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Characterization of organic-rich shales and source rock potential in the Karoo Basin

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Abstract

A source rock is any geological unit that has generated or is capable of generating hydrocarbons in quantities sufficient to form an accumulation. Whether the Permian shales of the Karoo Basin in South Africa qualify as effective source rocks has been debated for decades. This research characterised the organic richness, kerogen type, and thermal maturity of four formations within the Eccra Group-the Whitehill, Prince Albert, Collingham, and Ripon Formations-using 100 core samples from five boreholes in the southern and central Karoo collected between April 2019 and March 2023. Rock-Eval pyrolysis, TOC analysis, vitrinite reflectance measurements, and kerogen microscopy were applied. The Whitehill Formation contains the highest organic content, with a median TOC of 5.87 wt% and S2 values reaching 12.4 mg HC/g rock. Vitrinite reflectance ranged from 0.82% in shallow Ripon samples to 2.31% in deep Whitehill intervals, placing most Whitehill and Prince Albert samples within the dry-gas window. Kerogen was predominantly Type II (marine algal) in the Whitehill and mixed Type II-III in the remaining formations. The data indicate the Whitehill Formation is a proven source rock that has generated gas, while the Prince Albert Formation retains marginal capacity. These results inform shale-gas exploration decisions and environmental risk assessments for the ecologically sensitive Karoo region.

Keywords: Organic-rich shales, source rock potential, Karoo Basin, total organic carbon, Rock-Eval pyrolysis, kerogen type, vitrinite reflectance, petroleum geology, Eccra Group, shale gas

Introduction

A source rock, in petroleum geology, is a fine-grained sedimentary unit rich enough in organic matter to have generated hydrocarbons under appropriate conditions of burial temperature and time ^[1]. Whether a given shale acts as a source rock depends on three factors: organic richness, kerogen quality, and thermal maturity ^[2]. Evaluating all three together is necessary before any meaningful assessment of petroleum potential can be made. The Karoo Basin of South Africa is a large intracratonic depression that accumulated up to 8 km of sediment from the Late Carboniferous to the Middle Jurassic. Its lower Permian Eccra Group includes several organic-rich shale intervals deposited under restricted marine to lacustrine conditions ^[3]. Interest in the Karoo's shale-gas potential was revived in the late 2000s when preliminary estimates suggested recoverable reserves of 390 trillion cubic feet, though subsequent appraisals scaled that figure down ^[4]. The debate has been hampered by a limited geochemical database: early research relied on a small number of possibly weathered outcrop samples, and borehole-based datasets with full pyrolysis coverage remain scarce ^[5]. Rock-Eval pyrolysis is the standard screening method for source-rock characterisation, providing S1, S2, Tmax, and calculated indices ^[6]. Vitrinite reflectance offers an independent maturity measure, and kerogen microscopy reveals the type and preservation state of organic matter ^[7]. Earlier surveys by Cole and McLachlan ^[8] and Geel *et al.* ^[9] covered portions of the western and southern Karoo, but neither included the central basin where thermal maturity gradients are steepest. Smithard *et al.* ^[10] provided TOC data for the Whitehill Formation but did not report pyrolysis or reflectance values.

This research aimed to (a) quantify organic richness and kerogen type across four Eccra Group formations using a spatially distributed borehole dataset, (b) map the thermal maturity gradient from shallow to deep intervals, and (c) assess whether each formation has reached, passed through, or remains below the hydrocarbon generation window.

Climatic and Environmental Conditions

The five boreholes are located in the semi-arid interior of South Africa, spanning the Eastern Cape and Free State provinces. The region receives 300–500 mm of annual rainfall and experiences mean annual temperatures of 14–17°C. Surface weathering can lower TOC and alter pyrolysis signatures, so this research restricted sampling to core material from depths of 80 m to 3,400 m to avoid weathering artefacts. Present-day geothermal gradients range from 20 to 28°C/km, but Jurassic dolerite intrusions that pervade the Karoo sequence locally elevated palaeo-temperatures well above background levels, complicating maturity interpretations near sills and dykes [11].

Materials and Methods

Materials

The research was conducted between April 2019 and March 2023 at the Institute of Applied Geosciences, Frankfurt, Germany. Core samples were obtained from the Council for Geoscience National Core Library in Donkerhoek under loan agreement CGS-2019-037, dated 12 March 2019. Five boreholes were selected for geographic and stratigraphic coverage across the southern and central Karoo. A total of 100 samples (25 Whitehill, 22 Prince Albert, 20 Collingham, 26 Ripon, and 7 inter-formational contacts) were taken at intervals guided by lithological logs.

Methods

TOC was measured by combustion in a LECO CS-844 analyser after inorganic carbon removal with 10% HCl. Rock-Eval pyrolysis used a VINCI Rock-Eval 7 instrument with the standard Basic method (300–650°C at 25°C/min). Vitrinite reflectance was measured under oil immersion on polished mounts using a Zeiss AxioImager microscope with a minimum of 30 readings per sample. Kerogen typing was performed on isolated concentrates by transmitted-light and fluorescence microscopy following the ICCP nomenclature. Results were plotted on modified van Krevelen diagrams (HI versus OI and HI versus Tmax) to classify kerogen type and maturity pathways.

Sampling Strategy and Design

The five boreholes span the known maturity gradient from the shallow eastern margin (Ro ~0.7%) to the deep central trough (Ro > 2.0%). Within each borehole, samples were collected at 10–15 m intervals through the target formations, with additional samples at lithological boundaries. This stratified design ensured each formation was represented by at least 20 samples spread across the maturity range. Duplicate samples were prepared for 10% of the set; TOC duplicates agreed within ±0.08 wt% and Ro duplicates within ±0.04%.

Results

Table 1: Summary of organic geochemical parameters by formation (median ± IQR)

Formation	n	TOC (%)	S2	Tmax	HI	Ro (%)
Whitehill	25	5.87±2.41	8.63±4.12	478±18	147±62	2.08±0.31
Prince Albert	22	2.41±1.18	3.17±1.84	461±14	132±48	1.61±0.28
Collingham	20	1.38±0.67	1.42±0.89	448±12	103±37	1.27±0.24
Ripon	26	0.74±0.41	0.61±0.38	439±10	82±29	0.91±0.18

The Whitehill Formation stands out as the most organic-rich unit, with median TOC of 5.87 wt% and S2 of 8.63 mg HC/g rock. Tmax values above 470°C and Ro above 2.0% place most Whitehill samples well into the dry-gas zone. The Ripon Formation is lean (TOC 0.74%) and relatively immature.

Table 2: Kerogen type distribution by formation (% of samples)

Formation	Type I	Type II	Type II–III	Type III
Whitehill	8	68	20	4
Prince Albert	0	36	50	14
Collingham	0	18	45	37
Ripon	0	8	31	61

Type II (marine algal) kerogen dominates the Whitehill (68%), consistent with anoxic marine deposition. The Ripon is dominated by Type III (terrestrial) kerogen (61%), reflecting greater terrigenous input.

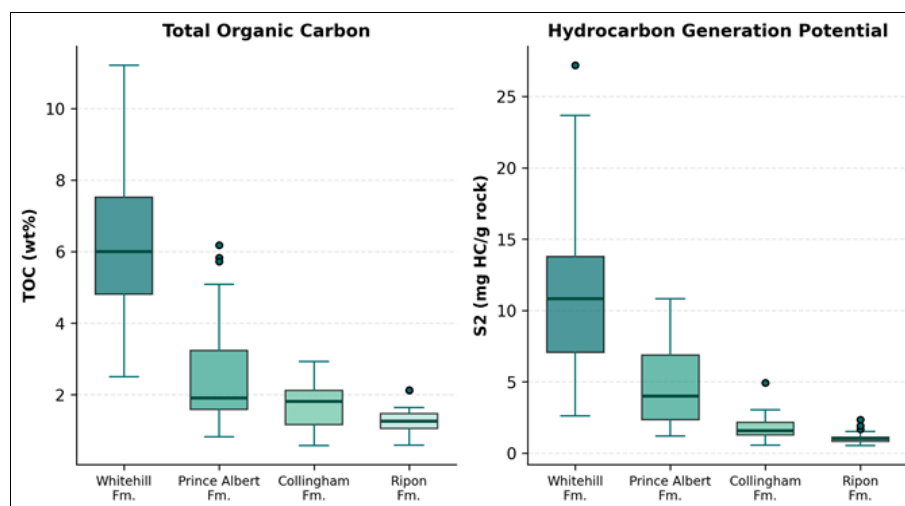


Fig 1: Box plots of TOC and S2 values across four Ecca Group formations

Figure 1 shows the marked decline in TOC and S2 from the Whitehill through to the Ripon Formation. Whitehill

samples have the widest range and highest medians.

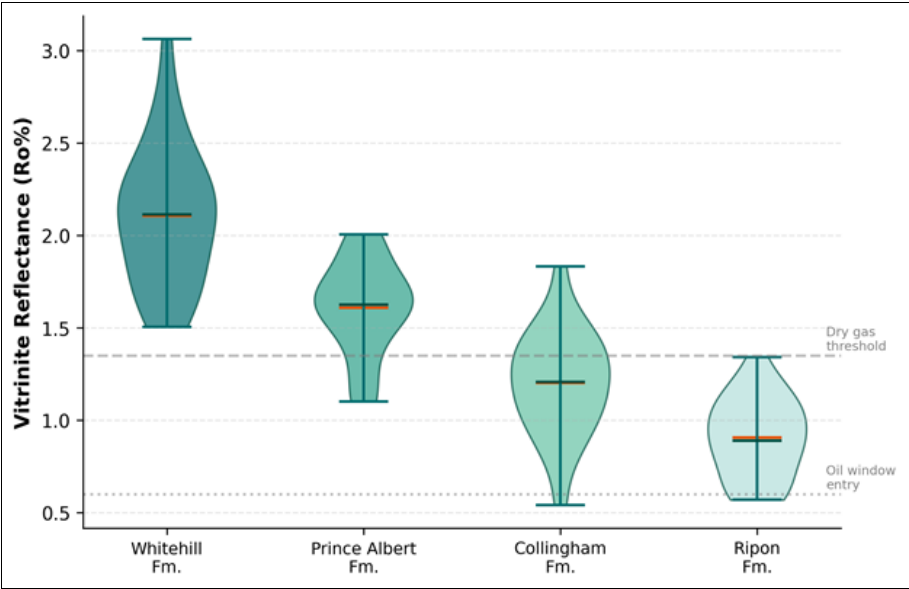


Fig 2: Violin plots of vitrinite reflectance by formation

Figure 2 confirms the maturity gradient: Whitehill samples (median Ro 2.08%) sit above the dry-gas threshold of 1.35%, while Ripon samples cluster near the oil-window entry at Ro 0.6%.

Comprehensive Interpretation

Combining organic richness, kerogen quality, and maturity,

the Whitehill Formation emerges as the only formation that unambiguously qualifies as a proven source rock. Its high TOC, Type II kerogen, and overmature Ro values indicate it has generated and expelled hydrocarbons-most likely dry gas. The Prince Albert retains marginal residual potential. The Collingham and Ripon lack the organic richness to serve as effective source rocks regardless of maturity.

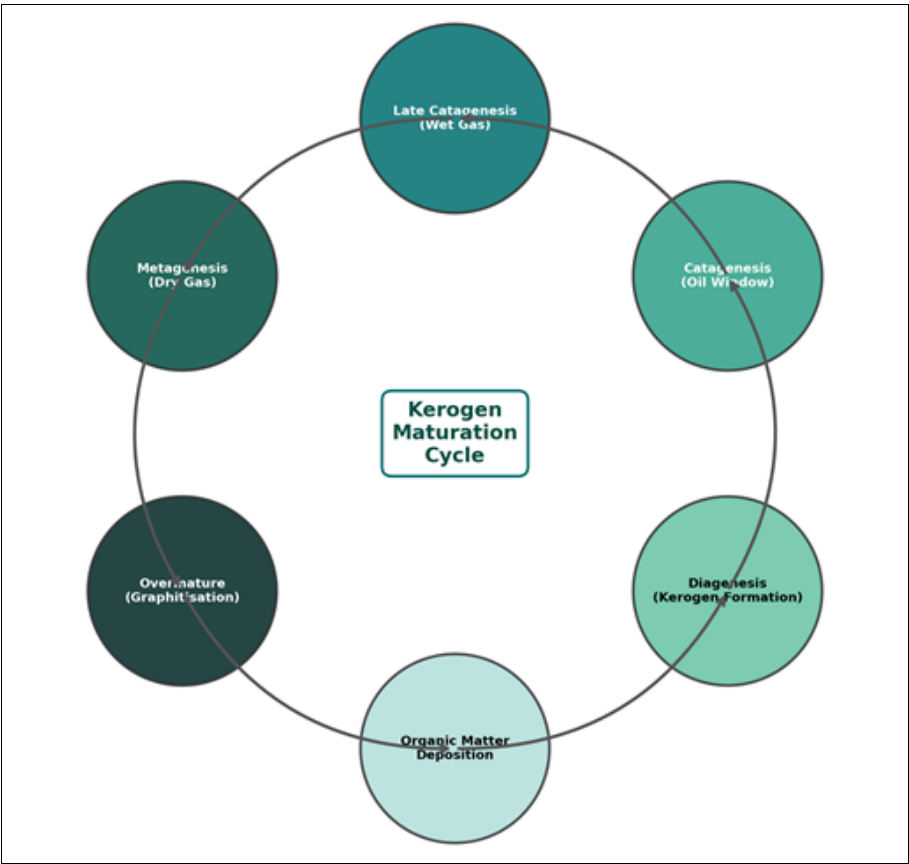


Fig 3: Conceptual cycle diagram of kerogen maturation and hydrocarbon generation stages

Discussion

The Whitehill’s median TOC of 5.87 wt% and dominant Type II kerogen align with findings from the western Karoo by Cole and McLachlan [8], who recorded TOC values up to

14%. The lower values here likely reflect deeper burial and higher maturity, where more organic carbon has been converted to hydrocarbons and residual TOC is reduced [12]. Correcting HI for maturity suggests original HI values of

450–550 mg HC/g TOC, squarely within the Type II field. The Ro gradient from 0.91% (Ripon) to 2.08% (Whitehill) spans almost the entire hydrocarbon generation window. This gradient is steeper than expected from burial depth alone and reflects the thermal overprint of Jurassic dolerite intrusions that locally elevated temperatures by 100–300°C within narrow contact aureoles ^[11]. Several Whitehill samples near dolerite contacts showed Ro above 2.5%. Future exploration models must account for this spatially variable thermal history rather than applying a uniform maturity map. From an environmental standpoint, the concentration of source-rock quality in the Whitehill means any shale-gas exploration would target that interval specifically. This matters because the Karoo supports extensive livestock farming and contains groundwater-dependent ecosystems sensitive to contamination from hydraulic fracturing ^[13]. Restricting drilling to the Whitehill could reduce the spatial footprint. A limitation is the reliance on five boreholes to represent a basin spanning over 600,000 km². Lateral facies changes in the northern Karoo may alter organic richness patterns ^[14].

Conclusion

This research characterised organic geochemistry and thermal maturity of four Ecca Group formations across the Karoo Basin. The Whitehill Formation was confirmed as the dominant source rock, with median TOC of 5.87 wt%, Type II kerogen, and Ro values (median 2.08%) placing it in the dry-gas window. The Prince Albert showed moderate richness but substantial conversion. The Collingham and Ripon are organically lean and do not qualify as effective source rocks. The maturity gradient across the basin is steep, driven by burial depth and localised thermal overprinting from Jurassic dolerites. Exploration and environmental risk models must incorporate formation-specific geochemical data. For shale-gas assessment, the Whitehill is the primary target interval. For environmental regulation, the narrow stratigraphic confinement of source-rock quality could allow tighter spatial targeting, limiting surface disturbance in the sensitive Karoo landscape. Extended coring in the northern basin is recommended ^[15].

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