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Cretaceous–Tertiary Rift Basins of Northwestern Kenya: Tectonics, Stratigraphy, and Petroleum Implications

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Abstract

This study looks at the potential for oil and gas in northwest Kenya, giving a broad overview of the geology, tectonic (Earth movement) features, and underground rock layers in four main basins from the Cretaceous to Tertiary periods: Lotikipi, Lake Turkana, Lokichar–Kerio, and Chalbi. These are part of the larger East African Rift System. Recently, important signs of oil and gas structures have been found in the Lokichar Tertiary Basin in northwestern Kenya. The area's Earth movements started with the splitting of the ancient supercontinent Gondwana in the Late Paleozoic era, continuing through the Mesozoic and Tertiary periods. This caused massive lava flows and created raised (horst) and sunken (graben) blocks due to stretching forces, faults, and sinking land, which made good spots for oil exploration. The study used gravity maps and seismic (sound wave) profiles to understand the structures, faults, depth of the basement rocks, and areas likely to hold oil. The basins built up thick layers of sediment (approximately 2,000 to 6,000 m deep) that could contain oil, deposited on very old Precambrian basement rocks. These were later covered by volcanic basalt flows, mostly from the Miocene period. Drilling records showing rock types were available for wells LT-1 and LT-2 in the Lokichar and North Kerio-Turkana basins (Tertiary period), and C1, C2, and C3 in the Chalbi Basin (Cretaceous period). The northwestern Lotikipi Basin (possibly spanning Cretaceous to Tertiary) was drilled by CEPSA industry in 2017, proving a working oil system with a Tertiary source rock and gas prospects, which supports the idea of strong exploration potential in the future.

Keywords: Asymmetric half-grabens, gravity–seismic integration, lacustrine source rocks, Northwestern Kenya rifts, petroleum prospects and systems

INTRODUCTION

I set out to distill, integrate, and clarify the geological implications, tectonic architecture, and subsurface stratigraphic framework of four intracontinental rift basins in northwestern Kenya—Lotikipi, Lake Turkana, Lokichar–North Kerio, and Chalbi—spanning Cretaceous to Tertiary evolution (Figure 1). Building on the premise that Gondwanan breakup initiated long-lived extensional deformation, I treat these basins as a linked system where reactivated Precambrian fabrics guided later Mesozoic–Cenozoic rifting. This rift history manifested as episodic block faulting, asymmetric half-grabens, and voluminous basaltic volcanism, particularly during the Miocene [1–5].

Using Bouguer gravity anomalies (Figures 2 and 3), targeted seismic profiles, and, where available, well control (LT-1, LT-2 in Lokichar–North Kerio; C1–C3 in Chalbi), I map horst–graben geometries, delineate basement depth variations, and infer the lithosphere–upper mantle configuration from density contrasts [1]. Gravity lows and growth-fault complexes consistently coincide with depocentres, while positive anomalies track basement-cored highs and mantle upwarps that segment accommodation space.

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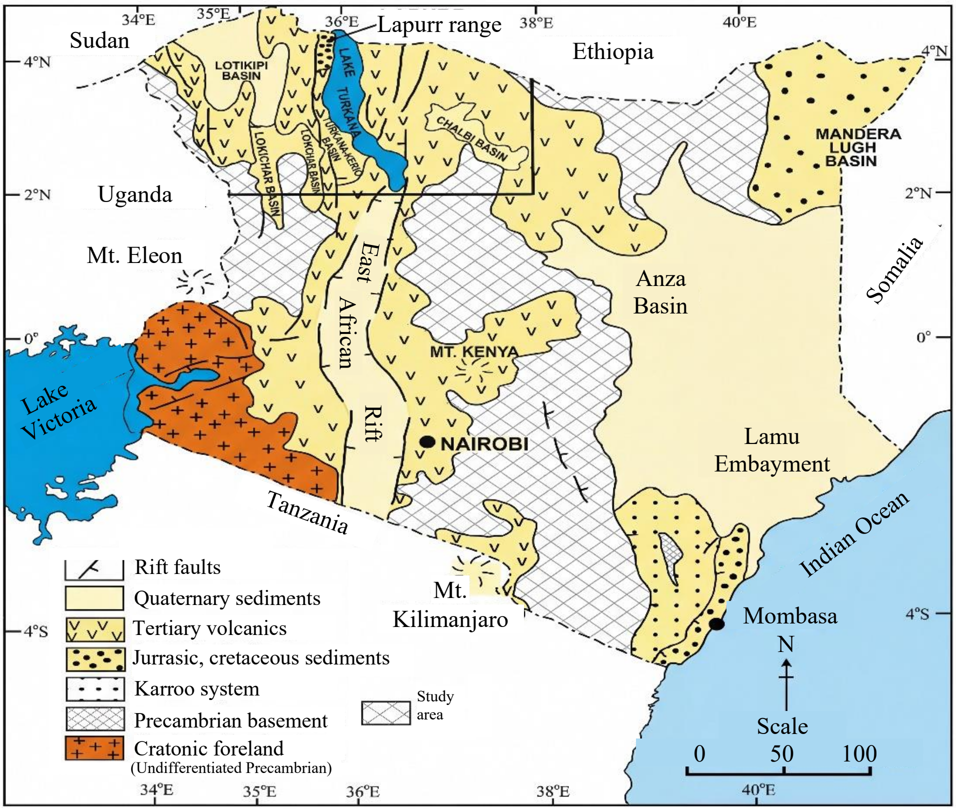

Figure 1. Geographical location of the study area in Kenya.

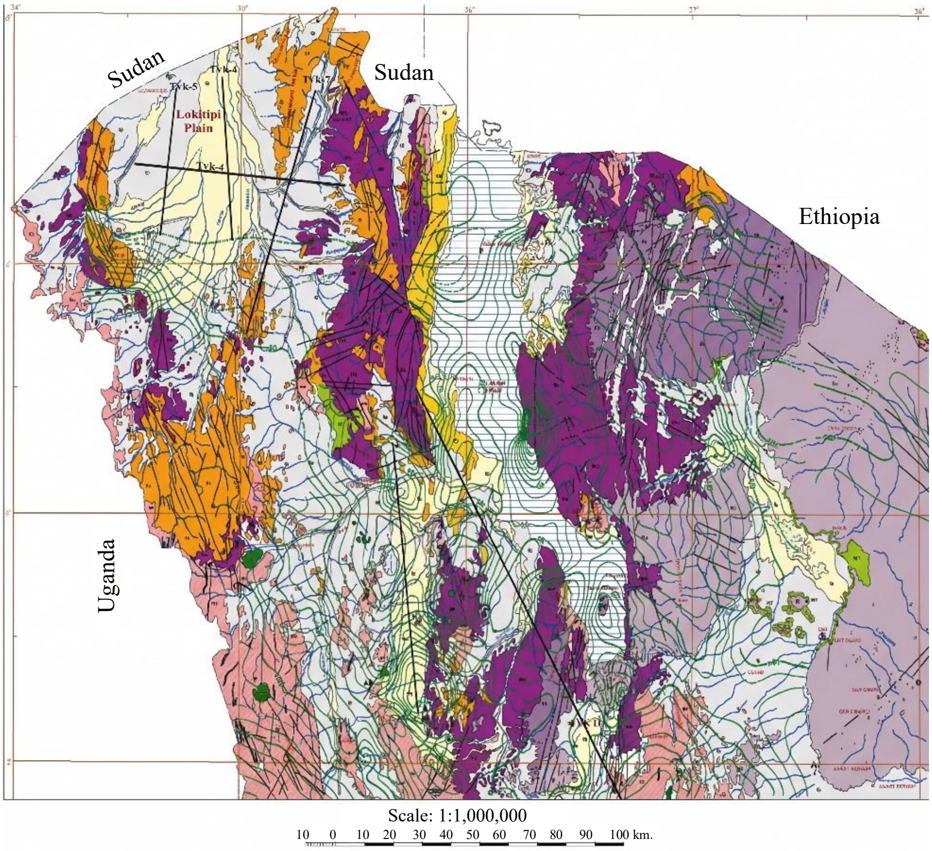

Figure 2. Bouguer gravity contour map with seismic lines TVK 4–7.

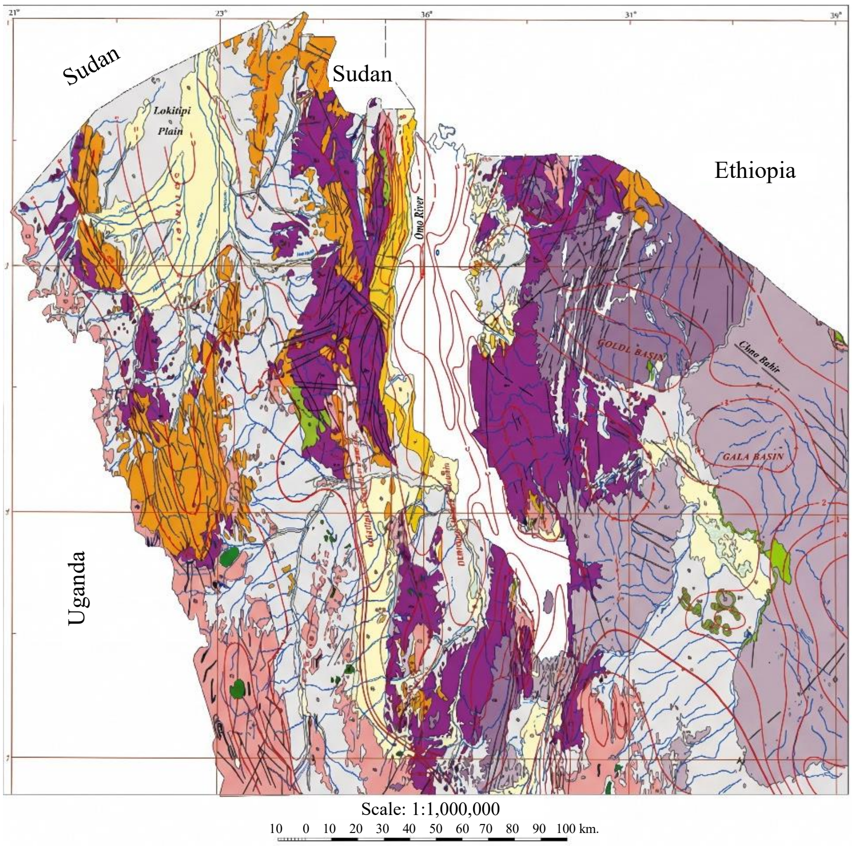

Figure 3. Basement structural contour map showing basement depths.

Seismic facies analysis distinguishes compact, higher-velocity packages (Vp ~3.0–4.0 km/s) from less consolidated, sand-rich intervals (Vp ~2.0–3.0 km/s), allowing me to propose basin-specific stratigraphic successions and to highlight synsedimentary thickening [6–8] adjacent to master faults (Tables 1 and 2).

I show that these rifts accumulated substantial petroliferous sedimentary piles (~2.0–5.3 km) over Precambrian basement, later draped by extensive Miocene basalts. In the drilled basins, core and cuttings indicate mixed fluvial–lacustrine depositional systems with organic matter inputs ranging from Type I algal to Type III terrestrial kerogen. Where burial and heat flow were sufficient, especially within persistent Bouguer lows, source intervals likely entered early to peak oil windows, with local thermal anomalies elevating maturity at shallower depths [1].

The then undrilled Lotikipi Basin (though presently drilled, but with unavailable data) remains a frontier; however, its gravity–seismic signature suggests Cretaceous equivalents to productive Sudanese rifts and warrants a focused reconnaissance (Figure 4). However, the basins in the area drew in thick layers of sediment (between 2,000 and 6,000 meters deep) that could potentially hold oil, laid down on ancient Precambrian basement rocks. These layers were later buried under volcanic basalt flows from the Miocene period.

Drilling records showing the types of rocks encountered were available for wells LT-1 and LT-2 in the Lokichar and North Kerio-Turkana basins (from the Tertiary period), and for wells C1, C2, and C3 in the Chalbi Basin (from the Cretaceous period).

The northwestern part of the Lotikipi Basin (possibly spanning the Cretaceous to Tertiary periods) was drilled by CEPSA in 2017. This confirmed a working oil system with a Tertiary source rock and signs of gas, backing up the idea that there is still good potential for oil and gas exploration there.

Table 1. Characteristics of densities of rocks and minerals: limiting depths of rift basins.

Rock type or mineral	Density (g/cm^3)
Sand	1.6–2
Sandstone (Mesozoic)	2.15–2.4
Sandstone (Paleozoic and older)	2.3–2.65
Quartzite	2.60–2.70
Limestone (compact)	2.5–2.75
Shales (younger)	2.1–2.6 (2.4)
Gneiss	2.6–2. (2.7)
Basalt	2.7–3.3 (2. 8)
Diabase	2.8–3.1 (2. 6)
Granite	2.52–2.81 (2.67)
Granodiorite	2.6–2.7 (2.72)

Source: Adapted from [9].

Table 2. Characteristics of seismic velocities (p) of rocks.

Rock type	Vp (km/sec)
Air	0.3
Alluvium, Sand	0.3–1.7
Sandstones	2.0–4.5
Slates and Shales	2.4–5.0
Limestones and dolomites	3.5–6.0
Rock Salt	4.0–5.5
Granites and Gneisses	5.0–6.2
Basalt	5.5–6.3
Gabbro	6.4–6.8
Dunite	7.5–8.1
Peridotite	7.8–8.4

***Source.** Adapted from [9].*

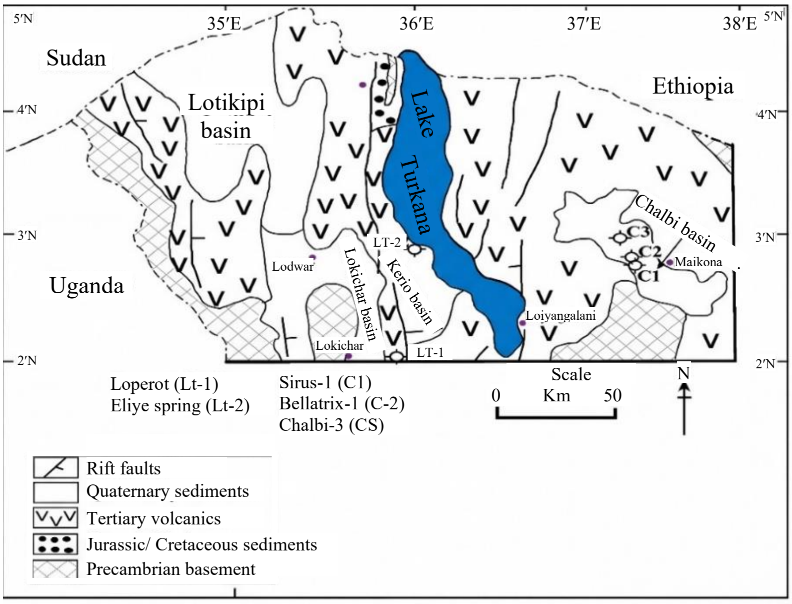

Figure 4. Map showing drilled wells in the northwest Kenya rift basins (adopted from [1]).

***Note:** (1) Seismic velocities often show anisotropy in stratified formations. (e.g., in slates, the velocity along the bedding direction may be approximately 10–20% higher than in the perpendicular direction). (2) Effects of compassion and lithification are important in sedimentary rocks, for which the velocity is largely dependent on the depth of burial.*

By comparing lithologs, shows, and petrophysical responses across LT-1, LT-2, and C1–C3, I characterize recurring source–reservoir–seal associations: lacustrine shales (sources, seals), stacked fluvial–deltaic sandstones (reservoirs), and intraformational tuffs/shales (seals).

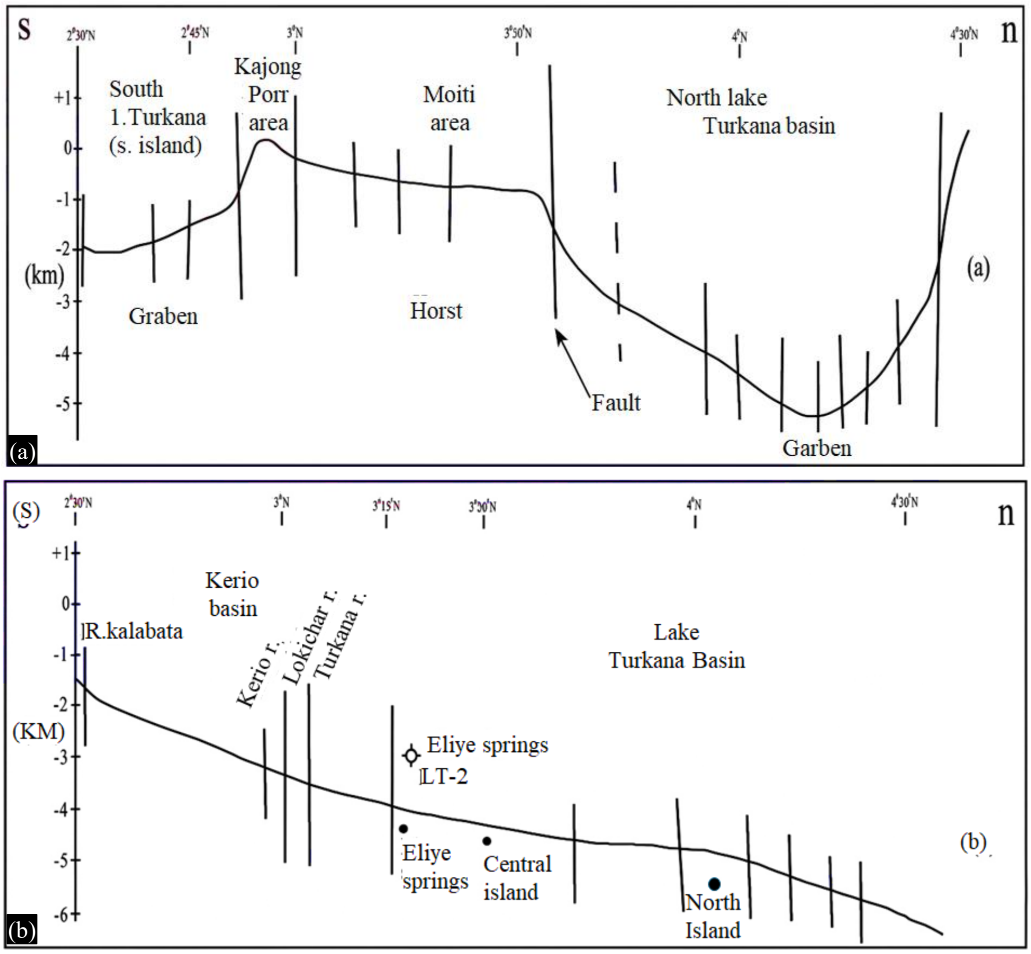

Figure 5. S-N cross-section of basement depth profile along Kerio/Turkana Basins. Between latitudes 2°30′N and 4°30′N: (a) From South Island to Lapurr Range. (b) From Kerio Basin to the NW corner of Lake Turkana.

Structural traps include fault-bounded closures and rollovers near growth faults; stratigraphic traps include pinchouts against basement highs and sand-body terminations along relay ramps [10–12]. Volcanic sills locally enhance lateral sealing but may compartmentalize flow (Figures 5–9).

I conclude that the most prospective fairways track long-lived depocentres defined by gravity lows and growth-fault corridors, where repeated accommodation creation preserved rich lacustrine facies and improved burial histories [13–17]. To progress from play-based screening to drillable prospects, I recommend integrated 2D/3D seismic over Bouguer lows, potential-field inversion to sharpen basement architecture, high-resolution stratigraphic coring across lacustrine wedges, and expanded geochemical programs (HI/OI, biomarkers, kerogen microscopy) tied to burial–thermal models that explicitly consider magmatic heat flow pulses.

Within this framework, I position Lotikipi as a high-impact reconnaissance target and Lokichar–North Kerio and Chalbi as near-term candidates for focused appraisal of defined traps and mature kitchens.

Executive Summary (Non-Technical)

I explore four linked rift basins in northwestern Kenya to understand where oil and gas might be found and why. Using maps of Earth’s gravity and echoes from sound waves sent into the ground, I outline deep valleys and buried ridges formed as the crust stretched over millions of years.

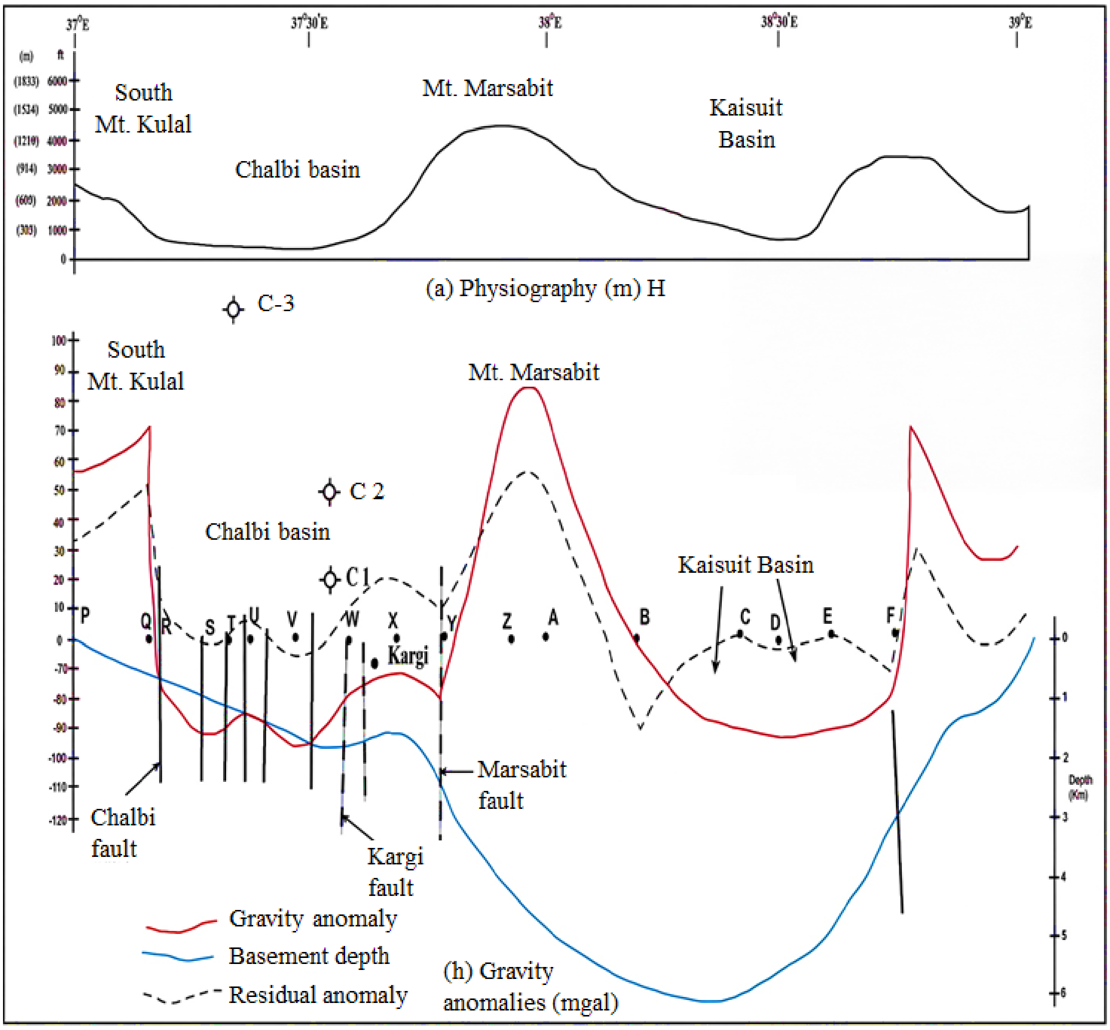

Figure 6. A cross-section along latitude 3°30′N (between longs. 35°30′E and 37°E) of the Chalbi and Kaisut Basins.

These shapes guided rivers and lakes that laid down layers of sand and mud, some rich in dead algae and plants that can become oil and gas when buried and heated. In places, these sediment piles are several kilometers thick and were later covered by lava flows. By comparing limited well data with the geophysical images, I identify likely combinations of "source" rocks that generate hydrocarbons, "reservoir" sands that can store them, and "seal" layers that keep them trapped. The most promising areas lie along long-lasting deep zones where sediments are thickest, and faults helped create traps. I recommend focusing on new surveys and carefully placed test wells to confirm these targets while managing uncertainties from past volcanism and uneven data coverage.

Tectonic Framework and Subsurface Stratigraphy of Basins

Introduction

This examines the tectonic framework and stratigraphic architecture of four subsurface basins, Lotikipi, Chalbi, Lake Turkana, and the Lokichar–North Kerio system, using Bouguer gravity anomalies and seismic profiles, supported where possible by well data.

Gravity surveys constrain basin and basement depths and illuminate lithosphere–upper mantle configuration through density contrasts. In the study area, dense Precambrian basement and extensive volcanic cover contrast with lower-density sedimentary infill. A thick succession of Mesozoic and Tertiary sediments lies concealed beneath basaltic lavas [18–22].

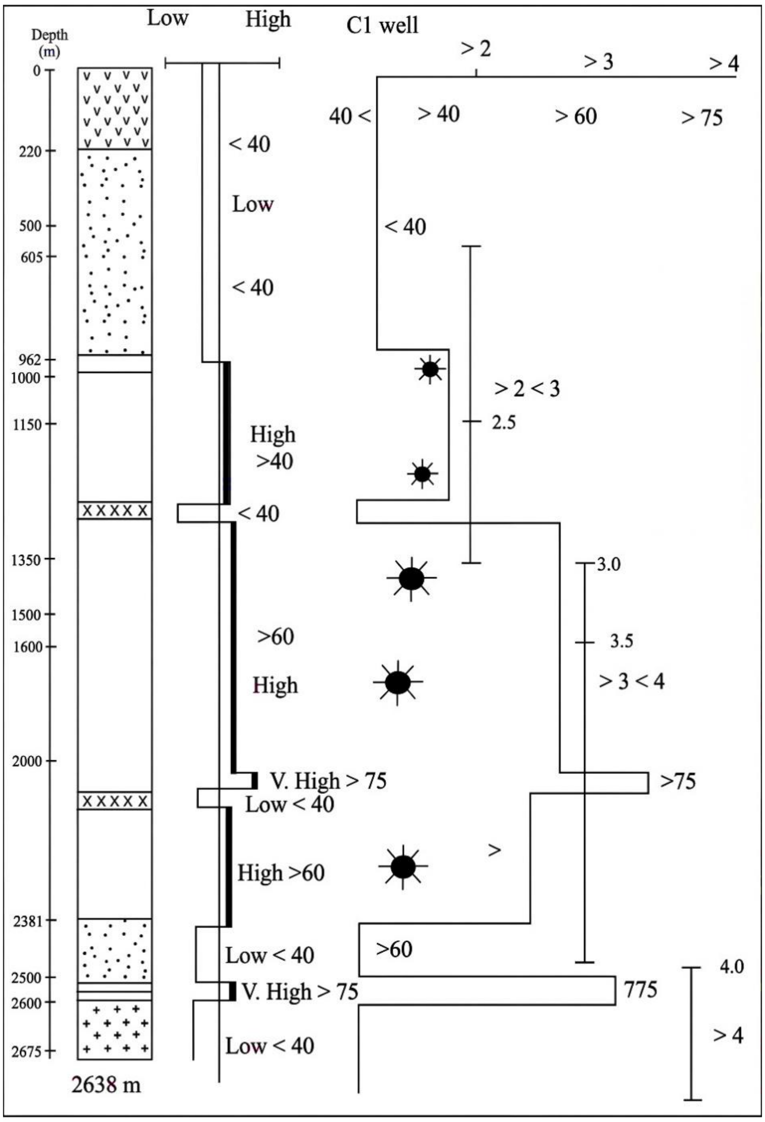

Figure 7. Component Stratotype of C1 Well based on gamma ray and p-wave velocity in the Chalbi Basin.

Across the region, basins are bounded by major fault systems, and gravity profiles reveal internal sub-basins that are typically asymmetric half-grabens: downthrown on one side against a master fault and stepped on the opposite margin by distributed faults.

These intracontinental rifts commonly overlie basement or mantle arches or rest on continental crust above trough-like mantle profiles. Landscape and subsurface geometries indicate rifting and block faulting initiated in the Cretaceous (or earlier) and continued episodically through the Tertiary and into the Quaternary.

Seismic Stratigraphy

Gravity and seismic methods are the principal geophysical tools for delineating prospective subsurface structures in hydrocarbon exploration. Seismic data, calibrated to well control where available, help confirm the presence, thickness, and internal character of sedimentary units and indicate physical properties such as compactness, rigidity, porosity, and permeability [6, 22]. Reflection facies analysis enables recognition of shale–sand alternations, compact versus porous reservoir quality sandstones, and possible carbonates

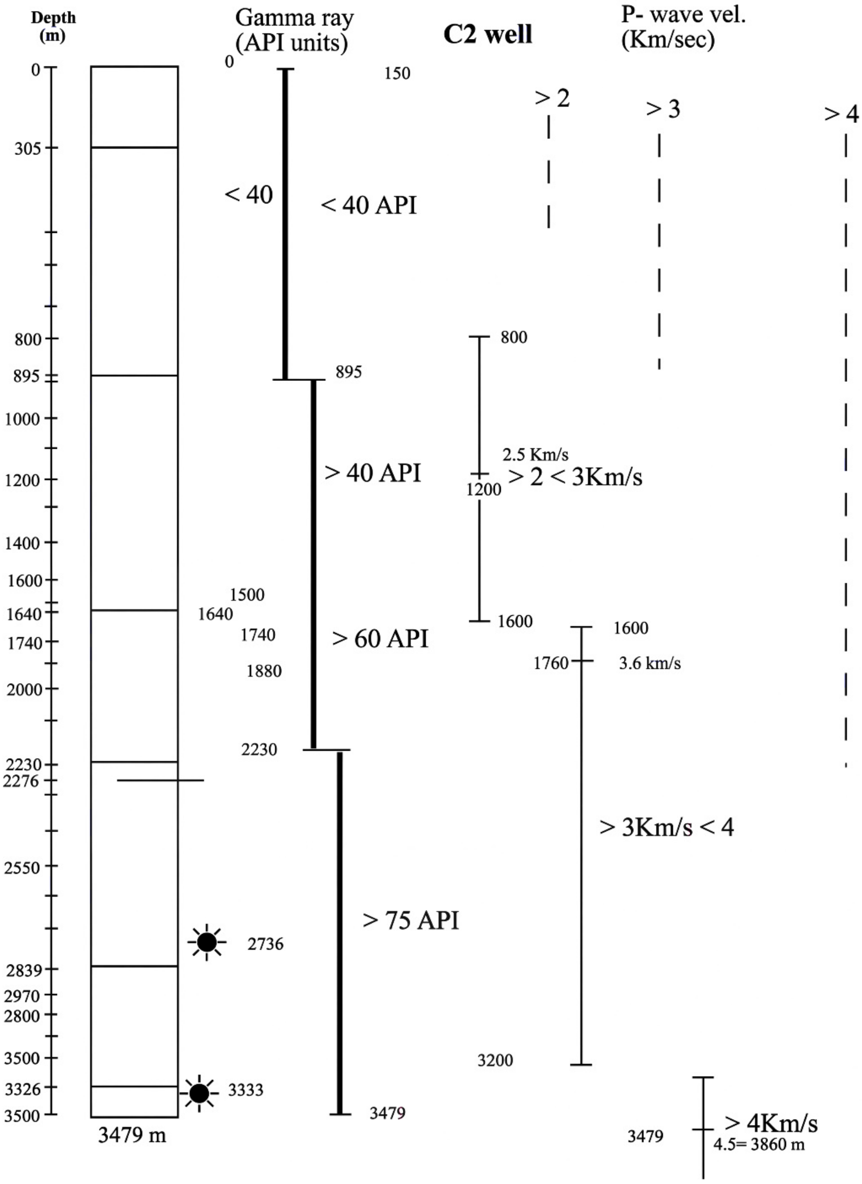

Figure 8. Component Stratotype of C2 Well based on gamma ray and p-wave velocity in the Chalbi Basin.

Lotikipi Basin

This study evaluates the premise that Mesozoic sedimentary sequences—analogous to the Jurassic–Cretaceous strata in southern Sudan, where oil accumulations are proven—continue beneath the extensive alluvial plains of the Lotikipi Basin (NW Kenya).

Reinterpretation of gravity and seismic data archived by the National Oil Corporation of Kenya (NOCK) indicates sedimentary sequences approximately 1,050–2,100 m thick beneath weathered volcanics and alluvium, potentially prospective for hydrocarbons. Since the Cretaceous, the basin evolved through complex rifting and block faulting linked to the Lamu–Anza and Central African Rift systems [1, 5] (Figure 9).

The Lotikipi Basin lies between 34°15′E and 35°30′E, and 3°30′N and 5°00′N (Figure 10). Limited outcrops and a thick alluvial cover deposited by the Anam, Natira, Tarach, and Nakalale rivers obscure the geology [1].

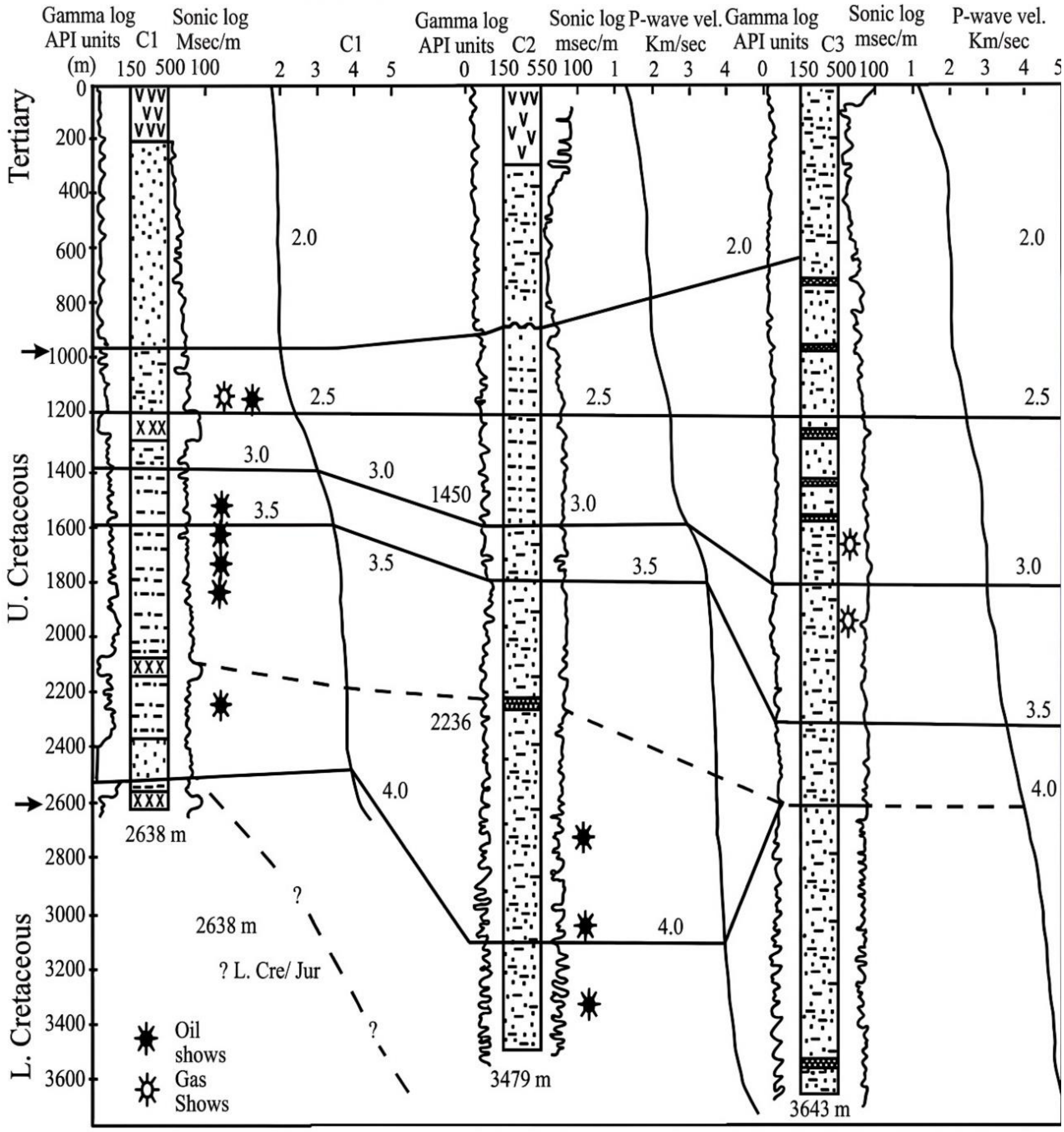

Figure 9. Comparative Lithologs of the Chalbi Basin C1, C2, and C3 wells based on gamma ray and sonic logs, p-wave velocities, and geological time.

These south–north rivers drain the western Songot–Mogila Ranges, Lomilio–Ngimorutai Hills, the Kenya–Uganda escarpment, and the eastern Lokwanamoru–Lorionetom and Murua Rith Hills. Their courses are tectonically guided along N–S fault systems subparallel to the Kenya Tertiary Rift.

Geological Setting

Surface exposures of older sedimentary sequences are rare, and no exploratory wells exist, so the subsurface beneath the Holocene alluvium is poorly known [1, 6]. Earlier work noted lavas directly overlying Precambrian basement and overlain by post-volcanic/alluvial deposits. Subsequent gravity and seismic studies south of Lotikipi revealed horst–graben structures below alluvium. Tertiary faulting and rifting likely enhanced erosion centrally, leaving a reduced volcanic thickness beneath alluvium. No volcanic or sedimentary rocks are exposed to major river channels. Geophysical surveys were therefore required to determine thickness and successions. Previous syntheses inferred that NW–SE Anza basin structures extend beneath Lotikipi, potentially hosting Jurassic–Cretaceous equivalents to southern Sudan over Precambrian basement (Figure 12).

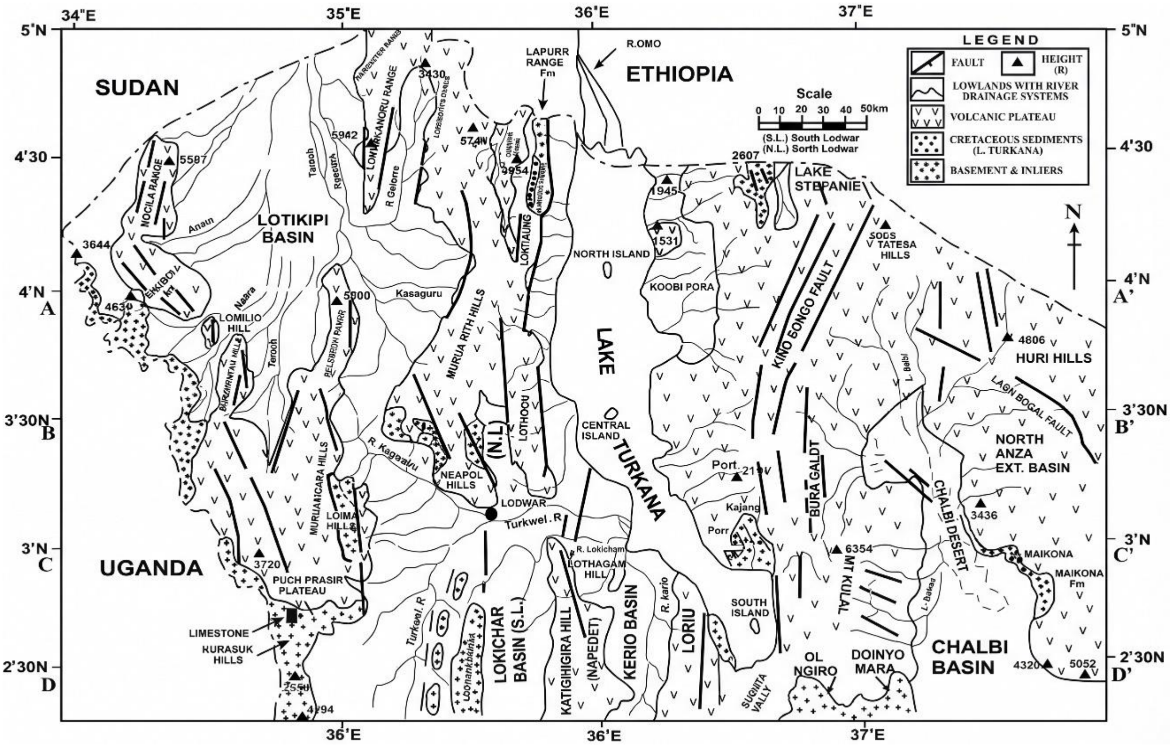

Figure 10. Physiography, drainage, and cross-sections of geological features.

The two river systems (Anam–Natira and Tarach–Nakalale), with tributaries from the southern Muruasingar–Pelekech Ranges, likely formerly drained toward the Lake Turkana depression along NW–SE faults sympathetic to the Anza–Abu Gabra rift. Reorientation by an E–W extensional stress regime active from the Early Miocene altered drainage. The basin is tectonically active, but rivers maintain gentle gradients (Figure 11).

Subsurface Structures and Tectonics

Bouguer anomaly and basement depth maps (Figure 12) define the weathered/volcanic cover limits, sediment thickness, and basement–mantle configuration. Contours predominantly strike N–S, indicating Tertiary rift effects at the crust–mantle interface. Cross-sections along 4°00′N, 4°15′N, 4°30′N, and 4°45′N delineate sub-basins [1].

From Figure 12, Bouguer lows of –50 to –90 mGal indicate thin volcanic cover, deep upper mantle, and near-surface low-density sediments over the basement. Along 4°00′N, anomalies become more negative westward (Murua Rith ~–60 mGal to Songot ~ –90 mGal), consistent with mantle downwarp; basement depth shallows east to west (~ –2 km east of Pelekech to 0 km at Songot). The basement deepens northwards from ~2.5 to 3.5 km, implying a north-plunging structure. Positive anomalies mark basement-cored horsts overlain by lava.

Between 4°15′N and 4°45′N, basement depth increases northward, and sediment thickness grows. The basin deepens gradually up to 4°30′N, then steepens. A central low (–80 mGal) transitions to relatively positive values (–65 mGal) toward the Mogila and Lokwanamoru ranges, reflecting NE–SW Mesozoic rifting overprinted by E–W Tertiary faulting. The deepest part (34°30′E–35°00′E; 4°15′N–4°45′N) likely hosts a thick Mesozoic section beneath Tertiary–Quaternary volcanics and alluvium. The basin forms a north-deepening half-graben near the Kenya–Uganda escarpment faults and may extend into Sudan. Eastern positive anomalies reflect basement uplift and mantle upwarp. Some bounding faults remain active, controlling Quaternary drainage. A minor N–S fault at the Nakalale River is likely linked to the Turkwel Fault.

Seismic Stratigraphy

Seismic lines TVK-4/5/6/7 (Figures 14–19) define two seismically distinct, river-named formations: Anam–Natira and Tarach–Nakalale, between 34°30′E–35°00′E and 4°15′N–4°45′N [1].

Anam–Natira Formation

Beneath the Anam–Natira rivers (Figures 11, 12, and 18), a ~1,050 m section (34°30′E–35°00′E) with Vp 3.0–4.0 km/s comprises sandstones and shales. Two seismic members are recognized:

1. *Lower member (350 m; 1,900–2,250 m):* Compact sandstones with frequent thick shale/clay layers, Vp 3.5–4.0 km/s.
2. *Upper member (700 m; 1,200–1,900 m):* Fine- to coarse-grained sandstones with minor shales; lower Vp 3.0–3.5 km/s; shale/compact sandstones locally 3.5 km/s.

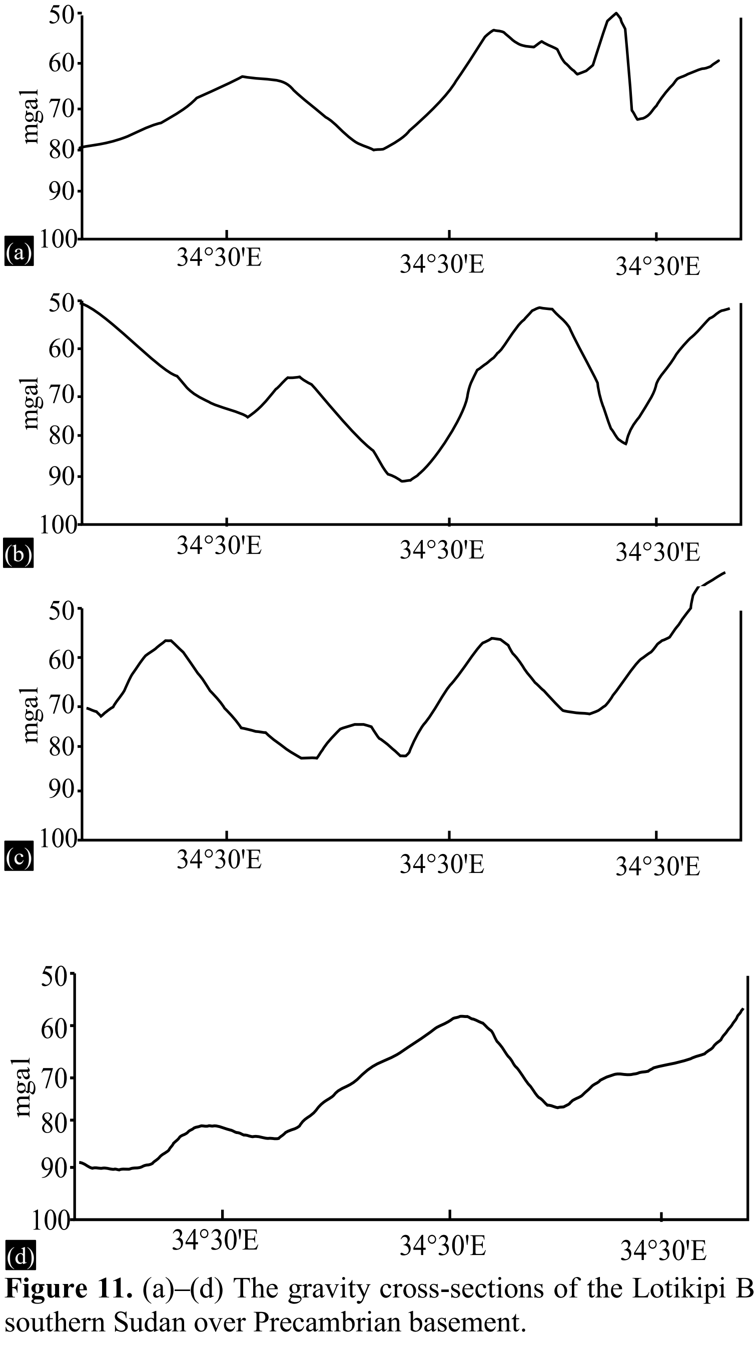

Figure 11. (a)–(d) The gravity cross-sections of the Lotikipi Basin along 4°00′N to 4°45′N latitudes. southern Sudan over Precambrian basement.

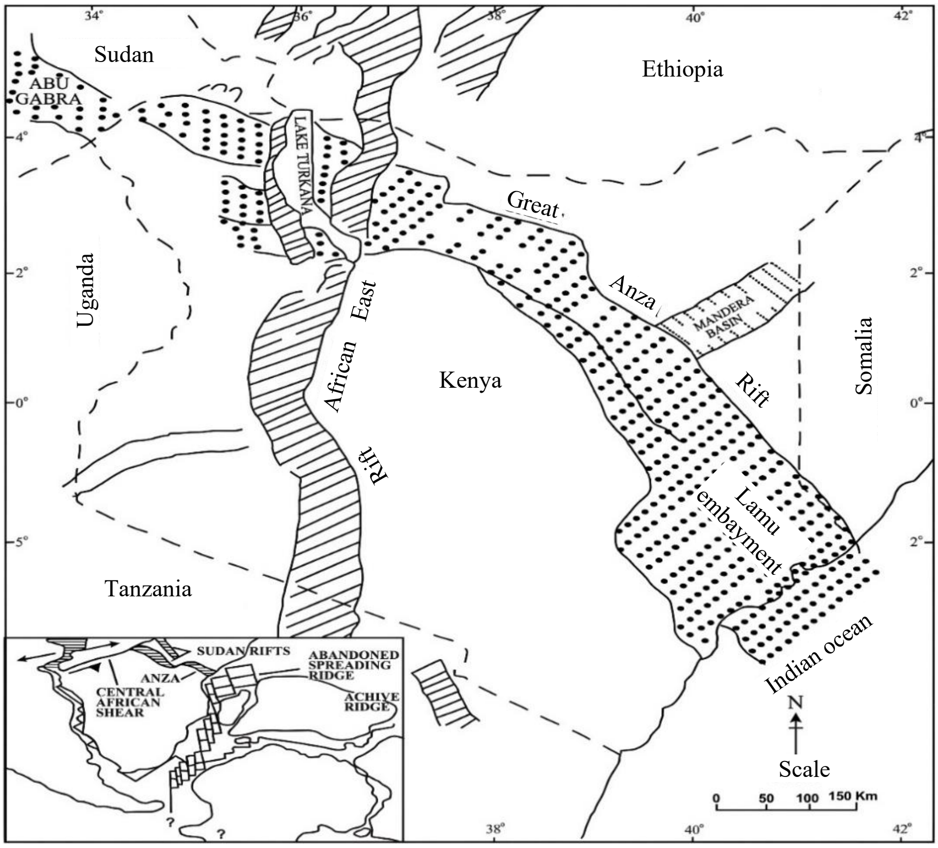

Figure 12. Map of Northwest-trending Anza Basin rift extension (modified BEICP, 1984). Inset: Gondwanaland breakup in Late Paleozoic time.

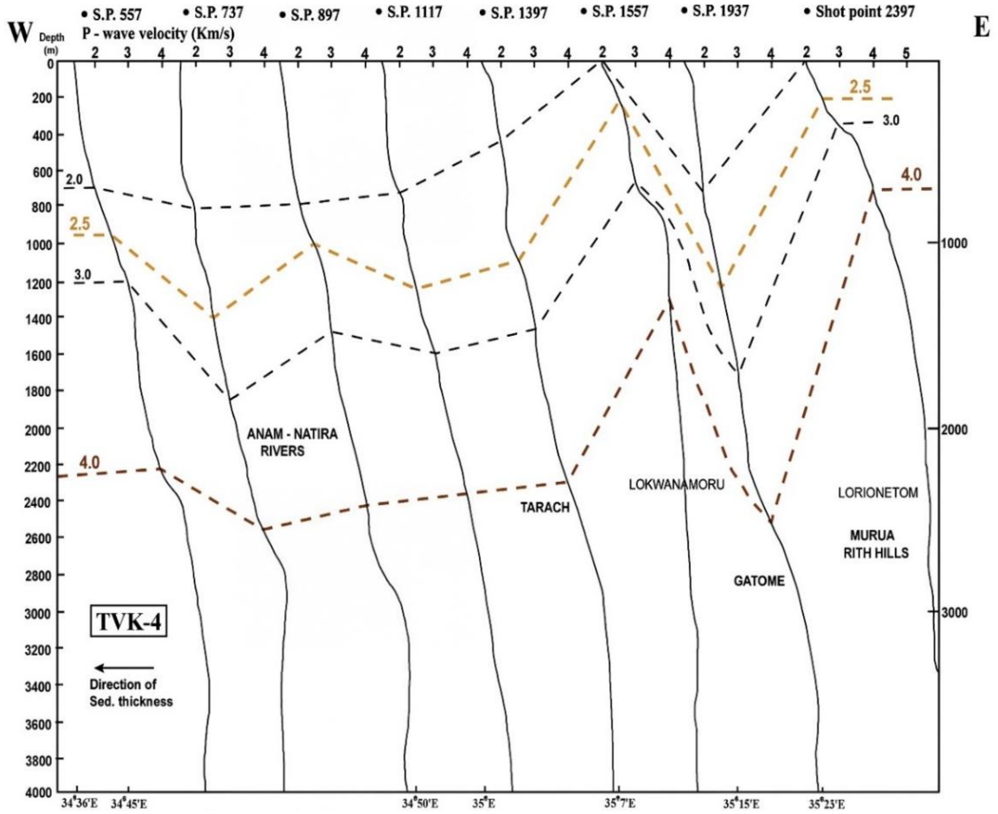

Figure 13. W-E cross-section in the Lotikipi along seismic line TVK-4.

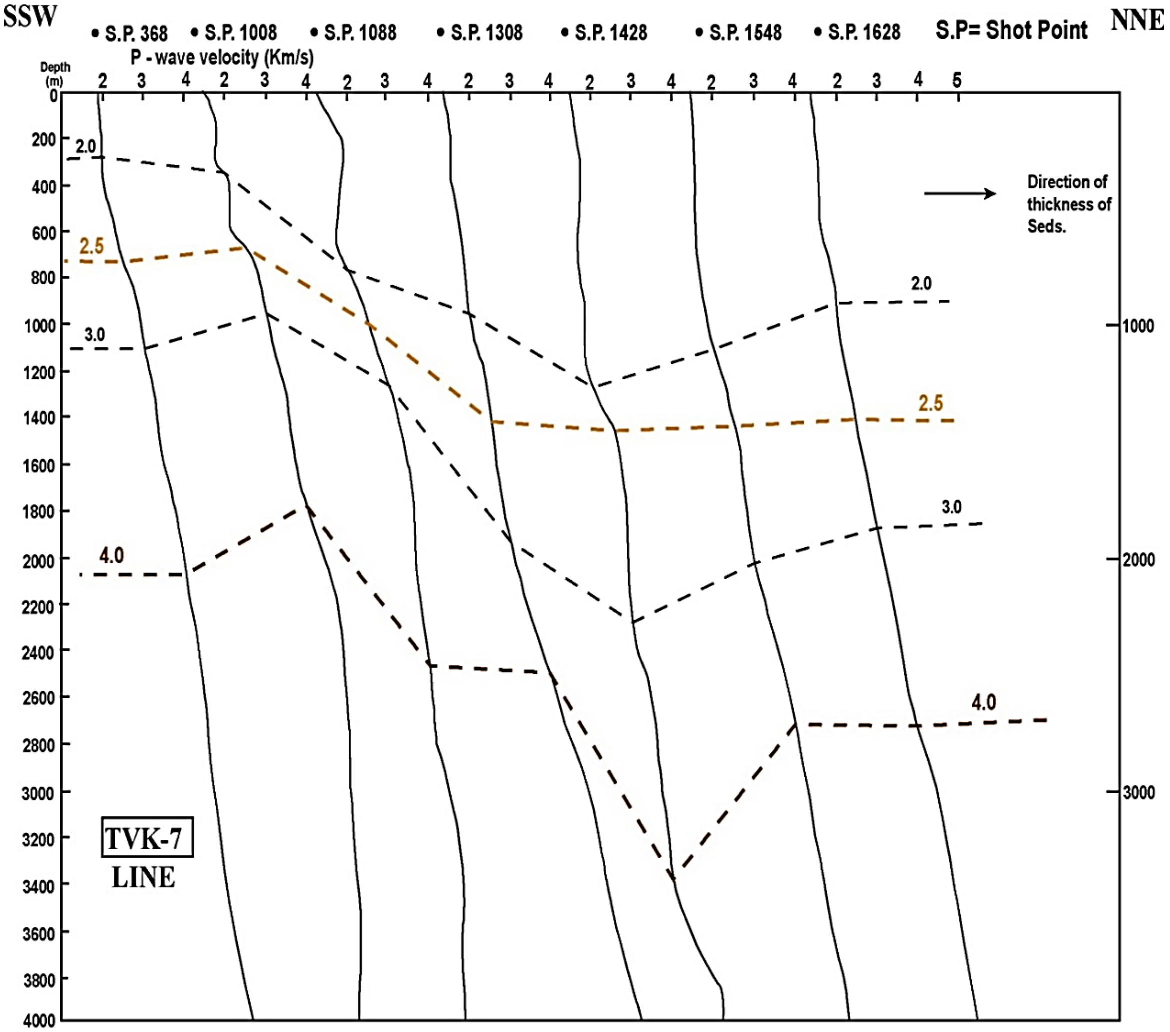

Figure 14. SSW-NNE cross-section in Lotikipi along seismic line TVK-7.

At maximum thickness beneath the Natira River (shot point 1428, TVK-7), the upper member dominates. On horst-like structures (e.g., TVK-4 shot points 1557, 2397; TVK-5 sp 542; TVK-6 sp 1162; TVK-7 sp 1008, 1088), the lower member is better developed. The basement is generally shallower on these horsts (~1,800 m), reaching ~2,100 m at TVK-5 sp 782 and TVK-6 sp 162. This indicates non-uniform subsidence during lower member deposition and renewed tectonism before upper member accumulation. Graben sectors (e.g., TVK-4 sp 1937; TVK-5 sp 142; TVK-6 sp 1162; TVK-7 sp 1428) show a thicker upper member, implying faster sedimentation.

Tarach–Nakalale Formation

Beneath the Tarach and Nakalale rivers (Figures 18 and 19), a ~1,420 m section exhibits Vp 2.0–3.0 km/s, interpreted as less consolidated sands, gravels, silts, and clays, becoming more compact downward (1,560–2,060 m). The type section is along TVK-6 between 34°45′E–35°03′E and 4°24′N–4°42′N, with two members (~800 m each):

1. *Upper member:* Vp >2.0–<2.5 km/s.
2. *Lower member:* Vp >2.5–<3.0 km/s.

The lower member is better developed on horsts and is shallow (<220 m) beneath the Lokwanamoru Range and Murua Rith Hills (TVK-4 sp 737 at 35°07′E; sp 2397 at 35°28′E). Elsewhere, it reaches ~750 m (TVK-5 sp 782) and ~1,460 m (TVK-7 sp 1482). Thickness patterns vary independently between members, indicating synsedimentary subsidence.

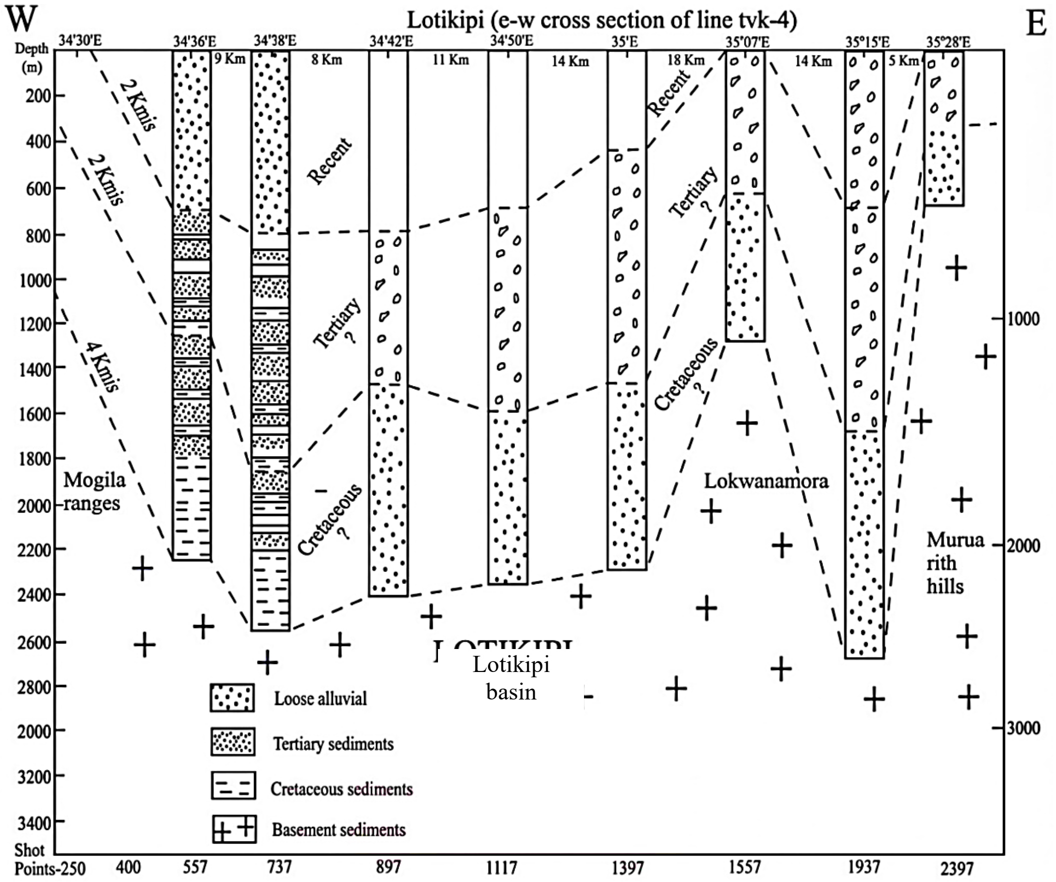

Figure 15. Probable E-W subsurface stratigraphic columns of seismic line. TVK-4.

Suspected Age

By tectonostratigraphic analogy, the Anam–Natira Formation may be homotaxial with the Sharaf and Abu Gabra formations (Neocomian to Albian–Aptian) of southern Sudan. The Tarach–Nakalale Formation may be broadly coeval with the early Tertiary Kordofan Group. Notably, sub-basins with thicker Anam–Natira (Upper Cretaceous?) differ from those with thicker Tarach–Nakalale (Lower Tertiary?) [1].

Conclusion and Prognostic Evaluation

Without wells, prognosis relies on age-equivalent basins along the Anza and Abu Gabra rifts. The seismically defined Anam–Natira (older; Vp >3.0–<4.0 km/s) likely includes lacustrine/fluvial shale–sandstone–conglomerate source facies, akin to Sudanese Cretaceous sequences. Equivalent-age formations in the Chalbi and Kaisut basins also contain potential source rocks. Correlation requires further seismic control (Figure 16).

Thus, the recommended target areas in Lotikipi Basin (Figures 11 and 12) are:

1. Immediately north of the Pelekech Range, 4°15′N–4°30′N; 34°45′E–35°15′E (eastern basin).
2. North of 4°30′N (possibly to the Kenya–Sudan border), 34°36′E–35°07′E (central basin).
3. NW of Pelekech Range (beneath Nakalale–Kasanguru and Gatome systems), 4°00′N–4°30′N; 35°07′E–35°17′E.

Cretaceous sequences accumulated in E–W and NE–SW rifted grabens with non-uniform subsidence along strike, explaining variable member thicknesses. Maximum Cretaceous thickness is in grabens; horsts carry thinner sections. Even thin Cretaceous on horsts (Vp 3.0–4.0 km/s) may include source rocks, but depths >1,800 m are favored for effective generation. Cenozoic rifting could have remobilized hydrocarbons into overlying Tertiary sandstones.

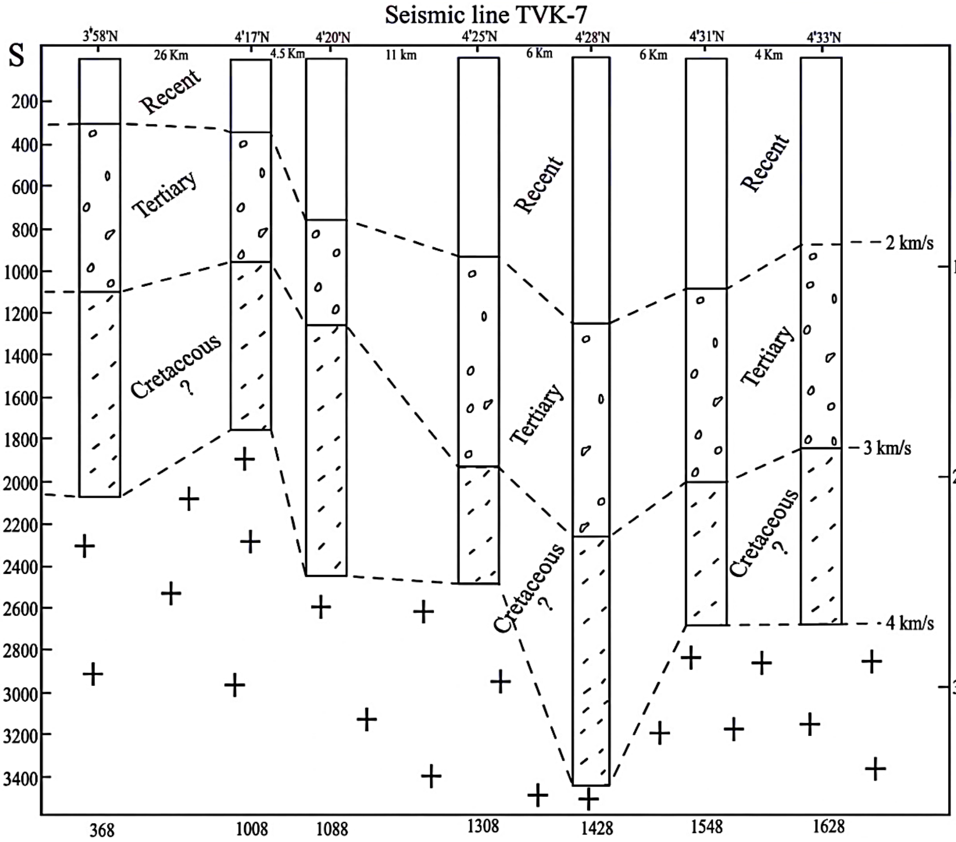

Figure 16. Probable S-N subsurface stratigraphic columns of seismic line TVK-7.

Chalbi Basin

The Chalbi Rift Basin evolved by extensional tectonics associated with Gondwana breakup, active from the Late Paleozoic through Mesozoic and Tertiary. (Figures 9 and 10). This synthesis uses gravity, seismic, and gamma ray data and well logs (C1, C2, C3). Bouguer anomaly patterns define basin geometry and basement highs, while reflection profiles and logs constrain stratigraphic stacking, facies, and depositional style.

Gamma logs show upward-fining cycles in Units B–C, with elevated API spikes at tuffaceous intervals. Porosity decreases downsection from ~28% (Unit B) to (Unit D).

Depositional Model and Structural Controls

Growth strata adjacent to the southern master fault and onlap toward northern highs record syn-rift subsidence. Relay ramps and transfer zones focus on fluvial entry points, generating sand-rich wedges along fault tips. Lacustrine conditions expanded during highstand intervals in Unit C, enhancing preservation of organic-rich mudstones in axial depocentres. Renewed volcanism punctuated Unit B deposition, creating perched aquifers and local diagenetic cementation.

Petroleum System Elements

- *Source:* Dark mudstones in lower Unit B and upper Unit C with total organic carbon (TOC) indicated by elevated gamma and sonic-density separation; likely Type II/III kerogen [1, 21–23].
- *Reservoir:* Stacked fluvial and delta-front sand bodies in Units B–C; best quality occurs in proximal fault-margin wedges and axial channel belts.
- *Seal:* Lacustrine shales/tuffs within Unit C and the finer-grained packages of Unit B.
- *Trap:* Fault-bounded closures, rollovers adjacent to growth faults, and stratigraphic pinchouts against basement highs; local volcanic sills provide lateral seals.

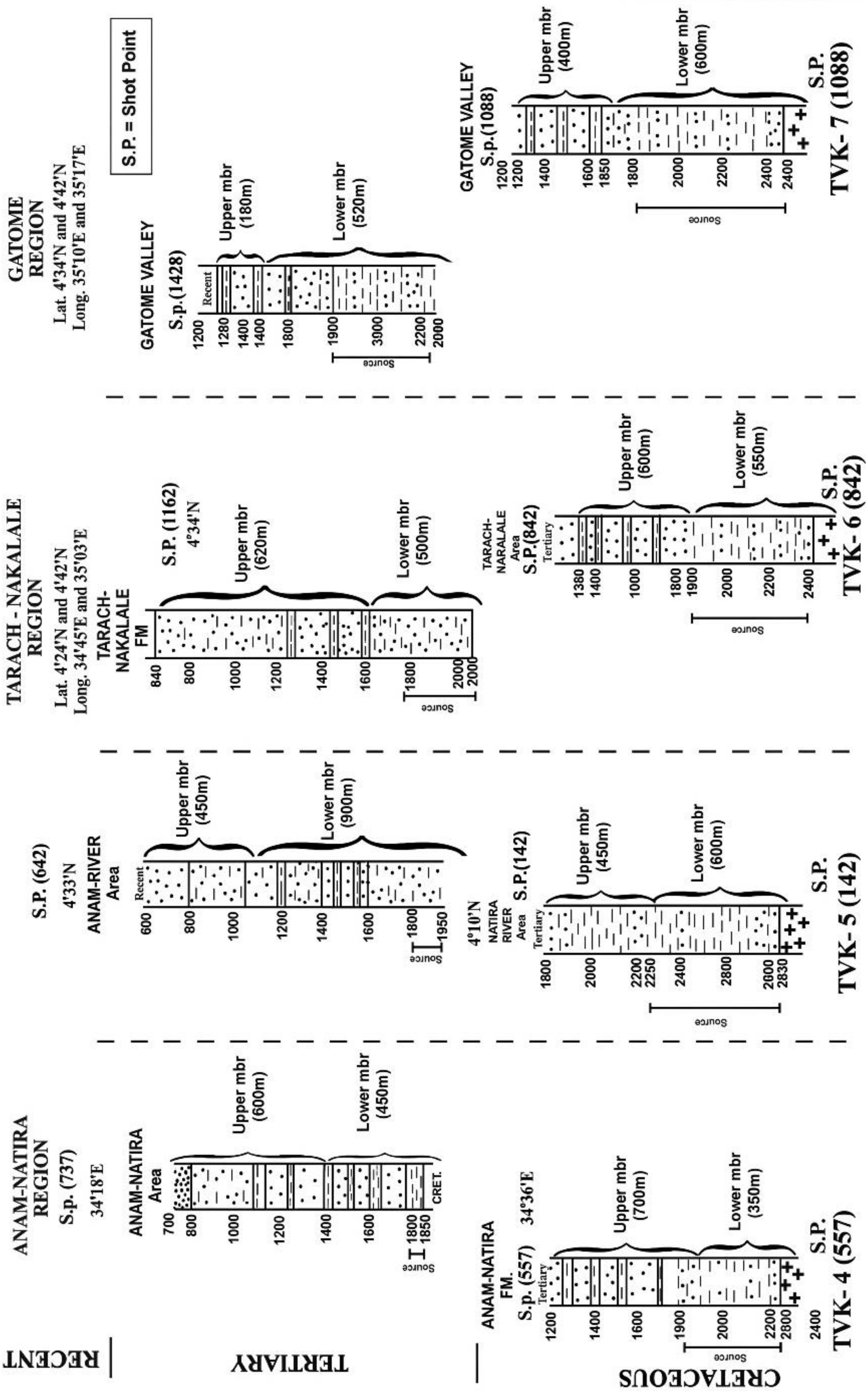

Figure 17. General stratigraphic columns variations of probable type sections of Lotikipi Formations based on Seismic profiles.

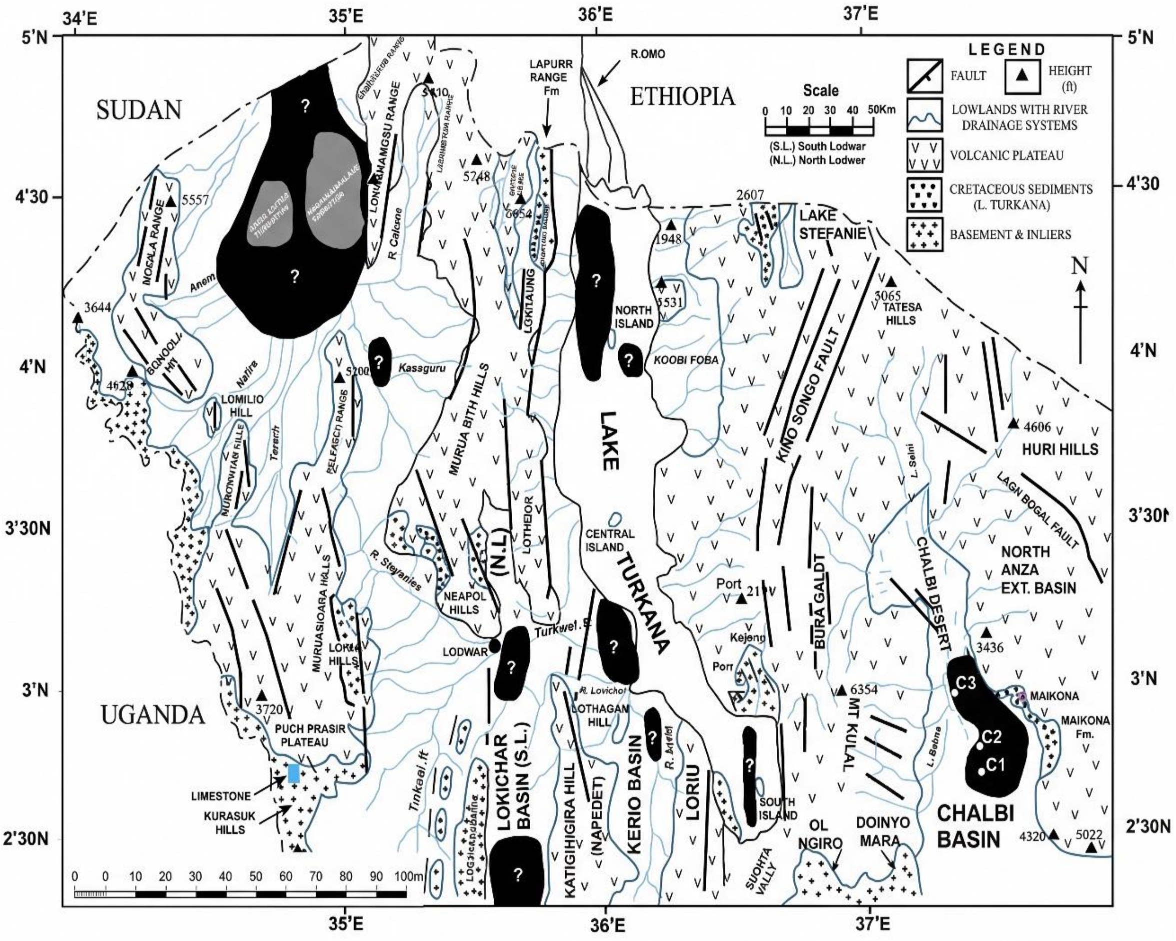

Figure 18. Map showing probable prospective areas for hydrocarbons (shaded black/grey) in the Northwestern Kenya Rift Lotikipi Basin.

Temperature-depth trends from well vitrinite data (where available) suggest an early oil window at ~2.0–2.5 km; the deepest central depocentre likely reached maturity during Late Tertiary burial.

Lake Turkana Basin

The Lake Turkana Basin occupies an axial rift segment characterized by Quaternary–Recent volcanism and active faulting. Bouguer lows coincide with the modern lake trough, while flanking highs delineate basement-cored ranges. Seismic profiles image tilted fault blocks with syn-rift packages thickening into half-grabens [1].

Stratigraphic Architecture

A tripartite subdivision is recognized:

- *Upper syn-rift:* Volcaniclastic sands, deltaic foresets, lacustrine muds; Vp 2.0–3.0 km/s; frequent onlap and downlap.
- *Middle syn-rift:* Sand-rich packages with interbedded basalts; Vp 3.0–3.6 km/s; channelized geometries and growth-fault rollovers.
- *Basal syn-rift:* Coarse alluvial–fluvial conglomerates over basement; Vp 3.6–4.1 km/s; strong angular unconformity.

Hydroacoustic and limited 2D lines reveal gas-charged zones in delta fronts; however, pervasive volcanics complicate imaging and reservoir continuity.

Lokichar–North Kerio System

Structural Setting

The Lokichar–North Kerio rift is a classic half-graben pair with master faults on opposite margins. Bouguer maps show linear lows (–80 to –100 mGal) parallel to the rift axis. Fault linkage and segmentation created multiple sub-basins partitioned by accommodation zones [1].

Seismic Character and Plays

High-quality 2D/3D data image thick syn-rift clastics sealed by lacustrine shales and, locally, trachyte/phonolite flows. Proven petroleum systems in nearby discoveries validate lacustrine shale sources and fluvial–deltaic sandstone reservoirs. Prospectivity focuses on footwall-derived fan deltas, hanging-wall rollovers, and stratigraphic pinchouts beneath regional flooding shales.

Synthesis and Implications

Across the four basins, gravity and seismic evidence support a mosaic of asymmetric half-grabens, with depocentres controlled by long-lived basement fabrics reactivated during Mesozoic–Cenozoic extension. Variations in subsidence, volcanism, and sediment supply govern facies distribution and reservoir quality. The most prospective trends coincide with persistent Bouguer lows, growth-fault complexes, and areas of repeated accommodation creation. Further work should prioritize integrated 2D/3D seismic, potential-field inversion, and targeted stratigraphic drilling to refine thermal histories and source rock risk.

How Oil and Gas Form in Rocks

Sedimentary rocks (like those from rivers or lakes) do not start with oil or gas inside them. Instead, oil and gas are made later when the rocks are buried deep underground [23–25], and the organic matter (old plant or animal bits) in them changes over time (a process called diagenesis). This happens in basins like the one here, which are cracks in the land inside continents.

In these basins, the heat from the Earth is often stronger than usual because of how the basin formed. It can reach 30–33°C per kilometer of depth. Extra heat also comes from radioactive bits mixed with organic matter. This means oil can form best between 2 and 3 km deep. If there is not much oil, there might still be gas, and the best gas spots are deeper than 2.8 km.

The LT-1 well was drilled down to 2960 m, but it did not reach the solid rock base (basement). Earth-shaking data (seismology) shows the layers of sediment go down to about 3500 m. The basin likely has Type I or Type III kerogen (the main organic stuff that makes fuel), since the organic matter came from lakes and rivers, not the sea [23–25].

TOC measures the carbon in rocks from kerogen and bitumen (sticky oil-like stuff). Organic matter turns into kerogen, and the type depends on what got buried. Not all organic matter can become fuel.

Looking at Changes in the Well's Rocks

This part checks how TOC and Tmax (the highest heat peak) change with depth in the LT-1 well (in the Lokichar Basin) to spot rocks that could make oil or gas. Basins like this do not get sea-based organic matter. Instead, it came from plants on higher land during the Cretaceous and early Tertiary periods, buried in lake and river settings.

Materials and Methods

Choosing Samples for TOC Tests

TOC measures the carbon in rocks from kerogen and bitumen. The LT-1 well went down 2960 m, and core samples (bits of rock from drilling) showed no big carbon-rich layers below 2000 m. So, samples from 800 m to 1800 m depths, where there were hints of organic matter, were tested using a method called Rock-Eval.

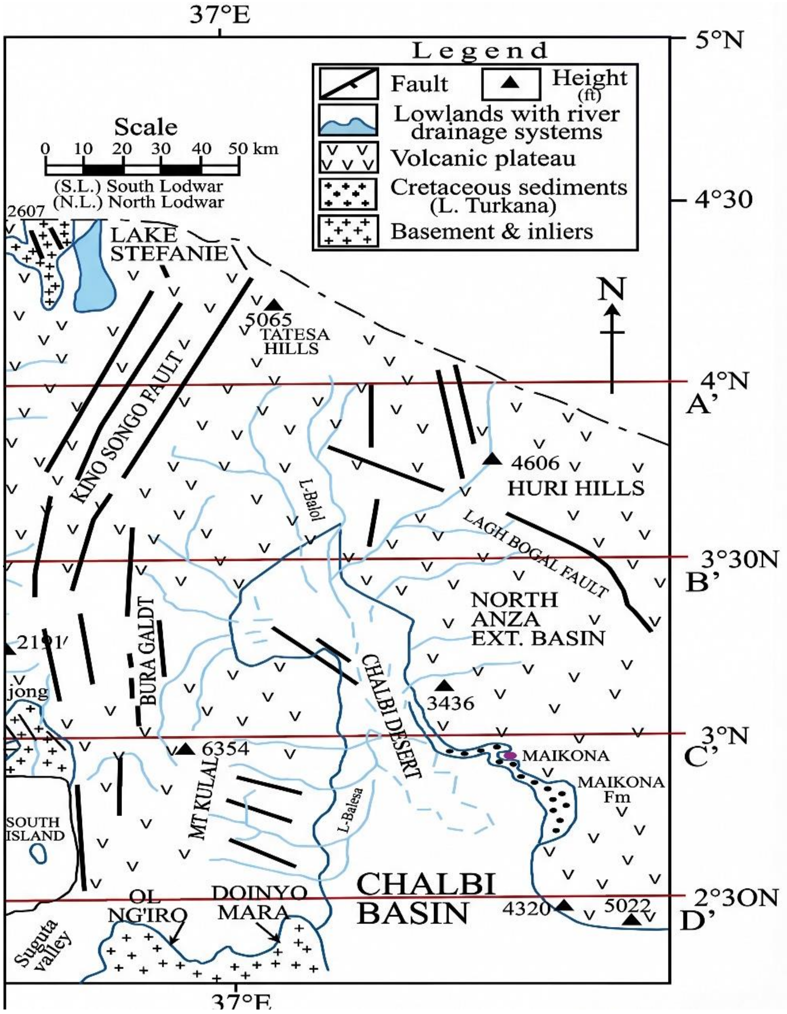

Figure 19. Physiographical and geological map of the Chalbi Basin (adopted from [1]).

This depth range was picked because of oil signs and rocks with high gamma ray readings (which detect radioactivity). The goal was to measure TOC and find possible fuel-making rocks Figure 21.

The rocks below ground show signs of oil and gas, backed by tests on TOC, maturity levels, and Tmax. These suggest good conditions for making fuel.

How TOC Tests Were Done

About 1 g of rock sample was treated with hydrochloric acid (HCl, 20% strength) to remove inorganic carbonates (like limestone bits). The acid was sucked out with a vacuum pump, the sample was washed with clean water, and dried in an oven at 40°C. They weighed it before and after to see the difference.

The system ran for an hour and was set up to measure TOC and CO_2. The dried sample went into a carbon analyzer (IR-212) with a heating furnace and computer control. Oxygen gas burned the sample, and nitrogen gas helped move things, both at 35 pounds per square inch pressure. The burning chamber was at 11–12 psi (Figure 20).

The CO_2 made was measured, and the machine gave the TOC as a percentage by weight. In shales (mud rocks), especially black ones, TOC is usually five times higher than in carbonates or other sediments. Organic matter in carbonates can make more fuel than in shales. But the LT-1 well has mostly sandy rocks with some shale layers, no carbonates.

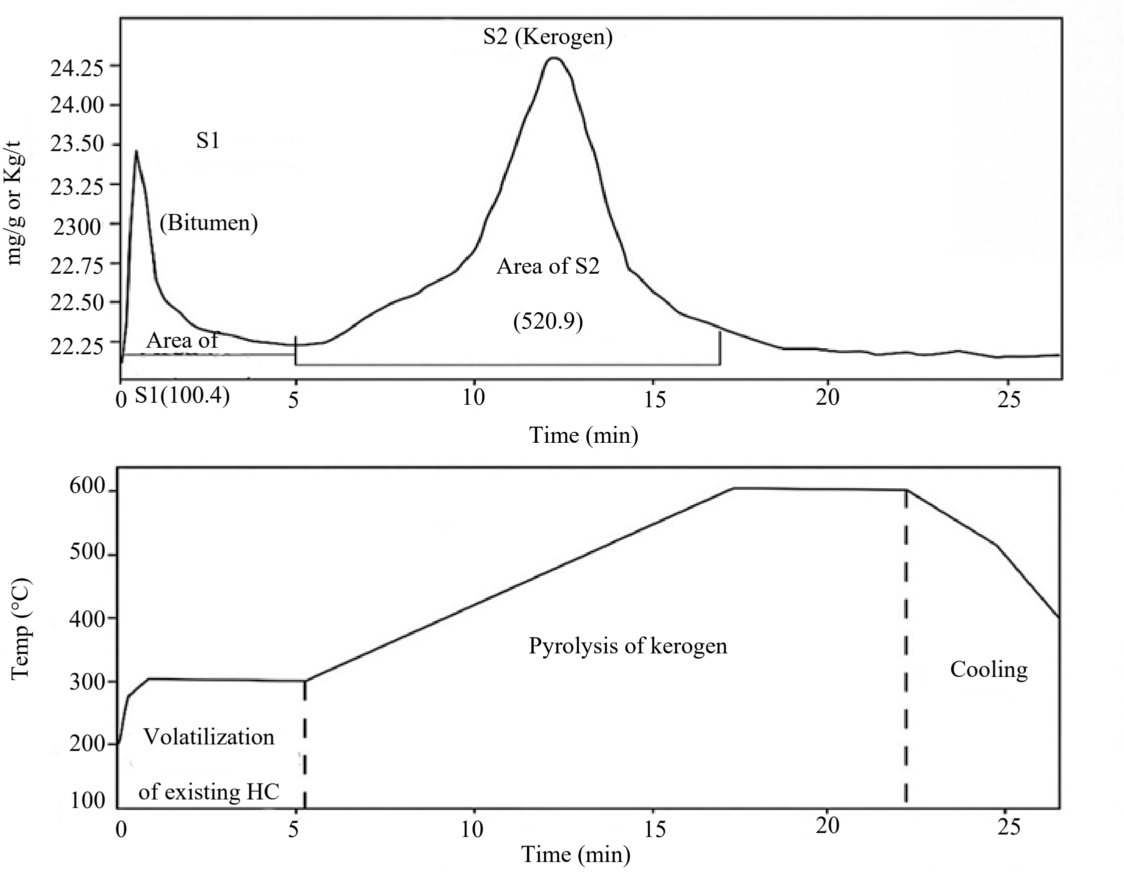

Figure 20. Laboratory rock pyrolysis showing the effect of heating an organic-rich sample at 1098 m depth of the LT-1 Well (Tmax 435.3°C) [1].

Oil and Gas Shows in the LT-1 Well

In the LT-1 well, signs of oil and gas were found at two main depth ranges: 800–1000 meters and 1400–1600 meters. The shallower level is above a layer with moderate levels of TOC, which measures how much organic material is in the rock. A TOC of 0.5% is often seen as the minimum needed for a rock to produce enough oil or gas. Below this, there is not enough organic material to generate hydrocarbons that could fill the rock.

The deeper level of oil shows is in a range where samples have consistent Tmax values (a measure of how mature the organic material is) and higher TOC. In a typical geothermal gradient (how heat increases with depth), temperatures reach 60–65°C around 1,800 meters, which is the point where oil can start forming from the organic matter. The deeper parts of this well, with their high Tmax, are likely the main spots for oil production. Most of the oil and gas signs in the LT-1 well are above this depth and in rocks with good porosity (spaces for fluids to flow).

Rock-Eval Pyrolysis Tests on LT-1 Samples

Samples were first soaked in organic solvents (like chloroform or acetone) to remove bitumen. Bitumen is the oil that can be extracted from the rock. Then, they were dried and tested with pyrolysis (heating in a Rock-Eval machine).

A small, dried sample (about 100 mg) went into a flame ionization detector (FID) and was heated in helium gas up to 300°C for five minutes to release free or trapped hydrocarbons (bitumen) already in the rock (Figure 21).

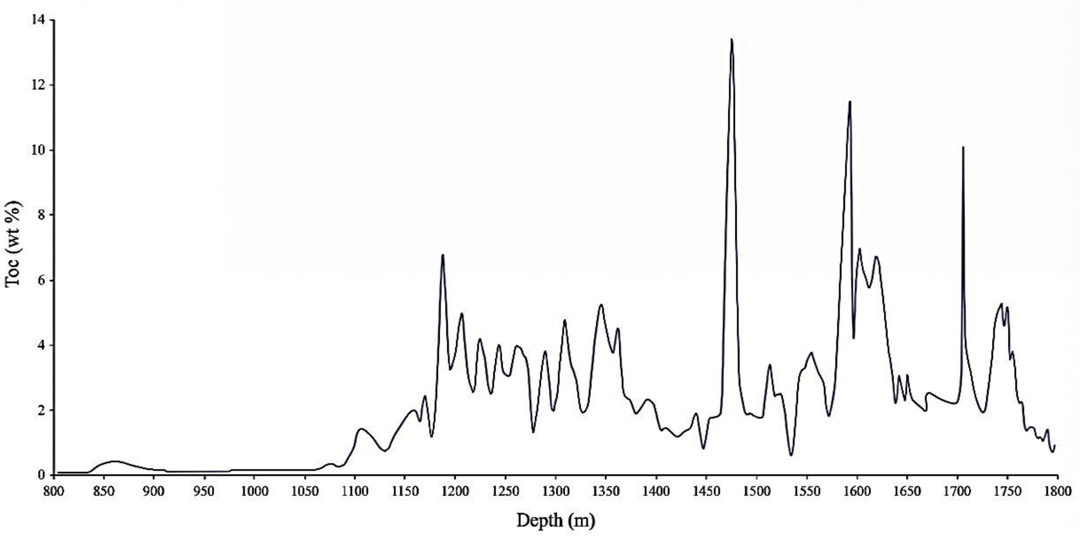

Figure 21. Variations between TOC and depth.

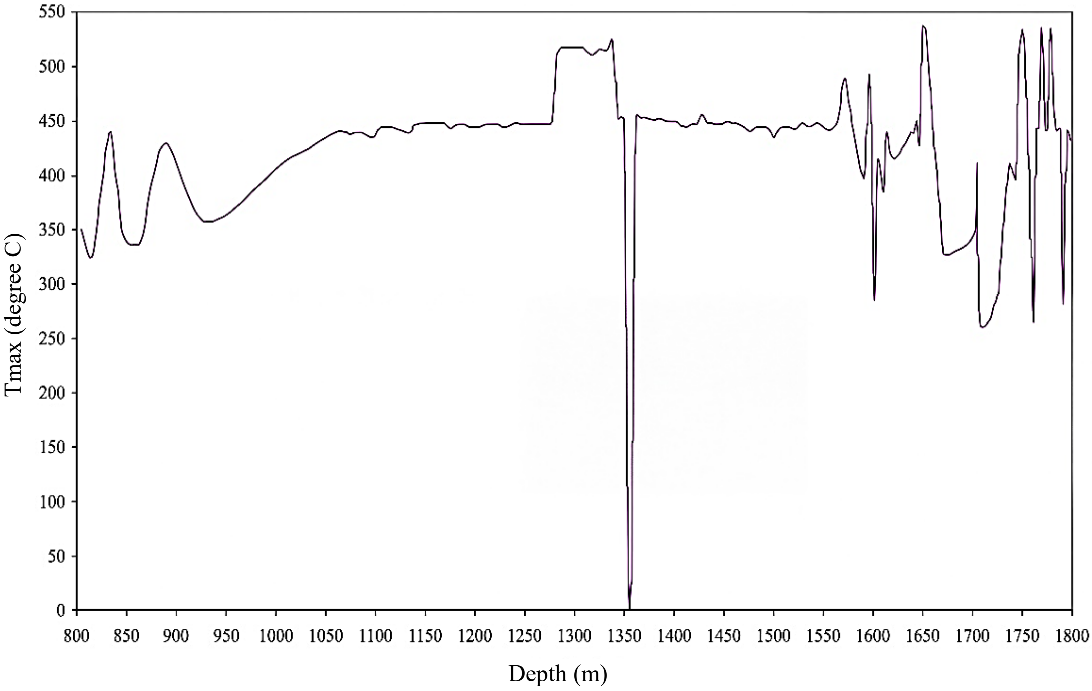

Figure 22. Variations of Tmax with depth.

Two peaks were recorded, showing the amounts of two parts of the organic matter (based on the area under the peaks). The first peak (S1) is from hydrocarbons that evaporate below 300°C, measuring already-made bitumen.

Not many samples had high S1 values. Most had S2 up to 20 kg/g and low S1 (<0.3), meaning a little bitumen was made below 300°C. S2 over 10 kg/g suggests better potential for making more hydrocarbons from kerogen.

Oil and Gas Shows in the LT-1 Well

In the LT-1 well, signs of oil and gas were found at two main depth ranges: 800–1000 meters and 1400–1600 meters (Figure 22). The shallower level is above a layer with moderate levels of TOC, which measures how much organic material is in the rock.

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The deeper parts of this well, with their high Tmax, are likely the main spots for oil production. Most of the oil and gas signs in the LT-1 well are above this depth and in rocks with good porosity (spaces for fluids to flow) (Figure 22).

The Highest Temperature Peak–Tmax (°C)

Tmax is the temperature where the S2 peak happens, and it shows how mature the organic matter is. As the matter gets more mature, Tmax usually goes up [23–25]. Figure 23 above shows how Tmax changes with depth in the well.

Figure 23 shows that the maximum number of samples between 1250 m and 1800 fall within the range of Tmax 445°C and 537°C. From 1062 m to 1578 m depths the Tmax shows a characteristics stable range of 445°C–450°C with a slight variation towards higher side between 1278 and 1350 m and a sudden very low value at 1356 m depth, but from 1590 to 1800 m the Tmax shows very frequent variations as high as 537°C at 1650 m depth and as low as 263°C at 1707 m depth.

These two levels are also characterized by the gamma rays' values. The upper one has a higher gamma ray range (>75 API units) while the deeper one has a lower gamma ray range (60–75 API units). The similarity between the production index (PI) and Tmax curves in this depth range is indicative of a kind of difference between the hydrocarbon type (bitumen or kerogen) on one side, and a difference in the temperature that can be attained [1].

The kind of kerogen that shows a lower Tmax range is a simpler type (maybe Type I), while those samples in the 1600 m to 1800 m depth range had a more complex type of kerogen (maybe Type III). The kerogen breakdown depends not only on the temperatures attained but also on the time it takes for the breakdown. Given sufficient time and temperatures in the range of 100–150°C, kerogen breakdown is facilitated. The more complex kerogen, however, takes higher temperature and a greater time for the cracking process. The time perception, of course, is in the range of thousands of years or even millions of years.

Spotting Rocks That Might Produce Oil or Gas

When we heat a rock sample at 25°C per minute up to 600°C, the organic matter (like ancient plant or animal remains) in the rock breaks down. This creates a peak on a graph called S2 (see above sections). The size of this S2 peak, especially at higher temperatures (550–600°C), shows how much oil or gas the rock could make. It is like measuring the rock's leftover ability to produce fuel.

Other gases, like carbon dioxide (CO_2) and water (H_2O), go to a separate detector and create a peak called S3. But in this study of the LT-1 well, they did not do that extra step.

We use two peaks, S1 and S2, to check how "mature." [23–25]. These are measured in milligrams per gram of rock (mg/g) or kilograms per ton (kg/ton).

- Rocks with S1 + S2 less than 2 kg/ton are not good for making oil or gas.
- Between 2 and 5 kg/ton, they might make some fuel, but not enough to push it out of the rock.
- Between 5 and 10 kg/ton, they could push out some oil.
- Over 10 kg/ton, they are rich enough to expel plenty of oil.

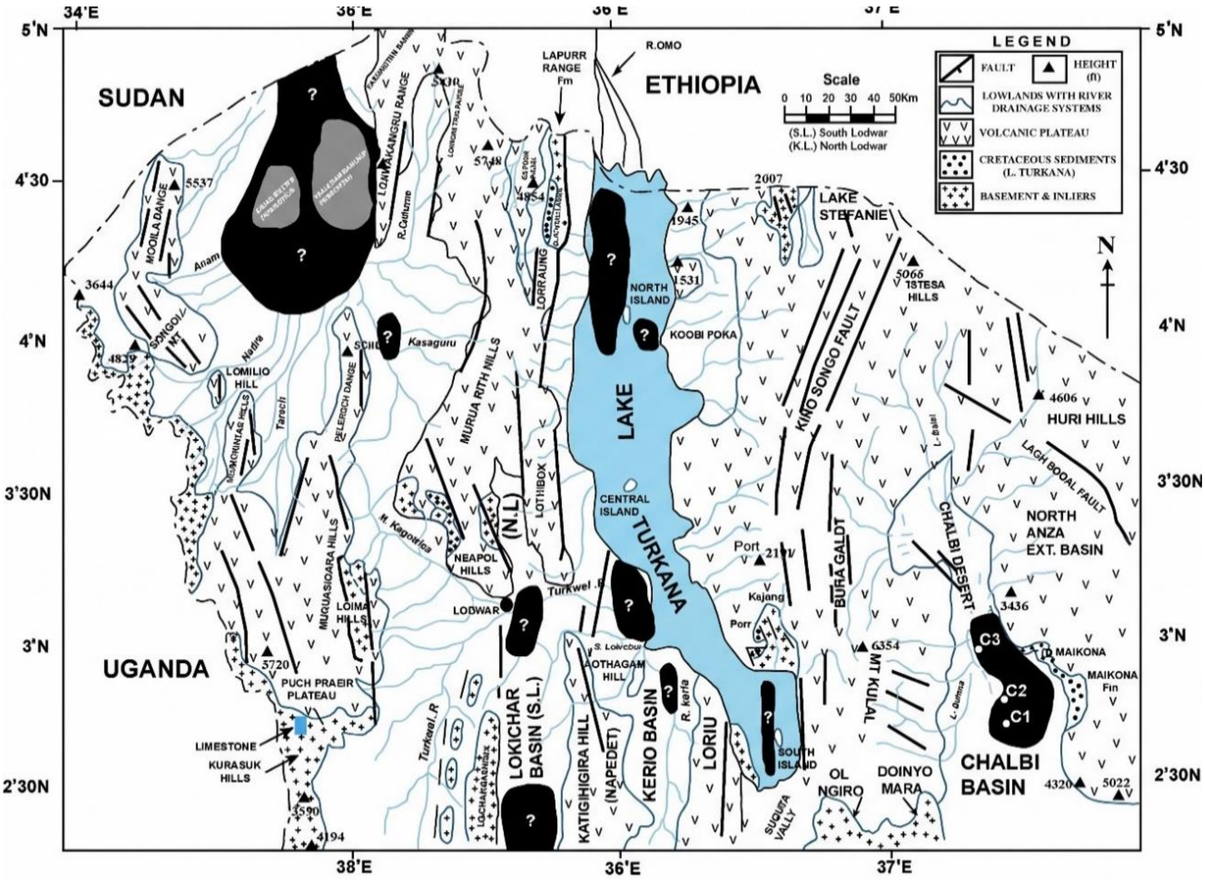

Figure 23. Map showing probable prospective areas for oil and gas prospects (shaded black/grey) in the Northwestern Kenya Rift Basins (Lotikipi, Lake Turkana, Chalbi, Lokichar–Kerio) (adopted from [1]).

Oil or gas only forms when the rock reaches at least 60°C. It also depends on how mature the organic matter is, shown by the highest temperature peak (Tmax in °C).

The rock might not have reached 60°C yet, or any fuel made has already moved away. To push fuel out, the rock needs to be full of it first, which happens with enough heat and time.

There are three main high points:

1. *At 834 m depth:* 437°C, and *at 888 m:* 429°C.
2. *At 1308 m:* 518°C, and *at 1650 m:* 537°C.
3. *At 1749 m:* 535°C, and *at 1770 m:* 536°C.

Higher Tmax means more mature organic matter, which is key to making oil. Immature matter makes no fuel, but as it matures, it first makes oil, then gas. Harder-to-break organic matter needs hotter temperatures.

Figure 23 shows that most samples between 1250 m and 1800 m have Tmax from 445°C to 537°C. From 1062 m to 1578 m, it is mostly steady at 445–450°C, with a slight rise around 1278–1350 m and a dip at 1356 m. From 1590 to 1800 m, it varies a lot, up to 537°C at 1650 m and down to 263°C at 1707 m.

These levels match gamma ray readings (a measure of rock radioactivity). The upper level has higher gamma rays (>75 API units), the deeper one has lower (60–75 API units). The similarity between Tmax and another measure (production index, or PI) suggests differences in fuel type (like sticky oil or kerogen) and heat levels.

Simpler organic matter (maybe Type I) has a lower Tmax, while complex types (maybe Type III) at 1600–1800 m need higher heat. Breakdown depends on heat (100–150°C) and time (thousands to millions of years). Complexes matter take longer.

Overall Findings

The study gathered and analyzed all available data, including structural details, land shapes, seismic (sound wave) profiles, gravity maps, and gamma ray readings from drilling cores. This came from three wells (C1, C2, and C3) in the Cretaceous rocks of the Chalbi Basin, and two wells (LT-1, also called Loperot 1, and LT-2, or Eliye Springs 1) in the Lokichar–Kerio/Turkana sub-basins, which mostly went through Palaeocene or younger rocks.

More drilling and fossil discoveries will help fill in details about the underground rock layers in the Lotikipi Basin, even though some recent wells by CEPSA turned out dry [26, 27]. However, a British company, Tullow Oil, has drilled in Blocks 10BB and 13T of the Tertiary Lokichar Rift Basin. They have found proven oil in all their wells so far, including Ngamia-1, Amosing-1, Twiga-1, Ewoi-1, Etuko-1, Ekunyuk-1, Ekales-1, Etom-1, Agete-1, and Erut-1 (now over 17 wells in total). These are in Turkana County and show strong oil potential, with the discoveries now being assessed for commercial development and production.

Ancient Geography and Environment

In the past (Triassic to Cretaceous periods), what is now northern Kenya was south of the equator. It had lush plants, swamps, wet weather, and lots of rain. This led to organic matter that could make Type I or Type III kerogen, producing waxy oil or gas [23–25].

The study checked how often shale (mudstone) layers appeared in sandy rocks, and how sand grain sizes varied. Extra heat from organic-rich rocks boosted the Earth's natural heat gradient, which is already high in rift basins (cracks in the land).

Black shales with 2% carbon and up to 400 ppm uranium (though more common in seas) can form in lakes with lots of life and no oxygen. Fast sinking of the land and quick sediment buildup stopped the organic matter from rotting, saving it for possible fuel production.

Otherwise, here is a quick wrap-up of the key takeaways from the simplified text:

- The LT-1 well's rocks show potential for oil and gas, especially at deeper levels with high maturity (Tmax) and organic content (TOC).
- Oil signs were found at 800–1000 m and 1400–1600 m, but the main generation likely happened deeper, where heat and time allowed it.
- Ancient conditions (swampy, rainy areas south of the equator) created the right organic matter for fuel production, preserved by fast land sinking and sediment buildup.

In the study area's intracratonic half-grabens, elevated heat flow associated with rifting and magmatism may steepen the geothermal gradient relative to stable cratonic averages. This can accelerate maturation at shallower depths, expanding the oil window upward and potentially shifting peak gas generation to moderate depths. These factors frame the evaluation of source quality, richness, and maturity presented below.

Hydrocarbon Characteristics of Source Rocks in LT-1 Well, Lokichar Basin

Geological and Operational Context

The Lokichar Basin, bounded approximately by 35°30′E–36°20′E and 2°00′N–3°30′N, forms a segmented north–south rift trough southwest of Lake Turkana and southeast of the Lotikipi Basin. Thick Tertiary volcanics and widespread alluvium conceal much of the stratigraphy, while the Turkwel and Kerio rivers drain basement highs and deliver clastics to the rift axis. Within this setting, the Loperot-1

(LT-1) exploration well penetrated 2,960 m of dominantly clastic strata without reaching crystalline basement; seismic control indicates sedimentary fill may extend to ~3,500 m.

In these syn-rift lacustrine and fluvial systems, observational method (OM) derives from mixed lacustrine algal blooms and terrestrial vegetation. Accordingly, kerogen is expected to be Type I and Type III, with variable hydrogen richness and gas-prone tendencies at higher maturity.

Thermal Regime and Maturity Conceptualization

Regional rift heat flow suggests geothermal gradients on the order of ~30–33 °C/km, locally higher near volcanic centers. Under such gradients, the main oil window broadly spans ~1.6–3.2 km (Tmax ~430–455 °C), with late oil to wet-gas generation continuing deeper. Gas generation can persist beyond ~2.8 km where effective kerogen is present. The LT-1 Tmax near 1,098 m (example: 435.3°C) implies localized heating, transient magmatic influence, or sample-specific kinetics; maturity must therefore be interpreted alongside depth trends rather than absolute depth alone.

Geochemical Indicators from LT-1

- Rock-Eval pyrolysis at select depths indicates low S1 (free hydrocarbons) in most samples (<0.3 mg HC/g rock), consistent with limited pre-existing bitumen in shallower intervals.
- S2 (remaining generative potential) values commonly ≤20 mg HC/g rock, with samples >10 mg HC/g rock considered potentially generative. Variability reflects facies shifts between organic-lean fluvial sands and more organic-rich lacustrine shales.
- TOC measurements from 800 to 1,800 m focus on intervals with oil shows and elevated gamma ray signatures; lithology is dominantly sandstone with interbedded shales, and no significant carbonates are observed.

Interim interpretation: Organic richness is heterogeneous but includes pockets of fair–good potential, most likely in lacustrine shale lenses. Maturity indicators (Tmax ~430–440+ °C in places) suggest an early to mid-oil window in parts of the section, with deeper intervals (not sampled here) more likely to reach peak oil and wet-gas windows.

Sample Selection for TOC and Pyrolysis

Core and cuttings from 800–1,800 m were prioritized due to documented oil shows and high gamma ray intervals suggestive of shale-rich facies. Below ~2,000 m, preliminary lithologic logging indicated limited carbonaceous content; additional deeper sampling is recommended to better constrain maturity and richness trends toward the basin center.

TOC Determination Protocol

- *Decarbonation:* ~1 g of powdered rock was treated with 20% v/v HCl to remove inorganic carbonates; residues were vacuum-filtered, rinsed to neutrality, and oven-dried at ~40 °C.
- *Instrumentation:* Carbon determinator (IR-212) coupled to an induction furnace and control computer; O_2 for combustion and N_2 for pneumatic functions were stabilized at ~35 psi; furnace chamber maintained at ~11–12 psi.
- *Quantification:* CO_2 evolved during combustion was measured by infrared detection; TOC wt.% was computed automatically after calibration.

Rock-Eval Pyrolysis Workflow

- *Bitumen extraction:* Samples were solvent-cleaned (e.g., dichloromethane, chloroform mixtures) to remove free bitumen prior to pyrolysis.
- *Pyrolysis:* ~100 mg aliquots were heated under helium; an initial hold to ~300 °C for 5 minutes quantified S1 (free hydrocarbons). Subsequent programmed heating generated S2 (cracked hydrocarbons from kerogen) and Tmax (temperature at S2 peak).
- *Interpretation:* S1 gauges pre-existing mobile hydrocarbons; S2 measures generative potential; Tmax approximates maturity. In this dataset, S1 is generally low, S2 ranges up to ~20 mg HC/g rock, and Tmax values near 430–440+°C indicate early–mid-oil window in parts of the analyzed interval.

Data Quality and Limitations

Matrix effects (clay-richness), mineral catalysis (e.g., pyrite), and residual solvents can bias pyrolysis metrics. Heterogeneous cutting mixes may dilute TOC and S2. Future work should emphasize consistent core plugs, solvent blank checks, duplicate analyses, and kerogen microscopy (palynofacies) for OM typing.

RESULTS

TOC Distribution and Depth Trends

TOC values from 800–1,800 m range from low to locally fair–good, with higher TOC clustering in shale-rich intervals identified by elevated gamma ray logs. Sand-dominated intervals generally show low TOC with sporadic organic laminae.

- A subtle increase in average TOC is observed toward the deeper part of the sampled window (≥1,300 m), consistent with more persistent lacustrine influence and reduced oxidation during deposition.

Tmax and Thermal Maturity

- Measured Tmax values cluster around ~430–440+°C, with an example peak near 435.3°C at ~1,098 m indicating entry to the early oil window in localized hotter pockets.
- The maturity profile suggests parts of the 1.2–1.8 km interval have reached early–mid-oil window conditions, while deeper untested intervals (≥2.0–3.0 km) are inferred to attain peak oil to wet-gas windows given regional gradients.

S1–S2 Patterns and Generative Potential

- S1 values are uniformly low (<0.3 mg HC/g rock in most samples), indicating limited pre-existing free hydrocarbons in the shallower analyzed section.
- S2 ranges up to ~20 mg HC/g rock, with intervals >10 mg HC/g rock classified as potentially generative. Variability corresponds to facies changes between organic-lean fluvial sands and organic-richer lacustrine mudstones.

Kerogen Typing (HI/OI Perspective)

- Direct HI/OI data are limited; however, depositional context (fluvial–lacustrine) and facies indicate mixed Type I (lacustrine algal) to Type III (terrestrial woody) kerogen, with subordinate Type II mixtures.
- Inferred hydrogen index (HI) is moderate in lacustrine shale lenses and low in sandy fluvial units; oxygen index (OI) is higher in more oxidized, terrestrial-leaning intervals. This mix implies liquid potential in richer lacustrine beds and gas-prone tendencies with increasing maturity and terrestrial input.

Quality Classification

- *Poor source potential:* TOC <0.5 wt.% and S2 <2 mg HC/g rock—typical of clean fluvial sands.
- *Fair:* TOC ~0.5–1.0 wt.%, S2 ~2–4 mg HC/g rock — mixed sand–silt intervals.
- *Good:* TOC ~1.0–2.0+ wt.%, S2 ~>5–10+ mg HC/g rock—lacustrine shales/silty shales; localized intervals approach very good where S2 nears ~20 mg HC/g rock.
- Effective source horizons are intermittent and laterally variable, tracking rift accommodation zones and lake expansion phases.

DISCUSSION

Burial–Thermal Modeling Context

Using a regional geothermal gradient of ~30–33 °C/km and reasonable surface temperatures, the main oil window is expected from ~1.6–3.2 km, with late oil to wet-gas continuing deeper. Local magmatic heat pulses can elevate maturity at shallower depths, explaining early oil signatures near ~1.1–1.4 km.

Liquids vs Gas Risk Balance

- Liquids (oil) potential is favored in lacustrine intervals with moderate–high HI that have attained early–peak oil maturity. Gas-prone outcomes increase where Type III kerogen dominates and where burial continues beyond ~2.8 km, or where thermal anomalies accelerate cracking.
- The low S1 in the analyzed samples suggests limited retained movable hydrocarbons in the shallower section; deeper, better-sealed lacustrine pods are more prospective for retained charge.

Migration, Retention, and Seals

- Intraformational lacustrine shales and tuffaceous layers provide effective local seals; regional flooding shales, where present, can aid vertical charge focusing.
- Growth faults and rollover geometries adjacent to the rift master faults offer migration pathways; however, volcanic sills/dykes may compartmentalize reservoirs and redirect charge, enhancing stratigraphic traps against basement highs and within pinchouts.

Comparison Across Basins

- *Lotikipi:* Seismic facies analogous to Cretaceous lacustrine–fluvial systems suggest a similar Type I/III kerogen mix with potential mature kitchens in deeper half-grabens.
- *Chalbi:* Well-calibrated Units B–C contain dark mudstones likely to host Type II/III sources; burial in central depocentres may have reached early to mid-oil window.
- *Lake Turkana:* Volcanic abundance increases thermal and imaging complexity; localized gas occurrences at delta fronts imply active charge but reservoir continuity risk.
- *Lokichar–North Kerio:* Proven lacustrine source presence with multiple working plays; LT-1 geochemistry fits the broader rift pattern of mixed kerogen and variable maturity.

Key Uncertainties

Spatial continuity of rich lacustrine facies; thermal anisotropy due to volcanism; and timing of trap formation versus charge. Data density (core, logs, 2D/3D seismic) remains the principal limitation on risk reduction.

Simplified Summary of Subsurface Stratigraphy and Oil/Gas Potential

This part of the study examines the layers of rock underground to identify potential oil and gas reserves in the basins (Figure 23). This information could also be extrapolated to other areas in these basins and to the unexplored northwest part of the Lotikipi Basin, where CEPSA drilled dry wells in 2017 [26, 27].

Chemical tests have shown there is a working system for oil in the Lotikipi Basin. The rock layers include sediments mixed with volcanic material, with two rich shale layers (Lokhone D and Lokhone E) full of organic matter. These shales are formed in lakes without oxygen and are affected by strong volcanic activity.

- *Sediment types:* The filled sediments are mostly from land (non-marine), but there might be some sea influence when the Chalbi Basin (from the Cretaceous period) first filled in the north Anza graben [1, 5, 12].
- *Temperature differences:* The heat levels underground in Cretaceous and Tertiary rocks varied due to uneven rising of the Earth's mantle, as seen in gravity maps.
- *Key features for oil/gas:* Using gravity, seismic, and gamma ray data, plus measures like TOC, porosity, and other rock properties [25–27], the study identified important structures with rocks that can produce, store, and trap oil/gas. This helps spot future targets for exploration, thanks to a proven oil system in the area.

CONCLUSIONS AND EXPLORATION IMPLICATIONS

As discussed, northern Kenya was south of the equator during the Triassic-Jurassic/Cretaceous times, with lush plants, swamps, humid weather, and good rain [8]. This led to buried organic matter that could produce waxy oil or gas (Type I or III kerogen). Pollen and fossil evidence from drilling shows sediments formed in sea, river delta, or lake environments, ideal for oil systems.

Sedimentation Control

Filling of these basins was shaped by faults inside and around them, some reaching deep basement rocks.

Assessment Goals

By studying underground layers and drilled cores, the aim is to evaluate oil/gas potential and extend findings to other basin parts, including the northwest Lotikipi area. Sediments are mainly non-marine, but early Chalbi Basin filling might have had sea input in the north Anza graben.

Heat Variations

Cretaceous and Tertiary basins had different underground temperatures due to uneven mantle rising, shown in gravity maps.

Prospects and Examples

Some similar basins are not great for oil, but they can have good storage rocks for any oil from land-based organic matter. Examples exist of such basins producing oil. Black shales with high carbon (2% TOC) and uranium (up to 400 ppm), usually from seas, can also form in productive, oxygen-free lakes. Quick sediment buildup and basin sinking preserve organic matter for oil generation (Appendix).

Future Implications

Key structures with source, reservoir, and cap rocks, analyzed via gravity, seismic, gamma ray, TOC, and rock properties, help identify targets for oil exploration in northwest Kenya's rift basins.

- The LT-1 dataset indicates heterogeneous but locally good source potential within lacustrine shale intervals, with early–mid-oil window maturity already achieved in parts of the 1.2–1.8 km section and higher maturity expected at ≥2.0 km.
- Low S1 values at sampled depths imply limited retained movable hydrocarbons shallowly; deeper depocentres and better-sealed intervals remain the prime targets.
- *Exploration should prioritize:* (1) mapping persistent Bouguer lows and growth-fault depocentres; (2) acquiring targeted 2D/3D seismic over these lows; (3) high-resolution stratigraphic coring across lacustrine wedges; (4) advanced geochemistry (HI/OI, biomarkers, kerogen microscopy) to refine typing and kinetics; and (5) burial–thermal modeling with magmatic heat flow scenarios.
- *Play focus:* footwall-derived fan deltas and axial channels overlain by lacustrine seals; stratigraphic pinchouts against basement highs; and rollover closures near growth faults. Where volcanics are pervasive, look for sill-bounded compartments that may enhance lateral sealing.
- Next steps include integrating potential-field inversion to sharpen basement architecture, executing a pilot vertical seismic profiling (VSP) in a future appraisal well to calibrate maturity with depth, and testing one stratigraphic well in a central depocentre to directly sample the mature lacustrine source interval.

DATA GAPS AND FUTURE WORK

- *Sparse geochemical coverage below ~2.0 km:* Acquire deeper core/cuttings for TOC, Rock-Eval (HI/OI), vitrinite reflectance, and biomarkers to directly sample the presumed mature kitchen.
- *Kerogen typing resolution:* Implement kerogen microscopy (palynofacies), Py-GC/MS, and full HI–OI datasets to refine Type I/II/III proportions and kinetics.
- *Thermal history uncertainty:* Build 1D/2D burial–thermal models with magmatic heat flow scenarios; calibrate with VSP, temperature logs, and Ro.
- *Seismic imaging in volcanic terrains:* Target reprocessing with demultiple and full-waveform inversion where feasible; infill 2D/3D over Bouguer lows and growth-fault zones.

- *Seal integrity and overpressure:* Evaluate shale/tuff seals via petrophysics (Vp/Vs, density-sonic), MDT tests, and capillary pressure analysis.
- *Migration pathways and trap timing:* Map fault kinematics and relay ramps; integrate fluid inclusion stratigraphy for charge timing.
- *Reservoir quality prediction:* Apply diagenetic modeling and thin-section/SEM to quantify porosity and permeability evolution in volcaniclastic-rich sands.
- *Risk integration:* Update basin/play common risk segment maps incorporating new geochem, structure, and thermal data.

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APPENDIX

Methods (QA/QC and Instrument Settings)

- *Sample preparation:* Solvent-clean for bitumen removal; 20% HCl decarbonation; oven dry at ~40°C.
- *TOC:* IR-212 carbon determinator; O_2 and N_2 lines stabilized (~35 psi); chamber ~11–12 psi; multi-point calibration daily; duplicates every 10 samples (RPD $\leq$10%).
- *Rock-Eval:* ~100 mg aliquots; S1 hold ~300°C for 5 min; programmed ramp for S2/Tmax under He; solvent blanks and standards in each batch; drift check every 20 samples.
- *Data validation:* Check S1 carryover vs blanks; flag Tmax from low-S2 peaks; cross-plot HI–OI where available; reconcile with lithology and gamma logs.
- *Chain of custody:* Barcoded vials; field-to-lab log reconciliation; archive residues for re-run.