

Geochemistry Of Onshore Oils Within Oil Mining Lease (OML A) Of The Southern Niger Delta, Nigeria

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Abstract: *The geochemical analysis of seven crude oil samples B,C,D,E,F,G,H from OML A were performed to determine the Bulk composition of oils, organic matter inputs, source depositional environment and thermal maturation comparatively. The crude oil samples were fractionated into individual bulk composition of Saturates, Aromatics, Resin and Asphaltene (SARA) using ASTM D4124-09 test standards. The pour point properties for flow assurance application and the Total acid number (TAN) were measured with ASTM D5853 and ASTM D664 methods respectively. Sulphur contents were analyzed by Wave length dispersive X-ray fluorescence spectrometer (WDXRF) according to ASTM D2622 standards. Evaluation of the biomarkers was achieved by GC-MS and GC-FID with saturates extracts in selected ion monitoring (SIM) according to ASTM D7169. API values ranged from 10.90 – 16.10. The Sulphur content for the crude oils ranged from 1.33mg/l-2.85mg/L, with the crude oil in B Well recording the highest sulphur content and D Well was found to be the lowest. TOC were found to be similar in crude oil from five oil wells as seen with B Well, C Well, G Well, F Well and H Well respectively. The saturated hydrocarbon content ranges from (40.0 -67.06) % with H Well crude recording the highest, while the aromatic hydrocarbon varied from (15.29 – 36.71) %. The ratio of Sat/Arom ratio ranges from 1.15 – 4.38 with H crude having the highest and F crude having the least concentration. The crude oil from the seven oil wells were all paraffinic and undegraded (non – biodegraded) crude. The result showed that the crude oil samples were all heavy crude and the crude oils were derived from source rocks containing type I and II kerogen from agal marine source deposited in anoxic environment. The Biomarker parameters CPI, Pr/Ph ratio, Pr/n-C17, Ph/n-C18, TAR etc. used for maturity indices, showed that the selected seven crude oils samples from OML A oil wells were all matured with some showing more maturity level than the others. However, we can use the crude oil from the result to reconstruct the nature of the source rock of the oil, since the crude oil is paraffinic and undegraded crude their features have not changed.*

Keywords: *Paraffinic, Biodegradation, Oil fields, Biomarkers, Mining*

I. INTRODUCTION

Hydrocarbon buildup and reservoir potential begin with source rocks. Source rocks, in general, are organic-rich sediments that contain or may generate hydrocarbons and are a key component of any petroleum system. The quality of source rock is critical to successful oil and gas exploration. For more than three decades, Rock-Eval pyrolysis procedures

have been used to determine source-rock parameters such as Hydrogen Index (HI), Oxygen Index (OI), Production Index (PI), remaining hydrocarbon producing potential (S2), and a variety of additional products (Peters, 2011), by providing information about their kerogen type and organic matter quality, type of organic matter and characteristics, thermal maturity of the organic matter, and hydrocarbon type, (oil, gas or both). Rock-Eval pyrolysis is used to rapidly evaluate and

characterize the petroleum generating potentials of prospective source rocks (Peters, 2011). The hydrocarbon generating potential of sediments is assessed by looking at the sediment's capacity for hydrocarbon generation, the type of organic matter present, and what hydrocarbons might be created, as well as the sediment's thermal maturity and how it has affected generation (Dembicki, 2009). Because of the dynamism of economic expansion, demand for hydrocarbons is always increasing and will continue to do so for many years. As the cost of Oil exploration continues to rise, the petroleum sector is seeking for ways to reduce exploration risk. Understanding the geochemistry and hydrocarbons potentials of oils in OMLA is one approach to do this. A number of studies have been conducted in the Niger Delta to identify the location and effectiveness of the region's source rocks (Ekweozor, and Daukoru, 2004).

However, collection of crude oil samples from locations B,C,D,E,F,G,H. in OML A, in southern Niger Delta, determining the Total organic carbon and Organic matter present in samples, as well as evaluating maturity indices, biodegradation status and source depositional conditions and organic matter type present in the Crude Oil wells, will contribute significantly to the knowledge on the elucidation of the qualities of Oils in the southern Niger Delta.

II. MATERIALS AND METHODS

THE STUDY AREA

The study area is located in the onshore Niger Delta, a prolific oil producing region and a producing conventional oil field. The licence covers 1,095 square km and contains 11 fields, B, F, C, D, L, E, H, G, I, K and M. L G, and K are the three fields that cross over the license line. The field was discovered between 1961 – 1966. OML A has nine flow stations and gas compression.



Plate 3. 1: Geologic location of the Oil Producing Region in OML A situated in the Onshore Niger Delta, showing 11 fields. B, F, D, C, H, E, I, G, K, L and M

SAMPLE COLLECTION

Samples were taken from wellhead at different field location with the use of nipple into 1 litre glass can and were

preserved according to APHA standard before taken to the Laboratory. The Collection of crude oil samples within Seven(7) locations in OML A from the different oil wells and evaluation of some physicochemical components under consideration were carried out. These analyses were carried out using standard operating procedures from the American Standard for Testing Material. These properties include the following

PHYSICO-CHEMICAL PARAMETER OF TEST SAMPLES

Specific gravity at 16°C/60°F, American Petroleum Institute (API) of the crude oil samples were measured using thermo hydrometer method ASTM6822 test, calibrated to API index standard ISO/IEC 17025.

✓ **PROCEDURE:** Crude oil sample was poured into a dry 500mL measuring cylinder filled approximately by ¾ full and air bubbles were allowed to rise to surface, then the hydrometer was gently lowered into the crude sample and stirred gently, however the hydrometer was allowed to come to rest by floating freely and not touching the walls of the cylinder. Readings were taken. Thereafter, the API for each of the seven crude oil samples were calculated with the formula $API = (141.5/S.G@60^{\circ}F) - 131.5$.

SARA SEPARATION OF SAMPLES

SARA analysis (ASTM D 4124-09), as well as the percentages of hopanes(m/z 191) and steranes (m/z 217 and 218) using ASTM D 7169 were carried out to standard. However, the crude oil samples were fractionated into saturates, aromatics (hydrocarbon) non-polar and Resin and Asphaltene (non – hydrocarbon) polar compounds by Column chromatography on a silica gel at room temperature. The 1000mL column was rinsed with dichloromethane (DCM) and later with petroleum ether, thereafter the column was plugged with cotton wool as a pad for the stationary phase(silica gel) and filled with petroleum ether. 2g of alumina was added to stabilize the surface. Then 1mL of oil sample in a dropping pipette was added followed by the eluent gently, 70mL of petroleum ether was added to elute the aliphatic fraction (saturates) and DCM was used to elute the aromatic fractions. 70mL of methanol was added to elute the resins. Thereafter the asphaltene fraction was reduced to near dryness with nitrogen stream and then diluted with DCM for GC-MS analysis.

Biomarkers like hopane and sterane contained in the saturates were analysed to provide critical information on crude oil correlation, characterization and quantification using GC-MS and GC-FID system. The saturates extracts were by MS in selected ion monitoring (SIM) using ASTM D 7169 standard, as well as quantifying the hydrocarbon chain from C₁ to C₄₀ for information on concentration, molecular weight and configurations of the biomarkers using GC-FID. The GC operation conditions were performed on HPCHEM with a silica capillary column (25m x 0.32mm x 0.52µm) in which the carrier gas was helium(He); kept at a flow rate of 1mL/min. The GC oven was programmed on 0min at 90°C then ramped to 270°C at 6°C/min, held at 270°C for 30mins. The

injected quantity was 1µL of 2% volume of solution in tetrachloromethane of sample. The temperature set for both the injector and FID were 270^oC

III. RESULTS AND DISCUSSION

RESULT

PHYSICAL CHARACTERISTICS OF CRUDE OIL

Specific Gravity

Specific gravity recorded in the sampled Crude Oil wells ranged from 0.96 – 0.99.

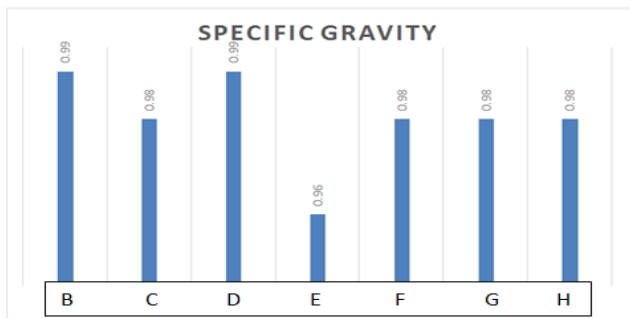


Figure 1: Specific Gravity Values of the Crude Oil in the Study Areas

AMERICAN PETROLEUM INSTITUTE (API) GRAVITY

American Petroleum Institute (API) Gravity values in the study stations ranged from 10.90 – 16.10. Well G had the highest API value of 16.10. Well E had API value of 13.30; C and D had similar values of 13.20, While F, H and B exhibited API values of 12.60, 11.60, and 10.90 respectively. API values for the various sampled oil wells are shown in the Figure 2.

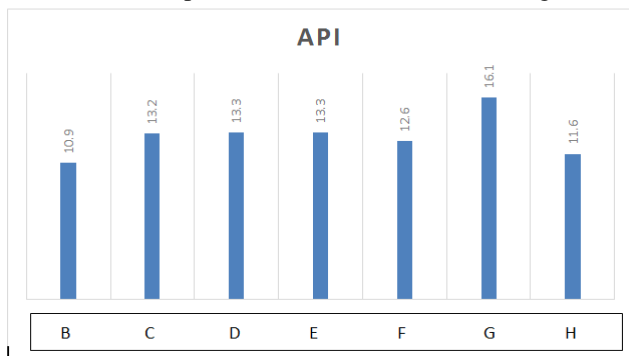


Figure 2: API Values of the Crude Oil in the Study Areas

CHEMICAL CHARACTERISTICS OF CRUDE OIL

TOTAL ORGANIC CARBON (TOC)

TOC in the study areas ranged from 1.29 - 7.96 %. B, C, G, F, and H oil wells had similar values of 7.96 % of TOC. D oil well had a lower value of 3.94 % while oil well E had the lowest value of 1.29 % (Figure 3).

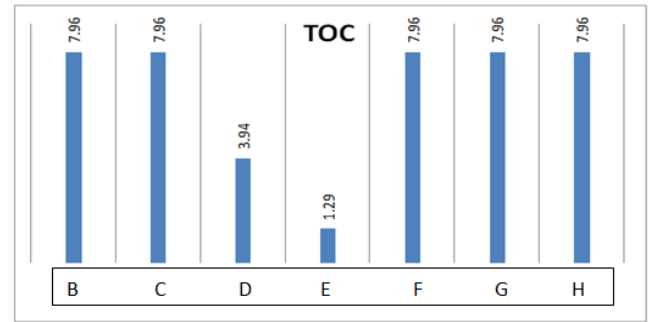


Figure 3: TOC Values of the Crude Oil in the Study Areas

SULPHUR

The highest sulphur value of 2.85 mg/L was recorded in the B oil well. The oil from H and E oil wells had similar values of 1.68 mg/L while G, C, F wells exhibited sulphur values of 1.66 mg/L, 1.46 mg/L, and 1.40 mg/L respectively. The lowest sulphur value of 1.33 mg/L was observed in the D oil well (Figure 4).

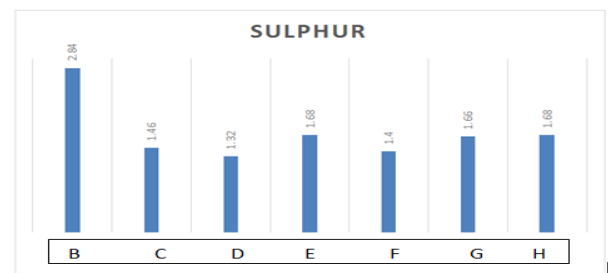


Figure 4: Sulphur Values of the Crude Oil in the Study Areas

COLLOIDAL INSTABILITY INDEX (CII)

CII in the study areas ranged from 0.97 -2.86. H oil wells had the highest CII value of 2.86. Figure 5 Shows the CII values obtained from the various oil wells studies.

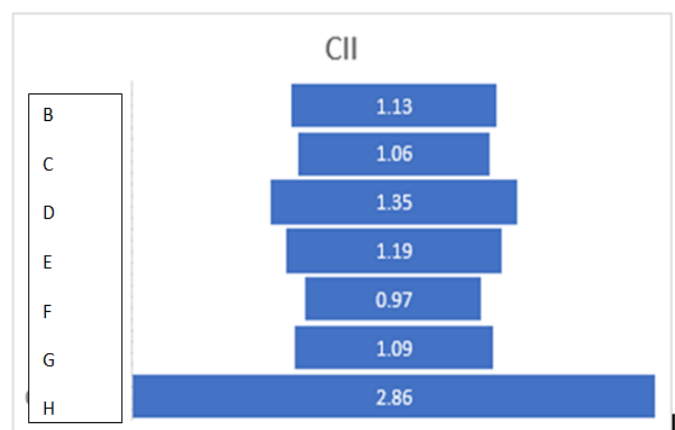


Figure 5: Colloidal Instability Index values of the Crude Oil in the Study Areas

SARA VALUES OF THE CRUDE OIL IN THE STUDY AREAS

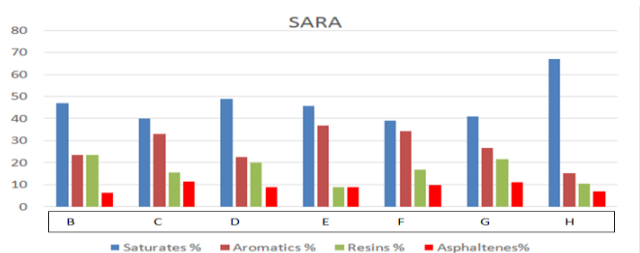


Figure 6: SARA Values of the Crude Oil in the Study Areas

%SATURATES AND %AROMATICS

% Saturates in the study areas ranged from 40.00 – 67.06 %. H oil field had the highest % saturates value of 67.06 % followed by oil from D, B, E, G, C and F with % saturates values of 48.75 %, 46.87 %, 45.57 %, 40.82 %, 40.00 % and 39.17 % respectively. Oil well F had a lower saturates % value (Figure 6). The % aromatic of the study areas varied between 15.29 % to 36.71%. Oil well E had the highest % aromatic value of 36.71 % followed by oil from F, C, G, B and D with % aromatic values of 34.16 %, 32.86 %, 26.53 %, 23.44 % and 22.50 % respectively. The lowest % aromatics was recorded in the D oil well (Figure 6).

%RESIN AND % ASPHALTENE

% Resin in the study areas ranged from 8.86 – 23.44 %. B oil field had the highest Resin % value of 23.44 % followed by oil from G, D, F, C, H and E with % Resin values of 21.43 %, 20.00 %, 16.67 %, 15.71 %, 10.59 % and 8.86 % respectively. E oil well had a lower saturated % value (Figure 6). The % asphaltene of the study areas varied between 6.25 % to 11.43 %. C oil well had the highest % asphaltene value of 11.43 % followed by oil from F, E, D, H and B with asphaltene % values of 11.22 %, 10.00 %, 8.86 %, 8.75 % and 7.06 and 6.25 % respectively. The lowest % asphaltene value was recorded in the B oil well (Figure 6).

SAT/AROM

Sat/Arom ratio in the study areas ranged from 1.15 – 4.38 %. H oil field had the highest sat/arom ratio value of 4.38 followed by oil from D, B, E, G, C, and F with sat/arom ratio values of 2.17, 1.99, 1.54, 1.24, 1.22 and 1.15 respectively. F oil well had a lower sat/arom ratio value.

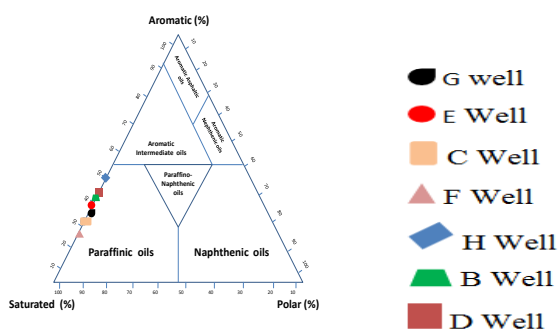


Figure 7: Ternary Plot illustrating the Proportions of Saturated and Aromatic Hydrocarbons, along with Resin and Asphaltene Components, found in the analyzed oils (Modified after Peters et al., 2005; Hakimi et al., 2020)

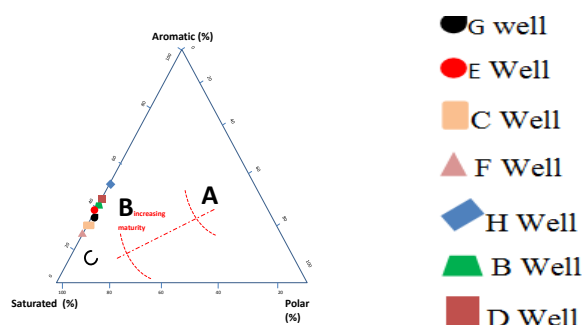


Figure 8: Ternary Plot of the analyzed Oils in terms of SARA (Modified after Peters et al., 2005; Hakimi et al., 2020)

Sample	%Sat	%Arom	%Res	%Asph	Sat/arom	As/R	CII	%Toc	Sulphur
B	46.87	23.44	23.44	6.25	1.99	0.27	1.13	7.96	2.84
C	40.00	32.86	15.71	11.43	1.22	6.68	1.06	7.96	1.46
D	48.75	22.50	20.00	8.75	2.17	0.44	1.35	3.94	1.32
E	45.57	36.71	8.86	8.86	1.24	1	1.19	1.29	1.68
F	39.17	34.16	16.67	10.00	1.15	0.59	0.97	7.96	1.40
G	40.82	26.53	21.43	11.22	1.54	0.52	1.09	7.96	1.66
H	67.06	15.29	10.59	7.06	4.38	0.67	2.86	7.96	1.68

Table 1: Bulk Composition of the Different Crude Oil Wells in the Study Areas

BIOMARKER PARAMETERS OF CRUDE

Molecular marker ratios Pristane/Phytane (Pr/ph), Carbon Preference Index (CPI), Pr/n-C₁₇, Ph/n-C₁₈ and terrigenous Aquatic Index (TAI) for all crude oil samples analyzed are presented in Table 3. The gas chromatography result for the oils from the crude oil wells in the study areas are presented in Figures 15 – 21.

Sample	CPI Ratio	Pr/ph	TAR	Pr/n-C ₁₇	Ph/n-C ₁₈
B	1.24	0.85	0.89	0.04	0.04
C	1.12	2.72	0.67	0.03	0.01
D	1.10	0.54	0.79	0.01	0.02
E	1.65	1.44	0.71	0.01	0.01
F	1.12	0.77	0.27	0.01	0.02
G	1.14	1.93	0.75	0.03	0.01
H	1.12	1.46	0.62	0.02	0.01

CPI=Carbon preference Index, Pr =Pristane, Ph = Phytane, TAR-Terrigenous to Aquatic index

Table 2: Biomarker Parameters of the Different Crude Oil Wells in the Study Areas

PR/PH

The gas chromatograms of the examined oils (Figure 15 – 21) show the distributions of normal alkanes (ranging from C₄ to C₃₆) and acyclic isoprenoids. The concentration of the isoprenoid phytane (Ph) was higher than the concentration of pristane (Pr) in B, D and F resulting in a Pr/Ph ratio of less

than 1.0 as shown in Table 3. C, E, G, and H was greater than 1.0, Table 3 which indicates higher pristane concentration compared to phytane (Ph). Figure 9 presents the Pr/Ph ratio values obtained in this study.

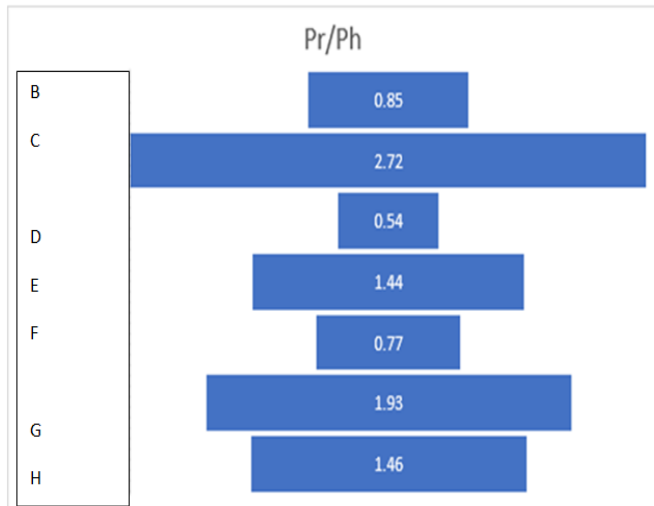


Figure 9: Pr/Ph Values of the Crude Oil in the Study Areas

CPI RATIO

CPI ratio in the study areas ranged from 1.10 – 1.65. E oil field had the highest CPI ratio value of 1.65 followed by oil from B, G, E, C, and F and H with CPI ratio values of 1.24, 1.14, 1.12, 1.12, 1.12 respectively. D had the lowest CPI ratio value of 1.10 (Figure 10).

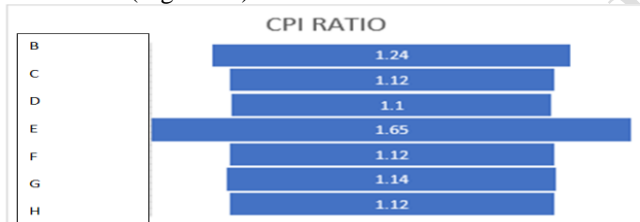


Figure 10: CPI Values of the Crude Oil in the Study Areas

TERRIGENOUS TO AQUATIC INDEX (TAR)

TAR ratio in the study areas ranged from 0.27 – 0.89 B oil well had the highest TAR value of 0.89. TAR values recorded in the sampled oil wells are presented in figure 11

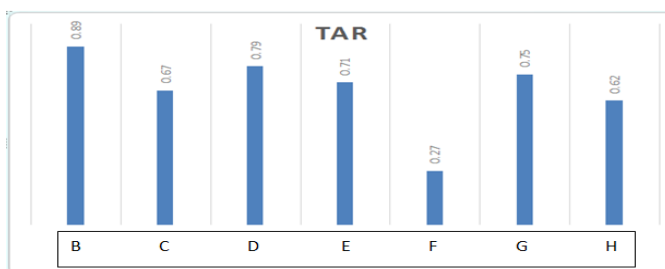


Figure 11: TAR Values of the Crude Oil in the Study Areas

PR/N-C₁₇ AND PH/N-C₁₈

Pr/n- C₁₇ in the study areas ranged from 0.01 – 0.04. B oil well had the highest Pr/n- C₁₇.

value of 0.04. Pr/n- C₁₇ value obtained in the sampled oil wells are presented in figure 12. Ph/n- C₁₈ in the study areas ranged from 0.01 – 0.04. B oil well had the highest Ph/n- C₁₈ value of 0.04. Ph/n- C₁₈ values observed in the sampled oil wells are presented in figure.12.

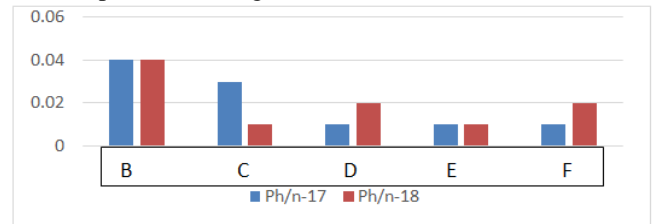


Figure 12: Pr/n-C₁₇ and Ph/n-C₁₈ Values of the Crude Oil in the Study Areas

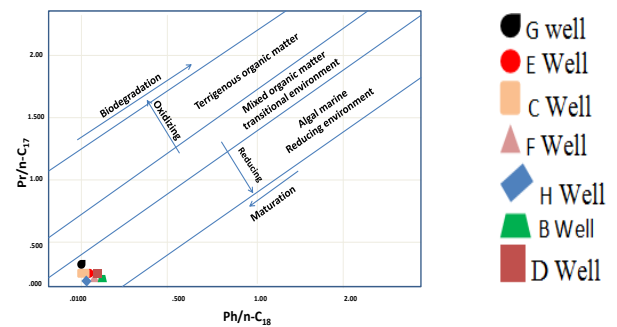


Figure 13: Cross Plot of Pr/n- C₁₇ and Ph/n- C₁₈ Values of the Crude Oil in the Study Areas

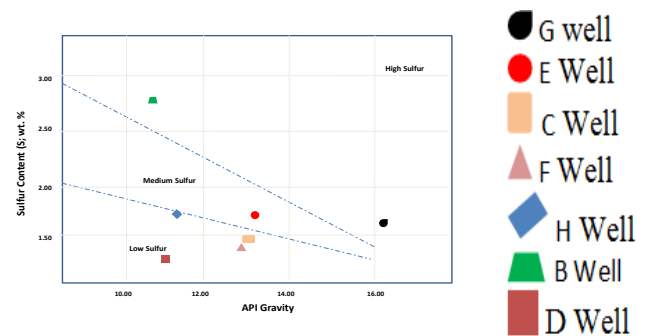


Figure 14: Cross Plot of Sulphur and API Values of the Crude Oil in the Study Areas

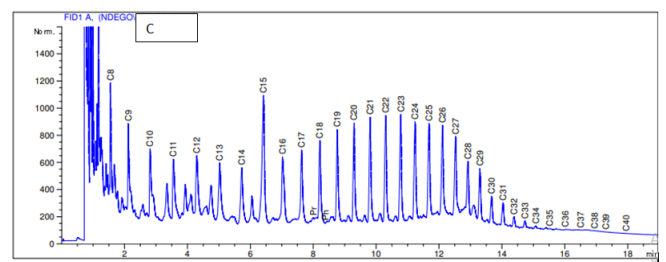


Figure 15: Chromatographic Results of Oil from Well C

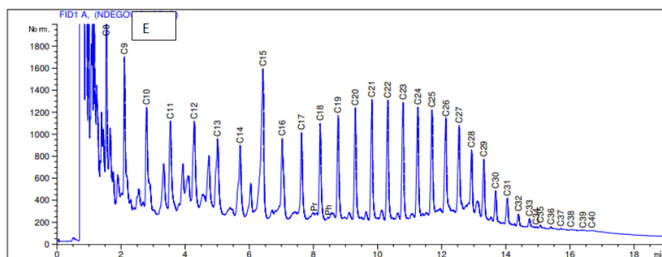


Figure 16: Chromatographic Results of Oil from Well E

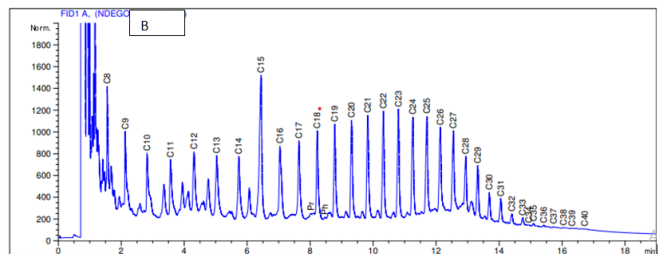


Figure 17: Chromatographic Results of Oil from Well B

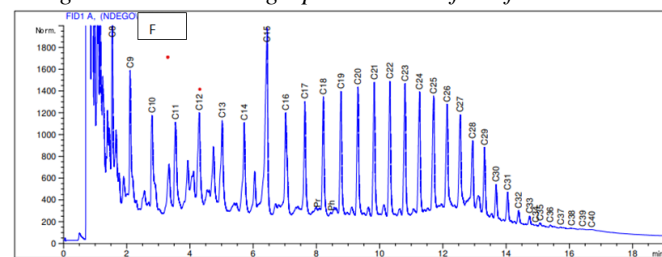


Figure 18: Chromatographic Results of Oil from Well F

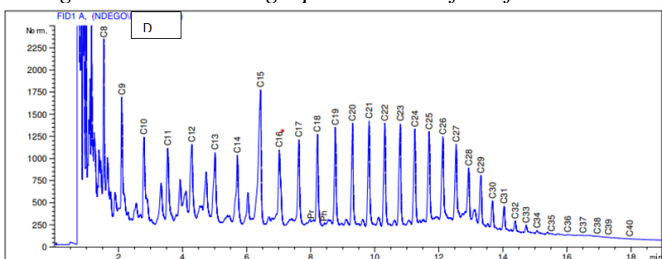


Figure 19: Chromatographic Results of Oil from Well D

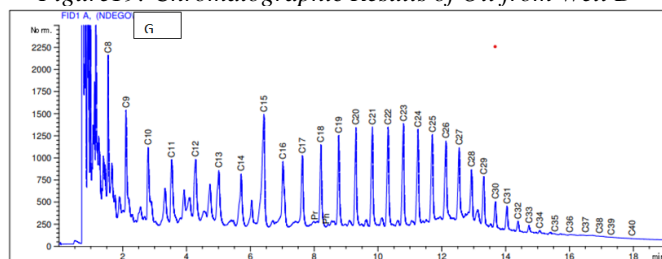


Figure 20: Chromatographic Results of Oil from Well G

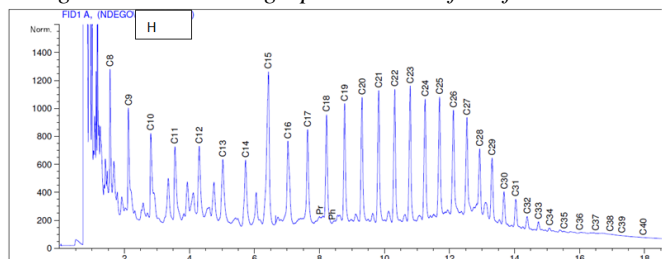


Figure 21: Chromatographic Results of Oil from Well H

DISCUSSION

Hundreds and thousands of different substances have been identified in Crude oils which are comprised of intricate combinations of hydrocarbons and other substances, spanning from small, easily evaporating compounds to larger, less volatile ones (Wang *et al.*, 2007).

PHYSICAL CHARACTERISTICS

The American Petroleum Institute (API) measures the density of crude oil (Chinenyeze and Ekene., 2015). The API gravity of crude oil is influenced by its composition, where lower-density crude oils are lighter and have higher API gravity values. Conversely, denser crude oils exhibit lower API gravity values (Chinenyeze and Ekene., 2015; Egbo *et al.*, 2015). Crude oils are classified into three groups based on API gravity: light (API > 35), medium (API: 25-35), and heavy (API < 25) (Wang *et al.*, 2007). In the current study, the API values obtained from the various sampling stations indicate that the crude oils belong to the heavy category (API < 25). Additionally, the sulfur (S) content in crude oil is used as an indicator of depositional conditions and thermal maturity level (Egbo *et al.*, 2015). Crude oil is termed “sweet” when its sulfur content is below 1%, and it is categorized as “sour” when its sulfur content is above 1% (API, 2011). All the studied oil samples within the study region exhibited sulfur levels surpassing 1%, indicating the presence of sour crude oil. In this work, API values and sulfur values were used to distinguish the S-classification, as described by Orr., 2001 and Hakimi *et al.*, 2020. Sulfur content versus the API gravity of oil samples from different crude oil wells in the study areas, showed that B and G oils had kerogenic high sulfur, E had kerogenic medium sulfur, and C, F, and H had Kerogenic low sulfur (Figure 14). Uzoegbu *et al.*, (2023) also reported higher API values ranging from 24.70 to 35.00 degrees in a similar study conducted on oils in Sapele, Nigeria.

IV. BULK COMPOSITION

The chemical makeup of crude oil consists of four primary components, namely saturated hydrocarbons, aromatics, resins, and asphaltenes (Sayed *et al.*, 2021). These components are collectively referred to as SARA. SARA can be used to estimate the thermal maturity of potential source rocks (Peters *et al.*, 2005; Hakimi *et al.*, 2022). When the oil contains relatively high amount of polar components such as resins and asphaltenes, it indicates that the source rock has lower maturity, as polar component tend to decrease with increasing thermal maturity (Peter *et al.*, 2005; Egbo *et al.*, 2020; Hakimi *et al.*, 2022). In this study the crude oil samples from different sampling stations showed higher levels of Saturated and aromatic hydrocarbons, while resin and asphaltene compounds are found in smaller quantities figure 5. The SARA values graphically represented in a ternary diagram following Tissot and Welte's method from 1984 (Modified by Orr., 2001; Hakimi *et al.*, 2020) grouped the oil samples in the study areas into moderate to highly mature source rock. H, F, B were in the high mature category while E,

G, C, and F were in the moderately mature category (Figure.8). The ternary diagram (Figure 7) classified crude oil based on the predominant group of hydrocarbons it contains into paraffin-based, naphthene-based, or a combination of both (referred to as naphthenic-paraffin base). In this study, crude oil samples from H,B, D, G, E, C and F are paraffin oils as shown in Figure 7 Paraffin oils. In a similar study conducted by (Egbo *et al.*,2020) in some onshore oilfields in the Niger Delta Basin, Nigeria reported that the oils from selected oilfields were of terrigenous organic matter origin.

The Colloidal instability Index (CII) is represented by the addition of the combined amounts of asphaltenes and saturates, divided by the combined amounts of aromatics and resins. If the CII value of oil is less than 0.7, it is categorized as stable; conversely, if the CII exceeds 0.9, it is characterized as unstable (Ashoori *et al.*, 2016; Krzysztof *et al.*, 2023). CII values observed in B, H, G, D, E, C, and F were all above 0.9 which inferred that the crude oils from these wells are unstable. If the ratio of asphaltenes to resins (As/R) is less than 0.35, the crude oil is deemed stable (Krzysztof *et al.*, 2023). The As/R observed in the H, D, G, E, F and C were above 0.35 which suggest that oil from these wells were unstable. The As/R ratio of B was below 0.35 which infers stable oil. The Stankiewicz plot serves as a visual technique for illustrating how the stability of crude oil is linked to the ratios of As/R and Sat/Arom. The areas indicating stability and instability are designated on the plot based on arbitrary assumptions (Guzman *et al.* 2017; Krzysztof *et al.*, 2023).

GEOCHEMICAL CHARACTERISTICS OF CRUDE OIL

BIODEGRADATION

Biodegradation is a process that significantly impacts the properties of most of the world's oils (Hakimi *et al.*, 2022). Consequently, the exploration and analysis of oil samples are affected by the considerable expenses involved in refining biodegradable oils (Hakimi *et al.*, 2022). Biodegradation can take place within an oil reservoir and significantly impacts the properties of the hydrocarbons it contains (Bahram *et al.*, 2016; Uzoegbu *et al.*, 2023). During the initial stages of oil biodegradation, there is a noticeable reduction in n-alkanes or normal alkanes, followed by a decrease in acyclic isoprenoids (e.g., pristane and phytane). In comparison to these groups of compounds, other classes of compounds (e.g., highly branched, and cyclic saturated hydrocarbons, as well as aromatic compounds) show greater resistance to biodegradation (Uzoegbu *et al.*, 2023). The pr/n-C₁₇ and ph/n-C₁₈ ratios have demonstrated their efficacy as reliable indicators of biodegradation (Egbo *et al.*, 2020). These ratios, which depict the distributions of n-alkanes in relation to isoprenoids, exhibit a wide range of variations based on the origins of organic matter, thermal evolution, and biodegradation (Peters *et al.*, 1999; Egbo *et al.*, 2020). In matured non-biodegraded oils, normal alkanes consistently exist in higher proportions compared to isoprenoids (Egbo *et al.*, 2020). Pristane/n-C₁₇ and Phytane/n-C₁₈ crossplot suggest that the examined oils were from mature, non-biodegraded oil (Figure 13) Figure 13 also shows that all the oil samples from the studied oil wells contained algal organic matter deposited

under reducing (anoxic) conditions which suggest that the oils were Kerogen Type 1. Kerogen Type I are from aquatic sources which yields hydrogen-rich oil (Al – Areeq., 2018) (Nady *et al.*,2014) reported similar values of Pristane/n-C₁₇ and Phytane/n-C₁₈ in a similar study conducted in Ashrafi and GH oil fields in the Gulf of Suez, Egypt.

SOURCE ROCK ORGANIC MATTER INPUT

The terrigenous to aquatic (TAR) ratio serves as a valuable tool for evaluating the proportion of organic matter originating from land plants compared to aquatic sources. However, it's crucial to recognize that this ratio can be affected by the maturity of the organic material (Peters *et al.*, 2005; Sabagh *et al.*, 2015). A TAR value greater than 1 signifies a higher presence of land plant-derived material, indicating a dominant terrestrial contribution. Conversely, crude oil samples with TAR values below 1 indicate that the primary organic matter source is not from significant land plant input. The low TAR values < 1 observed in the study areas (Table 4.3) are indicative of an origin from aquatic sources (Sabagh *et al.*, 2015). The potential of source rocks can be categorized by evaluating their organic carbon content as a percentage of their weight (Thomas, 1979; Al – Areeq., 2018). This categorization includes rocks with low potential (<0.5% organic carbon), moderate potential (0.5–1.0% organic carbon), favorable potential (1.0–2.0% organic carbon), and highly favorable potential (>2.0% organic carbon) (Thomas, 1979; Peter and Cassa, 1995; Al – Areeq., 2018). TOC values observed in H, B, C, G, and F and D, were > 2 in all the oil samples which indicates very good generative potential. TOC values of 1.29 obtained from E oil well falls in the favorable potential.

OIL ENVIRONMENTAL CONDITION

The pristane/phytane (pr/ph) ratio is a widely employed indicator to deduce the redox state of the source depositional environment. A pr/ph ratio greater than 3.0 generally indicates an oxic depositional condition, while low values of the ratio (<0.8) are characteristic of strong reducing (anoxic) conditions (Su and Jiang, 2022). Intermediate values are believed to indicate a suboxic condition (Hao *et al.*, 2009; Su and Jiang., 2022). The pr/ph ratio values of the study areas are within the range of < 3 and < 0.8 which infers the oils were formed in a sub-oxic environment.

OIL MATURATION LEVEL

The CPI was first introduced by Bray and Evans (1961) and has since been recognized as a valuable method for differentiating between immature and mature n-paraffin distributions in crude oils and source rocks (Dembicki., 2020). The carbon preference index (CPI) is defined as the ratio between the long-chain odd carbon number n-alkanes and the long-chain even carbon number n-alkanes (Peter *et al.*, 2005; Egbo *et al.*, 2020). It is commonly used to assess the thermal maturity level of oil source rocks, especially when nC₂₅-nC₃₃ n-alkanes are present (Egbo *et al.*, 2020). Immature source

rocks typically exhibit CPI values higher than 1.0, while mature source rocks and crude oils tend to have CPIs around 1.0 (Dembicki., 2022). As thermal maturation progresses, CPI values usually decrease, and values ranging from 0.95 to 1.10 are considered indicative of thermal maturity. Elevated CPI values are often associated with oils sourced from rocks deposited in terrigenous/deltaic environments. Conversely, oils derived from evaporate or carbonate rocks commonly exhibit a dominance of high even-numbered n-alkanes (Egbo *et al.*, 2020). The CPI results in the various crude oil wells were around 1, indicating terrigenous/deltaic sources.

V. CONCLUSION

Based on the bulk composition and geochemical analysis on investigating the physical and chemical composition, source organic matter input, depositional conditions, biodegradation and thermal maturity of selected crude oil wells in OML A of the southern Niger Delta. The API values ranges are indicative that the oils are categorized as heavy oil. The correlation between the sulphur content and the API gravity of the various crude oil samples is suggestive that the crude oil samples are majorly of low to medium and high sulphur content with type I and II kerogen. With $B > H$ and $E > G > C > F > D$. High sulphur content thus affects the quality of product and causes various problems during refining process. However, from the bulk composition of SARA, the crude oil samples showed higher level of saturated and aromatic hydrocarbon, indicative that all the oil samples are thermally matured, this infers that the reservoir may contain effective source rock that is presently generating and expelling hydrocarbons. Although some are more matured than the others. Base on the classification of the predominant hydrocarbon group, the crude oil samples are all paraffinic oils from matured source rock and are non-biodegraded as such this will favour more production, accumulation and preservation of organic matter for more hydrocarbon generation, since they may contain more of straight chain, branched chain (paraffins) and cyclo alkanes (naphthenes). Comparatively, Since the depositional environment is anoxic for the selected crude oil samples, this will favour the accumulation of organic rich sediment for excellent survival as it promote rich oil prone source rock containing algal as it organic matter precursor under anoxic condition. More so the terrigenous to aquatic ratio are indicative of origin from aquatic source and a suboxic depositional condition and the Carbon preference index also showed a maturity level on all the crude oils which implies that they all have odd-number aliphatic hydrocarbon contribution from biogenic source and petroleum origin. The results obtained in the different oil wells are comparable with those obtained from previous studies when GC-MS and GC-FID methods were used.

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