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Modeling and Performance Assessment of Produced Water Injection Efficiency in Homogeneous and Heterogeneous Reservoir System as an Enhanced Oil Recovery Approach

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Abstract: *Due to the increase in the demand of crude oil as precursor to energy base fuels production such as gasoline, as well as petrochemicals, the oil and gas production sector is challenged on optimizing their crude oil recovery measures as a means of meeting up the advancements in the oil and gas energy sector, hence calling interest of researchers and petroleum engineers to provide possible contributive ideas. On that bases, this work focuses on the performance assessment of produced water injection efficiency in homogeneous and heterogeneous reservoir system under enhanced oil recovery (EOR) as a cost, time and material conservative measure compared to the use of water as injection fluid. Reservoir and fluid properties data were obtained from IDU- Well10 (located in Orashi area of Niger Delta, Nigeria), and they were used to model the realistic reservoir using computer modeling group (CMG) computer-based software. Reservoir fluid model was created and after defining the fluid and rock properties, the model was initialized, well configuration was implemented by placing the producers along the length of the reservoir opposite to the injector well which conveys produced water at an injection pressure of 2040 psi and fluid temperature of 120^{o}F (48.9^{o}C). The studied reservoir model was recurrent to operates for 10 years using the CMG-GEM simulation engine collectively with CMG-WINPROP. Results shows that produced water has an RF value of 77.9% when used as injection fluid in a homogeneous reservoir, and it will generate 143094 bbl cumulative oil volume and 100445 ft^3 cumulative gas (CG) volume. While when applied to a heterogeneous reservoir system it shows a 73.9% RF value with 108851 bbl cumulative oil volume and 49654.9 ft^3 cumulative gas (CG) volume achieved, which are lesser when compare to those obtained from a homogeneous reservoir system. The result depicts that a convensional homogeneous reservoir is of higher higher recovery performance. It's recommended that produced water should rather be used as injection during crude oil recovery instead of normal sea water as it proves to be of higher recovery efficiency (> 73%), this will indeed save cost, and production time which are consummed when using normal sea water as injection fluid.*

Keywords: oil recovery factor, volume of oil recovered, permeability, computer modeling group (CMG), water cut, crude oil recovery

INTRODUCTION

Crude oil distillates and petrochemicals in today's technological era serves diverse purposes, ranging from domestic scale products to industrial utilities provision, for this reason the demand for quality crude oil in higher quantity is enveloping, opening rooms for deep scientific ideas on how to improve oil production performance as act of conserving industrial time, cost and materials (Al Mestneer & Bollino, 2024 Dahaghi *et al.*, 2008; Dusseault & Elhassan, 2018 ; de-Lima *et al.*, 2013; Abraham *et al.*, 2023; Al-Obaidi *et al.*, 2020). Crude oil is a fossil fuel which is of most pronounced benefits and applications among others (natural gas and coal). It's a hydrocarbon based natural resource which is used as a non-renewable energy source, consumed daily in billion tons of barrels as fuel to power automobile engines as well as enhances industrial practices as it provides feedstocks used as precursors by other industries to produces more stable and domestically essential products (Sammy *et al.,* 2023 Pery's and Green, 2007). It is a mixture of hydrocarbons (Paraffins, aromatics and naphthenes), inorganic salts that is formed as a result of organic remains decomposition over a long period of time beneath the earth crust, at suitable process operations and microbial interactions (Abraham *et al.*, 2023; Dahmani & Khodja, 2020; Farahbod, 2024; Ismail *et al.*, 2025; Zhou & Li, 2024). It's achieved from oil and gas reservoir and processed or refined in the refinery into distillates such as liquified petroleum gas (LPG), gasoline, diesel, etc. of which most of its products (especially the heavy fuel oils) generates petrochemicals and lube oil based stokes that are essential as precursors to production of daily consumed materials and utensils such as plastics, pesticides, adhesives, etc.. Crude oil usefulness is above estimations, beneficial to mankind as it promotes massive economical, national, technology and industrial development, which has made countries such that countries like Nigeria builds their budgets in oil and gas production and distribution as means of foreign trade (Dahmani & Khodja, 2020; Farahbod, 2024; Ismail *et al.*, 2025). Though crude oil still has its pros which involves it abilities in terms of promoting environmental pollution, thermal heat, agricultural value degradation, sea animals' mortality increase, atmospheric gases (GHGs) concentration elevation, as well as it promoting metallic corrosion and global warming (Benedict and Fredrick, 2023; Ugi *et al.*, 2025; Wordu *et al.*, (2023; NeeBee *et al.*, 2024; Benedict *et al.*, 2022; Ugi *et al.*, 2023; Ugi *et al.*, 2021). According to Ugi *et al.* (2022) crude oil is a black gold whose significance has blinded man from its negativities.

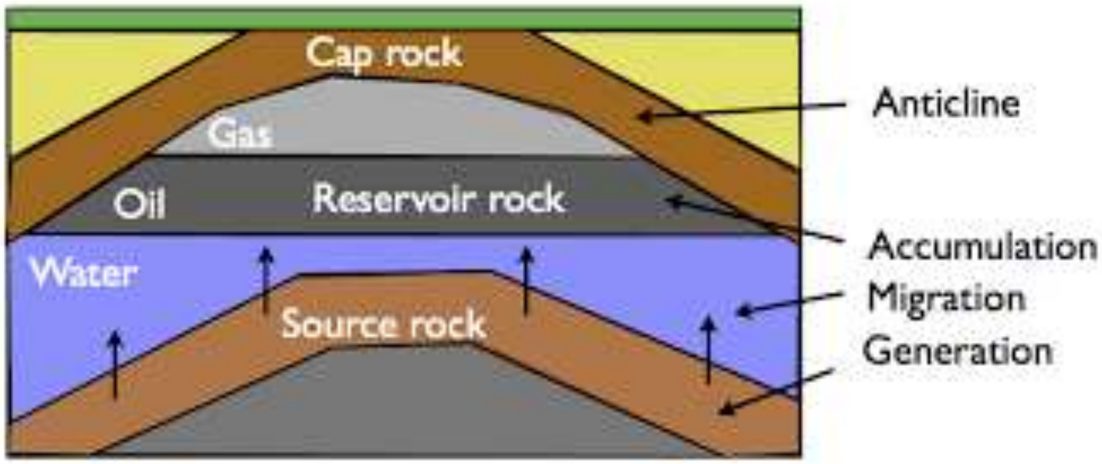

Figure 1: Crude oil formations within geological bends and folds

The availability of crude oil depends on its recovery abilities, of which generally it is a complex multi-operative activity that entangles different fields of engineering and sciences, as well as requires a wide range of machineries and operations. Crude oil lies beneath the earth crust, thousands of feet on an aquifer, enclosed or guided by geological folds and bends (Abraham *et al.*, 2023; Al-Obaidi *et al.*, 2020; Al-Obaidi *et al.*, 2021; Ali & Khan, 2023; Alireza, 2021; Jiang *et al.*, 2000a; Jiang *et al.*, 2000b; Kopac & Demirel, 2024; Kazlou *et al.*, 2024; Zhiguo *et al.*, 2021; Zhou & Li, 2024). Crude oil is trapped in-between water and gas layers separated by difference in gravity and density (Figure 1), the porosity and permeability of these rocks defines the efficiency of recovering the oil from the geological framework.

Reservoirs are base blocks for crude oil and natural gas formation that originates from kerogen (ancient plant matter) developments under high heat and pressure within surrounding rocks (Abraham *et al.*, 2023; Farahbod, 2024; Ismail *et al.*, 2025; Ihekoronye *et al.*, 2024; Iglina *et al.*, 2022; John, 2005; Jin & Kirk, 2016; Jeremy *et al*., 2022) that are buried beneath the earth surface. During crude oil exploration, reservoirs are identified as boundaries that keep oil and gas safe, their nature defines the performance of crude oil production. Reservoirs are mostly classified as *conventional* and *unconventional*, based on their degree of homogeneity. **Conventional reservoirs**, traps naturally occurring hydrocarbons (such as crude oil and natural gas) by overlying rock formations that are of lower permeability, while the **unconventional reservoirs** consist of base or surface rocks (but with no cap rocks) of high porosity though still with low permeability, which keeps the hydrocarbons trapped in place. Classification of reservoirs based on location is as offshore and onshore types. Onshore reservoirs are underground deposits of hydrocarbons, like oil and gas, that are located on land. Unlike offshore reservoirs found beneath the seabed, onshore reservoirs are accessed through drilling on land, which is generally less expensive and easier to access. These reservoirs are characterized by properties such as porosity, permeability, and hydrocarbon saturation, which are evaluated through techniques like well logging and seismic interpretation (Jin & Kirk, 2016; Jeremy *et al*., 2022; John, 1997; Jiang *et al.*, 2000a; Jiang *et al.*, 2000b; Kopac & Demirel, 2024; Kazlou *et al.*, 2024; Zhiguo *et al.*, 2021; Zhou & Li, 2024).

Oil and gas reservoirs are sub-units of oil and gas fields, of which multiple reservoirs can be present in a certain area to for an oil field. Extraction or production of crude oil and natural gas from involves the drilling of Producer well, of which need be for production enhancement a Recovery well is been drilled too as medium of supporting the reservoir performance in recovering high oil factor or oil percent recovery (Al-Ghamdi & Nasr-El-Din; 2016, Al.Obaidi *et al.*, 2021Ismail *et al.*, 2025; Ihekoronye *et al.*, 2024; Iglina *et al.*, 2022; John, 2005; Jin & Kirk, 2016; Jeremy *et al.*, 2022; John, 1997; Jiang *et al.*, 2000a; Jiang *et al.*, 2000b;; Zhou & Li, 2024), which is the primary focus of the petroleum industry. However, the oil or petroleum is been into three sectors: **upstream** (crude oil production from wells and separation of water from oil), **midstream** (pipeline and tanker transport of crude oil) and **downstream** (refining of crude oil to products, marketing of refined products, and transportation to oil stations), of which the mid and downstream depends fully on the performance of the upstream, which is the upstream sector a primary focus of the industry.

The feasibility and easiness of crude oil production is a function of the nature of production operations, crude oil type / properties as well as the nature of the reservoir formations or geology. Generally, crude oil is of diverse colors, quality, composition as well as physiochemical properties such as viscosity, most which are due to the oil nature of formation, microbial decomposition activities, and the soil type where the oil is formed (Choudhary *et al.*, 2021; Dahmani & Khodja, 2020; Farahbod, 2024; Ismail *et al.*, 2025; Ihekoronye *et al.*, 2024; Iglina *et al.*, 2022; John, 2005; Jin & Kirk, 2016; Jeremy *et al*., 2022). By classifying crude oil, we will identify as seen in Figure 2 that crude oil differs in API, sulphur content, color, nature organic composites, as well as in viscosity.

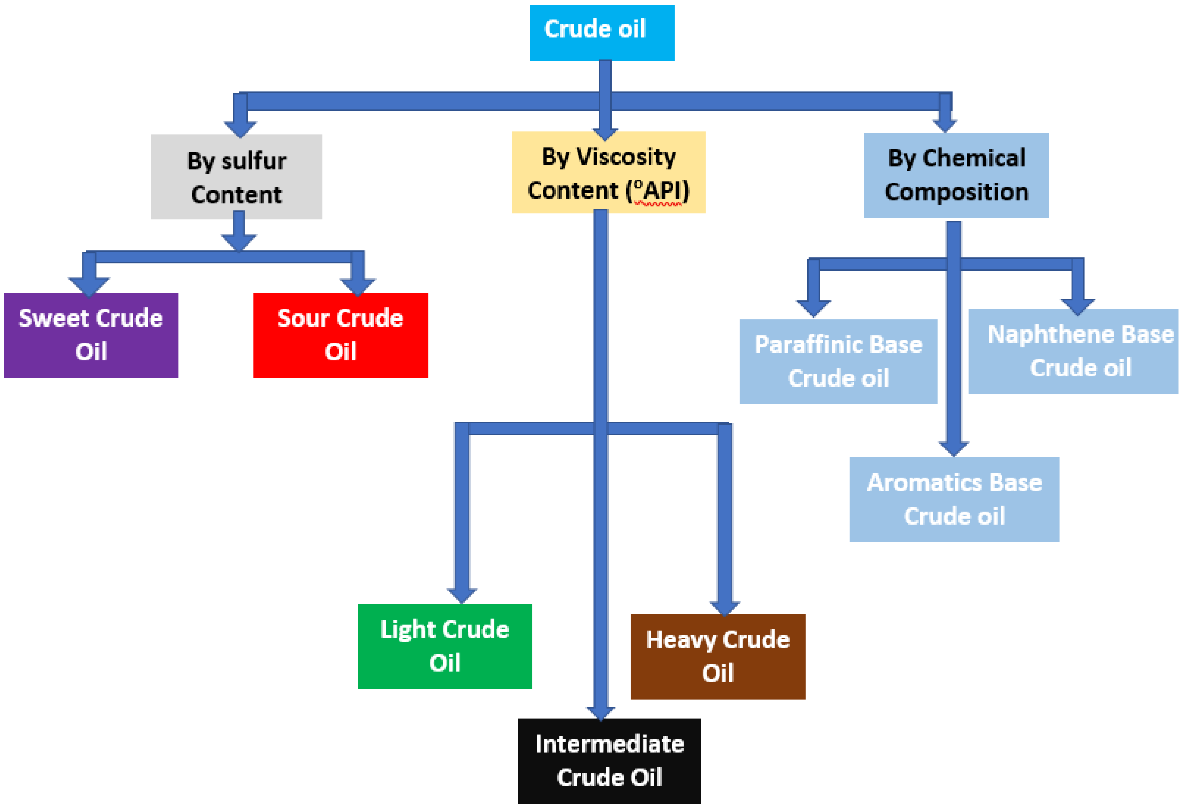

Figure 2: Fundamentals of crude oil classification

Production of crude oil from the reservoir is a multi-complex activity whose quality of operations determines the quantity and texture of crude oil produced. The system involves surface, well and bed activities, linked with different process utilities such as pump, separators, drilling rigs, pipeline network as well as controllers. Crude oil recovery is been carried out I three different ways of which each as its recovery ability as well as materials applied over time. They fundamental recovery process of crude oil are:

i. **Primary oil recovery (POR) method**
ii. **Secondary oil recovery (SOR) method**
iii. **Tertiary (Quaternary) or Enhanced Oil Recovery (EOR) method**

The POR methods depend on the use of the reservoir natural lift pressure, which depreciates after a very short period of production. While the SOR and EOR uses the artificial generated pressure promoted by the injected recovery fluids. Amongst all, the enhanced oil recovery holds the greatest efficiency in recovering of crude oil from the reservoir. The Enhanced Oil Recovery (EOR) is an advanced approach that can recover 40% - 75% and above**,** of trapped crude oil and natural gases, while the Secondary Oil recovery (SOR) recovers about 25% - 35% and the primary oil recovery

(POR) can only produce or recover 5% - 20% of the trapped oil in the geological folds and faults of the earth.

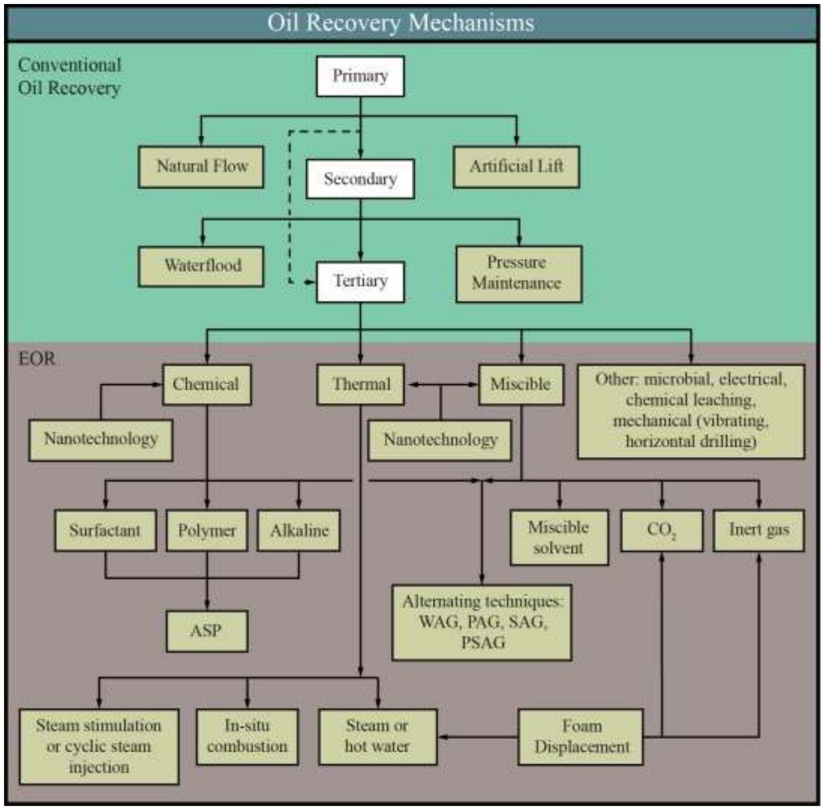

Figure 3: Classification of crude oil recovery methods (Xiao *et al.* (2023**)**

The secondary and tertiary crude oil recovery systems (SOR and EOR etc.) or approach tends to be more expensive to practice when compared to the POR system, but they are time conservative to attain desired production capacity of a reservoir. Their expensiveness lies on the nature and types of auxiliary materials that are put in place to ensure the attainment of the applied approach, as well as the cost of obtaining and procuring injection fluids, which some such as CO_2 gas are too expensive to venture into. The Secondary (SOR) and Tertiary (EOR) oil recovery methods are of slight resemblance especially on the bases that both systems used gas as their injection fluid, though that used for the EOR system falls among the chemical injection methods as seen in Figure 1.3, where the injected gas dissolve into the crude oil to enable flowability efficiency increase proportional to increase in the fingering efficiency of the injected flued.

Secondary Oil Recovery (SOR) process which is known to be of a 20% - 35% recovery capacity or efficiency of trapped oil and gas with respect to original oil in place (OOIP) of the reservoir, is based on the injection of fluids into a reservoir to improve the reservoir pressure; which tends to be dropping along the production line as the production period increases (Vamsi and Suriya, 2023; Tzimas, 2005; Perry's and Green, 2007, Sammy *et al.*, 2003). Secondary recovery techniques increase the reservoir's pressure by either water injection, gas reinjection or via gas lift. Gas reinjection and lift each use associated gas, carbon dioxide or some other inert gas to reduce the density of the oil-gas mixture, improving its mobility. This approach has been used for decades and as well investigated by multiple researchers, owing to optimizing the performance of the process to effective productivity of the petroleum upstream sectors. Secondary recovery process is sectioned into the following:

i. **Water flooding.**
ii. **Thermal recovery.**
iii. **Gas injection.**

Thermal recovery ranks next to water flooding and gas injection pressure-maintenance in popularity as a secondary oil recovery method. This is usually accomplished either by injecting steam (temperature range above 500^{o}C) as an external heating agent or by sustaining an in-situ flame front through injection of air to generate the heat by burning a portion of the reservoir oil. This process is most effective for oils of high viscosity (Al-Obaidi *et al.,* 2020; Al-Obaidi *et al.*, 2021). Frequently the primary production from such a field is so low (under 5 percent) that the operation is for all practical purposes a primary recovery application. Occasionally, thermal processes are considered for true secondary operations where lower viscosity oils (30° to 35° API gravity) have been depleted by gas drive or even water drive; however, the quantity of heat required to heat both the residual oil and the total reservoir rock may require burning too much of the oil for this method to be economical.

Gas flooding or injection involves the introduction of gases such as natural gas, nitrogen, or carbon dioxide (CO_2) into the reservoir, to improve the reservoir pressure due to the expansivity of these gasses, which grants their abilities of pushing the OOIP off their intense zones in the reservoir into the production wellbore. In a higher operating pressure and temperature some of these gases dissolve in the oil to lower its viscosity and improves its flow rate. Gas injection accounts for the recovery of about 60% oil from the reservoir (Wang & Zhang, 2022; Musa & Ekundayo, 2022; Ali & Khan, 2023; El-Hoshoudy & Alshahrani, 2023; Zhou & Li, 2024; Al-Ghamdi, & Nasr-El-Din; 2016; Chen & Zhang, 2016).

Water flooding is the most frequently practiced secondary oil recovery displacement mechanism. That effectively recover above 40% of the trapped oil via water injection. The economics of water flooding is usually more attractive than any alternative technique, which increases its preferred position (Vamsi and Suriya, 2023). Where water flooding is carefully designed and controlled, the ultimate recovery at the end of the secondary operation may be equivalent to a well-managed and efficient primary water drive. However, there are numerous cases where primary operations were conducted in such a manner that water flooding is precluded as a SOR operation. For instance, if a gas cap is allowed or caused to shrink, and reservoir oil moves into the gas zone, much of that oil will be unrecoverable by water drive. Often, most of the oil that remains after primary operations is in portions of the reservoir rock not readily accessible to the encroaching water. The shrinkage and increase in viscosity of oil denuded of dissolved gas render the oil less susceptible to displacement by water flooding. It should be recognized that not every old reservoir is a candidate for secondary recovery.

The displacement of crude oil in the reservoir by the water injected as an SOR system promotes the sweeping of the trapped oil towards the producers well as well as improve or maintain the reservoir pressure which was actually declined during primary recover process of oil production. The process is identified to be the cheapest and ecofriendly approach of Secondary oil recover (SOR) though it can only recover 31 – 55% of the trapped oil, but the always availability of water to be used in the system makes it very feasible. The success depends on reservoir properties like permeability and fluid viscosity, and common injection patterns include peripheral, line drive, five spot, and nine spots.

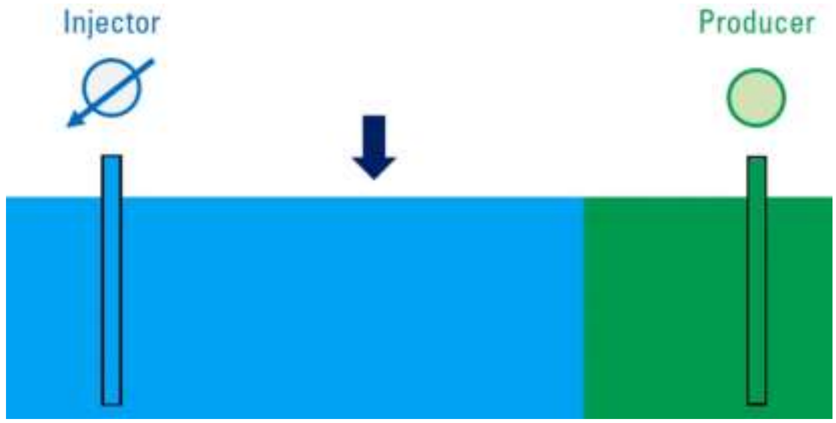

Figure 4: Reservoir under water flooding secondary oil recovery techniques

Water injection or waterflooding process has no actual effect to the reservoir structure as well it been able to alter the oil chemical / molecular nature, this is because water (as well as CO_2) is known to be of a low miscibility with oil, hence can rarely affects the oil hydrocarbons structure or nature (Kovscek and Cakici, 2005; Sammy *et al.*, 2023; Dang *et al.*, 2014.; Dahmani & Khodja, 2020; Farahbod, 2024; Ismail *et al.*, 2025; Ihekoronye *et al.*, 2024; Iglina *et al.*, 2022; John, 2005; Jin & Kirk, 2016Kopac & Demirel, 2024; Kazlou *et al.*, 2024; Zhiguo *et al.*, 2021). Water can as well be mixed with gases such as carbon dioxide (CO_2) during Water Alternating Gas (WAG) injection concept of EOR system as means of optimizing CO_2 performance in recovering oil from a reservoir (Choudhary *et al.*, 2021), and this is done on the bases that water has the abilities of lowering the mobility of carbon dioxide when injected into the reservoir, hence causing the gas to displace more oil over time (Kovscek and Cakici, 2005; Sammy *et al.*, 2023).

Despite the high availability of water and its relevant to crude oil recovery, the closeness of the water to the production zone for it to be used usually stand a hinderance, hence promoting production cost in the oil ad as production (upstream) sector. Secondly, complains arising over low oil recovery factor from the use of normal water for flooding or sweeping of a reservoir as SOR concept tends to drag attention towards the application of WAG concept, and to reduce the cost of production more approach are required in the oil and gas production sector, for this reason, this current work focus on the use of produced water as injection fluid for the recovery of oil as an EOR system due to the chemical composites of the produced water.

Produced water is a product of reservoir, a saline byproduct of oil and gas extraction or geothermal energy production (Chikwe & Igwe, 2024a; Chikwe & Igwe, 2024b; Klemz *et al.*, 2021; Su *et al.*, 2022; Song *et al.*, 2022) that contains oil, dissolved minerals, gases, and other substances. It is rich in kerogens, hydrocarbons, microorganism as well as other composites of the assessed reservoir in minutes form or proportion by mass (Su *et al.*, 2022; Song *et al.*, 2022; Tao *et al.*, 2022; Li *et al.*, 2022; Atoufi *et al.*, 2020). It is a challenge due to its complex and variable composition, posing environmental risks if not managed properly. However, it is increasingly being treated and reused for applications like industrial processes, agriculture, and precious metal recovery, as water scarcity drives demand for alternative water sources. Oil wells sometimes produce large volumes of water with the oil, while gas wells tend to produce water in smaller proportions. Some produced water contains heavy metals and traces of naturally occurring radioactive material (NORM), which over time deposits radioactive scale in pipelines. Metals found in produced water include zinc, lead, manganese, iron, and barium. In most cases, produced water is flushed into the sea as wastes water (Figure 4), which is totally unadvised due to the poisonous nature of the water contents to aquatic habitats, as well the approach is a waste of wealth.

Figure 5: Crude oil upstreammed produced water unlawful dischargements into water body

Produced water can be used in water flooding after it has been separated from crude oil mixture that is produced from the reservoir. First it will be separated from the oil-water mixture using an effective separator, then it is been treated to remove all hydrocarbons, inorganic salts as well as metals, then finally the treated water is been r-injected into the reservoir as waterflooding fluid. This act saves time and cost of achieving water for use during water flooding SOR system. It is believed that the use of the water without treatment will bust the recovery factor of the reservoir as well as it will drastically save or conserve production cost, time and operations when compared to the use of already treated produced water, though its pros (demerits) are still to be considered. This works stands to justify the claims by assessing the performance of untreated produced water in oil volume and recovery factor bases, in comparison with the treated produced water result assessed by other researchers. To attain the aim of assessing untreated produced water injection performance in oil recovery, the following objectives are structured to ease essential study of the system:

i. Design a functional realistic reservoir using realistic data achieved from functional oil field, applied on CMG-GEM simulation engine collectively with CMG-WINPROP.
ii. Determine the recovery efficiency of produced water used as injected fluid in homogeneous reservoirs
iii. Effects of reservoir homogenies on reservoir performance under produced water injection as an EOR concept
iv. Injection fluid pressure effects on oil and water cut over defined reservoir homogeneity

MATERIALS AND METHODS

Process Description

The reservoir modelling and simulation was conducted in CMG (Computer Modelling Group) suite under the structure of CMG-GEM simulation engine collectively with CMG-WINPROP fluid modeler accurately as structured at the process flow chart (Figure 7). The simulation consists the creation of realistic, three-dimensional numerical model representing the XYZ- oil field reservoir using the XYZ field analyzed data for reservoir geology as the fundamental bases of the enhanced recovery performance assessment of produced water.

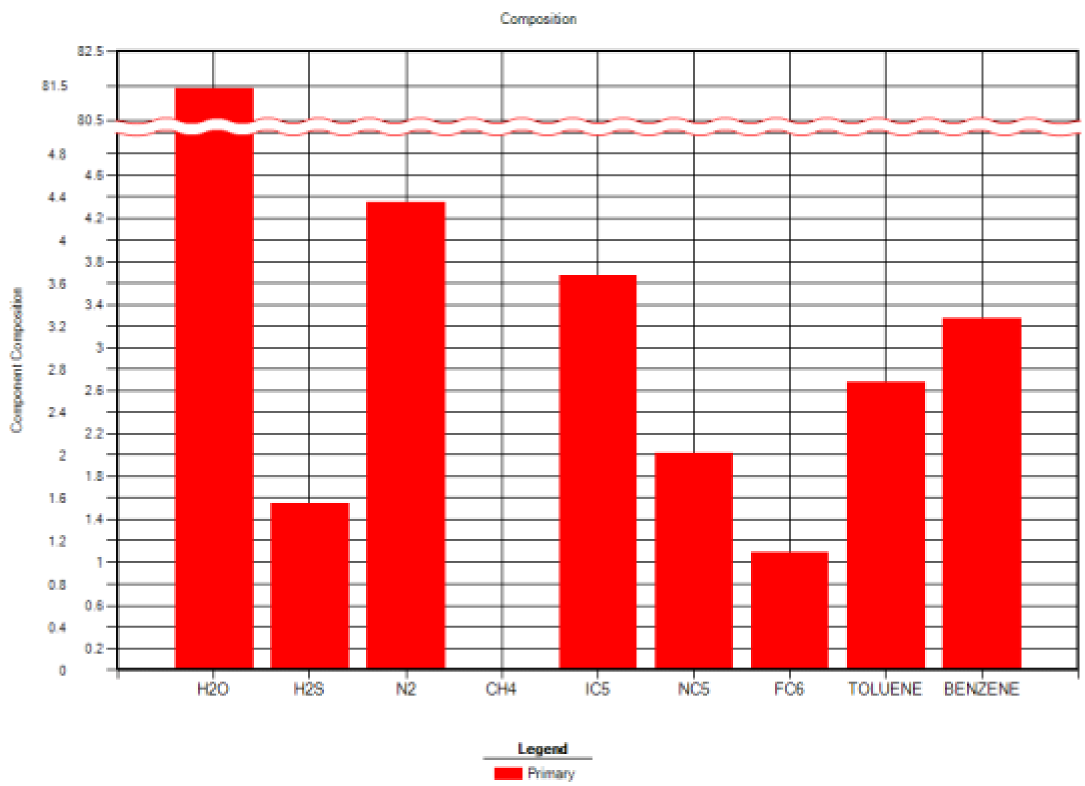

Figure 6: Injection fluid (Produced water) percentage (%) composition plots

The 3D model was gridded in the frame 20:9:7 which represents the x:y:z directions of the reservoir, identified as the length (x or i), depth (y or j) and the width (z or k) of the XYZ reservoir, forming reservoir mesh with a total of total of 1260grid blocks. Rock and reservoir properties at homogeneous and heterogeneous bases were separately specified in Builder using actual or representative field data (Table 1 – 5). The Corey-type relative permeability and capillary pressure curves were determined via correlation using the determined realistic reservoir saturation data for the oil, water, and gas phase permeability behavior in the system or within the porous medium.

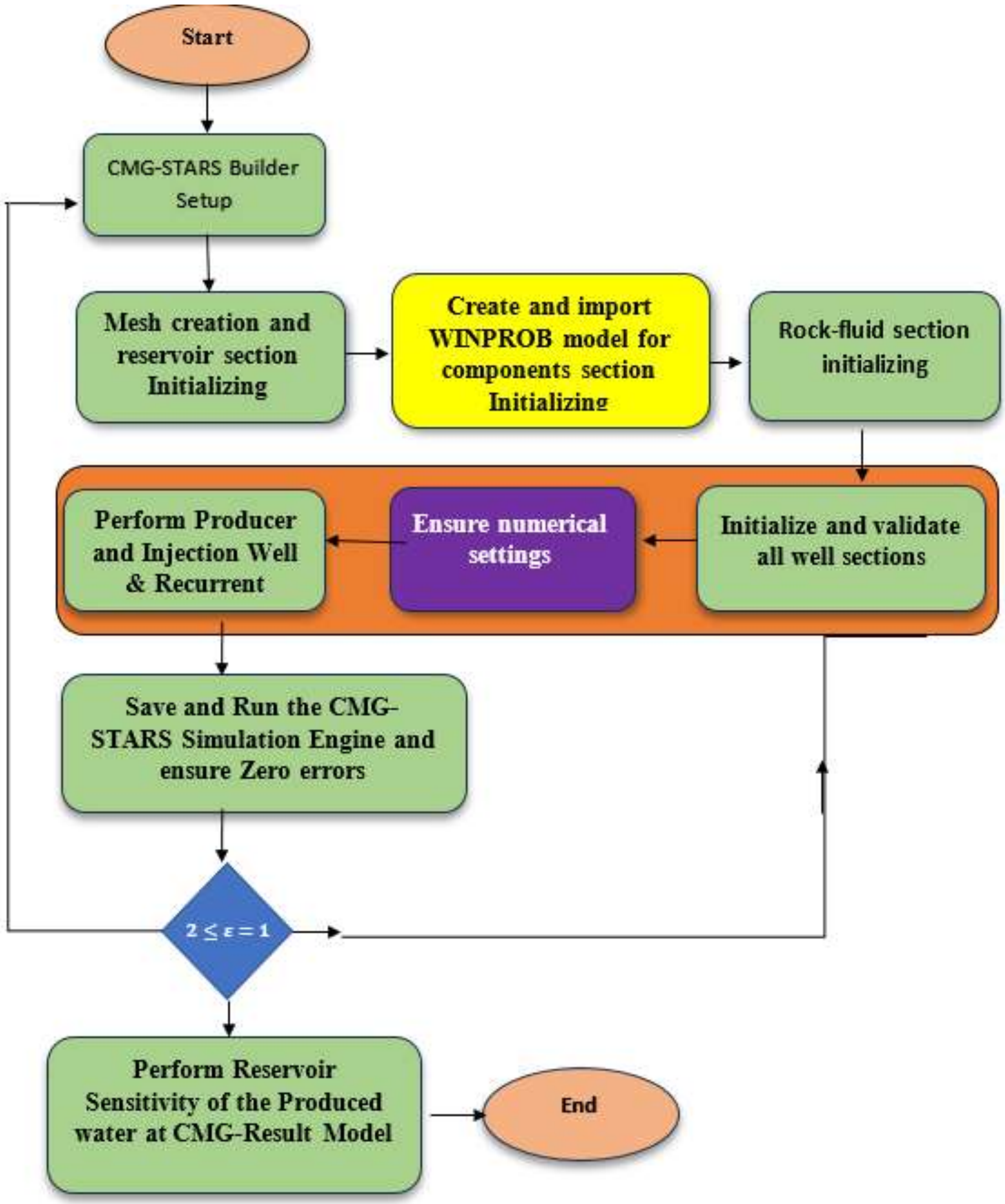

Figure 7: Process flow chart of CMG modeling of a crude oil recovery reservoir

The reservoir fluid model was created in CMG-WINPROP using simulator PVT: CMG_GEM_EOS_model, in hands with the Henry's law constant correlation: Li-Nighiem's method (1986), based on the Peng–Robinson (1978) Equation of State (EOS) structured to suit the analyzed produced water fluid physiochemical composites as well as components %mole compositions (Figure 6). The fluid model from the CMG- WINPROP was thereafter imported into the builder as a ***.dat* extensional file,** after which the fluid and rock properties were then defined using the realistic rock and reservoir data of reservoir XYZ. Initial reservoir pressure was applied uniformly and validated using an initialization run in CMG to ensure the reservoir state aligned with physical expectations.

A single producer and injection well structure was configured as liner well perforation nature to promote the sweep efficiency of the IDU- Well10 (located in Orashi area of Niger Delta, Nigeria) under produced water flooding with both wells placed at opposite side. Each well was assigned a control mode (bottom-hole pressure and injection rate), and completions were perforated across selected layers to match reservoir thickness and productivity zones. Well operations were scheduled overtime to simulate both homogeneous and heterogeneous produce water injection phases.

Reservoir, PVT and Produced Water Properties for the IDU-Well10-Reservoir Modeling

The produced water physiochemical results achieved via experimental approach, with the PVT, Rock and reservoir realistic data set achieved from IDU- Well10 (located in Orashi area of Niger Delta, Nigeria), are tabulated as follows:

Table 1: Reservoir static and dynamic data for IDU-Well10- Oil field

Variables	Data	Variables	Data
Seismic (Geological) Data			
width	3000ft	OOIP (barrel)	50000
depth	900ft	Crude API gravity	30°
Reservoir Thickness	10 ft		
Fluid or PVT Data			
Reservoir Pressure	200 psi	Water molecular weight	18.015 lb/lbmole
Reservoir Temp.	120°F (48.89°C)	Mass density of Oil	50 lb/ft3
Reservoir Fluid viscosity	0.76 Pa.S	Mass density of water	62.4 lb/ft3
Reservoir Fluid flow rate (cm^3/s)	4.9	Producer well min. BHP Bottom hole pressure	2060 psi
Petrophysical (Reservoir) Data			
Porosity "ϕ"	0.3	Oil Saturation	70%
permeability" K" at i, j and k	150mD, 200mD, 15mD	Water Saturation	100%
Poison's ratio "v"	0.56	Water critical pressure	2197.79 psi
Water critical temperature	75.56 F	Bubble point pressure	1325 psi
Water compressibility (/psi)	3.0E-6	Compressibility ratio "η"	0.11

Table 2: Injection fluid (Produced water) composition and physiochemical properties

Physiochemics		Chemical Composites		Solid Metals	
Property	**Value**	**Compounds**	**Mole comp.**	**Metal**	**Amount (mg/L)**
Density (kg/m^3)	1123	$H_2S - H_2O$	81.2636	Ca	89.38273
pH	5.67	N_2	1.15	Pb	0.03491
Conductivity($\mu S/cm$)	1750.24	CH_4	4.34	Mn	0.02968
Turgidity	122	$IC5$	0.004	Zn	1.84921
TDS (mg/L)	187399	Benzene	5.936	Cd	0.00174
TSS (mg/L)	40.67	$NC5$	3.67	Hg	0.0001
T.Oil (mg/L)	0.13	Phenol	0.00011	Fe	0.08574
TOC (%)	1.24	$i - C_4H_{10}$	0.00062	Cu	0.16590
DO (mg/L)	11.2	$n - C_4H_{10}$	0.00344	Ag	0.00001
BTX (μg/L)	45.21	$i - C_5H_{12}$	0.00001	Na	120.53981
Inorganic Salt (mg/L)	146.7	$n - C_9H_{12}$	0.00222	K	1.59024
Choride (mg/L)	350.67	Toluene	1.09	Mg	56.13913
Bicarbonate (mg/L)	4.01	$FC6$	2.01	Ti	0.00001
Sulfite (mg/L)	0.18	C_7H_{16}	0.27	Cr	0.01781
Sulfate (mg/L)	310.74	C_8H_{18}	0.19	Po-210	0.00021
NH_3 -N (mg/L)	5.10	C_9H_{20}	0.07	Ra-226	0.00001

Table 3: Injection fluid properties forIDU-Well10- Oil field Recovery process

Parameters	**Values**	**Parameters**	**Values**
BHP Bottom hole pressure	2040 psi	Choke constant (m^2)	0.013
Injection Temperature	250^{o}F	Viscosity Φ (cp)	0.0142

Table 4: Injection and Producer Well properties for XY- Oil field recovery process

Parameters	Values	Parameters	Values
Perforation Radi (ft)	0.311	Well horizontal distance (ft)	480
Wellbore radius (ft)	0.324	Well vertical distance (ft)	2900
Well depth (ft)	850	Annulus volume (ft^3)	234.56
Thickness (m)	30.5	Annulus inner diameter (ft)	0.543

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Table 5: anisotropy homogeneity data of the modelled reservoir

porosity	Porosity-i	Porosity-j	Porosity-k	Water saturation
0.3	150	200	15	0.15
0.24	125	168	12.5	0.21
0.21	112	143	11.2	0.36
0.16	93	123	9.3	0.46
0.28	54	144	5.4	0.67
0.2	32	76	3.2	0.88
0.1	18	43	1.8	1

RESULTS AND DISCUSSION

The developed heterogeneous and heterogeneous reservoir models structured for injection of produced water as a medium for EOR, was structured in this work as 7 layers deep, 9 layers width and 20 layers length with 3000 ft surface grid (grid top) distance to the reservoir, with a grid thickness of 10 ft, possessing a trajectory conventional / vertical production and recovery wells (Figure 8) positions at opposite sides to ease the oil recovering efficiency of the system.

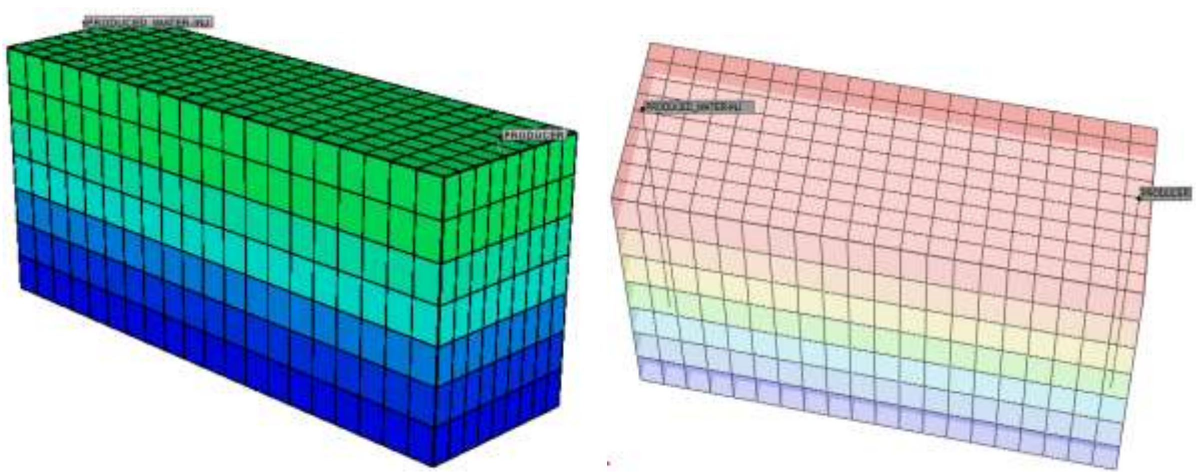

Figure 8: Trajectory reservoir system under produced water injection for oil recovery

Reservoir Permissibility Behavior Over Fluid Change in the Flooded Reservoir

In correlating the reservoir relative permeability (which is the ratio of a fluid's effective permeability to the absolute permeability of the medium) with changes in the water saturation (Sw) as IDU- Well10 (located in Orashi area of Niger Delta, Nigeria)was been flooded with produced water, shows that permeability decreases down the reservoir layers as well as across its length, in a spontaneous manner as seen at Table 5. This decrease is with respect to increase in pressure which proportionally reduces the oil viscosity (Visco) and promotes flowability and recovery of the crude oil. It is also seen that the relative permeability of water in a reservoir is at opposite influence to that of the gas, hence as the water saturation (Sw) in the reservoir increases from 0.25 to 0.78 it promotes the increase in the reservoir liquid saturation (Sl) from 0.55 to 1.0. This behavior inhibits the relative permeability of water for the first 3 cross sections of the reservoir, hence reduces or limits the oil volume recovery rate as well as the recovery factor.

Table 5: Correlation result of reservoir IDU-Well10 oil and gas permissibility behavior

	Water – Oil Correlation Results			Liquid – Gas Correlation Results		
	Sw	***Krw***	***Krow***	***Sl***	***Krg***	***Krog***
1	0.25	0	0.9	0.55	0.3	0
2	0.255	0	0.874768	0.573125	0.247192	0.000122138
3	0.26	0	0.850012	0.59625	0.200977	0.000977103
4	0.2925	0.00117187	0.700388	0.619375	0.160913	0.00329772
5	0.325	0.0046875	0.569441	0.6425	0.126562	0.00781682
6	0.3575	0.0105469	0.455927	0.665625	0.0974854	0.0152672
7	0.39	0.01875	0.358599	0.68875	0.0732422	0.0263818
8	0.4225	0.0292969	0.276212	0.711875	0.0533936	0.0418933
9	0.455	0.0421875	0.207522	0.735	0.0375	0.0625346
10	0.4875	0.0574219	0.151284	0.758125	0.0251221	0.0890385
11	0.52	0.075	0.106251	0.78125	0.0158203	0.122138
12	0.5525	0.0949219	0.0711802	0.804375	0.00915527	0.162565
13	0.585	0.117187	0.0448248	0.8275	0.0046875	0.211054
14	0.6175	0.141797	0.0259403	0.850625	0.00197754	0.268337
15	0.65	0.16875	0.0132814	0.87375	0.000585938	0.335146
16	0.6825	0.198047	0.0056031	0.896875	7.32422e-005	0.412215
17	0.715	0.229688	0.00166018	0.92	0	0.500277
18	0.7475	0.263672	0.000207522	0.96	0	0.680701
19	0.78	0.3	0	1	0	0.9

The relative permeability of oil in oil-water phase (Krow) decreases with respect to increase in the relative permeability of water (Krw) as seen at Figure 9, which promotes an equilateral increase in the oil in the in oil-gas phase (Krog), proving that the injected fluid is indeed reliable in recovering oil from the conventional reservoir system.

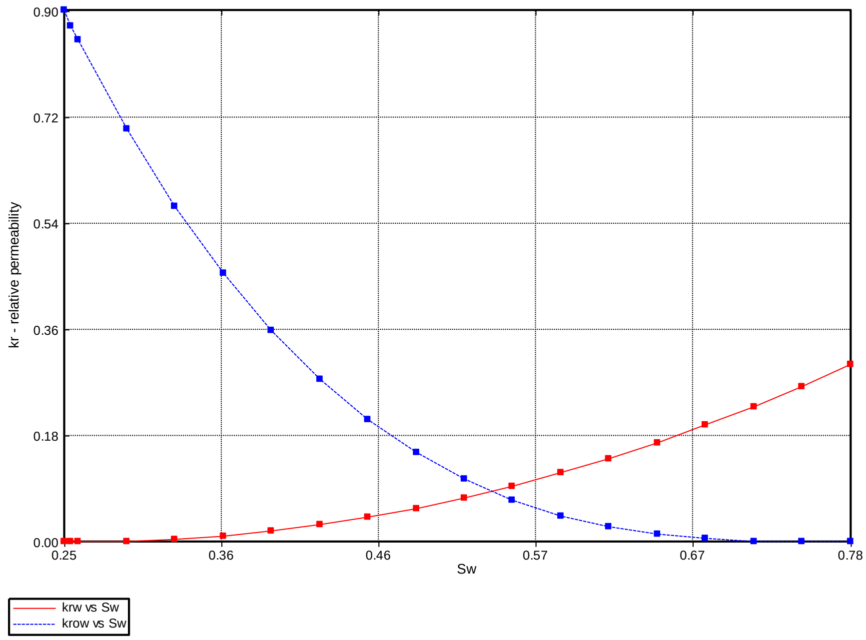

Figure 9: Oil – water relative permeability behavior over change in water permeability

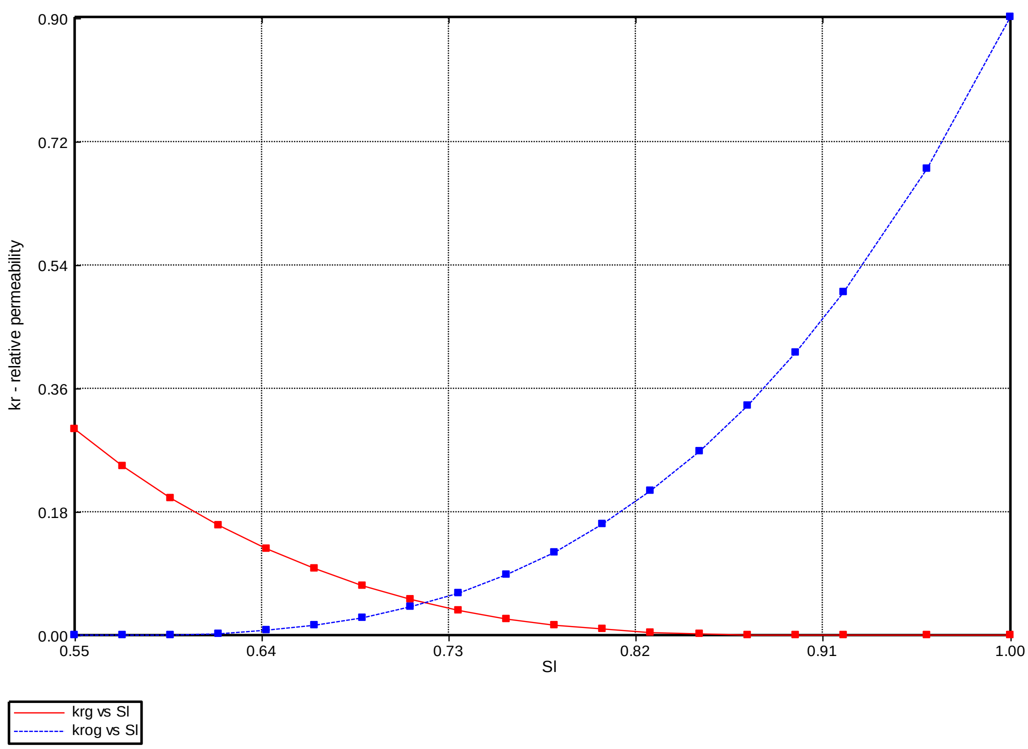

Figure 10: Oil – Gas relative permeability behavior over change in water permeability

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The relative permeability of oil in oil-water phase (Krow) attains stability in the reservoir at and in same rate to that of the relative permeability of gas in oil-gas phase (Krog) presented as Figure 10

Reservoir Homogeneity Effects on Produced water Recovery Efficiency

Effects on Homogeneity on Oil Saturation at Standard Conditions (SC)

The oil saturation assessed in standard conditions (SC) for a homogeneous and anisotropic heterogeneous conventional reservoir under produced water injection shows a responsive behavior of the reservoir to the produced water injected at 2040 psi bottom hole pressure (BHP).

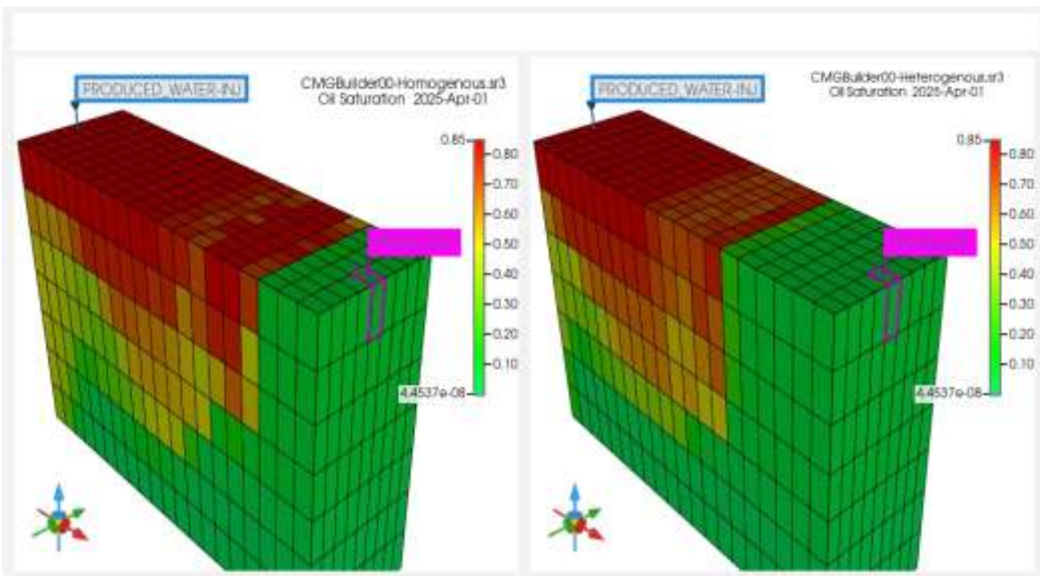

Figure 11: Reservoir Oil rate and saturation behavior under produced water injection

The homogeneous oil saturation shows a fast increase within the reservoir layer horizontally at 0.85097 from the injection well to the producer and gradually down the reservoirs depth as seen at Figure 9, such that within the 4th date out of 121 recurrent dates created for the production within year 2025 to 2035 the homogeneous reservoir shows that the oil saturation was 2550m closer to the production well, which is closer to compare to the oil saturation of the heterogeneous reservoir which at same recurrent date shows a 2100m distance from the production well. The increase oil saturation across the reservoir width and length has a continuous reducing effect on both reservoirs oil producing rate Also, Figure 11 shows that homogeneuty favours favoirs the increase in oil saturation down the reservoirs dept over tie as the layer 5 starts getting populated far before the attainment of the 4th layer from the grid top is populated at the heterogeneous reservoir.This results identifies the perfomanc eof reservoir under produced water injection to be high in a conventional homogeneous reservoir yjan at the heterougeneous reservoir.

Effects on Homogeneity on Oil Recovery Factor at Standard Conditions (SC)

The oil recosvery factor (RF) which is the ratio of the produced oil to the original oil in place (OOIP) achived during crude oil recovery from a reservoir, as achieved from this study differs with the nature of reservoir homoneuity. Figure 12 illustrate the oil recovery factor of a homogeneous and heterogenous reservoir under produced water injection, where the the 77.9% RF was noticed to be achieved by the homogeneous reservoir and 73.9% was chived by the heterougeneous reservoir under same produced water injection properties. The result depicts that a convensional homogeneous reservoir is of higher RF hnce will liably produce more of oil over the assessed period (10 years)

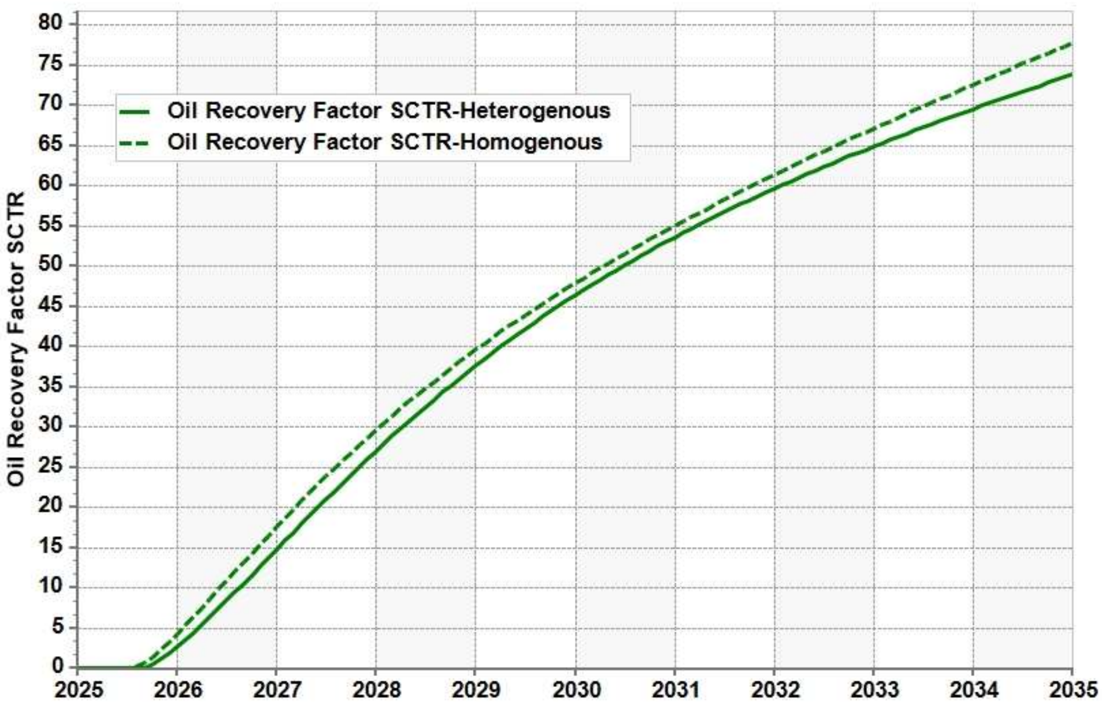

Figure 10: Oil recovery factor at homogeneous bases of produced water injection

The result presented at Figure 12 also shows that the recvery of crude oil under produced water injection EOR system isn't instataneous, as the trace line identifies that the homogeneouse reservoir RF scaleing started 185 days at 0.015% RF value after produced water injection while that of the hetereogeneous reservoir started 300 days after the injection at 0.19% RF value

Effects on Homogeneity on Cumulative Oil Volume at Standard Conditions (SC)

In assessing the cummulative oil of the homogeneous and hetereousgenous reservoi at standard condtions (SC), Figure 13 illustrate a wide difference in oil voume volume produced by the two reservoir systems as the heterorogeneous reservir attains 1.43903×10^5 bbl cumulative oil voulme produced within the 10years production period, which is high than that achived from te hetereogeneous reservoir (1.08851×10^5 bbl). This results are proprotional to thos of the RF which signifies that a homogeneous reservoir experiences high performance suder produced water injection thn the heterogeneous type.

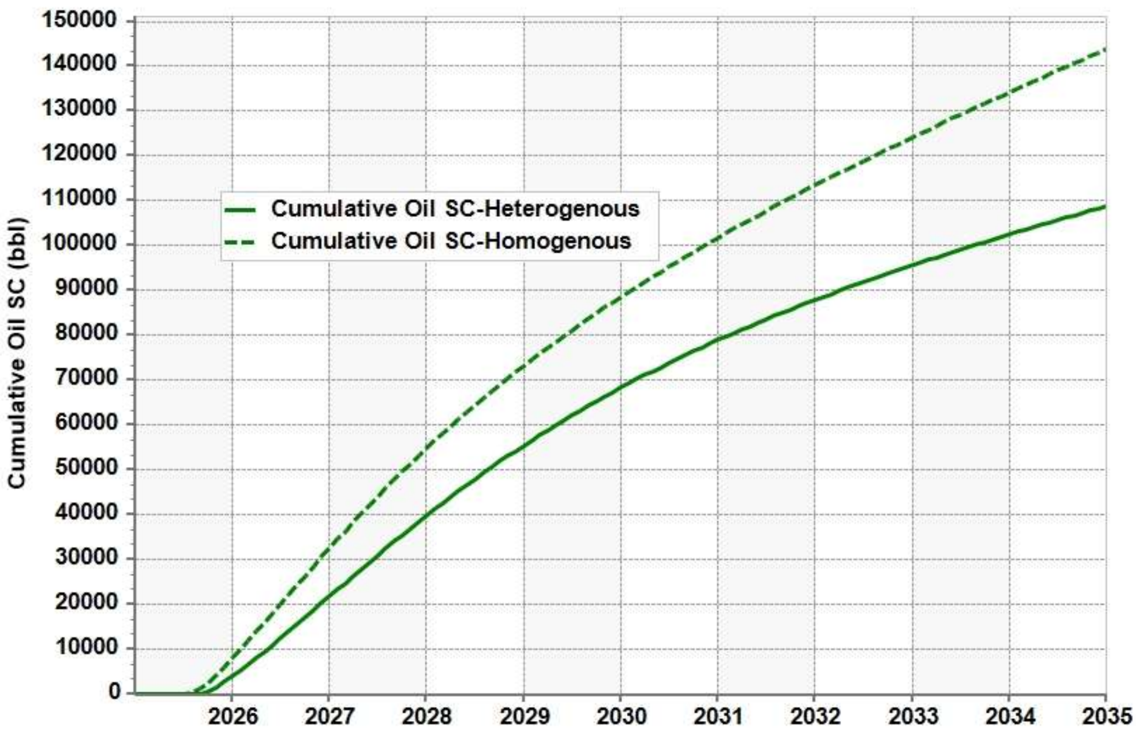

Figure 13: Homogeneous and hetereousgenous reservoir Cummulative oil under produced water injection

Figure 13 illustration also depicts in agreement to that of Figure 12 that the recovery proess of injecting produced water as an EOR concept into a convensional reservoir is ot an instantantaneous recovery process

Gas Oil Ratio (GOR) Behavior with Change in Oil Volume

The relationship between the gas oil ratio (GOR) and the oil volume in the resevoir are beign illustrated as Figure 14 over the EOR recovery period. The result shows that the GOR of the homogeneous reservoir experience an instant rise to peak point of 263180 ft^3/bbl after 143 days of produced water injection with a proportional incrase in oil vvolume from 177681 bbl to 263097 bbl which is greater than that from the heterergeneous reservoir (144597 bbl to 208647 bbl) over the instanstaneous rise in its GOR from initial to 44729.7 ft^3/bbl after 199 days of produced water injection.After which the homogeneous falls drastilly from 263180 ft^3/bbl to 18211.2 ft^3/bbl withing 100 days difference from the peak period of 143 days, then slowlay assended to a GOR value within 8years production period before steabilizing. Similare bahaviors were experienced in the heteregenous reservodir path but assends high than the homogenerous path.

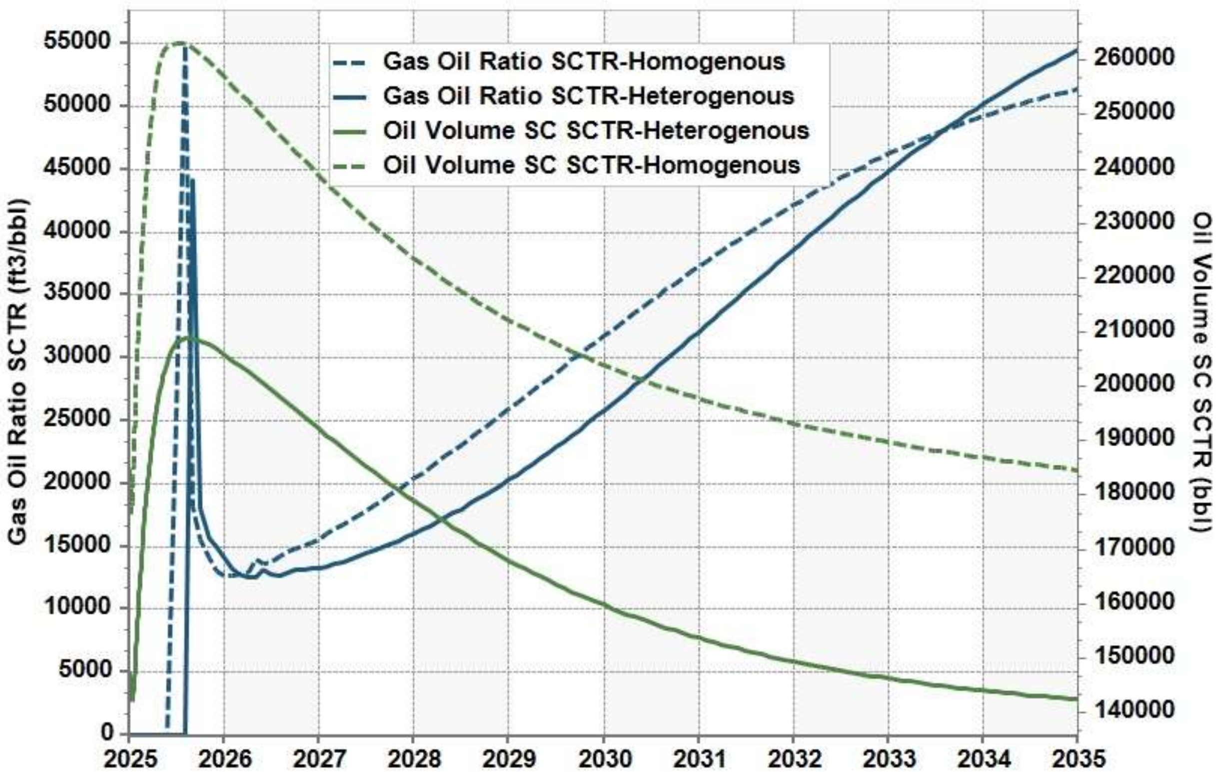

Figure 14: Gas-oil ratio (GOR) relationship with oil volume in a reservoir under produced water injectin

The sudden rise in gas-oil ratio (GOR) under produed water injection primarily means that more gas is being produced relative to the amount of oil, which is an indication that injected water is bypassing some of the oil and flowing through high-permeability zones or existing fractures, allowing trapped or less mobile oil to be left behind, which is potential problems staing pooor efficiency of the produced water withig the region, and that could result to poor sweep efficiency or gas channeling within the reservoir. Hence, the oil volume and RF of the system was mainy achived within the 207 – 3165 days after injection. This act may require Optimizing injection rates to achieve a more stable displacement front and avoid early gas/water breakthrough, or adjusting well locations or perforation strategies to better manage the fluid movement in the reservoir.

Pressure effects with Oil Ratio (GOR) Behavior with Change in Oil and Water Cuts

Figure 15 illustratedreservoir pressure behavior in both homogeneous and the heterogeneous reservoir systems under produced water injectio EOR scheme as a factor to water and oil cuts along the reservoir horizon. Pressure in the homogeneous reservoir tends to travel very fast and occupy the entire reservoir 20 grid horizon of 150ft length such that 1586.434 psi of the prpessure was noticed with the producer well region as fast as before the 6th recurrent date out of 121. When compaiered with the pressure behavior at the heterogeneous reservoir of which 1568.422 psi ressure attained was only experienced within the 7th horizontal grid layer away from the injection well, and 13th layer aware from the production weell. This defined the fact that heterogeneous reservoir under produced water injection will require the injected fluid to be aat twice the pressure applied for a homogeneous reservoir type.

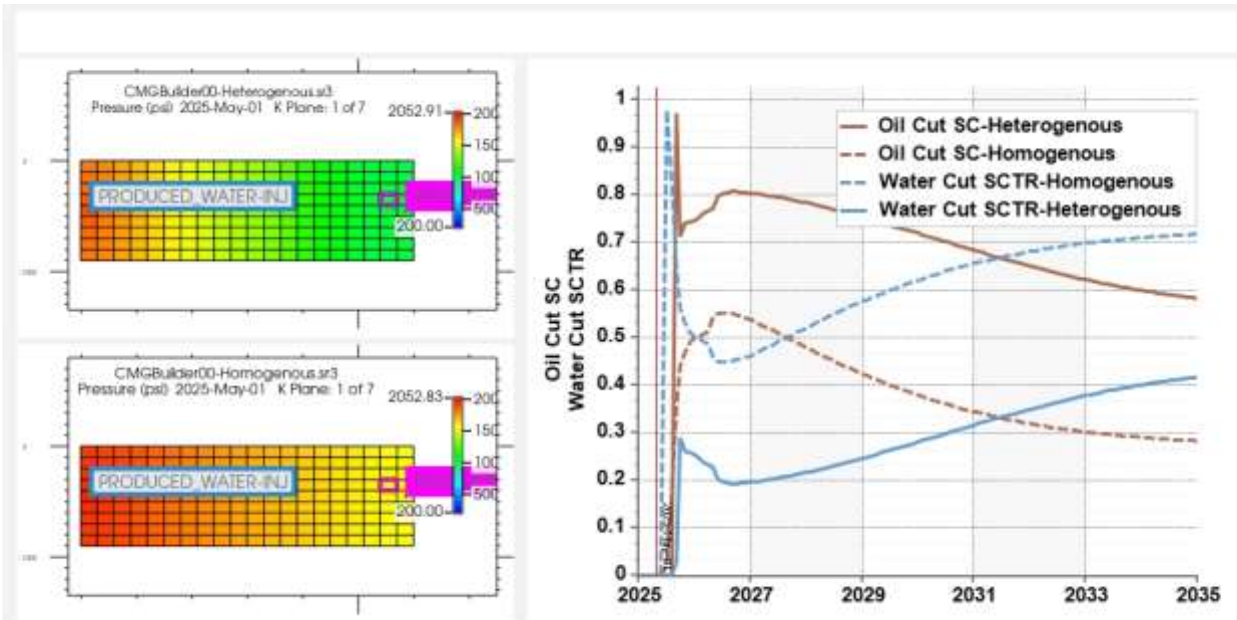

Figure 15: Gas-oil ratio and reservoir recovery performance under produced water injection at homogeneous bases

Also, Figure 15 descivbes the oil cut behavior along the production-well as an inverse proportional function of the reservoir water cut, and both enfluenced by the change in pressure along the reservoir horizontal planes. The reservoir water cut experieanced a vast inccrease up to 98.56% within the first 167 days of injection in the homogeneous reservoir, which is believed to have occurred due to the instanstaneous ainjection of produced water within the period, of which the water cut later on declines to 44.82% as the production period attains 541 days of oil recovery before graduao elevation till it atains 73.76%. While the water cut of the heterogeneous reservoir rises to 29.47% within 370 days after the production start up time, before it now declines slowly to 20.01% at 820 days recovering period before its gradual rise till it finally attends 41.66% at 3652 days recovering period. The behavior of the water cut influences the proportianal change at the oil cut path, as well as it defines the volumwe of oil recovered from both reservoirs.

Oil and water Saturation at Homogeneous and Heterogeneous Reservoirs

Figure 16 illustrates the relationship between oil saturation (S_o) and the water saturation (S_w) of a reservoir as studied over a 3060 ft horizontal distance from the injection well. The result shows that both homogeneous and the heterogeneous resrvoira oil satuiration depletes uniformly 83.9978% to 70.9087% as the injection fluid populates 3025.1 ft length of the resrvoir, at which the the oil saturation at the homogeneous reservoir experiences a vast decline to 25.6314% at 3046 ft distance from the produced water injection well, then processeds declination stepwisely till it attains a 7.9626% oil saturation level at the producer wedlxl region. While the heterogeneous reservoir oil saturation experienced the vast declination after 62.228% withing 3034.7 ft horizontal distance from injection well, which is father when compaired teoo the vast declinative point distance attained by the homogeneous reservoir oil saturation path (3025.1 ft) which signmifies that the heterogeneous oil saturation inhebits the oil qualitative generative abilities quite more distanced to compare to that of the homogenerous reservoir, hence its oil producing volume as well as its RF will abe lower.

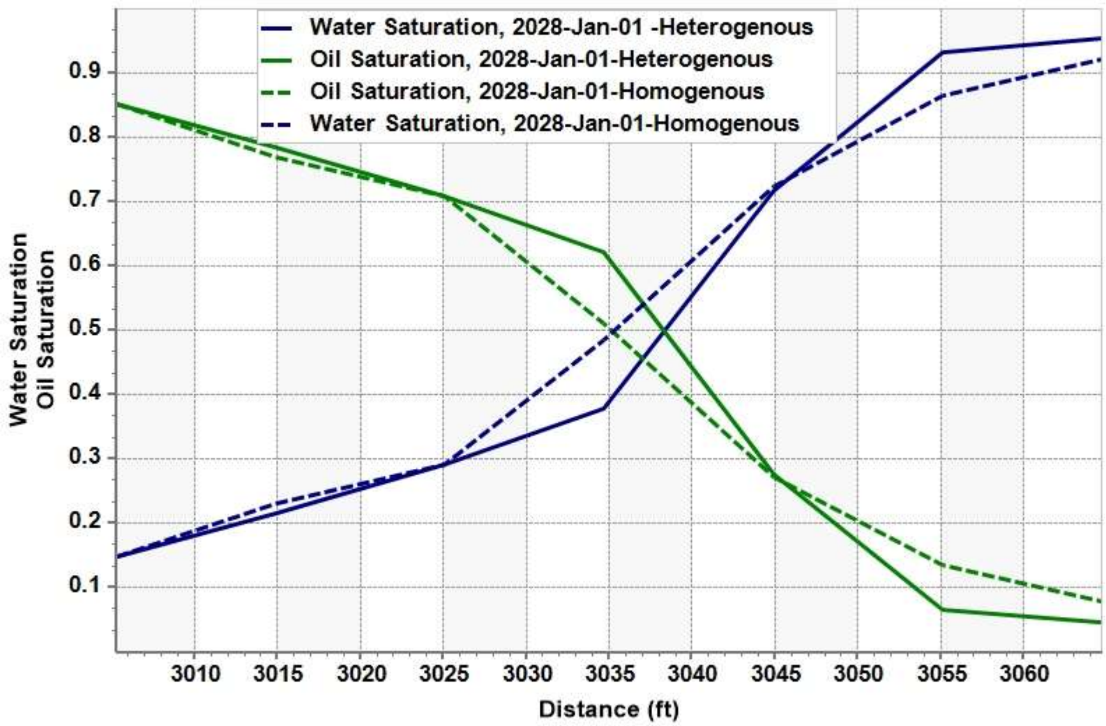

Figure 16: Water and oil saturation relationship for homogeneous and heterogeneous reservoirs under produced water injection

The behavior of the oil saturation (S_o) in the homogeneous ad heterogeneous reservoir are of similar both oposite actions as studied within same distance as seen at Figure 16, which depicts that increase in oil saturation (S_o) is proportional to reductifon in water saturation (S_w) in a reservoir vias versa. And this relationship determines the performance of the reservoir in terms of its recovery factor (RF) as well as volume of oil produced. Also, the relationship illustrated at Figure 16 identifies the fact that thetr is more oil in the reservoir than water within 3035.17 ft distance from the produced water injection well for both the homogeneous and heterogheneous wells.

Effects on Homogeneity on Producer's Oil Rate at Standard Conditions (SC)

Figure 17 illustrated the production rate of oil at per annum bases for both the homogeneous and the heterogeneous models simulated for as a conventional reservoir under process water injection. The result shows that the heterogeneous reservoir system produces more of the oil over the period of recovering as it has it presents the highest production peak of 67.3361 bbl/day oil production rate attained within the first 724.405 days (2years) of production. The homogeneous oil production rate kicks up from mean after 10 days from the injected time, at a steady production rate of 0.598393 bbl/day till it able to attain an oil production rate of 21.8593 bbl/day at 365 days (1years) recovery period using produced water as injection fluid at 2040 psi bottom hole pressure (BHP), after with the system gains altitude and accelerated spontaneously at a higher rate till it reaches the highest oi production peak rate of 67.3361 bbl/day a year after, which it now stated depleting or reducing gradually and steady within the nest 365 days (1 year) till 60.2617 bbl/day before it experiences a tangential fall for the remaining period of production till 26,4638 bbl/day rate was attained at year 2036 when the production process attained its dead end. The oil production rate actions of the reservoir was different and at lesser rate for the case of the heterogeneous reservoir which was modelled at same reservoir conditions as done with the homogeneous reservoir type.

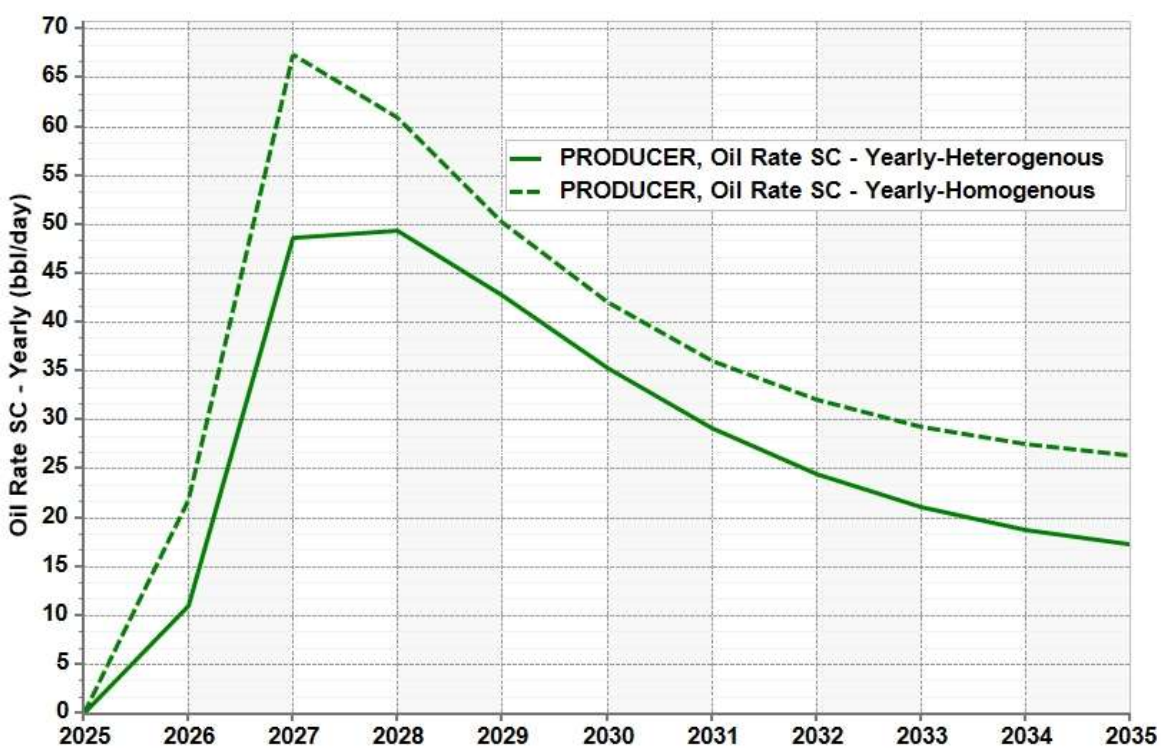

Figure 17: Homogeneity on Producer's Oil Rate at Standard Conditions (SC)

The heterogeneous reservoir shows the system attaining the highest oil production rate peak of 48.6266 bbl/day after 2years which it then produces at steady rate for 1 year before the tangential fall was experienced. It attains its dead end with the production rate of 17.2988 bbl/day, which is absolute lesser than that attained by the homogeneous reservoir at same period of operation. This result depicts that the homogeneous reservoir produces more oil than the anisotropic heterogeneous reservoir type.

Effects on Homogeneity on Oil Recovery Factor at Standard Conditions (SC)

The Figure 18 which Illustrated the behavioral relationship of cumulative oil and gas at standard conditions (SC) as well as at routine core (RC) conditions respectively in an EOR practiced homogeneous and heterogeneous reservoirs shows that the Cumulative gas (CG) formation kicks up 181 days after the injection of produced water for the homogeneous reservoir with accumulation altitude of 100427 ft^3 which was attended 455 days after the injection, before the gas formation attends stationarity (steady state conditions), which it maintained till the completion of the recovery process at 3634 days with 100445 ft^3 as the overall cumulative produced gas. While for the heterogenous reservoir GC started formation 241 days after the injection with an accumulative production altitude of 49473.9 ft^3 attended 485 days before it attained steady state till the end of the production period with CG of 49654.9 ft^3. Also, the result in Figure 16 presented over produced water injection shows that 143094 bbl cumulative oil achieved over the recovery period by injection of produced water at 2040psi into the homogeneous reservoir, while the heterogeneous reservoir yielded 108851 bbl cumulative oil volume within same period.

The behavior of the cumulative gas (CG) in both homogeneous and heterogeneous reservoirs are totally independent to those of the cumulative oils, which signifies that the performance of the well in terms of oil recovering during produced water injection is totally indep0endewnt on the amount of gas formed in the system over time. Also, gas formation during EOR is a flashed process which takes a short formation period to be compared to oil formation in a reservoir.

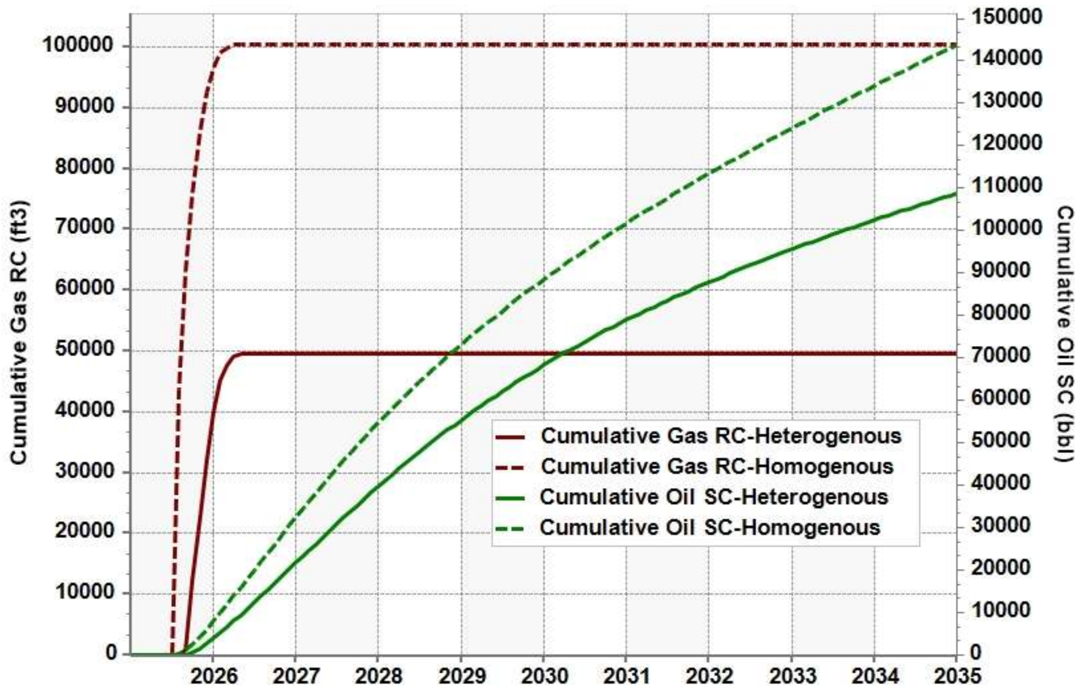

Figure 18: Homogeneity effects on reservoir cum. gas and oil behavior under produced water injection

Producers Well Block Pressure Relationship with Liquid Rate and Reservoir Ternary

Reservoir ternary for produced water injection EOR system illustrated as Figure 19 shows a high fingering rate of the injected fluid at the homogeneous reservoir than at the heterogeneous reservoir type, which is good sign of identifying homogeneous reservoir to be of a better performance. The ternary behavior of the reservoir is highly experienced with the first period of injection and this act increases the reservoir pressure from 204.17 psi to recoverable or producer block pressure of 2001.55 psi within 251 days for heterogeneous reservoir system, and 2008.83 psi within 260 days for homogeneous reservoir system, which is maintained throughout the precovering period of the produced water injection EOR system.

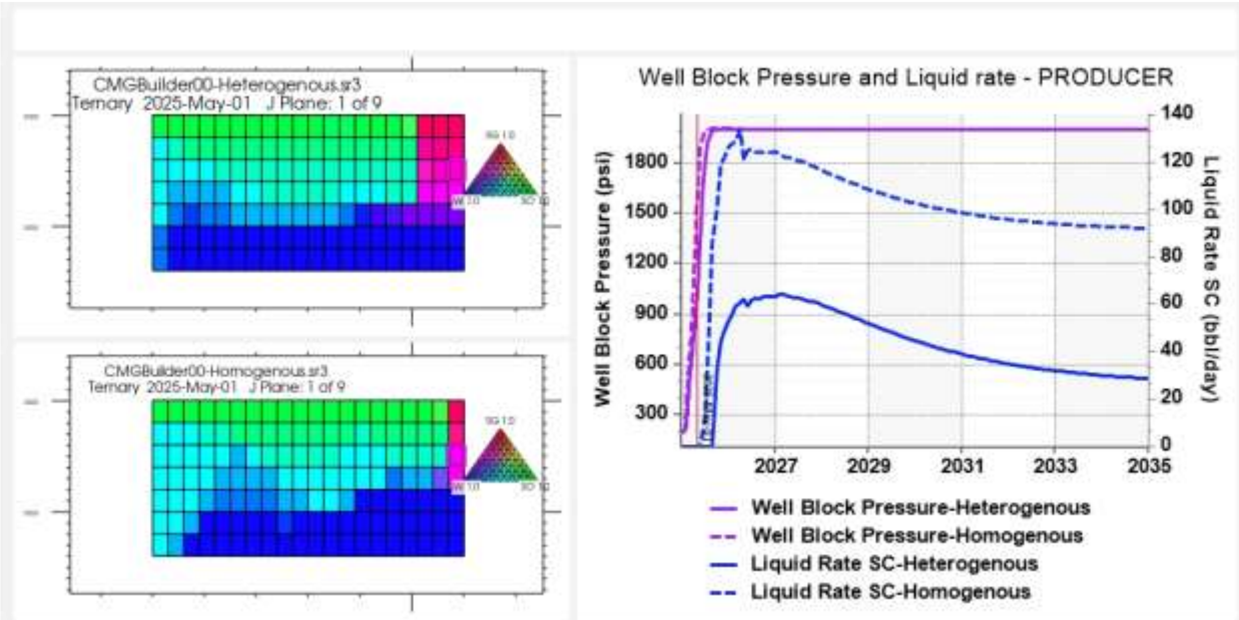

Figure 19: Reservoir ternary and producer well block pressure behavior in an EOR system

The increase in the reservoir block pressure promotes the increase of the reservoir liquid rate assessed at standard conditions from level (0.0 bbl/day) too 134.365 bbl/day for homogeneous reservoir within 103 – 450 days after injection, and rises to 63.3373 bbl/day within 260 – 727 days after injection of produced water into heterogeneous reservoir system, which after the period, both reservoir types liquid rate starts reducing till 92.2266 bbl/day was attended by the homogeneous reservoir and 28.8427 bbl/day by the heterogeneous reservoir.

CONCLUSION

A realistic homogeneous and heterogeneous reservoir were designed using CMG-GEM simulation engine collectively with CMG-WINPROP for assessment of produced water recovery performance efficiency in a black oil reservoir system as an EOR technique. The produced water achieved from IDU- Well10 (located in Orashi area of Niger Delta, Nigeria) was appropriately examined and its physiochemical properties and composites were equally determined, then used in simulating an EOR process as a recovery fluid, in which it was identified to be very effective in hydrocarbons recovery at a recovery factor (RF) greater than the use of normal water as injection fluid. The study which examines homogeneity effects on the produced water recovery efficiency was able to identify that produced water has an RF value of 77.9% when used in a homogeneous reservoir with 143094 bbl cumulative oil volume achieved when injected at a pressure of 2040 psi. While when applied to a heterogeneous reservoir system 73.9% RF value was achieved with 108851 bbl cumulative oil volume, which are lesser when compare to those from a homogeneous reservoir system. The result depicts that a convensional homogeneous reservoir is of higher RF and cumulative oil recovering abilities.

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Appendix A1
WINPROP Simulation Output for Produced Water model

```
********************************************************************************
         *                                                                    *
         *                              WINPROP  2015.10                      *
         *                         EOS Phase Property Program                 *
         *                        General Release for Win x64                 *
         *                          2015-May-22   09:59:51                    *
         *                                                                    *
         *                        (c) Copyright 1977 - 2015                   *
         *                Computer Modelling Group Ltd., Calgary, Canada      *
         *                           All Rights Reserved                      *
         *                                                                    *
********************************************************************************

         Command-line Arguments:  -dd
                                  -f WINPROP PRODUCED water.dat

 Maximum Dimensions:
    Component                  = 200
    SCN Group in + Fractions = 200;   Lab. Calculation points   = 200
    Streams in Process         = 200;   Units in Process          = 20
    Regression variables       = 150;   Regression data points    = 10000

 **FILE NAME:     WINPROP PRODUCED water.dat
 *FILENAMES *OUTPUT *SRFOUT *REGLUMPSPLIT *NONE *GEMOUT
            *STARSKV *NONE *GEMZDEPTH *NONE *IMEXPVT *NONE
 *WINPROP     2015.10
```

```
**=-=-=Titles/EOS/Units
**REM
*TITLE1 'WINPROP PRODUCED WATER'
*TITLE2 ''
*TITLE3 ''
*UNIT *FIELD
*INFEED *MOLE
*MODEL *PR *1978

**=-=-=Component Selection/Properties
**REM
*NC 9 9
*TRANSLATION    1
*TRESDEF    285.0
*EXCESSPROP  *EOS

*COMPNAME
'H2O'  'H2S'  'N2'  'CH4'  'IC5'
'NC5'  'FC6'  'TOLUENE'  'BENZENE'

*HCFLAG
2  4  0  1  1
1  1  1  1

*PCRIT
217.6  88.2  33.5  45.4  33.4
33.3  32.46  40.6  48.3

*TCRIT
647.3  373.2  126.2  190.6  460.4
469.6  507.5  591.7  562.1

*AC
0.344  0.1  0.04  0.008  0.227
0.251  0.27504  0.257  0.212

*MW
18.015  34.08  28.013  16.043  72.151
72.151  86.0  92.141  78.114

*VSHIFT
0.0  0.0  0.0  0.0  0.0
0.0  0.0  0.0  0.0

*VSHIF1
0.0  0.0  0.0  0.0  0.0
0.0  0.0  0.0  0.0
```

```
*TREFVS
60.0  60.0  60.0  60.0  60.0
60.0  60.0  60.0  60.0

*ZRA
0.2338  0.2851  0.2905  0.2876  0.2716
0.2685  0.271261267148  0.2646  0.2696

*VCRIT
0.056  0.0985  0.0895  0.099  0.306
0.304  0.344  0.316  0.259

*VISVC
0.056  0.0985  0.0895  0.099  0.306
0.304  0.344  0.316  0.259

*OMEGA
 0.457235528921  0.457235528921  0.457235528921  0.457235528921
0.457235528921
 0.457235528921  0.457235528921  0.457235528921  0.457235528921

*OMEGB
 0.0777960739039  0.0777960739039  0.0777960739039
0.0777960739039  0.0777960739039
 0.0777960739039  0.0777960739039  0.0777960739039
0.0777960739039

*SG
1.0  0.801  0.809  0.3  0.625
0.631  0.69  0.874  0.883

*TB
212.0  -76.63  -320.35  -258.61  82.13
96.89  146.93  231.17  176.27

*PCHOR
52.0  80.1  41.0  77.0  225.0
231.5  250.1088  245.1  205.1

*IGHCOEF
 -1.93001  0.447642  -2.1898e-005  3.0496e-008  -5.6618e-012
2.7722e-016  -0.300251
 -0.23279  0.237448  -2.3234e-005  3.8812e-008  -1.13287e-011
1.14841e-015  -0.040641
 -0.65665  0.254098  -1.6624e-005  1.5302e-008  -3.0995e-012
1.5167e-016  0.048679
 -2.83857  0.538285  -0.000211409  3.39276e-007  -1.164322e-010
1.389612e-014  -0.602869
```

```
 17.69412  0.015946  0.000382449  -2.7557e-008  -1.43035e-011
2.95677e-015  0.641619
 9.04209  0.111829  0.000228515  8.6331e-008  -5.44649e-011
8.1845e-015  0.183189
 0.0  -0.0165434629528  0.000411690689916  -5.77427572385e-008
0.0  0.0  0.0
 21.18262  -0.053111  0.00034561  -4.363e-008  -9.8553e-012
2.68913e-015  0.815513
 49.94758  -0.185637  0.000532277  -1.8231e-007  3.6689e-011  -
3.20047e-015  1.490507

 *HEATING_VALUES
 0.0  0.0  0.0  844.290010539  3353.66003806
 3353.66003806  3975.91004979  3705.97004316  3097.15003912

 *IDCOMP
 59  0  2  3  8
 9  10  56  57

 *VISCOR   *HZYT
 *MIXVC   1.0

 *VISCOEFF
 0.1023  0.023364  0.058533  -0.040758  0.0093324
 *HREFCOR   *HARVEY

 *PVC3    1.2

 *BIN
 0.12
 0.275  0.13
 0.4907  0.07  0.025
 0.5  0.07  0.1
 0.5  0.07  0.11
 0.48  0.05  0.11
 0.48  0.0  0.1
 0.48  0.0  0.1

 *SALINITY   *MOLAL    324.0

 **=-=-=Composition
 **REM
 *COMPOSITION   *PRIMARY
 81.4   1.55   4.34   0.004   3.67
 2.01   1.09   2.67   3.266

 **=-=-=CMG GEM EOS Model
 **REM
```

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Website: https://www.eajournals.org/
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```
**NC 9 9
*PRNGEM
*TRES  200.0
*AQUEOUS-DENSITY  *ROWE-CHOU
*AQUEOUS-VISCOSITY  *KESTIN

**=-=-=     END


WinProp 2015.10
Total EOS calls without derivatives =        0
Total EOS calls with    derivatives =        0
Total calculations performed        =        3

Date and Time at End of Run : 2025 Nov  5,  18:48:56
CPU seconds used            :    0.02
```

Appendix B1

Physiochemical analytical results of the used produced water

AUSTINO RESEARCH
& ANALYSIS LABORATORY NIG. LTD.
MOTTO: IMPROVING KNOWLEDGE VIA RESEARCH WORK
RC- 1268575

HEAD OFFICE:
#2 UPTH Road,
Alakahia Junction,
Opposite Alakahia Park,
Behind Jovit Restaurant,
Alakahia Uniport, PH.
Email: austinoralab@gmail.com
Tel: 07066198333;09092856207

Certificate of Analysis

NAME OF CLIENT:	Mr Igwe
NO. OF SAMPLE (S):	5
SAMPLE TYPE:	Waste water
ANALYSIS REQUIRED:	Physiochemical Analysis
REPORTING DATE:	13/10/2023

Sample	Outlet filter 1	Outlet filter 2	Outlet filter 3	Outlet filter 4	Outlet filter 5	WHO Standard
pH (ppm)	5.67	5.84	5.73	5.68	5.76	6.5-8.50
E.C (ppm)	1750.24	1741.60	1753.01	1761.85	1758.30	1000
TOC (%)	1.24	1.18	1.21	1.25	1.20	0.5
TSS (ppm)	40.67	40.84	40.72	40.36	40.53	250
T. Oil (ppm)	0.13	0.18	0.15	0.17	0.14	0.01
BTEX (µg/l)	45.21	44.98	45.18	45.11	45.27	10
Chloride (ppm)	350.67	353.17	350.48	350.17	350.94	250
Bicarbonate(ppm)	4.01	3.98	3.86	4.11	3.96	2.0
Sulphate (ppm)	310.74	310.60	310.52	310.79	310.82	250
NH3-N (ppm)	5.10	5.13	5.18	5.11	5.17	0.5
Sulphite (ppm)	0.18	0.21	0.14	0.19	0.16	0.04
Total polar (THC) (µg/l)	550.46	550.89	550.02	550.62	550.46	300
Higher Acid Ethanoic acid (µg/l)	38.21	38.95	38.73	38.20	38.42	10
Phenol (µg/l)	75.86	75.50	75.63	75.92	75.83	50
Volatile Fatty acid (µg/l)	0.53	0.58	0.51	0.57	0.55	0.1

Sign.............................
Lab Analyst

AUSTINO RESEARCH & ANALYSIS LABORATORY NIG. LTD.

MOTTO: IMPROVING KNOWLEDGE VIA RESEARCH WORK

RC- 1268575

HEAD OFFICE:
#2 UPTH Road,
Alakahia Junction,
Opposite Alakahia Park,
Behind Jovit Restaurant,
Alakahia Uniport, PH.
Email: austinoralab@gmail.com
Tel: 07066198333;09092856207

Certificate of Analysis

NAME OF CLIENT:	Mr Igwe
NO. OF SAMPLE (S):	3
SAMPLE TYPE:	Waste water (Treated)
ANALYSIS REQUIRED:	Heavy Metal Analysis
REPORTING DATE:	13/10/2023

Sample	Outlet filter 1	Outlet filter 2	Outlet filter 3	WHO Standard
Pb (ppm)	0.03491	0.02974	0.02721	0.05
Cd (ppm)	0.00174	0.00206	0.00187	0.005
Ca (ppm)	89.38273	90.08471	89.14093	200
Na (ppm)	120.53981	119.94892	119.48136	200
K (ppm)	1.59024	1.51157	1.49563	5.0
Mg (ppm)	56.13913	56.49173	55.21940	150
Fe (ppm)	0.08574	0.08114	0.08367	0.3
Al (ppm)	0.05904	0.06265	0.05148	0.2
B (ppm)	0.00392	0.00411	0.00342	0.01
Ba (ppm)	0.02143	0.02314	0.02620	1.0
Cu (ppm)	0.16590	0.14231	0.13085	1.0
Cr (ppm)	0.01781	0.01613	0.01493	0.05
Li (ppm)	0.01827	0.01730	0.01315	0.03
Mn (ppm)	0.02968	0.03104	0.02819	0.1
Sr (ppm)	BDL	BDL	BDL	0.02
Ti (ppm)	BDL	BDL	BDL	0.004
Zn (ppm)	1.84921	1.81154	1.79036	5.0
As (ppm)	0.00185	0.00213	0.00177	0.05
Hg (ppm)	BDL	BDL	BDL	0.001
Ag (ppm)	BDL	BDL	BDL	0.02

Sign..............................
Lab Analyst