

**ASSESSMENT OF RESERVOIR HETEROGENEITY AND IT'S IMPACT  
ON SWEEP EFFICIENCY**



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**A PROJECT SUBMITTED TO THE DEPARTMENT OF PETROLEUM ENGINEERING,  
FACULTY OF ENGINEERING, UNIVERSITY OF BENIN.  
IN PARTIAL FULFILMENT OF THE REQUIREMENTS FOR THE AWARD OF  
BACHELOR OF ENGINEERING (B.ENG) DEGREE.**

**NOVEMBER 2025**

## **DECLARATION**

I, **EHIDIAMEN GIFT OSOSE** with Matriculation number **ENG2006105**, do hereby declare that:

1. This project work is based on a study undertaken by me in the Department of Petroleum Engineering, University of Benin, Benin City, under the supervision of **ENGR.NSISONG ISUK**
2. This research work has not been previously submitted for the award of a degree elsewhere.
3. All ideas and views are a product of my personal research; and where the views of others have been expressed, they were duly acknowledged.
4. All liabilities arising from the study are entirely mine and not of the supervisor.

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**EHIDIAMEN GIFT OSOSE**

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**DATE**

## CERTIFICATION

This is to certify that this project work was carried out by **EHIDIAMEN GIFT OSOSE** with Matriculation Number **ENG2006105** under my supervision. It is adequate and satisfactory, both in scope and content, for the award of Bachelor of Engineering (B.ENG) Degree in Petroleum Engineering of the University of Benin.

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**ENGR. NSISONG ISUK**  
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**DR. OLUWASEUN TAIWO**  
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**(External Supervisor)**

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**12/11/2025**

**DATE**

## **DEDICATION**

This project is dedicated to God Almighty, the giver of knowledge and understanding for His protection, provision, guidance and strength He accorded throughout the research and academic pursuit, and for the wisdom and grace to complete this project successfully.

I also dedicate it to my family, especially my parents, for their unwavering support, prayers, and encouragement.

## **ACKNOWLEDGEMENT**

I sincerely thank God Almighty for His grace, wisdom, and strength throughout my academic journey and the successful completion of this project.

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Finally, I appreciate my classmates and everyone who, in one way or another, offered support, shared ideas, or provided encouragement during the course of this research.

## **ABSTRACT**

Reservoir heterogeneity, characterized by spatial variation in rock properties such as porosity and permeability, is a defining feature of petroleum reservoirs that influences fluid flow behavior and hydrocarbon recovery. Traditional methods to quantify heterogeneity rely mainly on static petrophysical measurements and indices such as the Dykstra-Parsons coefficient, which provide numerical expressions of permeability variation but often lack dynamic insights into fluid connectivity and migration pathways. Recent advances have demonstrated the value of integrating geochemical techniques, notably Strontium Residual Salt Analysis (Sr-RSA), with permeability data to reveal subtle compartmentalization, fluid discontinuities, and internal flow barriers that directly impact sweep efficiency during secondary and tertiary recovery processes. This integrated approach facilitates a multidimensional characterization of reservoir architecture, enabling better prediction of fluid displacement patterns and optimization of injection and production strategies. Such insights are critical for improving hydrocarbon recovery efficiency and maximizing asset value. This study assesses the extent and impact of reservoir heterogeneity on sweep efficiency, employing both traditional petrophysical metrics and advanced geochemical fingerprinting to provide a comprehensive understanding of reservoir behavior. The findings aim to support enhanced reservoir characterization and guide strategic decisions in field development and enhanced oil recovery operations.

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# CHAPTER ONE

## INTRODUCTION

### 1.1 BACKGROUND OF STUDY

Oil and gas reservoirs are rarely homogeneous. Instead, they are characterized by significant variation in their physical and geological properties, such as porosity and permeability, which vary across different sections of the reservoir. This variability, known as reservoir heterogeneity, is a fundamental attribute of natural geological systems, shaped by complex depositional, diagenetic, and tectonic processes over geological time.

Heterogeneity exists at multiple scales, ranging from microscopic pore-scale differences in grain size and mineralogy to macroscopic features such as stratification, facies changes, faults, and fractures. These spatial variations have a profound influence on how fluids move within the reservoir, dictating the pathways for hydrocarbon flow and strongly controlling fluid distribution during production and injection operations. Reservoir heterogeneity plays a pivotal role in hydrocarbon recovery because it controls the connectivity and distribution of porous media through which fluids migrate. High-permeability zones, such as streaks or channels, can act as rapid conduits for injected fluids like water or gas, leading to early breakthrough at production wells, while low-permeability zones may remain unswept, trapping significant volumes of oil. Consequently, heterogeneity frequently causes uneven fluid movement that limits the efficiency of displacement processes such as waterflooding or gas injection used in secondary recovery. The rock properties variations leads to bypassed oil, reducing the overall sweep efficiency, the key metric quantifying the effectiveness with which injected fluids displace hydrocarbons from the reservoir toward production wells, Sweep efficiency essentially measures the volume fraction of the reservoir contacted by the displacing

fluid and is directly influenced by injection strategies, fluid properties, and most importantly, reservoir heterogeneity. While the traditional approach to characterizing reservoir heterogeneity has relied primarily on petrophysical data derived from core samples, well logs, and seismic imaging to measure static properties like porosity and permeability distributions, these methods often fall short of capturing the complex, dynamic interactions between the rock matrix, fluids, and pore connectivity. Conventional quantification metrics such as the Coefficient of Variation (CV), Lorenz Coefficient (LC), and Dykstra-Parsons coefficient (Vdp) offer numerical measures of permeability variation but do not fully elucidate the subtle heterogeneities caused by stratification, facies architecture, or compartmentalization that profoundly influence fluid flow patterns.

Recent advances in reservoir characterization have emphasized integrating dynamic and geochemical techniques with traditional petrophysical data to provide a more holistic understanding of heterogeneity and its impact on fluid flow. One notable development is the application of Strontium Residual Salt Analysis (Sr-RSA), a geochemical fingerprinting technique that analyzes formation water and residual salt compositions to reveal fluid sources, migration pathways, and mixing zones within the reservoir. Sr-RSA offers complementary insights into fluid connectivity and natural barriers that are not readily identifiable through petrophysical data alone. By correlating strontium isotopic signatures with permeability structures, this method allows for the identification of subtle compartmentalization, the existence of flow barriers, and preferential fluid migration pathways at facies boundaries. Incorporating geochemical data alongside high-resolution permeability analyses enhances the ability to predict sweeping efficiency more accurately. Vertical and lateral heterogeneity control fluid movement through complex pore networks; variations along bedding planes or across facies transitions can lead to bypassed oil, uneven displacement fronts, and lower recovery ratios. The combined approach enables reservoir engineers to pinpoint high-priority zones for

secondary and enhanced oil recovery, optimize well placement, and design more effective injection strategies. Moreover, understanding reservoir heterogeneity and its effects on sweep efficiency carries significant economic implications. Inefficient displacement resulting from heterogeneity, such as early breakthrough and trapped oil increases operational costs, reduces total recoverable reserves, and diminishes asset value.

Therefore, accurately characterizing heterogeneity and mitigating its negative impact is essential not only as a technical objective but also as a strategic business imperative. Optimized heterogeneity management leads to better project economics by minimizing operational waste, reducing capital expenditure overruns, and maximizing the recovery factor for enhanced profitability and resource utilization. This study focuses specifically on assessing the impact of reservoir heterogeneity on sweep efficiency. It investigates the nature and extent of heterogeneity within a target reservoir, examines various quantification approaches including traditional petrophysical metrics and geochemical Sr-RSA techniques and analyzes how these heterogeneities influence displacement efficiency during recovery operations. By providing a comprehensive evaluation of heterogeneous reservoir properties and fluid flow behavior, the study aims to generate insights that enhance reservoir characterization accuracy and support the selection of optimized enhanced oil recovery (EOR) methods. Ultimately, the integration of multidisciplinary data sets forms the basis for the continual evolution of reservoir management strategies. Embracing the full complexity of heterogeneity from microscale pore differences to macroscale geological structures and understanding its fluid flow consequences allow for better well positioning, adaptive injection schemes, and targeted interventions to improve sweep efficiency. As the petroleum industry advances analytical methodologies and expands multidimensional datasets, accurate reservoir heterogeneity characterization will remain critical to achieving maximum hydrocarbon recovery and strengthened asset value.

## **1.2 STATEMENT OF PROBLEM**

Despite advances in enhanced oil recovery (EOR) technique, achieving high sweep efficiency in heterogeneous reservoirs remains a persistent problem. However, many reservoirs are geologically complex, with varying rock and fluid properties that hinder uniform displacement. In such cases injected fluids may bypass large portions of the oil, leaving significant reserves unrecovered, this leads to poor reservoir utilization and economic inefficiencies

This problem is often underestimated when reservoir models rely on average properties, making the effects of heterogeneity. Without a clear understanding of heterogeneity impacts, sweep efficiency, recovery projects may fail to reach their expected performance, leading to reduced profitability and premature abandonment of wells.

Therefore, there is a need for a more comprehensive reservoir characterization tool that integrate geochemical and Petrophysical data to better predict sweep efficiency and guide enhanced oil recovery methods.

## **1.3 SIGNIFICANCE OF STUDY**

The significance of this study lies in its comprehensive approach to understanding and managing reservoir heterogeneity to optimize hydrocarbon recovery. Reservoir heterogeneity, the variability in rock properties such as porosity and permeability across different spatial scales, is a fundamental and challenging characteristic of petroleum reservoirs that profoundly influences fluid flow behavior, sweep efficiency, and ultimate recovery. By combining traditional petrophysical assessment with innovative geochemical methods, notably Strontium Residual Salt Analysis (Sr-RSA), this study addresses critical gaps in accurately characterizing

reservoir complexity and fluid connectivity that often go undetected using static, single-disciplinary approaches. The study's significance can be summarized as follows:

- **Improved Reservoir Characterization:** Integrating permeability data with Sr-RSA enables the detection of subtle reservoir features such as fluid compartmentalization, flow barriers, and migration pathways. These insights offer a more accurate and multidimensional understanding of reservoir heterogeneity at both micro and macro scales, which traditional methods may overlook.
- **Enhanced Recovery Prediction:** By linking heterogeneity characterization to sweep efficiency and displacement behavior during secondary and tertiary recovery stages, the study provides essential knowledge for predicting areas of bypassed oil, early breakthrough, and uneven fluid front propagation. This enhances the ability to forecast production performance more reliably.
- **Optimization of Recovery Strategies:** Knowledge gained from the integrated approach supports more targeted well placement, injection design, and enhanced oil recovery (EOR) techniques that are tailored to the specific heterogeneity and fluid flow conditions of each reservoir. This strategic optimization contributes directly to increasing hydrocarbon recovery factors.
- **Economic and Operational Benefits:** Minimizing recovery inefficiencies caused by heterogeneity translates into reduced operational costs, improved project economics, and higher asset value. This is especially critical in mature fields or complex reservoirs where maximizing recovery under challenging conditions is a priority.
- **Application to Nigerian Reservoirs:** Emphasizing this method's potential use in Nigeria's petroleum sector adds practical relevance, as many Nigerian reservoirs exhibit significant heterogeneity impacting production efficiency. Implementing this

integrative study approach could help improve reservoir management and recovery outcomes within the country's oil and gas industry.

- **Contribution to Reservoir Engineering Knowledge:** The study advances the current understanding of how dynamic geochemical data combined with static petrophysical measures enhances reservoir modeling, simulation, and decision-making, contributing novel perspectives to the field.

In essence, this study is significant because it bridges the gap between static rock property assessment and dynamic fluid flow characterization, enabling a more thorough understanding of heterogeneous reservoirs. This integrated perspective is crucial for devising effective reservoir management strategies that maximize hydrocarbon recovery while controlling costs and operational risks. As reservoir development increasingly relies on multidisciplinary data, such comprehensive heterogeneity characterization will remain a cornerstone for successful hydrocarbon exploration and production.

#### **1.4 AIM AND OBJECTIVES**

**Aim:**

To develop and apply an integrated characterization approach for quantifying reservoir heterogeneity and assessing its effect on sweep efficiency in hydrocarbon reservoirs.

**Objectives:**

1. To evaluate previous information on heterogeneity and its effect on sweep efficiency
2. To evaluate the static heterogeneity measures used to characterize heterogeneity
3. To integrate geochemical and permeability data for a comprehensive assessment of reservoir heterogeneity.

4. To interpret the impact of heterogeneity on fluid displacement and sweep efficiency using data from the South Pars field and Elgin field.

#### **1.4 SCOPE OF STUDY**

The scope of this study encompasses a comprehensive examination of reservoir heterogeneity and its influence on sweep efficiency during hydrocarbon recovery. It includes

1. Characterization of reservoir heterogeneity by analyzing variations in rock properties such as porosity and permeability across different scales from microscopic pore structures to macroscopic geological features like stratification, facies changes, faults, and fractures.

2. Evaluation of traditional petrophysical methods to quantify heterogeneity, including statistical metrics such as Coefficient of Variation, Lorenz Coefficient, and Dykstra-Parsons coefficient, highlighting their capabilities and limitations. Integration of advanced geochemical techniques, specifically Strontium Residual Salt Analysis (Sr-RSA), to enhance understanding of fluid connectivity, migration pathways, and subtle heterogeneities not evident from static petrophysical data alone.

3. Investigation of how reservoir heterogeneity affects fluid displacement processes, focusing on its impact on sweep efficiency.

#### **1.5 JUSTIFICATION OF STUDY**

This study is justified by the need to improve reservoir characterization techniques beyond traditional methods that rely solely on static rock properties. By integrating geochemical analyses like Strontium Residual Salt Analysis (Sr-RSA) with conventional data, the research aims to better identify reservoir heterogeneity, fluid connectivity, and barriers that impact oil recovery efficiency. Such an approach supports more accurate modeling and optimized

resource extraction, making it vital for enhancing hydrocarbon recovery and effective field management

## **1.6 LIMITATION OF STUDY**

While this study aims to provide a comprehensive understanding of reservoir heterogeneity through the integration of geochemical and petrophysical data, several limitations exist. First, the availability and resolution of core and fluid samples may restrict the spatial coverage and detail of heterogeneity characterization. Second, geochemical analyses like Strontium Residual Salt Analysis (Sr-RSA) require careful interpretation within complex reservoir environments and may be influenced by diagenetic processes or mixing effects. Third, the study's findings are constrained by the quality and resolution of permeability data, which may not capture all relevant small-scale heterogeneities that impact flow behavior. Finally, modeling assumptions and simplifications necessary for reservoir simulation may limit the direct applicability of results to all reservoir types or conditions. These limitations highlight the challenges inherent in reservoir characterization but also underscore the need for continued methodological improvement and integration of multi-disciplinary data sources to better understand and manage reservoir complexity.

## CHAPTER TWO

### LITERATURE REVIEW

Variations in reservoir rock characteristics is extremely difficult to construct a precise mathematical analog of detailed reservoir rock, since bulk sample of the reservoir in question is not gotten, sometimes the sample gotten from the reservoir can be insignificant compared to how bulk in volume the reservoir is. This observation highlights a major challenge in reservoir characterization. Unlike laboratory systems where controlled samples can be tested repeatedly, reservoir systems are vast, complex, and only partially accessible through drilling and coring. Even when cores are collected, they represent only a narrow cylinder of rock and often fail to capture the full three-dimensional variability of the reservoir. This limited sampling makes it difficult to establish fully representative models, which explains why many reservoir models rely heavily on interpolation, stochastic simulations, and analogs from outcrops or modern depositional systems.

#### **Challenges faced with the need for:**

A valid description of certain physical and textural variants in the reservoir such as the rock's capacity to store fluids (porosity), its ability to transmit fluids (permeability), strata, fixation of continuity

#### 2. Means for enumerating such description

The above challenges summarize the dual problem of description and quantification. First, geoscientists must identify what the relevant heterogeneities are including properties like the rock's capacity to store fluids (porosity), its ability to transmit fluids (permeability), stratification, and lateral continuity. Second, they need systematic ways to measure and represent these variations in a model. Without both descriptive and quantitative clarity, reservoir models may fail to capture flow patterns accurately, leading to unexpected production behaviors. Geostatistics emerged precisely to address this gap by providing tools to describe

and quantify spatial variability. As regard to the stratification characteristics, the layer cake or stratified its ability to transmit fluids (permeability) configuration each layer as unique with respect to its range and continuity of its ability to transmit fluids (permeability), hence each layer possesses an overall its ability to transmit fluids (permeability) average and areal extent different from its neighbor, most reservoir are extensively stratified. This “layer cake” analogy remains a fundamental way to visualize stratification, though in reality, many reservoirs exhibit far more irregular geometries. Each stratum has distinctive its ability to transmit fluids (permeability) characteristics, influenced by the depositional conditions during its formation. For example, fluvial sandstones may produce alternating high-its ability to transmit fluids (permeability) channel sands and low-its ability to transmit fluids (permeability) floodplain silts. The variation in its ability to transmit fluids (permeability) between layers significantly impacts vertical communication within reservoirs. vertical heterogeneity often dictates overall displacement effectiveness (sweep efficiency) during secondary recovery methods like waterflooding. Permeability in a sedimentary rock is primarily related to such textural conditions as grain shape, surface area, interconnected pore space, grain packing and grain size composition. Stratification can be seen as a result of the frequent changes in grain size composition of sediment during deposition. This textural control is central to the study of clastic reservoirs. Grain size variations reflect energy fluctuations in depositional environments. High-energy systems (e.g., braided rivers) deposit coarser, better-sorted sediments, which generally yield higher its ability to transmit fluids (permeability). By contrast, low-energy environments (e.g., floodplains, deep marine shales) accumulate fine-grained, poorly sorted sediments, producing much lower permeabilities. Furthermore, the interconnectedness of pore spaces influenced by packing, sorting, and cementation plays a major role in determining effective its ability to transmit fluids (permeability). In investigating, the type of stratification or rather the degree of stratification a

reconstruction of the geologic history of the area and sequence of sedimentary events in the final resting site of the sediment should be the starting point. Here, the text emphasizes the importance of geological context. Modern reservoir characterization does not treat rock layers as isolated; instead, it integrates sequence stratigraphy to reconstruct depositional settings. Sequence stratigraphy helps correlate layers regionally by understanding sediment supply, sea level fluctuations, and tectonic influence. This framework allows geoscientists to predict heterogeneity patterns beyond well control points. Concept of "Band of Genetic similarity"; it's the concept of instead of identifying the individual microstrata between wells and risking misinterpretation of stratigraphy in the reservoir, an entire band is identified collectively and texturally similar microstrata are traced together from well to well within the confines of this band to establish their collective continuity. The "band of genetic similarity" method addresses the difficulty of correlating thin beds across wells, especially when such layers are discontinuous or below seismic resolution. Instead of forcing one-to-one bed correlations, geologists group texturally similar strata into broader genetic units. This approach reduces correlation errors and improves consistency in reservoir models, grouping sedimentary units into genetic packages better reflects the depositional processes that created them and provides a more reliable basis for predicting lateral continuity.

## **2.1 Historical Perspectives on Reservoir Heterogeneity**

Reservoir Heterogeneity refers to the quality or condition of being heterogeneous and it was first defined in 1898 as difference or diversity in kind from other things or consisting of parts or things that are very different from each other (Oxford English Dictionary; Simpson & Weiner 1989). The earliest definitions highlight the contrast between heterogeneity and homogeneity, a distinction that has since been refined within the geosciences. In geology, heterogeneity implies that no two parts of a reservoir are exactly alike in composition, texture,

or property distribution. Simpson and Weiner's (1989) broad linguistic framing paved the way for technical definitions used in modern reservoir engineering. Normi et al. (1990) suggest that the distinction between homogeneous and heterogeneous is often relative and is based on economic considerations. This economic perspective is particularly relevant in petroleum engineering. A reservoir may appear heterogeneous under a microscope, but if those variations do not significantly influence production, it may be treated as effectively homogeneous for engineering purposes. Conversely, small-scale heterogeneities can become economically significant if they impact recovery factors or sweep efficiency. Li and Reynolds (1995) and Zheng Quan et al. (1997) state that heterogeneity is defined as the complexity or variability of the system property of interest in three-dimensional space. This definition is widely cited in reservoir modeling literature because it emphasizes the three-dimensional nature of heterogeneity. Reservoir properties such as the rock's capacity to store fluids (porosity) and its ability to transmit fluids (permeability) vary both vertically (stratification, post-depositional alteration of rock properties (diagenesis)) and laterally (facies changes, structural controls). Quantifying these variations requires sophisticated 3D models, which often combine seismic, well log, and core data. Normi et al. (1990) suggest that heterogeneity, in electrical borehole images, refers to elements that are distributed in a non-uniform manner or composed of dissimilar elements/constituents within a specific volume. Electrical borehole imaging tools (e.g., FMI logs) provide high-resolution pictures of borehole walls, allowing geoscientists to observe bedding, fractures, and heterogeneities directly. These tools reveal features invisible to conventional logs, such as small-scale lamination, vugs, and microfractures. Such insights demonstrate how definitions of heterogeneity are also tied to the scale and resolution of the measurement method.

### **2.1.1 Homogeneity vs. Heterogeneity in Reservoir Rocks**

Pure homogeneity, with regard to a reservoir rock, can be visualized in a formation that consists of:

1. Single mineralogy with
2. All grains of similar shapes and sizes with
3. No spatial organization or pattern present

Similar grains shape and size together with the lack of spatial pattern would lead to a uniform distribution of the rock's capacity to store fluids (porosity) and its ability to transmit fluids (permeability).

This theoretical "pure homogeneity" is rarely encountered in natural reservoirs. Even relatively homogeneous formations, such as eolian sandstones, typically exhibit subtle variations in grain size or cementation. Nonetheless, this idealized scenario provides a benchmark for understanding how heterogeneity impacts flow. In homogeneous reservoirs, Darcy's law can be applied uniformly, simplifying modeling and prediction. In heterogeneous reservoirs, however, flow paths become irregular, leading to bypassed zones and reduced recovery efficiency (Lake, 1989).

Lake & Jensen (1991) suggest that there are 5 basic types of heterogeneity in earth science:

1. Spatial – lateral, vertical & three-dimensional
2. Temporal – one point at different times
3. Functional – taking correlation and flow paths into account
4. Structural – either unconformities or tectonic elements such as faults and fractures
5. Stratigraphic.

This classification provides a comprehensive framework for analyzing heterogeneity. Spatial heterogeneity is the most discussed in reservoir engineering, but temporal heterogeneity is also significant because reservoir properties can change over

production time due to compaction, pressure depletion, or fluid substitution. Functional heterogeneity considers how heterogeneity impacts actual flow behavior, while structural and stratigraphic heterogeneity emphasize geological controls. Although, some researchers may perceive a regularly structured system, for example a laminated or bedded reservoir, as homogeneous because these structures are spatially continuous and occur throughout the formation. This highlights the relativity of the homogeneity–heterogeneity distinction. A laminated reservoir may appear homogeneous at a seismic scale but reveals strong heterogeneity when viewed microscopically. Thus, scale and resolution play critical roles in defining what counts as heterogeneous.

### **2.1.2 Reservoir Heterogeneity and Its Geological Controls**

Variations in reservoir rock characteristics refers to vertical & lateral variations in the rock's capacity to store fluids (porosity), its ability to transmit fluids (permeability) and capillary pressure (Alpay, 1972; Evans, 1987). Variations in reservoir rock characteristics in sandstone bodies occur at various extents and scales, ranging from micrometers to hundreds of meters & is commonly attributed to variations in depositional facies, post-depositional alteration of rock properties (diagenesis) & structural features such as the presence of fractures and faults. Heterogeneity strongly influences reservoir performance by controlling fluid flow and recovery factors (Wardlow & Taylor, 1976). Elucidation and prediction of the reservoir heterogeneity are of prime importance for the planning and execution of efficient hydrocarbon production strategies (Hamilton et al., 1998).

This section underscores how heterogeneity manifests across scales. Microscopic features such as pore throat geometry impact capillary behavior, while macroscopic structures like faults influence field-scale compartmentalization. Importantly, these variations directly affect hydrocarbon recovery strategies. For instance, highly compartmentalized reservoirs may require infill drilling or horizontal wells to contact bypassed hydrocarbons. Predicting

heterogeneity, therefore, is not merely academic but central to field development planning (Jensen et al., 2000).

### **2.1.3 Diagenetic Evolution Pathways of Sandstone**

Many common diagenetic processes can be systematically related to attributes of depositional facies. These processes include:

1. Mechanical compaction & formation of semi-steady matrix
2. Grain dissolution (feldspar, rock fragments, mud intraclasts)
3. Formation of pore-lining minerals including iron oxide, smectite
4. Formation of grain-replacing kaolinite
5. Cementation by carbonates (calcite, dolomite)

Diagenesis profoundly alters original depositional textures. Mechanical compaction reduces the rock's capacity to store fluids (porosity) by reorienting grains, particularly in poorly sorted sediments. Dissolution of unstable grains (e.g., feldspar) can generate secondary the rock's capacity to store fluids (porosity), temporarily enhancing reservoir quality. However, cementation often reduces pore space, with carbonates like calcite and dolomite being particularly detrimental to the rock's capacity to store fluids (porosity). Depositional and early diagenetic attributes determine the pore system evolution of sandstone during burial post-depositional alteration of rock properties (diagenesis). Early post-depositional alteration of rock properties (diagenesis) can have both positive and negative impact on deep reservoir quality. Positive effects include the inhibition of compaction of late quartz. Cementation by early pore-lining cements. Negative effects include the filling of pores by cement and the reaction of early formed kaolinite with remnants of undissolved K-feldspar to form reactants for high temperature diagenetic illite. This balanced perspective recognizes that post-depositional alteration of rock properties (diagenesis) is not uniformly destructive.

Early diagenetic cements may protect grains from later compaction, preserving the rock's capacity to store fluids (porosity). On the other hand, pervasive cementation can occlude pores irreversibly. Understanding these pathways helps predict which sandstones retain reservoir quality at depth.

## **2.2 Framework Grains in Sandstone: Types, Origin & Impact on Diagenetic Evolution and Reservoir Heterogeneity**

The mechanical & chemical stabilities of sandstone are strongly linked to grain composition (Bloch, 1994; De Ros et al., 1994). Detrital framework constituents of sandstones can be broadly classified in 4 groups:

1. Extrabasinal non-carbonate grains
2. Extrabasinal carbonate grains
3. Intrabasinal non-carbonate grains
4. Intrabasinal carbonate grains

Framework grains form the essential skeletal fabric of sandstones and exert first-order control on both diagenetic evolution and reservoir quality. Their mineralogical composition dictates chemical stability during burial, while their mechanical properties determine how they respond to compaction and stress. Differences in provenance, tectonic setting, and climate strongly influence the relative abundance of these grain types in a given basin.

### **Extrabasinal Non-Carbonate Grains**

These grains are derived from weathering and erosion of igneous, metamorphic & older sedimentary rock in the hinterland. These grains are primarily monocrystalline & polycrystalline quartz, feldspar, rock fragments. Grain composition depends primarily on source rock composition and relief (Zuffa, 1985; Suttner & Duttar, 1986). The source rock composition & the sand composition are strongly controlled by the tectonic setting of the basin.

Quartz is by far the most stable of these grains, contributing to the durability of quartzose sandstones. Feldspars, while mechanically competent, are chemically less stable and prone to dissolution or alteration into clays during post-depositional alteration of rock properties (diagenesis). Lithic fragments, often derived from volcanic or metamorphic rocks, are mechanically weaker and prone to deformation during compaction (McBride, 1989). Chemical weathering is most efficient if the source area has low relief, implying a longer duration of weathering prior to erosion, which is typical for basins lying in tectonically stable areas such as intracratonic basins (Dickinson et al., 1983). This statement emphasizes that tectonic stability fosters prolonged chemical weathering, producing mature quartz-rich sandstones. Conversely, active tectonic settings (e.g., foreland basins) yield immature sandstones rich in feldspars and lithic fragments, which are more diagenetically reactive. These differences directly impact reservoir quality, with quartzose sandstones generally retaining better the rock's capacity to store fluids (porosity) during deep burial (Bloch et al., 2002).

In principle, mature sandstones are both chemically and mechanically stable and have the better potential to form good reservoirs even when deeply buried (Scherer, 1987; Bloch et al., 2002). Feldspar-rich sandstones are mechanically stable but can be chemically unstable. Sandstones with abundant mechanically unstable rock fragments suffer rapid decline in the rock's capacity to store fluids (porosity) and its ability to transmit fluids (permeability) during burial because of mechanical compaction (Bloch, 1994). Not all sandstones that are rich in lithic fragments are both chemically and mechanically unstable; sandstones rich in felsic plutonic rock fragments are mechanically and, to a great extent, chemically stable (Melvin & Knight, 1985). This nuanced view underscores the importance of provenance analysis in predicting reservoir quality. A quartzose sandstone in a cratonic setting may remain porous at depths exceeding 4 km, while a lithic-rich sandstone in a foreland basin may lose reservoir

quality much earlier. These distinctions explain why exploration geologists often couple petrography with tectonic reconstructions to anticipate heterogeneity.

### **Extrabasinal Carbonate Grains**

These grains are relatively rare in sandstone, because carbonate source rocks tend to weather chemically instead of physically, particularly under humid climatic conditions (Wright, 1988). Extrabasinal carbonate grains also contribute to the rock's capacity to store fluids (porosity) reduction through chemical compaction. Although uncommon, when extrabasinal carbonate grains are present, they often accelerate diagenetic cementation. Their chemical reactivity leads to early carbonate cement, which reduces pore space. This explains why mixed siliciclastic-carbonate systems frequently show lower reservoir quality compared to pure siliciclastic systems.

### **Intrabasinal Carbonate Grains**

These grains occur in continental shallow water, marine and deep-water marine sandstones and when abundant, they form hybrid arenites (Zuffa, 1980). Carbonate intraclasts may be derived from the erosion of carbonate concretions, crusts and cemented layers of vadose and phreatic calcrete and dolocrete deposits by abusing rivers and episodic floods (Tandon & Narayan, 1981). Hybrid arenites, containing both siliciclastic and carbonate grains, represent depositional mixing zones. These deposits are often associated with high-energy environments such as delta fronts or shallow marine shoals. Their heterogeneity reflects both variable grain composition and subsequent diagenetic pathways.

Sediments rich in intrabasinal carbonate grains are prone to pervasive carbonate cementation, which greatly reduces depositional the rock's capacity to store fluids (porosity) and its ability to transmit fluids (permeability) (Fontana et al., 1986; James, 1992). This observation aligns with multiple case studies from the Mediterranean and Middle East, where

carbonate-rich sandstones frequently exhibit poor reservoir performance due to pervasive cementation. However, in some cases, selective dissolution of carbonate grains can generate secondary the rock's capacity to store fluids (porosity), improving reservoir quality locally.

### **Intrabasinal Non-Carbonate Grains**

These grains can have an impact on reservoir heterogeneity, including the following:

**1. Mud intraclasts:** These grains, which are called rip-up clasts, are defined as fragments eroded from low-energy deposits & redeposited in high-energy environments. These clasts are derived from erosion of:

- Floodplain deposits
- Muddy slope deposits by turbidity currents
- Shelf sediments during marine transgression.

Depositional layers rich in mud intraclasts may also be cemented extensively by eogenetic carbonate. Rip-up clasts often act as nucleation sites for early cementation, reducing local the rock's capacity to store fluids (porosity). Their abundance indicates fluctuating depositional energy conditions, which increase heterogeneity within fluvial and deltaic reservoirs.

**2. Glaucony:** These grains are ductile and rapidly deform upon compaction, contributing to the rock's capacity to store fluids (porosity) deterioration (McBride, 1978) but are chemically stable in most burial diagenetic environments. Glauconitic sandstones are common in marine settings and often associated with reduced reservoir quality due to mechanical compaction. However, their chemical stability means they may not contribute to significant secondary alteration during deep burial.

**3. Silicic Bioclasts:** Silicic bioclasts, derived from skeletal material such as sponges or radiolarians, may influence reservoir properties depending on their abundance and degree of recrystallization.

**4. Berthierine Odinite:** Berthierine and odinite are iron-rich clay minerals that typically occur in shallow marine deposits. Their presence often promotes early cementation, reducing initial the rock's capacity to store fluids (porosity) but sometimes stabilizing frameworks against later compaction.

### **2.2.1 Impact of Depositional Facies on Diagenesis and Reservoir Quality**

Depositional facies has considerable impact on the distribution of eogenetic & mesogenetic alterations and, by virtue, on evolution pathways of reservoir quality & heterogeneity in siliciclastic successions. This statement recognizes that depositional environment dictates both original grain characteristics and the initial conditions for post-depositional alteration of rock properties (diagenesis). For example, high-energy fluvial sandstones may start with high the rock's capacity to store fluids (porosity) but are often prone to compaction, while marine sandstones with abundant bioclasts may undergo early cementation. Facies-controlled post-depositional alteration of rock properties (diagenesis) is one of the most predictable sources of reservoir heterogeneity.

#### **1. Fluvial Deposits**

Different types of fluvial systems produce significant variations in sand-body architecture, grain size & sand/mud ratio (Einsele, 2000). The depositional heterogeneity in fluvial reservoirs is strongly related to the geometry and lateral & vertical interconnection of sandstone bodies. The dimension, geometry and grain size of channel sandstones vary widely depending on variations in accommodation space and morphology of the fluvial system (braided, meandering, anastomosing) (Einsele, 2000). Braided rivers deposit sheet-like sand bodies with

high lateral continuity but variable grain size; while meandering rivers produce narrow, sinuous channel belts with more compartmentalization. Anastomosing rivers yield multiple interconnected channels, generating complex heterogeneity. These differences are crucial for predicting connectivity between wells in fluvial reservoirs. Case studies from the Niger Delta illustrate how channel stacking patterns control reservoir compartmentalization.

## **2. Eolian Deposits**

Eolian sandstones typically have quartzose or quartzofeldspathic compositions. These chemically and mechanically stable framework compositions make it possible for the rock's capacity to store fluids (porosity) to be preserved even upon burial. Eolian reservoirs, such as the Permian Rotliegendes in the North Sea, often retain excellent the rock's capacity to store fluids (porosity) and its ability to transmit fluids (permeability) because of their high sorting, well-rounded grains, and quartz-rich composition. Their cross-bedded architecture also provides predictable directional its ability to transmit fluids (permeability) trends. However, localized cementation by evaporites or infiltration of clays can still introduce heterogeneity.

## **3. Deltaic and Estuarine Deposits**

Deltaic sediments include medium to fine-grained sand, silt and mud in both subaerial (fluvial, lagoon) and subaqueous (delta front) settings. Most deltaic environments are established on wide inner shelf areas. During times of major relative sea-level fall, deltas also develop at the shelf break where they feed slope and submarine fans (Einsele, 2000). Delta shape is controlled by the rate of river sediment supply and the tide and wave regimes in the coastal area. Deltas are among the most prolific hydrocarbon reservoirs globally, including the Niger Delta, Mahakam Delta, and Mississippi Delta. Their heterogeneity stems from the interplay of distributary channels, mouth bars, and delta-front deposits. High sediment supply and strong river dominance create lobate, channel-rich deltas, while tide- and wave-dominated deltas

produce more sheet-like sand bodies. Delta front deposits commonly have abundant grain coating and ooidal Fe-rich clays, particularly in warm, tropical, river-dominated deltas. These coatings often promote early diagenetic cementation, reducing the rock's capacity to store fluids (porosity). However, their predictability allows for better reservoir quality forecasting in deltaic plays.

#### **4. Shallow-Marine Deposits**

Shallow-marine deposits form in foreshore, shoreface and offshore depositional environments and are similar to wave-dominated deltas. Although shallow-water marine sandstones are commonly texturally and mineralogically mixed, they may, in some cases, be enriched in carbonate bioclasts that promote eogenetic cementation by calcite. Shallow-marine reservoirs, such as those in the Brent Group of the North Sea, often exhibit stacked parasequences with coarsening-upward trends. Their lateral continuity makes them excellent reservoirs, but bioclastic enrichment can create zones of poor quality. Predicting these variations requires integration of sequence stratigraphy, facies analysis, and diagenetic studies.

### **2.3 Scale and Measurement Resolution**

Variations in reservoir rock characteristics is an intrinsic characteristic of all subsurface systems and has long been recognized as one of the most challenging factors in reservoir characterization, modeling, and production forecasting. The complexity arises because reservoir properties are not distributed uniformly but vary spatially across a wide range of scales, from the microscopic pore level to the entire reservoir. To account for this complexity, the concept of scale and measurement resolution has been introduced, and hierarchies of heterogeneity are frequently used to classify variability over levels of decreasing magnitude within a broad stratigraphic framework.

### 2.3.1 Hierarchies of Heterogeneity

Heterogeneity hierarchies allow geologists and reservoir engineers to break the apparent continuum of geological and petrophysical properties into discrete, interpretable classes or ranges. This approach has been applied successfully across a range of depositional environments and reservoir types:

1. Wave-influenced shallow marine reservoirs (e.g., Sech et al., 2009)
2. Fluvial reservoirs (e.g., Jones et al., 1995)
3. Fluvio-deltaic reservoirs (e.g., Choi et al., 2011)
4. Carbonate reservoirs (e.g., Jung & Aigner, 2012)

These hierarchical models enable systematic categorization of heterogeneity into scales that are meaningful for both geological interpretation and engineering decision-making. By considering hierarchies, the continuum of variability is discretized into manageable levels, thereby allowing for the design of workflows that target the scale most relevant to the problem at hand. For example, in carbonate reservoirs, the rock's capacity to store fluids (porosity) may exist and vary across multiple length-scale may occur at the sub-micrometer scale in chalks of the North Sea (Brasher & Vagle, 1996), while interparticle and crystalline the rock's capacity to store fluids (porosity) can be observed at the millimeter scale in Middle Eastern carbonate reservoirs (Lucia, 1995). Additional diagenetic processes such as dissolution and erosion may further generate macropores or even "megapores" at the meter to kilometer scale (Akbar et al., 1995; Kennedy, 2002). This wide spectrum illustrates that a single geological property, such as the rock's capacity to store fluids (porosity), can manifest across scales of several orders of magnitude.

### **2.3.2 Measurement Resolution in Subsurface Studies**

Subsurface measurements are typically performed at specific length-scales, and the resolution of observation is directly dependent on the physics of the tool employed. For example: Seismic data generally capture reservoir architecture at the kilometer scale, suitable for large-scale structural and stratigraphic interpretations but limited in capturing small-scale heterogeneity. Well logs provide information at the centimeter to meter scale, offering insight into vertical variations in lithology, the rock's capacity to store fluids (porosity), and fluid saturation. Petrophysical core measurements capture data at the millimeter to centimeter scale, allowing for detailed analysis of grain-scale properties such as pore throat size, mineralogy, and textural variation. The challenge arises when these measurements, taken at different scales, are integrated into a unified reservoir model. Each dataset "sees" the reservoir differently, and mismatches between scale and resolution can lead to uncertainties.

### **2.3.3 Representative Elementary Volume (REV)**

The impact of scale and resolution on measured heterogeneity can be represented through the concept of the the concept of Representative Elementary Volume (REV), defining the smallest volume over which a property remains statistically consistent (REV). The REV refers to the smallest volume over which a measurement can be made such that further increases in sample size do not significantly alter the average value of the measured property (Bear, 1972). For the rock's capacity to store fluids (porosity), for example, once the REV has been reached, additional increases in sample size yield the same mean the rock's capacity to store fluids (porosity) value, even though variability at smaller scales may persist. The REV is not constant across properties. For the rock's capacity to store fluids (porosity), the REV might be reached at a relatively small sample size, but for its ability to transmit fluids (permeability), which is far more scale-dependent, the REV may require a much larger sample. In carbonates, the REV for its ability to transmit fluids (permeability) can extend over several orders of

magnitude larger than the REV for the rock's capacity to store fluids (porosity) because of the strong influence of fractures, vugs, and connected macropores.

### **2.3.4 Shallow vs. Deep Measurements**

The degree of heterogeneity measured also changes as the measurement volume changes. This is particularly evident when distinguishing between shallow and deep investigation tools:

1. Shallow measurements such as bulk density or micro-resistivity logs sample small volumes immediately surrounding the borehole. They are sensitive to small-scale variability, including bedding laminations, mud drapes, or fine-scale diagenetic features.
2. Deep measurements such as gamma radiation, acoustic travel times, or deep resistivity logs penetrate much larger volumes of rock, averaging out local heterogeneity and highlighting broader-scale variations in reservoir quality.

This distinction is critical when interpreting data for modeling and simulation purposes. Over-reliance on shallow-scale measurements may exaggerate heterogeneity, while deep-scale tools may underestimate it. The combination of measurements across scales is therefore essential for developing a balanced reservoir characterization.

## **2.4 Evaluating Heterogeneity**

Once heterogeneity has been described qualitatively through hierarchies and measurement scales, it becomes necessary to quantify it. Quantification enables heterogeneity to be expressed as numerical values that can be compared across datasets, reservoir intervals, or entire fields. A variety of statistical and geostatistical techniques have been developed for this purpose.

## **2.4.1 Quantitative Measures of Heterogeneity**

### **Classifications and Implications of Heterogeneity**

Heterogeneity is broadly categorized into static and dynamic types. Static heterogeneity derives from core sample analyses typically permeability measurements using statistical metrics like coefficient of variation (Cv), Vdp, and Lc. Dynamic heterogeneity, by contrast, utilizes fluid flow experiments to directly measure the effect of heterogeneity on fluid movement. Additionally, heterogeneity manifests vertically and areally. Vertical variations generally exert a stronger influence on flood sweep efficiency through cross-layer fluid flow effects, whereas areal heterogeneity tends to play a lesser role; however, in complex depositional environments marked by tectonic and diagenetic activity, areal heterogeneity becomes increasingly significant.

Several indices have become standard in petroleum reservoir characterization, particularly for quantifying the rock's capacity to store fluids (porosity) and its ability to transmit fluids (permeability) distributions. Among the most widely applied are:

1. Coefficient of Variation (CV)
2. Lorenz Coefficient (LC)
3. Dykstra-Parsons Coefficient (Vdp)

These indices provide single-value measures of variability, allowing direct comparisons between different reservoir datasets. They are widely used in exploration and development workflows, especially for constructing the rock's capacity to store fluids (porosity) and its ability to transmit fluids (permeability) models.

#### **1. Coefficient of Variation (CV)**

The coefficient of variation is a dimensionless measure of variability relative to the mean value of the dataset. It is defined as:

$$CV = \frac{\sigma}{\mu}$$

Where:

$\sigma$  = standard deviation

$\mu$  = mean

In a homogeneous reservoir, CV approaches zero, while increasing heterogeneity leads to a rise in CV values. This makes CV a simple and widely applicable tool. The advantage of CV lies in its ability to compare heterogeneity across datasets of different scales and units. For example, CV can be applied to its ability to transmit fluids (permeability) data collected from core plugs, well logs, or even seismic-derived the rock's capacity to store fluids (porosity), enabling cross-comparisons. However, CV is sensitive to sample size and tends to underestimate variability in small datasets (fewer than 40 samples). In such cases, corrections may be necessary to account for statistical bias.

A key limitation of CV is that it is only valid for ratio-scale data with a true zero point. This makes it unsuitable for certain properties like temperature measured in Celsius or Fahrenheit. Additionally, while CV increases without limit as heterogeneity grows, it does not provide information about the spatial arrangement of heterogeneity, which is critical for flow behavior in reservoirs.

## **2. Lorenz Coefficient (LC)**

The Lorenz technique was originally developed in economics to measure inequality in wealth distribution (Lorenz, 1905). It was later adapted to petroleum engineering by Schmalz & Rahene (1950), who modified the method for application to reservoir properties such as the rock's capacity to store fluids (porosity) and its ability to transmit fluids (permeability).

In reservoir studies, the Lorenz curve is constructed by plotting cumulative flow capacity against cumulative reservoir thickness. In a perfectly homogeneous system, the cumulative

property increases linearly with depth, producing the so-called “line of perfect equality.” Deviations from this line indicate increasing heterogeneity. The Lorenz Coefficient (LC) is calculated as twice the area between the Lorenz curve and the line of perfect equality. LC values range from:

0, Perfect homogeneity

1, Maximum heterogeneity

The Lorenz coefficient, which evaluates inequality in flow distribution is particularly useful because it is scale-independent and provides an intuitive graphical representation of heterogeneity. In practice, carbonate reservoirs typically yield LC values between 0.3 and 0.6, reflecting the influence of the rock’s capacity to store fluids (porosity) variability, diagenetic overprints, and fracture systems. Permeability variability has a strong influence on Lorenz results, often producing curves that highlight flow-dominant zones in otherwise low-its ability to transmit fluids (permeability) reservoirs.

### **3. Dykstra-Parsons Coefficient (Vdp)**

The Dykstra–Parsons variability measure coefficient (Dykstra & Parsons, 1950) remains one of the most widely applied metrics for quantifying its ability to transmit fluids (permeability) variation. The calculation begins by ranking its ability to transmit fluids (permeability) values in descending order and determining the difference between the 50th percentile (X50) and 84th percentile (X84). The formula is:

$$Vdp = \frac{k_{50} - k_{84.1}}{k_{50}}$$

As heterogeneity increases, the slope of the best-fit line through the ranked its ability to transmit fluids (permeability) values steepens, leading to higher Vdp values.

Interpretation of Vdp values:

0, Homogeneous system

0.6–0.8, Typical range for heterogeneous oilfield cores

1, Maximum heterogeneity

One strength of the Dykstra–Parsons variability measure coefficient is its focus on its ability to transmit fluids (permeability), which is the property most directly linked to fluid flow in reservoirs. However, this focus also introduces limitations. Because the method emphasizes central data trends, it can downplay extreme values, potentially underestimating heterogeneity in reservoirs with bimodal or fractured distributions.

Despite these limitations,  $V_{dp}$  is widely used in waterflood design and simulation studies, where it provides a robust, though simplified, representation of reservoir variability.

#### **2.4.2 Comparative Evaluation of Heterogeneity Indices**

The three quantitative measures Coefficient of Variation (CV), Lorenz Coefficient (LC), and Dykstra-Parsons Coefficient ( $V_{dp}$ ) each provide different insights into reservoir heterogeneity. While they share the common goal of describing variability in the rock's capacity to store fluids (porosity) and its ability to transmit fluids (permeability) distributions, they differ significantly in sensitivity, data requirements, and interpretative value.

##### ***Sensitivity to Data Distribution***

CV is sensitive to the mean and standard deviation of the dataset. As a result, it works best for normally distributed data. In highly skewed distributions, which are common in its ability to transmit fluids (permeability) datasets, CV may underestimate variability because a few extreme values can disproportionately influence the standard deviation.

LC is less affected by skewed distributions because it relies on cumulative proportions rather than absolute variance. It highlights inequality in flow capacity, making it particularly useful in reservoirs where a small fraction of the rock volume accounts for most of the transmissibility.

Vdp, by focusing on the difference between percentiles, captures variability in the central part of the distribution while ignoring extreme values. This makes it robust for datasets with outliers but potentially misleading for reservoirs dominated by bimodal or fractured distributions, where extreme values control flow.

### **2.4.3 Application to Reservoir Types**

The choice of heterogeneity index often depends on reservoir type and depositional environment.

#### **1. Fluvial Reservoirs**

Characterized by high lateral heterogeneity due to channel belts, levees, and floodplain deposits.

CV is useful for capturing wide variations in its ability to transmit fluids (permeability) between sandstone bodies and mudstones.

LC provides insight into the degree of channel connectivity and the dominance of high-flow zones.

Vdp is valuable in identifying overall displacement effectiveness (sweep efficiency) during waterflooding, as channelized systems often create preferential flow paths.

#### **2. Carbonate Reservoirs**

Exhibit heterogeneity at multiple scales, including matrix, vugs, and fractures.

CV alone is often insufficient because it does not capture spatial clustering of high-its ability to transmit fluids (permeability) features.

LC highlights the dominance of fracture corridors or vug clusters, which may account for most production.

Vdp provides a practical measure of its ability to transmit fluids (permeability) variability but may miss the extreme effects of megapore systems.

### **3. Deltaic and Shallow Marine Reservoirs**

Stratification and lateral facies changes dominate.

CV helps quantify vertical variations between sand-rich and mud-rich intervals.

LC is effective in assessing the continuity of high-quality sand bars across the delta front.

Vdp supports evaluation of heterogeneity in distributary channel deposits, where variations in its ability to transmit fluids (permeability) influence reservoir connectivity.

### **4. Deepwater Turbidite Reservoirs**

Characterized by stacked channel–levee systems and mass-transport complexes.

CV captures broad variations but may be too simplistic for complex bedding structures.

LC excels in revealing the dominance of channel axis sands compared to overbank deposits.

Vdp provides insight into its ability to transmit fluids (permeability) variation within stacked channels but may underplay thin-bedded heterogeneity.

## **2.4.4 Strengths and Limitations of Quantitative Indices**

### **1. Coefficient of Variation**

#### **Strengths**

1. Easy to calculate.
2. Dimensionless and comparable across datasets.
3. Useful for quick screening of core or log data.

#### **Limitations**

1. Sensitive to sample size and distribution.
2. Lacks spatial resolution.
3. Does not directly relate to flow performance.

## **2. Lorenz Coefficient**

### **Strengths**

1. Provides both a numerical index and a graphical curve.
2. Effective at identifying inequality in flow contribution.
3. Scale-independent, making it suitable for comparing across different reservoirs.

### **Limitations**

1. Requires detailed flow capacity data.
2. Interpretation can be subjective, depending on how the Lorenz curve is drawn.
3. May oversimplify highly compartmentalized systems.

## **3. Dykstra-Parsons Coefficient**

### **Strengths**

1. Long-established and widely used.
2. Directly linked to its ability to transmit fluids (permeability), the most critical flow property.
3. Practical for waterflood design and reservoir simulation.

### **Limitations**

1. Overlooks extreme values and bimodal distributions.
2. Sensitive to data ranking and percentile estimation.
3. Less effective in reservoirs dominated by fractures or megapore systems.

### **2.4.5 Scale Effects and Flow Behavior**

The relationship between heterogeneity and fluid flow is strongly scale-dependent. This is particularly important when transitioning from small-scale core analysis to field-scale reservoir management.

## **Core Scale**

At the core scale, heterogeneity manifests as variations in grain size, pore throat diameter, and cementation. These small-scale variations influence initial the rock's capacity to store fluids (porosity) and its ability to transmit fluids (permeability) measurements but may not directly represent reservoir-scale flow.

## **Well Log Scale**

At the well log scale, vertical variations in lithology and facies become more apparent. Thin beds, shale laminations, and diagenetic features contribute to vertical heterogeneity, which directly influences log-derived the rock's capacity to store fluids (porosity) and its ability to transmit fluids (permeability) estimates.

## **Reservoir Scale**

At the reservoir scale, heterogeneity reflects the combined effects of depositional architecture, stratigraphic compartmentalization, and structural features such as faults. This scale has the greatest influence on recovery efficiency and production performance.

## **Flow Implications**

In reservoirs with low heterogeneity (low CV, LC, Vdp), injected fluids advance uniformly, leading to high overall displacement effectiveness (sweep efficiency). In highly heterogeneous reservoirs (high indices), flow is dominated by high-its ability to transmit fluids (permeability) streaks, causing early water or gas breakthrough and leaving bypassed oil.

In stratified reservoirs, vertical permeability contrasts markedly impact sweep efficiency by affecting crossflow during injection operations. High contrasts often lead to earlier water breakthrough, diminishing oil recovery effectiveness. Gravitational segregation further influences vertical fluid migration, impacting lateral sweep patterns and recovery in layered porous media. As heterogeneity increases, viscous fingering intensifies, causing uneven sweep and reducing the conformance coefficient, thereby impairing water flooding efficiency.

Variations in relative permeability and residual oil saturation also markedly affect oil production rates and water breakthrough timing, with relative permeability playing a dominant role in petroleum recovery processes. The heterogeneity of reservoir pore structure, including pore size distribution, connectivity, and porosity influences multiphase displacement patterns and stability zone boundaries. In layered systems, increasing heterogeneity and permeability contrast tend to lower ultimate recovery factors, underscoring the need for accurate heterogeneity characterization in reservoir development and monitoring.

#### **2.4.6 The Role of Static Heterogeneity Measures and Geochemical Methods in Reservoir Characterization**

Understanding heterogeneity within petroleum reservoirs is essential for optimizing sweep efficiency in enhanced oil recovery operations. Permeability variation, a key indicator of heterogeneity directly affects critical factors such as breakthrough time and maximum hydrocarbon production, both of which bear significant economic consequences.

##### **Static Heterogeneity Measures: Limitations and Importance**

In practice, simple static heterogeneity indicators like the Dykstra-Parsons coefficient ( $V_{dp}$ ) are often employed due to constraints such as limited datasets or the impracticality of detailed analyses. Despite its simplicity and widespread use,  $V_{dp}$  is prone to substantial statistical errors that can lead to inaccurate predictions of sweep efficiency performance. Jensen and Currie identified the primary factors influencing the reliability of  $V_{dp}$  estimates as the size of the dataset, the actual heterogeneity level, and the estimation method. Notably,  $V_{dp}$ 's finite scale of 0 to 1 limits its capacity to resolve highly heterogeneous reservoirs. Additionally, it cannot differentiate lithological variations, an important consideration in stratified or complex formations. Other static measures, such as the Lorenz coefficient, share similar drawbacks underestimating heterogeneity particularly when based on small sample sizes. Both  $V_{dp}$  and Lorenz can compress heterogeneity at higher levels, which reduces sensitivity in performance

predictions. Given that reservoir behavior can differ significantly even at similar Vdp or Lorenz values due to asymmetric permeability distributions, sole reliance on these indices risks overlooking essential heterogeneity aspects that influence production.

**Table 2.1**

<b>Heterogeneity measures</b>	<b>Summary</b>	<b>Advantages</b>	<b>Disadvantages</b>
Coefficient of variation (Cv)	Homogeneous=0 Heterogeneous=1	1. Simple statistical technique, no pre processing of data required 2. Easily applied to any data	1. No minimum value, different measurements scale may influence heterogeneity results.
Lorenz coefficient (Lc)	Homogeneous=0 Heterogeneous=1	1. Simple, Graphical plot for comparison, easily applied to any data 2. Direct comparison for different tools, formation and reservoir.	1. Possible user error in sorting and normalization. 2. Negative value may complicate processing but uncommon on well log data sets
Dykstra-parsons coefficient(Vdp)	Homogeneous=0 Heterogeneous=1	1. Simple statistical basis classification scheme established for interpretation. 2. Direct comparison for different tools, formation and reservoirs.	1. Complicated preprocessing required (probabilities), percentile values used on best fit line, rather than actual data.

#### **2.4.7 Integrating Geological and Engineering Perspectives**

While heterogeneity indices provide quantitative insights, they must be integrated with geological understanding to capture the full complexity of reservoirs.

##### **Depositional Controls**

Depositional environment determines the initial distribution of reservoir properties. Fluvial systems produce channelized architectures, deltas create mouth bars and distributary channels, and carbonates build shoal complexes. Each of these depositional settings produces characteristic heterogeneity patterns that can be quantified by indices but must be understood in their geological context.

##### **Diagenetic Modifications**

Post-depositional processes such as cementation, dissolution, and dolomitization further enhance heterogeneity. For instance, secondary the rock's capacity to store fluids (porosity) created by dissolution may increase CV and LC values dramatically, altering reservoir performance.

##### **Structural Influences**

Faulting and fracturing superimpose structural heterogeneity on depositional and diagenetic patterns. These features often dominate flow pathways, producing high LC values even in otherwise homogeneous reservoirs.

#### **2.4.8 Integrating Geochemical Insights with Permeability Data**

Beyond static physical measurements, geochemical analysis offers a powerful tool for elucidating compositional heterogeneities within reservoirs. For instance, Rockheim's study demonstrated that petroleum fluids extracted from lower-porosity, lower-permeability sand intervals exhibit distinct molecular compositions compared to those from higher-porosity zones, indicating variations in oil maturation and migration history. Such geochemical

fingerprints are particularly valuable in reservoirs characterized by high heterogeneity in vertical and lateral petrophysical properties. Incorporating geochemical data enriches the understanding of reservoir heterogeneity by revealing fluid distributions and mixing mechanisms that static measures alone may not capture. This holistic approach enables a more comprehensive mapping of heterogeneity, informing exploration strategies and enhancing production planning to improve sweep efficiency

## **2.5 Methods of reservoir image creation**

3- dimensional images of reservoir are obtained from geological models constructed with core, wireline log and geophysical data, Petro physical properties, obtained from core, wireline log, and production data and model is put into a numerical simulator for testing and predicting future performance. Rock- fabric facies are the basic elements for characterizing a reservoir. Rock fabrics are geologic descriptors that characterize pore size according to particle size and sorting, interparticle the rock's capacity to store fluids (porosity) and various type of vuggy the rock's capacity to store fluids (porosity). Each rock fabric has a specific the rock's capacity to store fluids (porosity) - its ability to transmit fluids (permeability) transform of the vertical racking of rock fabric facies, together with inter particle the rock's capacity to store fluids (porosity), provides the basis for estimating its ability to transmit fluids (permeability) in uncored wells. The wireline log problem is determining interparticle the rock's capacity to store fluids (porosity), as well as total the rock's capacity to store fluids (porosity) and rock fabric, for input into general the rock's capacity to store fluids (porosity), its ability to transmit fluids (permeability) transform.

### **2.5.1 Classification of image creation**

**Structure imitating methods:** This rely on one or more of the following to constrain the geometry of spatial pattern in sediments and hydraulic properties, correlated random fields,

probabilistic rules and deterministic constraints developed from facies relations. There are 2 broad categories of this method;

- Spatial statistical methods
- Sedimentation pattern methods

**I. Spatial statistical methods:** This is using random field generators attempts to represent the range of possible spatial patterns in the subsurface through generating multiple, equally likely images and geologic facies or hydraulic property fields. These images can be used as input to flow and transport models to assess the effects of uncertainty in hydraulic property fields on predictions of aquifer behavior. Spatial statistical methods reproduce the observed sedimentary geometry without addressing the mechanisms by which sedimentary deposit form. Therefore, such methods cannot provide physical insight into the nature of the controlling process and they therefore may lead to interpolated values that are geologically unreasonable

**II. Sedimentation pattern imitation:** This method predicts the geometry and lithology of sedimentary deposit using rules derived from conceptual depositional models. These methods predict the time, evolution and patterns in depositional environments, grain size and primary sedimentary structures in discrete geologic units. Although an image of sedimentation is built through time, fluid flow and sediment transport are not explicitly represented. Sedimentation patten imitating methods have not been conditioned on hard geologic or hydraulic property data, not has a methodology been proposed to accomplish this, this limitation have been calibrated to;

**a. Analytical sedimentation patterns:** This method produce cross sectional images of sedimentary geology on scales ranging from flow regime features to cross sections of sedimentary basins. These methods are based on simplified equations for sedimentation and

prediction of geometric patterns in sedimentary deposits. The actual flow of water or wind and transport of individual grains is not represented.

**b. Stratigraphy models:** They are popular in the petroleum industry because they quickly simulate basin-scale sedimentation patterns over geologic timescale. Stratigraphy models have been applied to understand heterogeneity and basin scale correlations in shallow marine settings to demonstrate the importance of basin scale wide erosional unconformities and flooding surfaces to decipher the record of relative sea level change affected by subsidence mechanisms, sediment supply, fluctuation, basin geometry and eustatic sea level change.

**Process imitating models:** These models construct images of heterogeneity through mathematical models of either subsurface fluid flow and transport or the geologic process governing sedimentary basin formation and filling. There are 2 categories of process imitating models;

**i. Aquifer model calibration methods:** Unlike all other methods of image creation, aquifer model calibration methods incorporate the physics of groundwater flow and transport and link the predicted maps of heterogeneity directly to fluid flow and transport simulators. These methods seek to imitate groundwater flow system behavior while estimating hydraulic property fields. They do not explicitly consider sedimentation processes that led to the formation of an aquifer.

**ii. Geologic process models:** these models build images of sedimentary geology through time from some initial conditions, given prescribed boundary conditions and fluxes of fluid and sediment. Geologic process imitating models based on representation the geologic evolution of an area provide a tool to examine the relation between its ability to transmit fluids (permeability) structure and the processes that form geologic media. These models can be used to predict geologic structure and heterogeneity through trends in sediment grain size

distributions, grain orientation and primary sedimentary structures. Geologic process models are restricted to generating images for a limited range of scales of heterogeneity depending on the purpose of the model. The greatest weakness of process model is their inability to condition to measured values. While process model can be calibrated to achieve a good match to field data through trial and adjustment of inputs, currently, there is no way to force model results to match data exactly

**Descriptive methods;** it produces images of subsurface architecture by combining site-specific and regional data with conceptual depositional models and geologic insights. For a given field site, descriptive methods produce one deterministic image of aquifer architecture showing heterogeneity at scales ranging from stratigraphic features to basin fill.

**Hydraulic property estimation:** images of geologically heterogenous must be linked to spatial variations in the rock's capacity to store fluids (porosity), effective the rock's capacity to store fluids (porosity) and hydraulic conductivity — the rate at which fluids move through porous media. Both direct and indirect hydraulic property estimation methods provide the link.

I. Direct measurement of hydraulic conductivity — the rate at which fluids move through porous media can be made with a borehole flow rate, laboratory permeameter tests, slug tests, single and multiple well pumping tests, tracer tests and air permeability from outcrops.

II. Indirect estimates of hydraulic conductivity — the rate at which fluids move through porous media, the rock's capacity to store fluids (porosity) and effective the rock's capacity to store fluids (porosity) come from tables or nomographs of grain size and sorting versus hydraulic properties.

The choice of a representative hydraulic conductivity — the rate at which fluids move through porous media for a given lithology from tabulated values or nomographs subject to uncertainty, because the range in reported hydraulic conductivity — the rate at which fluids move through

porous media value for a given grain size class spans several orders of magnitude, This is because its ability to transmit fluids (permeability) is related to the pore structure and not to simply to grain size.

### **2.5.2 Main influencing factors of reservoir heterogeneity**

**Structural factors:** effects of structural factors on reservoir heterogeneity depends mainly on tectonism, owing to which faults and fractures are transformed and superimposed on the primary reservoir framework thus resulting in a fluid block or channel formation. Fractures usually change the seepage direction and capacity of a reservoir, which leads to considerable differences in its ability to transmit fluids (permeability) in longitudinal, traverse and vertical 3D spaces.

**Sedimentation factors:** sedimentation factors, which are mainly determined by sedimentation or processing, impact the architecture or configuration (spatial form & internal composition of original skeleton and sand body) of a reservoir. Different distribution of sand bodies in diverse sedimentary facies cause the internal physical properties of sedimentary sand bodies to be different which results in different levels of reservoir heterogeneity

**Diagenetic factors:** diagenetic factors, which are determined by the characteristics of rock minerals and underground fluids in a reservoir, can lead to the transformation of clay minerals, cementation, corrosion and leaching, as well as improvement or degradation of basic reservoir properties. Degree of reservoir heterogeneity is increased owing to the extremely uneven formation and spatial distribution of secondary pores.

### **2.6 The major division of reservoir heterogeneity**

- Macroscopic heterogeneity
- Microscopic heterogeneity

**Macroscopic heterogeneity:** This type of heterogeneity is comprised of ;

**1. Intrastratal heterogeneity:** This means reservoir characteristics change in the vertical direction within a single sand layer and it refers to the difference level of intrastratal permeability in the vertical direction, location of the highest permeability section, intrastratal granularity rhythm, permeability rhythm, heterogeneity degree of permeability. Intrastratal heterogeneity is a key geological factor that directly controls and affects the swept volume of injectant in a single sand layer.

**2. Interlayer heterogeneity:** This refers to the difference between reservoir or sand bodies. It involves the general study of an oil reservoir or oil-bearing series between sand-mudstones, which belongs to the description of a reservoir on a set scale. It comprises either the regularity or cyclicity of sand bodies occurring alternatively on section in various sedimentary environments. Interlayer heterogeneity is the technical basis for the selection of a series of developments and slice mining

**3. Plane heterogeneity:** This refers to the geometry, scale and continuity of a reservoir sand body, the rock's capacity to store fluids (porosity) within sand bodies and heterogeneity arising from the level change in its ability to transmit fluids (permeability). It is directly related to injectant overall displacement effectiveness (sweep efficiency).

**Microscopic Heterogeneity:** This refers to the geological factors that affect fluid flow in microscopic throats. These geological factors include pore and throat size, connectivity degree, configuration relationship, sorting degree and heterogeneity of particle. The heterogeneity of the scale directly affects the microscopic displacement efficiency of the injectant. This type of heterogeneity comprises of;

**1. Pore heterogeneity:** Bigger space defined by rock particles are known as pore generally speaking, while narrow parts between two connected particles are called throat. A pore is a

basic reservoir space for storing fluid in a rock, while a throat is the main factor controlling the seepage characteristics of a fluid in a rock.

**2. Particle heterogeneity:** This refers to the particle size, shape, sorting, arrangement and contact relationship. It affects not only pore heterogeneity but also results in anisotropy of its ability to transmit fluids (permeability) while affecting dynamic changes in a reservoir during displacement development.

**3. Interstitial material heterogeneity:** Interstitial material includes clay matrix and cements. Its type, content and occurrence vary greatly in various reservoirs which leads to disparities in the rock's capacity to store fluids (porosity), its ability to transmit fluids (permeability) and heterogeneity across reservoirs. Sweep efficiency is a fundamental metric in reservoir engineering, quantifying how effectively an injected fluid displaces oil within a reservoir. It is defined as the fraction of the reservoir volume that is contacted by the injected fluid during a displacement process. Essentially, it measures how well the displacing fluid moves through the reservoir to push oil towards the production wells.

## **2.7 SWEEP EFFICIENCY**

Sweep efficiency is typically broken down into different components to better understand the volumetric coverage:

**1. Areal Sweep Efficiency ( $E_a$ ):** This measures the fraction of the reservoir area contacted by the displacing fluid in a horizontal plane. It is primarily influenced by the arrangement of injection and production wells (well patterns) and the relative mobility of the fluids involved.

**2. Vertical Sweep Efficiency ( $E_v$ ):** This measures the fraction of the reservoir thickness contacted by the displacing fluid. It is predominantly influenced by the vertical distribution of its ability to transmit fluids (permeability), the presence of layering, and gravity effects.

**3. Macroscopic Sweep Efficiency:** This is the product of areal and vertical sweep efficiencies ( $E_a \times E_v$ ), representing the overall volumetric sweep at the reservoir scale. It indicates the total volume of the reservoir that has been contacted by the injected fluid.

**4. Microscopic Displacement Efficiency ( $E_d$ ):** While related, microscopic displacement efficiency is distinct from overall displacement effectiveness (sweep efficiency). It refers to the efficiency of oil displacement at the pore level, representing the fraction of oil removed from the rock within the contacted pore

*Sweep efficiency =  $E_a \times E_v \times E_d$  = macroscopic displacement efficiency  $\times$  microscopic displacement efficiency*

Sweep efficiency on displacement process are influence by these factors

1. Reservoir heterogeneity
2. Fluid property
3. Injection-production scheme and production system

### **2.7.1 Impact of reservoir heterogeneity on sweep efficiency.**

#### **1. Influence of macroscopic heterogeneity on displacement development (case study waterflooding);**

*1.* interlayer heterogeneity is an inherent cause of interlayer interference and monolayer breakthrough in water flooding development. In the presence of a greater number of layers, greater interlayers contradictions and higher single well production, water content is usually high. The water injection well of good oil absorbs higher amount of water with a fast front advance which lead to high output from a high its ability to transmit fluids (permeability) reservoir. In contrast, a low its ability to transmit fluids (permeability) reservoir has a higher starting pressure, low water absorption and slow front advance, even without flow owing to interlayer contradictions between high low its ability to transmit fluids

(permeability)reservoirs. Significantly interlayer interference is shown in both the producing well and water injection well. As a result monolayer breakthrough of high its ability to transmit fluids (permeability) reservoir and outstanding remaining oil by low its ability to transmit fluids (permeability) reservoir occurs. The its ability to transmit fluids (permeability) ratio is proportional to the inactive sand body thickness. That is the higher the ratio, the more inactive the oil reservoir will be.

2. "Plane fingering" arising from plane heterogeneity can decrease the flooded area coefficient by causing a discontinuous distribution across individual reservoirs on the plane. Moreover "regions of bypassed oil" that are omitted during drilling are formed at the corners of an oil reservoir during water flooding development. In addition, the injected water tongues quickly because of its ability to transmit fluids (permeability) difference along the high its ability to transmit fluids (permeability) zone on the plane. Moreover, its ability to transmit fluids (permeability) directivity directly affects the advance direction and speed of various oil displacement methods and often lead to better oil displacement efficiency in a higher its ability to transmit fluids (permeability) zones constitute the major remaining oil distribution area after a period of displacement.

3. "Region of bypassed oil" or "water channeling" resulting from intrastratal heterogeneity; interstratal heterogeneity reduces the water flooding thickness coefficient. Heterogeneity among all monolayers is presented mainly as the its ability to transmit fluids (permeability) difference, where the difference may be several, dozens of or even hundreds of times. The injected water firstly tongues quickly a long reservoir with good connectedness and high its ability to transmit fluids (permeability), hence it quickly enters into the producing well to improve the water cut in the oil well or even brings about the flooding production suspension. However, owing to the low degree of production of low its ability to transmit fluids (permeability) reservoirs, most crude petroleum remaining underground forms "bypassed oil"

## **11. Relationship between microscopic heterogeneity and hydrocarbon recovery ratio**

1. Microscopic heterogeneity directly affects the microscopic displacement mode and efficiency of an injectant and the microscopic i.e displacement force. Capillary force serves as water driving resistance in oil wet (oleophilic) reservoirs while it serves as a driving force in sucking water into small pores automatically in water wet (hydrophilic) reservoirs, which has also known as the spontaneous imbibition phenomenon. In a single pore, the course of displacing crude petroleum by using an injectant is the process in which the driving force overcomes resistance. However, the reservoir pore systems are very complicated and heterogeneity among various pores in the displacement process can cause interference between holes. Moreover, wettability difference and clay minerals in pores complicate the microscopic development process

2. Influence of pore heterogeneity on oil displacement: As is well known, the formation of residual oil has a lot to do with reservoir pore structures. In other words, oil displacement efficiency during water flooding development is closely related to the reservoir pore structure (size and distribution of pore and throat). For petroleum reservoirs with residual oil the efficiency of displacing residual oil in the tertiary oil recovery is also related to the pore structure. This is because the re-movement of residual oil hinges on the capillary and viscous forces in the pores. In general, the stronger the pore heterogeneity, the lower the oil displacement efficiency is.

### **2.7.2 Opinions on other displacement process on relationship of sweep efficiency to reservoir heterogeneity**

1. Shu-Ren Liu et Al propose a method for uniformly displacing oil in a reservoir that is unequal in its ability to transmit fluids (permeability) by separately inject the least movable slug into the most permeable layers respectively, a relatively more movable slug in the less permeable

layer. It's theoretically possible to achieve the effect of piston-like flow for miscible displacement process but practically not quite possible.

2. Panthangkal & others study the effects of polymer concentration, the amount and rate of polymer injection, depending on the degree of heterogeneity of the formation. The higher the heterogeneity, the lower the oil recovery coefficient. A high concentration of the polymer and its low injection volume leads to a low oil recovery ratio compared to the same polymer volume at low concentration.

3. Si Le Van et Al consider a change in oil recovery coefficient for surfactant-polymer flooding, depending on the configuration of the wells. In his work, the author considered several options

- a) vertical injection & production wells
- b) horizontal injection & production wells
- c) vertical injection & horizontal production wells
- d) horizontal injection & vertical production wells.

According to the experiment conducted on the star program the most optimistic option is to use horizontal injection and production wells parallel to each other. The production well should be in the lower layer with the lowest its ability to transmit fluids (permeability).

## CHAPTER THREE

### METHODOLOGY

Quantifying of the heterogeneity should be more of a rock property calculation, accounting of the fluid behavior should be known, and how the fluid relates with the rock like the fluid connectivity within the reservoir. It can be done with integration of strontium residual salt analysis with the rock ability to flow fluid(permeability).

#### 3.1 STRONTIUM RESIDUAL SALT ANALYSIS

Strontium Residual Salt Analysis (Sr-RSA) is a tracer isotopic method that examines the strontium isotope ratios ( $^{87}\text{Sr}/^{86}\text{Sr}$ ) preserved in residual salts left behind in core samples which identify the movement pathway of formation water in the reservoir system.

When oil is produced or moved through rock pores, parts of the formation water containing dissolved salts (like  $\text{Na}^+$ ,  $\text{Cl}^-$  e.t.c) remain in the rock surface or within the oil as residual salts.

By analyzing the  $^{87}\text{Sr}/^{86}\text{Sr}$  isotopic ratio of these salts, geologists along with petrophysicist can determine whether the reservoir system is hydraulically connected or if they come from different depositional or diagenetic environments.

The  $^{87}\text{Sr}/^{86}\text{Sr}$  isotopic ratio in salts or formation water is a chemical “fingerprint” of the water’s presence in the rock. If different sections have different ratios, they must have had different fluid histories and poor connectivity. Strontium does not react with the formation water during physical processes like evaporation or dissolution, meaning the measured  $^{87}\text{Sr}/^{86}\text{Sr}$  isotopic ratio is a very accurate recorder of the water’s history. Sr isotopes vary a little when fluids interact with different rocks (e.g., clays).

If a reservoir is well-connected, the Sr isotopic ratio is uniform with all section of the reservoir.

If there are compartments/barriers, different sections of the reservoir show different Sr isotopic ratios.

This shows how it works in a reservoir system:

1. Formation water contains dissolved ions like  $\text{CO}_3^{2-}$ ,  $\text{Cl}^-$ , etc.
2. When conditions change (like evaporation, pressure drop, or mixing of waters), salts precipitate from the water examples:
  - Anhydrite ( $\text{CaSO}_4$ )
  - Gypsum ( $\text{CaSO}_4 \cdot 2\text{H}_2\text{O}$ )
3. Using formation salt Anhydrite as an example Strontium ion ( $\text{Sr}^{2+}$ ) substitute for calcium in these minerals (because  $\text{Sr}^{2+}$  and  $\text{Ca}^{2+}$  have similar ionic sizes).
4. The strontium isotopic ratio ( $^{87}\text{Sr}/^{86}\text{Sr}$ ) of the water gets “chemical bond” to these salts/minerals during precipitation in the reservoir.
5. Later, when geologists analyze residual salts from cores, they measure this isotopic ratio which reflects the original water composition and helps detect barriers with poor fluid connectivity.

**When is Sr isotope analysis most effective? During coring or drilling in/around the reservoir zone:** in this time, the core sample are still fresh and less altered you wait until much later (e.g, after long production), the fluid composition can be altered by injection water contamination.

**When testing well-to-well fluid connectivity:** If multiple wells are drilled to the same reservoir, comparing isotopic ratios can quickly show whether they share a common fluid system or there is a barrier between wells.

### **Why its important to consider the drilling time**

Fresh cuttings and core material equals less least contamination of the core

Early measurement of the core samples gives you the “true” fluid connectivity because of less contamination before injection water which disturb the chemistry.

### **3.2 PERMEABILITY EVALUATION**

As for permeability, it is a rock property that’s concerned with fluid flow, which can be measured in various methods and the accuracy is dependent on the condition necessary for the measurement to taken Permeability is the ability of a rock formation to flow fluids, expressed in darcies (D) or millidarcies (md), where  $1 D = 1000 \text{ md}$ .. A darcy is defined as the permeability that allows a fluid of 1 centipoise viscosity to flow at  $1 \text{ cm}^3/\text{s}$  through a rock with a  $1 \text{ cm}^2$  cross-section under a  $1 \text{ atm/cm}$  pressure gradient.

#### **3.2.1 Laboratory Measurement Procedure**

Dry gas (commonly air) is used in laboratory permeability measurements because it:

- Minimizes fluid–rock reactions,
- Is easy to handle,
- Ensures clean and dry flow conditions.

#### **ii.Pulse decay method**

The pulse decay is the main method employed to determine permeability for tight rocks, and has been widely used in oil industry.

#### **iii. The steady state method**

This requires a constant flow rate and pressure difference to be maintained until equilibrium is reached, then uses Darcy's Law to calculate permeability

### **Permeability depends heavily on rock texture:**

- Fine-grained sandstones have small pore spaces which directly influences fluid flow, this implies that it has low permeability.
- Coarse sandstones, fractured or oolitic limestones has high permeability, due to the fact that it has big pore space.

Some prolific reservoirs combine low matrix permeability with high fracture permeability (e.g. North Sea), this condition is rare.

### **3.2.2 Permeameter Operation**

In a steady-state permeameter, air is passed through a dry, snug-fitting core plug while pressure difference and flow rate are recorded. A calibrated orifice measures the flow rate at atmospheric conditions. To avoid side bypass, the core must seal tightly within the holder.

Non-steady-state permeameters, developed for low-permeability gas formations, allow faster measurements (within minutes) by analyzing transient flow data mathematically without waiting for steady-state equilibrium.

### **3.2.3 Sidewall Core Measurements**

Sidewall cores (rotary tools) can also be analyzed:

- i. When large enough, samples are cut and tested like plugs.
- ii. When small, permeability is estimated from correlations between porosity, grain size  
e.t.c

However, sidewall permeability deviates often.

**Soft rocks:** measured permeability is lower.

**Hard rocks:** measured permeability may be higher (due to its hard surface, measuring permeability is good).

### **3.2.4 Factors Affecting Measured Permeability Values**

#### **(a) Klinkenberg Effect (gas slippage)**

This effect shows that gas permeability varies with mean pressure:

At low mean pressure, gas molecules slip through pores easily, causing higher measured permeability and at high pressure, friction drag increases, and gas acts more like a liquid, lowering permeability.

Klinkenberg corrections are used mainly for plug sample (due to heterogeneity).

Non-steady-state permeameters can directly compute both  $k_L$  and the slippage constant (b), allowing prediction of permeability at any desired mean pressure.

Due to the fact that reservoir has high reservoir pressure, Klinkenberg-corrected permeability is better illustration of true reservoir permeability.

#### **(b) Relative Permeability and impermeable particle in permeable layer**

When multiple fluid phases exist (oil, gas, water), each has an effective permeability lower than the absolute permeability.

In low-permeability rocks, interstitial water drastically reduces effective permeability to hydrocarbons and in high-permeability rocks, the reduction is minor.

Clay section and interaction with sandstone reduce permeability by:

- i. pore throat blockage
- ii. Clay swelling

Both effects cause laboratory permeability to exceed true reservoir permeability.

#### **(c) Overburden Pressure effect to measured permeability**

Routine laboratory tests often neglect the fact that overburden pressure, but usual under

reservoir conditions, rock compaction reduces permeability of the layer of the reservoir measured.

Reductions from 7% to 100% have been observed at pressures up to 5000 psi.

Unconsolidated materials shows a great reduction which in return affects the permeability of that layer because they deform more under stress.

Permeability reduction is generally greater than porosity reduction.

### **3.3 Procedure for Strontium Residual Salt Analysis (Eichrom Technologies, Inc. 2006)**

#### **3.3.1 Materials, Consumables, Labware and Equipment:**

- A cleanroom environment classified as Class 1000 or better is recommended, especially for the final column separation steps. An ultra-trace laboratory setup is ideal.
- Use acid-washed low-density polyethylene (LDPE) bottles and centrifuge tubes (15 and 50 mL). Teflon beakers with volumes ranging from 30 to 250 mL should be used for sample evaporation and dissolution steps.
- An ultrasonic bath is needed for leaching salts from core samples. Analytical balances with a precision of  $\pm 0.1$  mg, centrifuges capable of 4000–6000 $\times$ g, and vacuum filtration systems with 0.45  $\mu$ m and 0.2  $\mu$ m PTFE or cellulose acetate filters are necessary.
- Evaporation requires a hotplate, oven, or block heater. Other equipment includes a pH meter, micropipettes (10  $\mu$ L to 10 mL) with acid-resistant tips, column chromatography manifolds with flow control, syringes, and disposable or glass chromatography columns loaded with strontium-specific resin.

### **Instrumentation:**

For high-precision isotopic measurements, multi-collector ICP-MS (MC-ICP-MS) or Thermal Ionization Mass Spectrometry (TIMS) are preferred. Quadrupole or sector field ICP-MS with collision/reaction cells may be acceptable if interference is managed.

### **Reagents and Standards:**

Use ultra-pure Milli-Q water, high purity nitric acid (HNO<sub>3</sub>), hydrochloric acid (HCl), hydrogen peroxide (H<sub>2</sub>O<sub>2</sub> - 30%), and perchloric acid (HClO<sub>4</sub>) for digestion under a fume hood. Strontium standard solutions such as NIST SRM 987 along with rubidium (Rb) standards, lab procedural blanks (acid blanks), and instrument calibration solutions are required.

### **Samples and Sample Handling:**

Core plugs, whole core sections, or leachates are used. Use clean sample bags, secure core boxes, and appropriate personal protective equipment including gloves and masks. Chain-of-custody and sample labeling are essential.

### **3.3.2 Safety and Cleanliness**

Use fume hoods when handling concentrated acids and oxidizing agents, and wear acid-resistant personal protective equipment. Maintain strict separation between preliminary sample extraction areas and clean zones used for column chemistry to prevent contamination. All labware must be acid-cleaned by soaking in 10% HNO<sub>3</sub> overnight, rinsing with ultrapure water, and storing covered.

### **Sr-RSA Workflow**

#### **A. Sample Extraction (Residual Salt from Cores)**

- Log and document core ID, depth, orientation, and storage history, as salt composition can be altered during storage.

- Remove 1–2 cm of core surface using clean tools in a controlled environment to avoid contamination.
- Leach residual salts by placing known amounts of core material in Milli-Q water, aided by ultrasonic agitation or shaking, collecting the leachate multiple times if needed. Filter the collected liquids through sequential 0.45  $\mu\text{m}$  and 0.2  $\mu\text{m}$  filters into acid-washed vials, measure volume and pH, and refrigerate until further processing.

### **B. Pre-concentration and Matrix Reduction**

- If necessary, evaporate large volume leachates to a smaller volume ( $\sim$ 1–5 mL) while avoiding complete dryness unless redissolving later in acidic media.
- Adjust acidity to approximately 0.5–1.0 M  $\text{HNO}_3$  to maintain Sr solubility for column processing.
- Measure Sr and Rb concentrations through screening (ICP-MS or AAS) to assess purification needs considering Rb interference.

### **C. Chemical Separation by Column Chromatography**

- Prepare the chromatography resin per manufacturer instructions, pre-washing and conditioning it with acid matching the sample matrix.
- Load samples slowly at controlled flow rates, collecting the effluent for quality assurance.
- Rinse the column with acid washes to remove matrix ions such as Ca, Na, K, and Mg.
- Elute Sr fractions using appropriate acid solutions, collecting purified Sr in acid-cleaned containers.
- Evaporate eluted fractions to near dryness, then re-dissolve in dilute nitric acid to a concentration suitable for instrumentation.

## **D. Instrumental Analysis and Quality Control**

- Employ MC-ICP-MS or TIMS for precise isotopic ratio measurements, with corrections for mass bias and isobaric interferences (particularly from Rb).
- Use standard bracketing, replicate measurements, and blanks to ensure data quality.
- Check for Rb interference and perform additional clean-up if necessary.
- Maintain strict lab cleanliness protocols and procedural blanks to avoid contamination.

## **3.4 PROCEDURE FOR CALCULATING FOR PERMEABILITY**

### **3.4.1 Materials**

- core sample
- measuring device "measuring tape"
- sealing equipment "tape"
- Drying vacuum
- plates
- shrinkage tubing
- heatgun
- double hook clamp
- circumferential lvdts
- vertical lvdts
- control panels
- testing system

### 3.4.2 Procedure

1. Prepare the core with an appropriate diameter and length
2. Put the prepared sample into a vacuum to dry for 12 hours and at a prescribed temperature of 120<sup>°</sup>c
3. Measure the dimensions of the dry sample
4. Move into the sample installation
5. The core is sandwiched between top and bottom plates
6. Make sure you use tape to stabilize the sample with the plate together
7. Cut the shrinkage tubing and the sample into the heat shrink sleeve
8. Use the heat gun to properly shrink the shrinkage tubing to the sample and cut off every excess piece
9. For sealing purposes, we install double hook clamp at each end outside the shrink sleeve
10. Then we install circumferential lvdts on the circumferential chain and 2 vertical lvdt on the support frame  
  
(These lvdts can precisely capture the strains in both vertical and circumferential directions and they are wired through the channel pins on the load base of the GCTS rapid triaxial rock testing system).
11. Then we hook up the upstream and downstream gas lines through the ports left on the upper and lower plates, the design fluid injection system, includes both upstream and downstream reservoir along with pressure transducers and pumps  
  
(Both steady state and pulse decay methods can be used for permeability test using this system, after the sample installation, we put down the tri - axle load cell by controlling the air pump the confining oil is pumped in.
12. Through computer control panel we set up the in-stu confining and axle stresses
13. The upstream and downstream pressures can be controlled by the external pump.

### **For steady state permeability calculation**

I. The need to keep upstream pressure constant and downstream volume fixed by calculating the differential pressure and flowrate in real time, permeability can be acquired through Darcy's law

### **For pulse decay method**

I. The need to maintain the constant upstream and downstream volumes and continuously monitor the pressure change in respect to time

II. The permeability can be calculated by fitting the linear slope of natural logarithm of differential pressure versus time

### **3.4.3 Table and Graph**

- Generate a table for the values of depth and sr values
- Plot a Cartesian graph of depth vs sr value
- Plot a semi log graph of depth and permeability

## CHAPTER FOUR

### RESULT AND DISCUSSION

The use of Sr-RSA (strontium residual salt analysis) in conjunction with the permeability variation provides a deeper understanding of the reservoir system. The more sections of the reservoir analyzed, the better we understand the interconnectivity of layers and pores system. Geology of the depositional process will reveal to us the degree of heterogeneity in the reservoir formation, which in the long-run will help understand how fluid interact in the formation to each other and to the rock itself. With this information, the idea of a mathematical calculation of the reservoir heterogeneity without the idea of the depositional history provides a partial view of the heterogeneity of the reservoir, like the idea of calculating heterogeneity with dykstra-parson permeability variation, we are making assumptions of the reservoir as fluid flow are based solely on the permeability (rock ability to flow fluid) of the rock( which is high permeability= high flow, low permeability=low flow that is too straightforward for a complex system as the reservoir system), which in real cases is not completely true. Fluid flow shouldn't be based solely on a rock property but be based on fluid interaction with fluid in respect to the rock. The study of Sr-RSA will complement the permeability analysis by introducing a geochemical perspective, assessing the connectivity and fluid history of the formation rather than relying solely on physical flow properties (permeability). When combined with permeability data, Sr-RSA provides a more complete evaluation of reservoir heterogeneity. Due to the limitation of this study of Sr-RSA, which is the requirement of a freshly drilled core which connate water (formation water still intact), Data's of sr-RSA are gotten from previous sr-RSA study of reservoir from Elgin field and south pars field located in North Sea region, can serve as a comparative reference.

## ELGIN AND ELGIN WEST FIELD

The Elgin field is located in the Central Graben of the North Sea, 160 km (99 miles) east of Aberdeen (United Kingdom). The Elgin West reservoirs are located 2–3 km (1.2–1.8 miles) to the southwest and are separated from Elgin by a northwest-southeast (sealed fault). The possible contamination of core fluids by the drilling mud can be misleading if no precaution is taken. This is the main technical limitation of the Sr-RSA method. Both wells have been drilled using an oil-based mud, which strongly reduces the risk of pore-water contamination. The isotopic ratios of strontium in the residual salts from Elgin range from 0.712502 to 0.714051 ( $\pm 0.000024$ ). Those from Elgin West range from 0.711779 to 0.713203 ( $\pm 0.000025$ ). In Elgin, the  $^{87}\text{Sr}/^{86}\text{Sr}$  ratio continuously increases with depth and also in the Elgin West reservoirs, the isotopic ratios roughly increase with depth but there is a slight decline of isotopic ratio from 0.713203 to 0.712899.

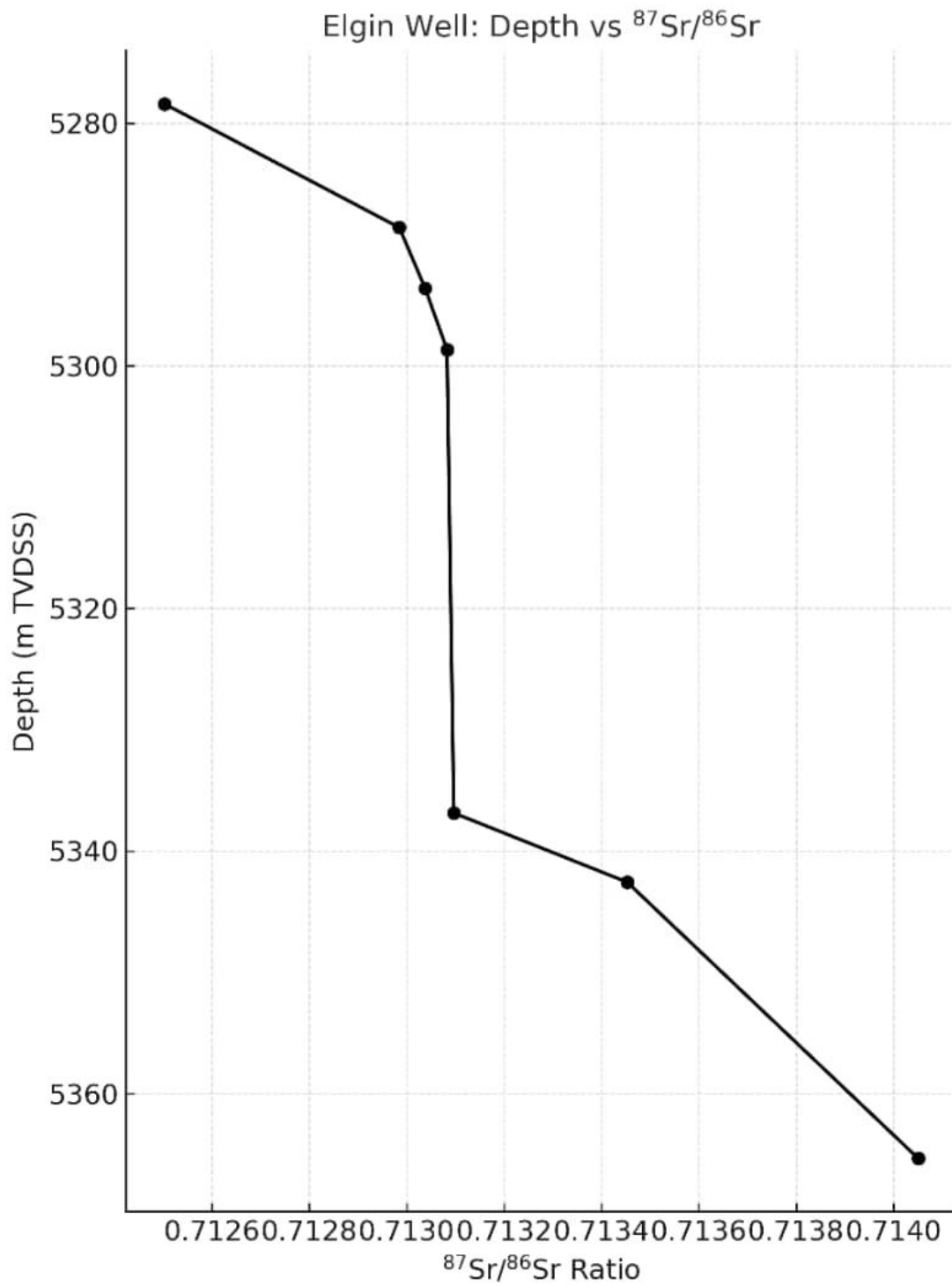
**Table 4.1 Depth vs  $^{87}\text{Sr}/^{86}\text{Sr}$  Data Tables**

### Elgin Well

Depth (m TVDSS)	$^{87}\text{Sr}/^{86}\text{Sr}$ Ratio
5278.39	0.712502
5288.60	0.712985
5293.60	0.713038
5298.65	0.713083
5336.87	0.713097
5342.57	0.713453
5365.35	0.714051

## Elgin West Well

Depth (m TVDSS)	$^{87}\text{Sr}/^{86}\text{Sr}$ Ratio
5572.31	0.711779
5574.37	0.711813
5586.45	0.712498
5595.30	0.712636
5599.33	0.712755
5629.30	0.712768
5631.63	0.712669
5635.30	0.712778
5672.65	0.712809
5676.87	0.712915
5682.42	0.713058
5683.64	0.713003
5704.95	0.713203
5747.95	0.712995
5755.96	0.713004
5763.21	0.712899



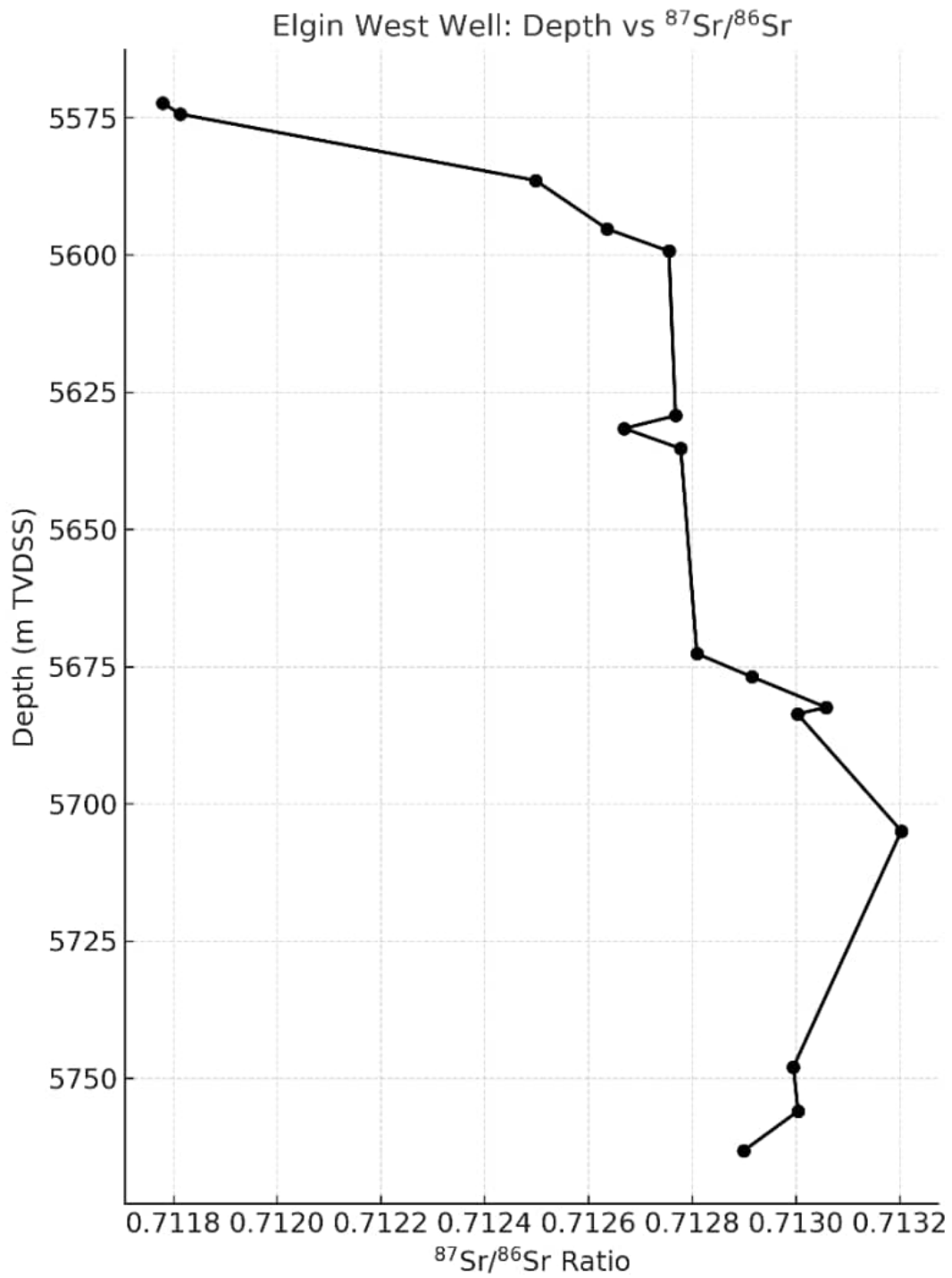
**Fig 4.1**

The graph illustrates the variation in fluid connectivity between reservoir layers within the Elgin field, at depths ranging from 5250 m to 5400 m. Two main zones can be identified: a slightly homogeneous interval and a highly heterogeneous interval.

The slightly homogeneous section (5288.60 m–5336.87 m) exhibits good fluid connectivity, and when combined with the relatively high permeability values in this zone, it supports efficient fluid flow. Consequently, sweep efficiency in this section is high, as fluids can move more uniformly through the interconnected pore network and the more permeable layers.

In contrast, the highly heterogeneous section (5342.57m–5365.35 m) shows poor interlayer connectivity. This reduced communication between layers, together with variable permeability, leads to restricted fluid movement and poor sweep efficiency. Even if a single layer in this interval possesses high permeability, flow will be concentrated in that layer, potentially causing viscous fingering and early breakthrough due to uneven displacement.

Overall, the degree of heterogeneity strongly influences the reservoir's displacement efficiency, with more homogeneous sections promoting better fluid distribution and recovery.



**Fig 4.2**

From the table and the plotted graph, it can be observed that the strontium isotopic ratio increases with depth in the Elgin West field. This trend indicates increasing heterogeneity and reduced fluid connectivity in deeper sections of the reservoir.

The graph further shows that only a small portion of the formation exhibits slightly homogeneous fluid connectivity, while the majority of the interval is highly heterogeneous. When this poor connectivity is coupled with variable permeability, it suggests that the sweep efficiency of the Elgin West field is generally low.

In comparison, the Elgin field shows relatively better fluid connectivity and is slightly more homogeneous, which allows for improved sweep efficiency and more uniform fluid displacement. Therefore, in the Elgin West field, the poor interlayer communication and heterogeneity imply that enhanced oil recovery (EOR) methods such as polymer flooding or other injection techniques are required to improve fluid mobility and minimize viscous fingering during displacement

The pattern of Sr-RSA variation with depth in Elgin and Elgin West does not overlap, indicating that reservoirs are not in communication.

## SOUTH PARS FIELD

**Table 4.2. Depth vs  $^{87}\text{Sr}/^{86}\text{Sr}$  Table (Sr-RSA Data)**

Depth (m)	$^{87}\text{Sr}/^{86}\text{Sr}$ Ratio
1802.00	0.707430
1806.00	0.707355
1810.00	0.707507
1814.00	0.707365
1818.00	0.707418
1822.00	0.707397
1826.00	0.707217
1830.00	0.707317
1831.00	0.707333
1832.00	0.707624
1836.00	0.707334
1840.00	0.707347
1844.00	0.707287
1848.00	0.707357
1852.00	0.707183
1856.00	0.707430
1858.00	0.707348
1860.00	0.707708
1862.00	0.707598
1866.00	0.707679
1869.70	0.707393
1872.00	0.707457
1876.00	0.707466
1880.00	0.707496
1884.00	0.707256

1888.00	0.707424
1892.00	0.707413
1900.00	0.707232
1920.00	0.707369
1927.00	0.707016
1981.00	0.707074
1985.00	0.706994
1989.00	0.707083
1993.00	0.707017
1997.00	0.707010
2001.00	0.707010
2003.50	0.707016
2005.00	0.707050
2009.00	0.707021
2013.00	0.707011
2017.00	0.707003
2021.00	0.706979
2025.00	0.707122
2029.00	0.707548
2030.00	0.707711

The South Pars–North Dome super-giant gas field, was formed due to the positive nature of the Qatar Arch. In the South Pars field, gas accumulation is mostly limited to the Permian–Triassic stratigraphic units. The forty-five samples come from the K1 to K4 hydrocarbon-bearing units of the Permo–Triassic aged formations, at depths ranging from 1802 to 2030.6 m. Mean uncertainty in  $^{87}\text{Sr}/^{86}\text{Sr}$  ratios measurements is about  $\pm 0.000018$  ( $2\sigma$ ). They are about 1 cm<sup>3</sup> core plugs cut in the most central part of the core in order to minimize the risk of contamination due to the drilling fluid. Additionally, in the case of the present material, limestone and dolomitic limestone, being very dense and compact, the risk is low for a contamination with drill-mud. To distinguish any possible effect of drilling mud on the results one sample of it was also analyzed. variations in  $^{87}\text{Sr}/^{86}\text{Sr}$  ratios could reveal presence and/or absence of barriers to fluid mixing in the reservoir, and hence measure the degree of reservoir connectivity. The  $^{87}\text{Sr}/^{86}\text{Sr}$  ratio is controlled by the diagenetic reactions and mixing processes that have operated in the reservoir since deposition.

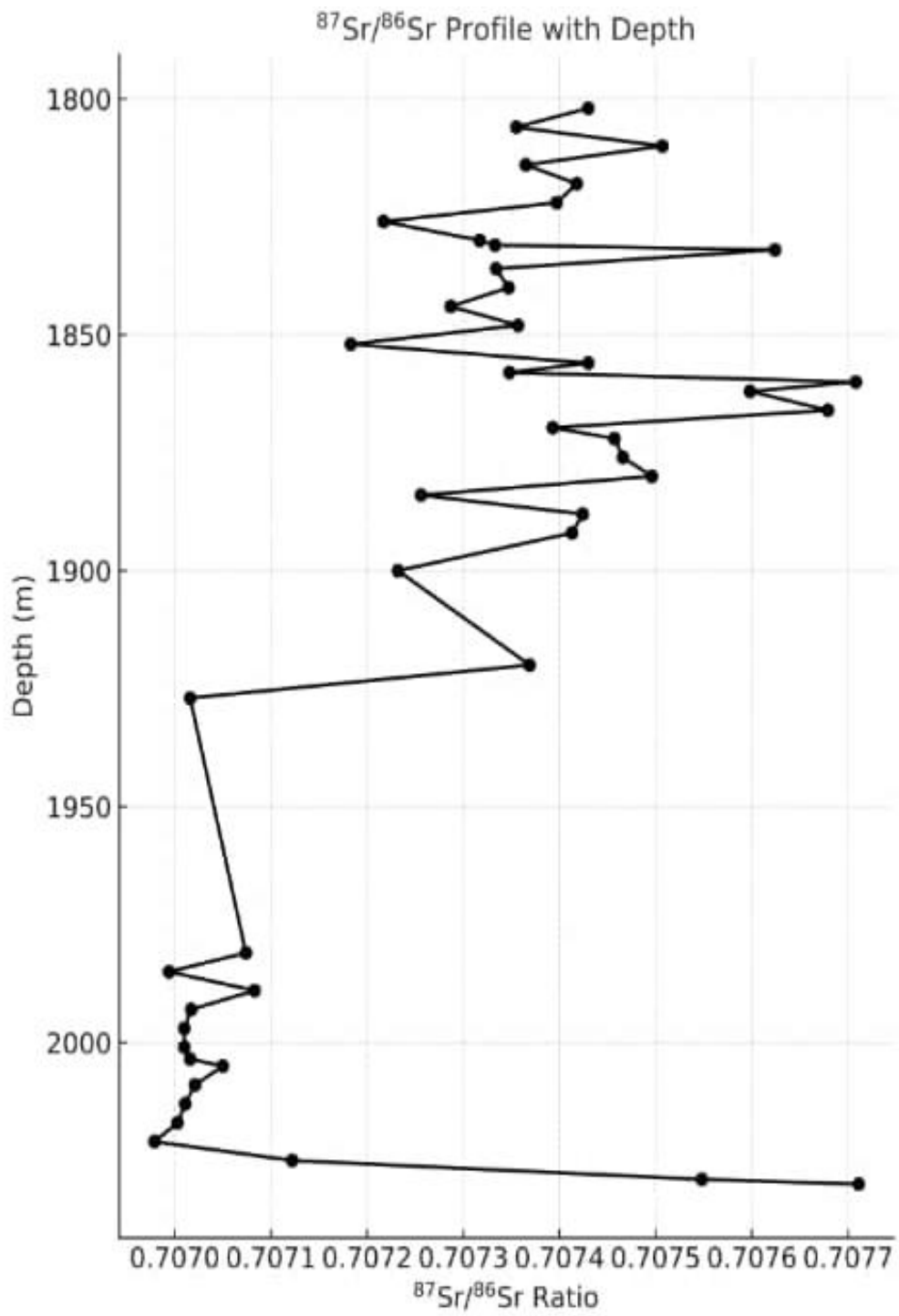


Fig 4.3

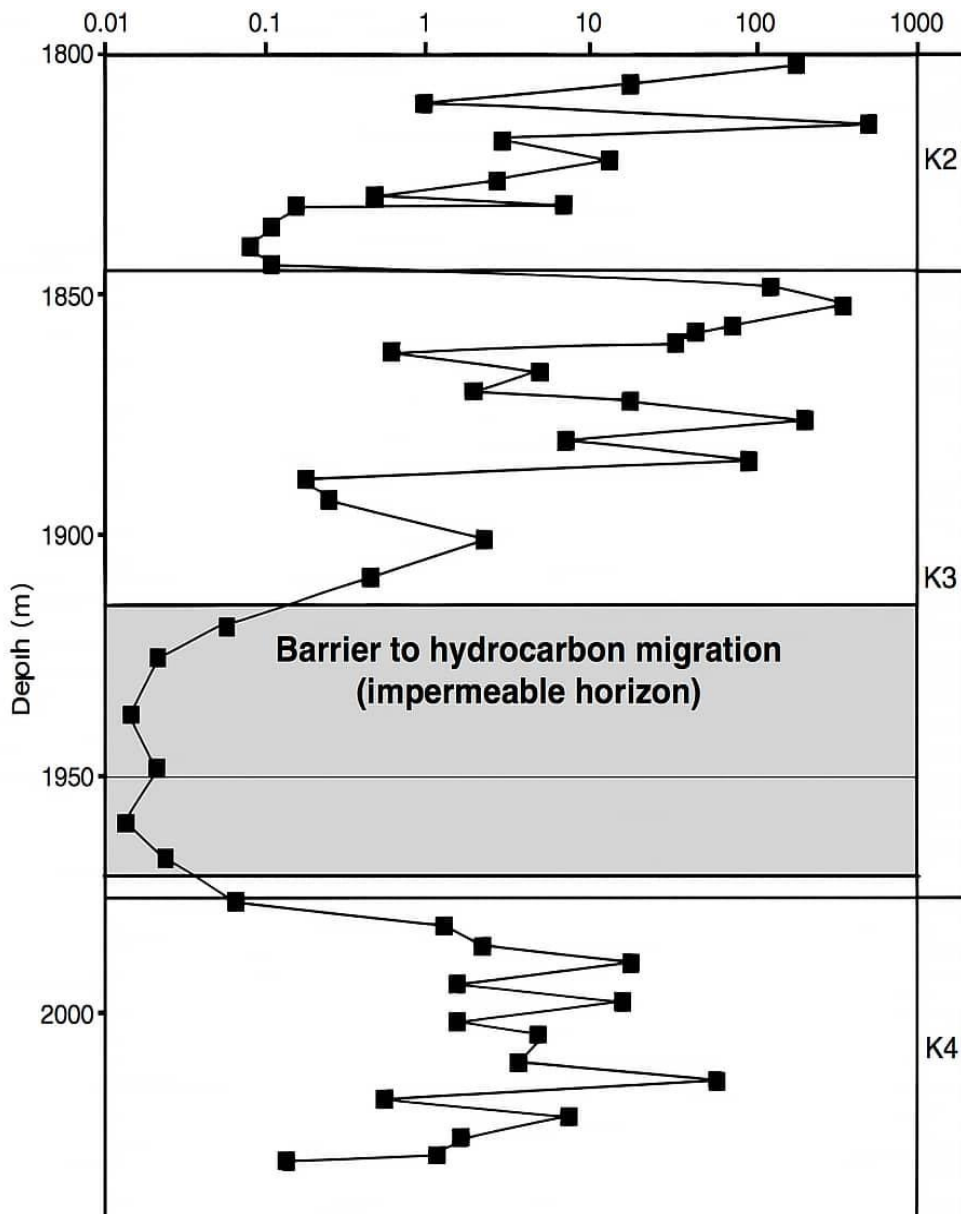


Fig 4.4

With both the permeability against depth and the Sr isotopic ratio against depth graphs. We can tell, the permeability characteristics of the zone exhibiting slightly homogeneous fluid connectivity suggest that this interval 1977 to 2021m would likely experience relatively good sweep efficiency. This zone lies directly beneath an impermeable layer (anhydrite), which acts as a barrier to vertical fluid movement, the horizontal permeability confirms helps to confirm the presence of this impermeable zone due to the very low permeability variation(negative value) in that layers and it between the 1920 to 1977m. The layer situated above the impermeable bed which is between 1802 to 1920m, however, displays a high degree of heterogeneity in fluid connectivity, indicating poor sweep efficiency, but has a layer which experience the highest permeability, with this knowledge of this layer we can tell experience poor sweep efficiency and if not properly considered before injection of fluid to the reservoir can lead to viscous fingering.

In contrast, the layer below the impermeable zone demonstrates more uniform and well-connected fluid pathways, reflecting a homogeneous flow pattern. This enhanced interconnectivity promotes better fluid displacement and higher sweep efficiency within that lower interval. Overall, the impermeable layer serves as a flow boundary, separating two zones with distinctly different permeability and fluid connectivity behaviors

## **4.2 RESERVOIR HETEROGENEITY AND SWEEP EFFICIENCY IN RESPECT TO FLUID FLOW**

### **1. SINGLE PHASE**

For fluid flow in the reservoir, the two (2) important equation is the flowrate equation by darcy's law which indicates the volume of fluid that flows through the rock per second and the velocity equation that shows the distance cover by the fluid per second in the rock.

## I. Flowrate equation by darcy's law (Q)

$$Q = \frac{-KA(dp)}{\mu dx}$$

Q = volumetric flow rate (m<sup>3</sup>/s)

K = permeability of the formation (m<sup>2</sup>)

A = cross-sectional area (m<sup>2</sup>)

μ = dynamic viscosity of the fluid (Pa·s)

dP/dx = pressure gradient along the direction of flow (Pa/m)

When permeability is high, fluids flow easily. When the pressure difference is large, the flow increases. When the rock area available for flow is bigger, more fluid can pass through. But when viscosity is high (the fluid is thicker), flow becomes slower. Viscous fingering, Viscosity also plays a big role. Water is usually much thinner (less viscous) than oil. Because of this, injected water moves faster than oil in the same rock. When that happens, the water starts to push through the oil unevenly, creating narrow fingers.

In a heterogeneous reservoir, where permeability already varies, these fingers grow faster through the high-permeability zones. The water then reaches the production wells early (early water breakthrough) while much of the oil remains trapped in the low-permeability regions. This reduces the overall sweep efficiency.

## II. Velocity and Flow Through Pores

The velocity of the flowing fluid can be thought of in two ways apparent and true velocity. The apparent velocity is the average speed through the rock as a whole, while the true velocity accounts only for the open pore spaces where flow actually occurs. True Velocity accounts for the true fluid flow in respect to its distance to speed

**Volume flowrate = Apparent velocity x Area**

$$Q = V_{app} \times A$$

$$\frac{-KA (dp)}{\mu dx} = V_{app} \times A$$

$$V_{app} = \frac{-KA (dp)}{\mu dx} \div A$$

$$V_{app} = \frac{-KA (dp)}{\mu dx} \times \frac{1}{A}$$

$$\text{Apparent Velocity, } V_{app} = \frac{-k dp}{\mu dx}$$

**As for True velocity of the rock,**

$$Vt = \frac{V_{app}}{\phi}$$

$$Vt = \frac{-k dp}{\mu dx} \div \phi$$

$$\text{So, } Vt = \frac{-k dp}{\mu \phi dx}$$

**Effects of permeability, pressure gradient cross sectional area and viscosity to sweep efficiency**

a. Effect of Permeability (K)

Higher permeability zones allow fluids to flow more easily. Therefore, in a heterogeneous reservoir, where permeability varies laterally and vertically, flow is uneven. High-permeability streaks transmit more injected water than low-permeability ones, leading to preferential flow paths and bypassing of oil in tighter zones. This behavior directly reduces sweep efficiency during displacement processes such as waterflooding.

b. Effect of Pressure Gradient (dP/dx)

The pressure difference ( $P_{out} - P_{in}$ ) across a distance drives fluid flow. In heterogeneous systems, the pressure distribution is irregular because flow resistance varies with lithology and permeability contrasts. This uneven pressure drop across layers causes non-uniform displacement fronts, resulting in early water breakthrough and poor vertical sweep.

c. Effect of Cross-sectional Area ( $A$ )

A larger cross-sectional area shows a greater volume of interconnected pore space available for flow. Heterogeneous formations often contain variable pore geometries wide channels, small throats, and disconnected pores all of which influence the effective area available for flow. This heterogeneity can cause localized high flow zones, affecting how uniformly the injected fluid sweeps the reservoir.

d. Effect of Viscosity ( $\mu$ )

Viscosity resists fluid flow. The inverse relationship between viscosity and flow rate indicates that less viscous fluids (like water) move faster through the same rock compared to more viscous ones (like oil).

**4.3 Comparison between this integrated method of geochemical and petrophysical data(permeability) with dykstra parson coefficient (vdp)**

**Table 4.3**

<b>Features</b>	SrRSA integrated with permeability variation	Dykstra-parson coefficient (Vdp)
<b>Type of measures</b>	Dynamic (reflects fluid flow and mixing over geological time).	Static (Based solely on core/log permeability statistics.
<b>Connectivity &amp; Barriers</b>	Directly identifies barriers.	Quantifies variation in permeability but does not locate or define specific barriers to flow.
<b>Spatial context</b>	Provides a measure of lateral and vertical compartmentalization because the sr isotopic ratio of the formation water is sensitive to fluid mixing/migration.	Ignores spatial correlation, its a single numerical value representing the overall spread of permeability values.
<b>Data type</b>	Utilizes geochemical data combined with petrophysical data(permeability).	Relies solely on permeability data.
<b>Time scale</b>	Captures long-term fluid flow and mixing history (geological timescale) within the reservoir .	Reflects the variability of the rock property, at the time of measurement, not the fluid flow history.

This table shows advantage of this method of the conventional method (dykstra-parson coefficient), it shows how better it is as an evaluation tool for reservoir heterogeneity, better characterization means better sweep efficiency of the reservoir.

## CHAPTER FIVE

### CONCLUSION

Reservoir heterogeneity describes the diversity in rock properties within a reservoir, with permeability variation being a key factor. This heterogeneity plays a crucial role in controlling the reservoir's sweep efficiency by influencing fluid flow paths and displacement mechanisms. Conventional methods to quantify heterogeneity, such as static measures like the Dykstra–Parsons coefficient, simplify the complex nature of reservoirs by representing heterogeneity as a single number between 0 and 1 based mainly on permeability differences. These static approaches do not account for critical factors like fluid-rock interactions and geochemical histories, which are vital for understanding fluid behavior during production. This project applied an integrated approach combining strontium residual salt analysis and permeability data to better characterize reservoir heterogeneity and evaluate its impact on sweep efficiency. Using comparative data from the South Pars and Elgin fields, the method demonstrated the ability to capture both chemical and physical variations within the reservoirs. Compared to static heterogeneity indices, this integrated method provides a more comprehensive and dynamic insight into how fluids move and interact in heterogeneous formations. It allows improved visualization of reservoir complexity and reduces uncertainties in predicting sweep performance. Thus, this approach offers a more robust foundation for planning and optimizing secondary and tertiary recovery techniques to boost sweep efficiency.

## 5.1 RECOMMENDATION

1. Due to the fact that dykstra parsons coefficient is a static variation method and it's coupled with stimulation to understand reservoir behavior, this method study helps to strategic optimize the recovery process best for the reservoir due to it's heterogeneity on fluid continuity.
2. These study methods should be used in Nigeria as part of a visual information on the recovery process for secondary and territory stages
3. The Niger Delta reservoirs share similar depositional heterogeneity and complex stratigraphy with multiple layered formations and permeability contrasts, leading to uneven fluid flow and sweep inefficiencies.
4. Integrating geochemical and permeability data can enhance understanding of fluid connectivity and flow barriers in Niger Delta fields, likely improving reservoir management and sweep efficiency.
5. Targeted enhanced oil recovery (EOR) methods, informed by detailed heterogeneity characterization, can help mitigate early water breakthrough and improve oil displacement, as seen in South Pars.
6. Implementing these integrated approaches and tailored injection strategies will optimize hydrocarbon recovery in complex Niger Delta reservoirs by accounting for both physical and chemical heterogeneities.

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