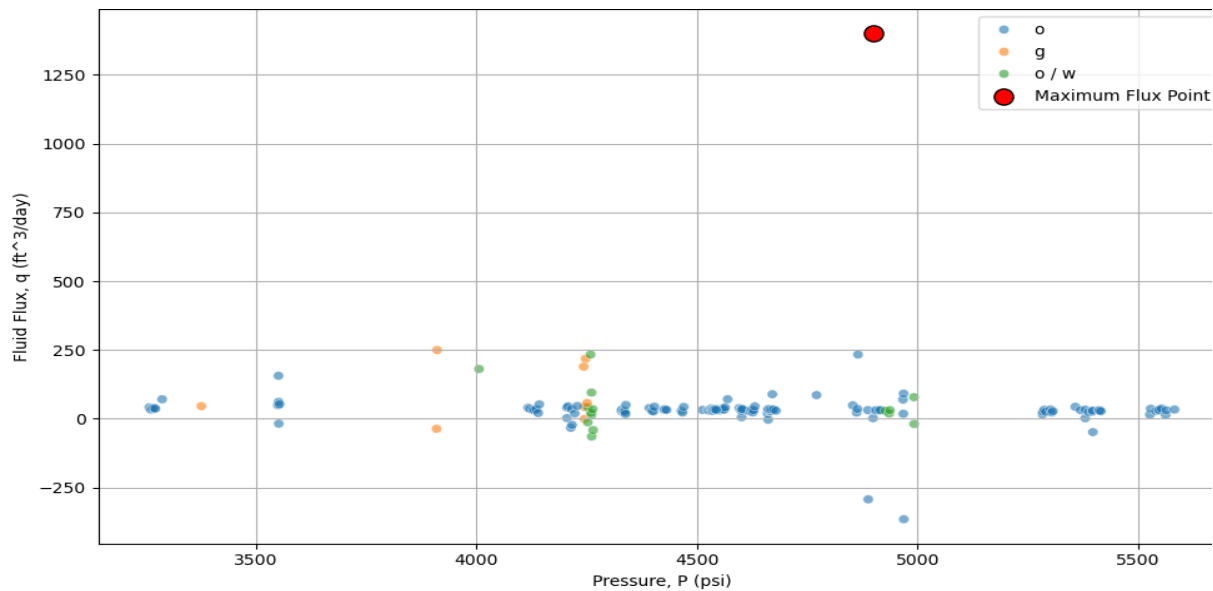


Figure 3. The plot showing maximum fluid flux versus pressure. Maximum fluid flux 1,400 ft³/day can be noted at 4899 psi pressure.

Relationship between reservoir pressure and fluid flux

The relationship between reservoir pressure and fluid flux for various fluid phases across the study area is shown in Figure 3. The plot shows fluid flux (ft³/day) on the vertical axis versus pressure (psi) on the horizontal axis, with data points color-coded by fluid type oil (“o”), gas (“g”), and oil-water mixtures (“o/w”). A prominent red marker highlights the maximum fluid flux point, recorded at approximately 1,400 ft³/day and occurring at a pressure of 4899 psi. This critical point is further emphasized by a red notation labeled “Maximum Flux Point”. The distribution of data points reveals that at pressures below 4000 psi, fluid flux across all phases remains relatively low, typically under 250 ft³/day, and in some instances, negative values are observed. These negative fluxes reflect localized backflow or pressure insufficiencies unable to overcome the capillary entry pressures of the reservoir matrix (Yang et al., 2022).

As reservoir pressure increases within the range of 4500 to 4900 psi, a noticeable increase in fluid flux is observed, with the oil phase (blue points) showing the most prominent response. This suggests that the onset of significant hydrocarbon migration occurs within this pressure interval, reaching a peak at 4899 psi. Beyond this critical pressure, no further substantial increases in fluid flux are recorded, indicating a plateauing behavior likely due to reservoir heterogeneities such as permeability barriers or capillary end effects (Adagunodo et al., 2017). This finding has significant

operational implications; maintaining reservoir pressures at or above the identified threshold (4899 psi) is essential for sustaining hydrocarbon flow and maximizing recovery (Santra et al., 2021).

Determination of threshold pressure, (P_{thrsh})

The relationship between pressure and mean fluid flux across all wells was investigated, revealing significant variability in fluid flow behaviour at specific pressure ranges. From approximately 4800 psi to 5600 psi, mean fluid flux demonstrated a general increasing trend, peaking at 4899 psi threshold pressure (P_{thrsh}). A sharp decline followed this peak, with flux values stabilizing positively to about 4800 psi. A notable increase in mean fluid flux was observed around 4900 psi, which was then succeeded by a dramatic decrease in negative values. This pressure range, between 4800 psi and 5050 psi, was characterized by a substantial standard deviation, indicative of high variability and uncertainty in fluid flux measurement (Figure 4). Beyond 5100 psi, the mean fluid flux gradually recovered to positive, relatively stable values. This observed high variability at approximately 4900 psi, suggests a critical pressure range where the hydrocarbon fluid flow dynamics exhibit significant and potentially unpredictable changes, transitioning from positive to negative flow, a phenomenon that warrants further investigation to understand underlying geological or operational factors.

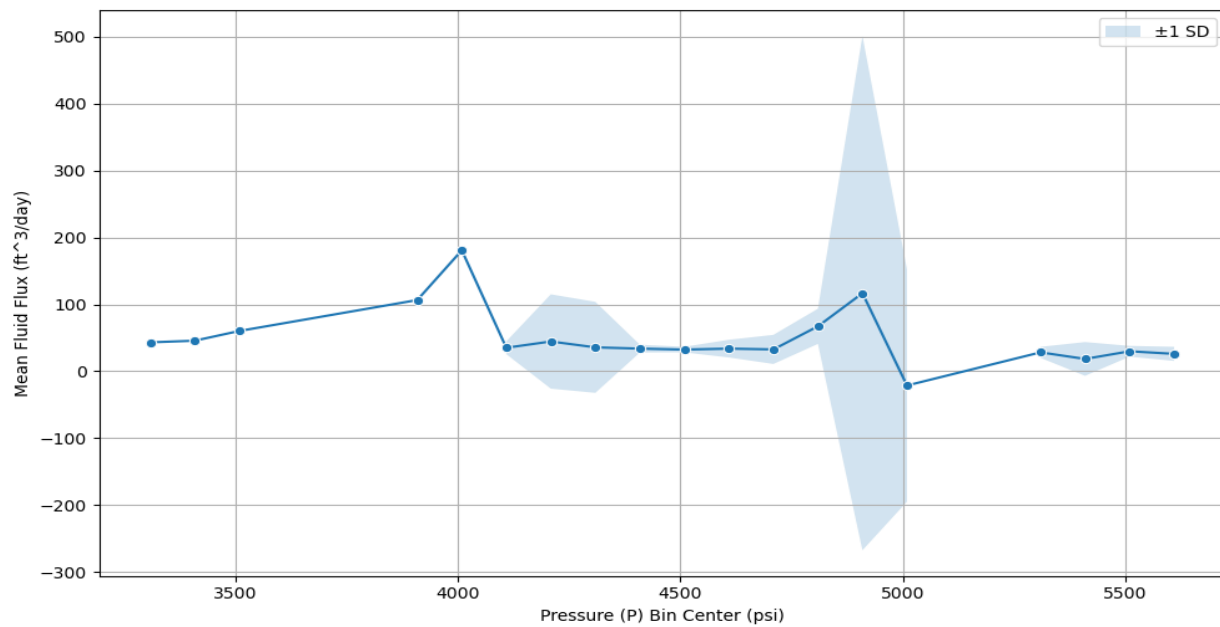


Figure 4. The plot between mean heat flux versus threshold pressure, showing the threshold pressure (P_{thrsh}) is 4899 psi.

Comparative analysis

The 4,899 psi P_{max} value corresponds to a pressure gradient of approximately 0.44–0.47 psi/ft at the sampled depths (approximately 10,400–11,000 ft), which is consistent with the normal hydrostatic gradient range (0.43–0.47 psi/ft) reported for the Agbada Formation in the central Niger Delta (Adagunodo et al., 2017; Akroun et al., 2021). This suggests that maximum hydrocarbon mobility in the Freeman Field occurs at near-normal hydrostatic conditions, rather than at over-pressured states, which has important implications for pressure maintenance design. Fields in the shallow offshore Niger Delta with similar settings have reported production threshold pressures in the 3,500–5,200 psi range (Harry et al., 2022), broadly consistent with our P_{thrsh} of 4899 psi.

Analysis of fluid flow system

The analysis of fluid flow across the study area revealed distinct pressure dependent regimes and a critical threshold range influencing overall system behavior. Mean fluid flux, derived from bin averaged pressure data across all wells (Figure 4), demonstrated an initial increase from approximately 3300 psi to a peak of around 4000 psi, indicating optimal bulk fluid transmissibility within this pressure window. Beyond this peak, flux values exhibited a sharp decline, stabilizing in positive territory until approximately 4800 psi. Critically, the pressure range between 4800 psi and 5050 psi, represented a transition zone

characterized by a dramatic shift in mean fluid flux, from positive to negative values, coupled with an exceptionally wide standard deviation. This substantial variability signifies a highly heterogeneous and unstable flow regime within this specific pressure interval. Further detailed investigation into individual well performance (Figure 5a), corroborated this finding, pinpointing a maximum seepage velocity of 7000 ft/day for well Freeman-2ST3 at a pressure of 4899 psi. This singular, high magnitude fluid event, occurring precisely within the identified threshold pressure range, strongly suggests the activation of a highly conductive pathway, potentially indicative of capillary breakthrough of a sealing formation or the propagation of a significant fracture network enabling rapid fluid migration. Equally, other wells within the same pressure range exhibited widely disparate seepage velocities, including instances of near-zero or negative flow, further emphasizing the localized and highly variable nature of fluid transport at this critical pressure.

Beyond 5050 psi, the mean fluid flux gradually stabilized into a new positive, albeit lower, equilibrium regime, with reduced variability. These findings collectively establish the pressure range 4800 to 5050 psi as a critical threshold, where reservoir scale fluid flow transitions fundamentally, likely governed by localized geological features and exceeding specific geomechanical or petrophysical thresholds for fluid mobility (Bai et al., 2020).

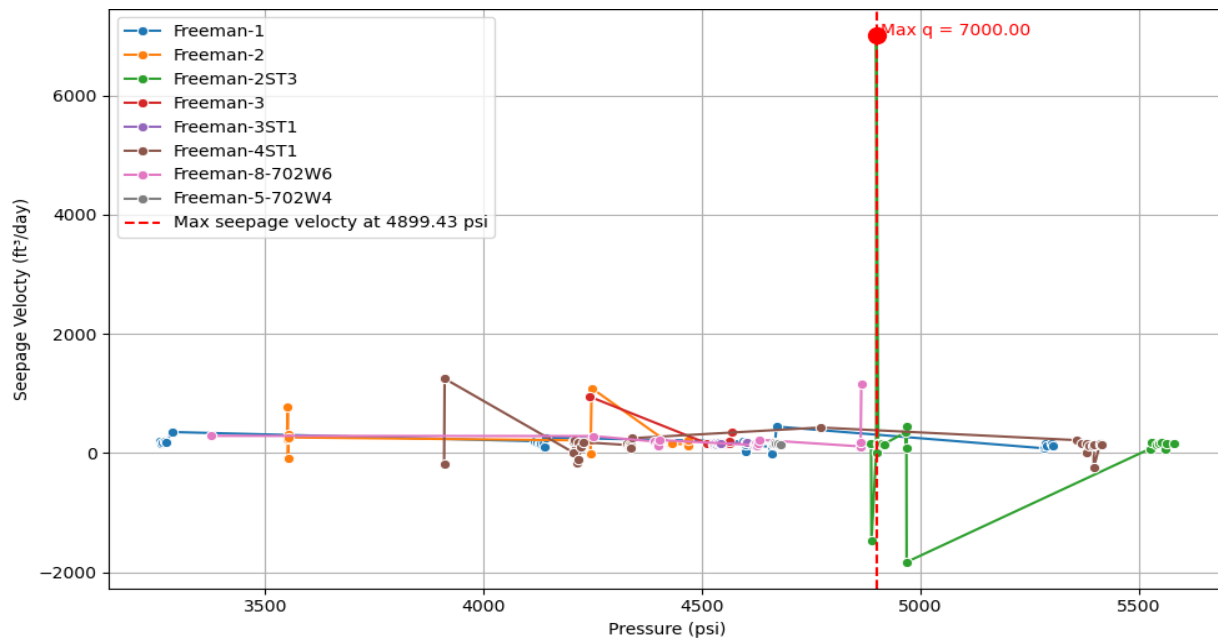


Figure 5a. The plot between seepage velocity versus pressure, showing a maximum seepage velocity of 7000 ft/day for well Freeman-2ST3 at a pressure of 4899 psi.

Characterization of fluid flow

The characterization of fluid flow dynamics across the study area reveals distinct pressure dependent regimes and a pivotal threshold range governing overall system behavior. Analysis of mean fluid flux, derived from bin averaged pressure data across all wells (Figure 5a), demonstrates an initial increase from approximately 3300 psi to a peak of 4000 psi, indicative of optimal bulk fluid transmissibility within this pressure window. Beyond this peak, flux values exhibit a sharp decline, stabilizing in positive territory until approximately 4800 psi. The pressure interval between 4800 psi and 5050 psi, represents a critical transition zone. Within this range, the mean fluid flux undergoes a dramatic shift from positive to negative values, coupled with an exceptionally large standard deviation, signifying a highly heterogeneous and unstable flow regime. This pronounced variability suggests the activation of complex subsurface processes, potentially including capillary breakthrough of sealing formations or the initiation of new fluid pathways (Espinoza and Santamarina, 2017).

Detailed investigation into individual well performance (Figure 5b), corroborates this interpretation, revealing a maximum seepage velocity of 7000 ft/day for well Freeman-2ST3 at a pressure of 4899 psi. The association of this high magnitude fluid event with oil (“o”) flow, precisely within the identified critical threshold, strongly indicates the activation of a highly conductive pathway or the breakthrough of a significant hydrocarbon (oil) column at

this specific pressure point. On the other hand, other wells within the same pressure range, exhibit widely disparate seepage velocities and fluid types (“g” for gas, “o/w” for oil/water), including instances of near-zero or negative flow. This heterogeneity underscores the localized nature of fluid transport and the significant influence of compartmentalization or specific geological features. Beyond 5050 psi, the mean fluid flux gradually stabilizes into a new, lower positive equilibrium regime (approximately 20 to 30 ft³/day), with reduced variability. These findings collectively establish the 4800 to 5050 psi pressure range as a critical threshold for this hydrocarbon system, where reservoir scale fluid flow dynamics are fundamentally altered, likely driven by exceeding precise petrophysical thresholds for fluid mobility and migration (Bai et al., 2021).

Determination of threshold pressure range (P_{range})

The threshold pressure range for highest fluid flux across all wells (Figure 4) and the threshold pressure range for seepage velocity across all wells (Figure 6), reveal critical insights into the pressure-dependent fluid flow dynamics of the reservoir system. Both plots, which are fundamentally related, measuring fluid transport through porous media, exhibit remarkably consistent trends concerning mean values and their associated standard deviations across varying pressure bin centres. This consistency underscores the robust identification of key flow regimes and a pivotal pressure threshold. Maximum pressure shown on the graph is approximately 5600 psi. This is the highest-pressure bin

centre displayed on the x-axis. From approximately 3300 psi to 5600 psi, both mean fluid flux and mean seepage velocity, demonstrate a positive increasing trend, culminating in a peak around 5600 psi. This initial enhancement in fluid transmissibility suggests that increasing reservoir pressure within this range is conducive to general fluid movement, potentially facilitating the initial stages of hydrocarbon migration by overcoming minor flow resistances. Following

this peak, both mean values sharply decline and then stabilize at relatively low positive levels until about 4800 psi, indicating a less efficient or more restricted bulk fluid transport regime in this intermediate pressure window. Both figures highlight a highly significant and common pressure range, approximately 4800 psi to 5600 psi, as a critical threshold (Zhang et al., 2022; Shagapov et al., 2023).

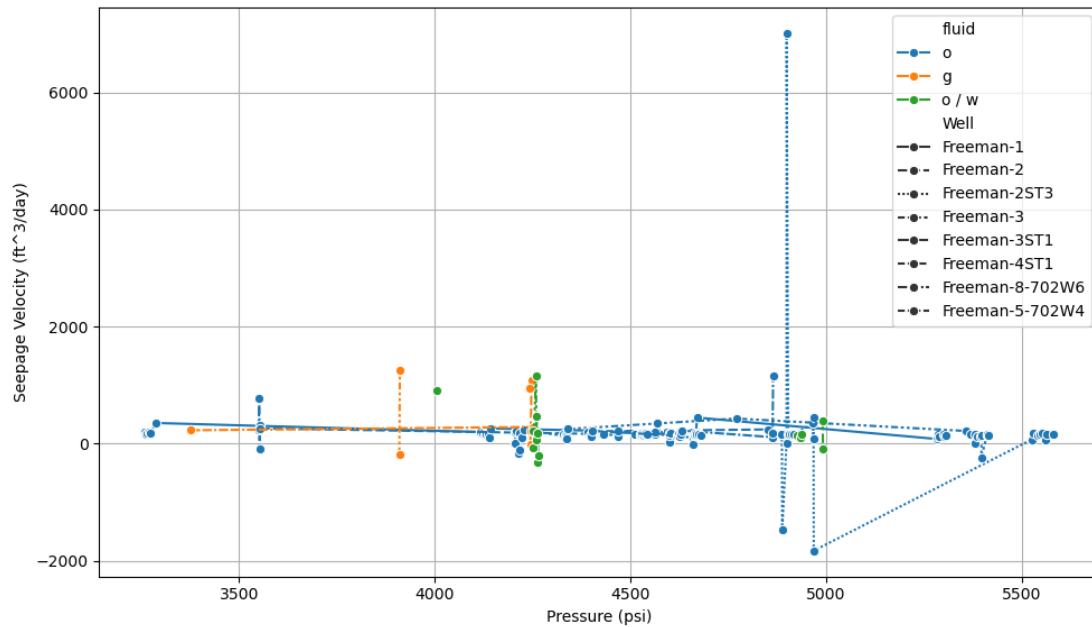


Figure 5b. The plot between seepage velocity and pressure revealing a maximum seepage velocity of 7000 ft/day for well Freeman-2ST3 at a pressure of 4899 psi including the type of fluid across the wells.

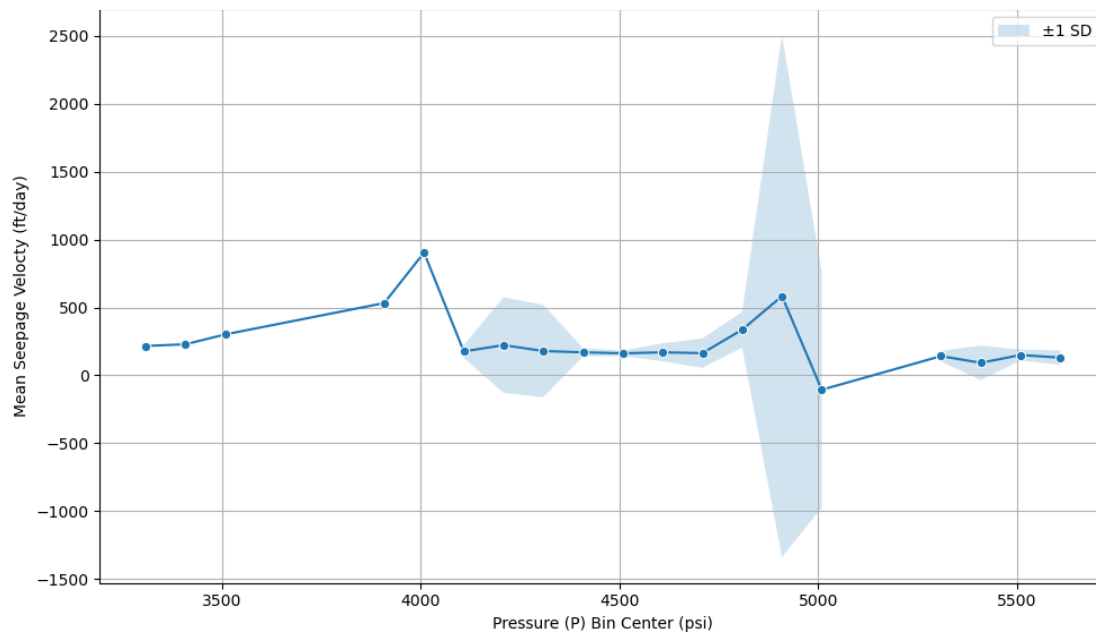


Figure 6. The plot between mean seepage velocity and pressure, showing threshold pressure range of 3300 psi to 5600 psi for seepage velocity of 900 ft/day.

Projection of fluid phases present across the pressure range

The fluid phases present across the pressure range were displayed in Figure 7. The plot primarily shows a high density of data points at fluid type code 1 (oil) throughout the entire observed pressure range (3300 psi to 5600 psi), indicating that oil is the predominant fluid encountered in the wells. Isolated occurrences of fluid type code 0 (gas), are observed at various pressures, including around 3400 psi, 3900 psi, 4200 psi, and near the 4800 to 5050 psi threshold. Moreover, instances of fluid type code 0.5 (oil/water) are present, notably around 4000 psi, 4200 psi, and within the 4800 to 5050 psi range. These figures provided a comprehensive understanding of the reservoir's behaviour. The extreme variability and directional shift in mean fluid flux observed in Figure 6 within the 4800 to 5050 psi pressure range, combined with the presence of oil, gas, and oil/water mixtures in Figure 7. within the same interval, strongly suggest that this represents a critical threshold for hydrocarbon mobility. This pressure range signifies the capillary breakthrough pressure of a sealing formation or the activation of high conductivity pathways, such as fractures or faults, which facilitate significant hydrocarbon migration (Rezaeyan et al., 2015; Zhang and Wang, 2022; Cheng et al., 2024).

The predominance of oil (fluid type code 1) throughout the entire pressure range from roughly 3,300 psi to 5,600 psi, suggests that the Freeman Field reservoirs are primarily oil-

charged, which is consistent with the Agbada Formation's well-established position as the Niger Delta's principal oil-producing interval. With a stable hydrocarbon column maintained throughout all recorded depth intervals, this oil dominance is indicative of a mature charge history. The isolated gas occurrences (code 0) at pressures of approximately 3,400, 3,900, and 4,200 psi, are explained as either dissolved gas that has separated from solution as local pressure falls below the bubble point or localized gas caps within structurally raised reservoir compartments. The presence of gas in the crucial 4,800–5,050 psi threshold range is especially important because it could be an indication of gas liberation or pressure-induced phase segregation related to the capillary breakthrough event detected at this period. In the studied wells, the oil/water mixture occurrences (code 0.5) around 4,000 and 4,200 psi indicate proximity to the oil-water contact (OWC), where log-derived fluid classification captures the transition zone between the hydrocarbon column and the aquifer. The reappearance of oil/water mixtures in the critical range of 4,800–5,050 psi, indicates dynamic upward movement of the OWC caused by pressure transients, which may indicate active water influx into the lower reservoir intervals when pressure drops. Taken together, Figure 7 show of spatial distribution of fluid phases supports the interpretation that the 4,800-5,050-psi pressure interval represents a zone of complex fluid-rock interaction, where simultaneous oil migration, gas exsolution, and water contact movement converge to produce the high flux variability seen in companion figures.

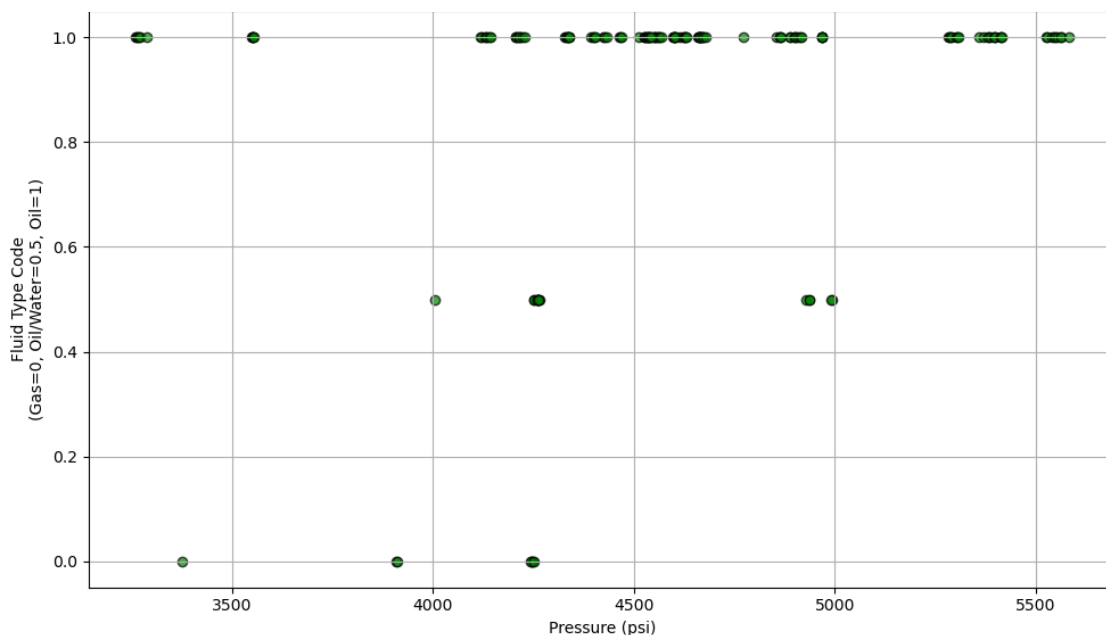


Figure 7. The plot of fluid type code versus pressure, showing the fluid phases present across the pressure range.

The occurrence of different fluid types within this highly dynamic pressure window further points to complex fluid-rock interactions or the movement of fluid contacts (oil-water contact, gas-oil contact) that dramatically impact bulk fluid flow. These findings are crucial for understanding the mechanisms of hydrocarbon accumulation and for optimizing future exploration and production strategies (Zhu et al., 2015; Li et al., 2023; Wang et al., 2025). Although capillary pressure curves were not available, the observed threshold behaviour is consistent with capillary-controlled flow mechanisms. Quantitative capillary pressure analysis (e.g., J-function) is recommended for future studies. Due to data confidentiality constraints, historical production data were not available for validation. However, the observed pressure-flux relationships are consistent with established reservoir flow behaviour.

CONCLUSIONS

This study used static pressure and wireline log data from eight Freeman Field wells, to examine pressure-dependent fluid flow dynamics in a Niger Delta reservoir. The fluid flux, seepage velocity, and pressure thresholds controlling hydrocarbon migration were measured using modified Darcy's Law. Some of the key findings reached as follows:

1. The lowest pressure needed to start a major hydrocarbon migration in the study reservoir was determined to be a threshold pressure (P_{thrsh}) of roughly 4899 psi. Fluid flux stays low at this pressure, indicating that there is not enough pushing energy to get past capillary barriers in the pore network.
2. The Freeman Field reservoir system has a maximum fluid flux of 1400 ft³/day at approximately 4899 psi (P_{max}), indicating peak hydrocarbon mobility.
3. The pressure range of 4800 and 5050 psi has been recognized as the crucial ideal window for continuous hydrocarbon flow. High flux variability and the presence of oil, gas, and oil/water phases within this interval are interpreted as signs of capillary breakthrough or the activation of high-conductivity fracture channels.
4. In every sampled pressure range (4800 – 5050 psi), oil is the predominant fluid phase. Gas and oil/water mixtures are defined as proximity to the oil-water contact and localized gas caps or exsolved gas, respectively, and occur at discrete pressure intervals.
5. Maintaining reservoir pressure over the defined threshold of 4899 psi is critical to ensuring hydrocarbon mobility and production efficiency. The quantitative pressure windows obtained here serve as a direct foundation for the planning of pressure-maintenance EOR activities,

such as waterflooding and gas injection, in the study area and similar Niger Delta reservoirs.

The Python-based multi-well computational approach that combines Darcy's Law with petrophysical log and static pressure data, provides a repeatable, cost-effective framework for pressure migration analysis that may be applied to other heterogeneous basins.

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Author Credit Statement

Olusegun Alabi and Abigail Olaoluwa developed the concept and design this work. Enock Oladimeji and Bosede Ojo did the analysis and interpretation of the data while Samuel Sedara and Abigail Olaoluwa did the writing and editing of the manuscript. In general, Olusegun Alabi supervised and validated the work. The authors approved the submission and publication of the manuscript and therefore take public responsibility for the research

Data Availability

The data that support the findings of this study are available from the corresponding author upon request.

Compliance with Ethical Standards

The authors declare no conflict of interest and adhere to copyright norms

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