Shale gas potential of the Prince Albert Formation: A preliminary study

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Abstract

Recent investigations of the shale gas potential in the main Karoo Basin have concentrated on the Whitehill Formation within the Ecca Group. This study focuses on the shale gas potential of the underlying Prince Albert Formation using the parameters of volume porosity, permeability, total organic carbon (TOC), vitrinite reflectance and Rock-Eval data. Shale samples were retrieved from three surface localities in the southern part of the main Karoo Basin and from core of three boreholes drilled through the Prince Albert Formation near Ceres, Mervewille and Willowvale. The sampling localities occur near the borders of the prospective shale gas areas ("sweet spots") identified for the Whitehill Formation. Kerogen was found to be Type IV with hydrogen indices less than 65 mg/g.

Shale porosities are between 0.08 and 5.6% and permeabilities between 0 and 2.79 micro-Darcy, as determined by mercury porosimetry. TOC varies between 0.2 and 4.9 weight % and vitrinite reflectance values range from 3.8 to 4.9%. Although the porosity and TOC values of the Prince Albert Formation shales are comparable with, but at the lower limits of, those of the gas-producing Marcellus shale in the United States (porosities between 1 and 6% and TOC between 1 and 10 weight %), the high vitrinite reflectance values indicate that the shales are overmature with questionable potential for generating dry gas. This overmaturity is probably a result of an excess depth of burial, tectonic effects of the Cape Orogeny and dolerite intrusions. However, viable conditions for shale gas might exist within the "sweet spot" areas, which were defined for the Whitehill Formation.

Introduction

The southern part of the main Karoo Basin of South Africa is a potential target for shale gas in argillaceous sedimentary rocks of the Ecca Group (Cole, 2014; Mowzer and Adams, 2015; Geel et al., 2015; de Kock et al., 2017; Chere et al., 2017). "Sweet spots" identified for shale gas in the Whitehill Formation are found between latitudes 31°00'S and 33°00'S and longitudes 20°30'E and 29°00'E. These "sweet spots" are based on an interpreted paucity of dolerite intrusions, vitrinite reflectance values lying within the dry gas window, total organic carbon content (TOC), formation thickness, and the 1500 m depth

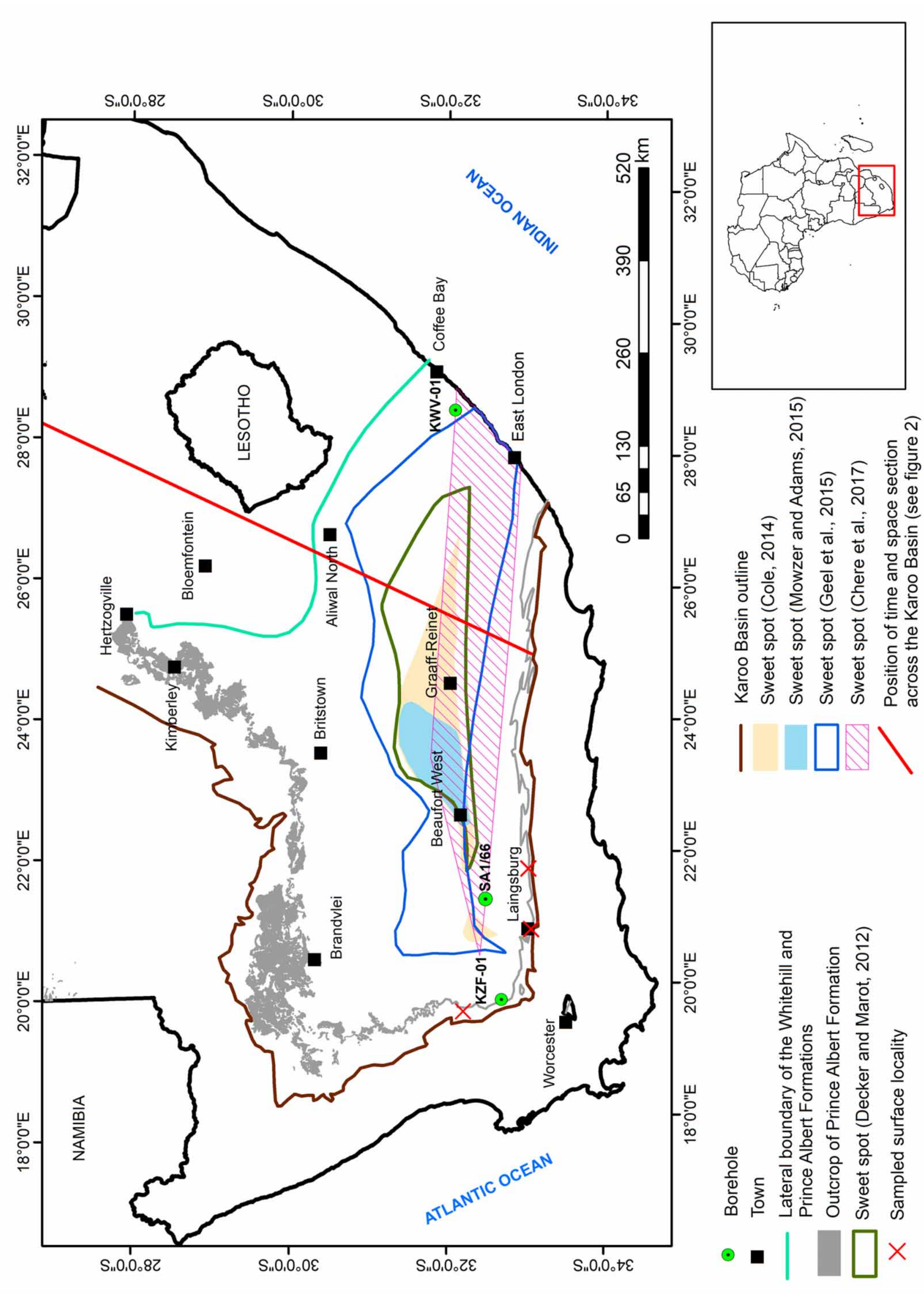

Figure 1. *Distribution of the Prince Albert Formation and "sweet spots" or potential shale gas areas for the Whitehill Formation in the main Karoo Basin.*

contour to avoid groundwater contamination (Figure 1; Decker and Marot, 2012; Cole, 2014; Mowzer and Adams, 2015; Geel et al., 2015; Chere et al., 2017; Cole, 2019).

Stimulation of commercial interest in extracting shale gas requires additional detailed investigation and sampling of the lower Ecca Group through fieldwork and drilling. Examples of such research recently conducted include the Karoo Research Initiative (KARIN – part of the DST – NRF Centre of Excellence of Integrated Mineral and Energy Resource Analysis (CIMERA) hosted by the University of Johannesburg), which drilled two deep boreholes in the Karoo Basin in 2015 (Figure 1; KZF-01 (Total Depth: 671m) and KWV-01 (Total Depth: 2 353 m). The two KARIN boreholes have provided new lithostratigraphic information and fresh core for sampling purposes in the lower Ecca Group. Previously, the Southern Oil Exploration Corporation (SOEKOR, now PETROSA) drilled 22 deep oil exploration, cored boreholes in the southern and central parts of the main Karoo Basin during the 1960s and 1970s (Figure 3; Rowsell and De Swardt, 1976). One of these, borehole SA 1/66 (Figure 1), is housed at the National Core Library of the Council for Geoscience at Donkerhoek near Pretoria, and provided two samples for this study. It was drilled some 17 km west of Merweville in the late 1960s by SOEKOR and is located in close proximity to one of the defined "sweet spots" (Figure 1).

Until now, the main hydrocarbon target in the Ecca Group has been the Whitehill Formation and much research has been focused on this unit, e.g. Geel et al. (2015), de Kock et al. (2017). However, several studies have been made on the Prince Albert Formation. Geel et al. (2013, 2015) retrieved four core samples from a borehole (SFT2) drilled near Jansenville in the southeastern part of the main Karoo Basin for Rock-Eval analysis, total organic carbon (TOC) content, stable isotope analysis, vitrinite reflectance and porosity. Ferreira (2014) undertook a field study in the Laingsburg area and selected eleven outcrop samples of the Prince Albert Formation for TOC, Rock-Eval and organic geochemistry analyses. De Kock et al. (2017) studied five core samples from a borehole (KZF-01) drilled near Ceres in the southwestern part of the basin for Rock-Eval and TOC. Chere et al. (2017) retrieved five samples from a borehole (KL1/65) in the southwestern part of the basin and a borehole (SP1/69) in the southeastern part of the basin for TOC and Rock-Eval analyses. Baiyegunhi et al. (2018) selected eleven core samples from four boreholes (KWV-01, SP1/69, CR1/68, SC3/67) and twelve outcrop samples, all in the southeastern part of the basin for TOC, Rock-Eval, vitrinite reflectance and porosity. These authors concentrated on specific areas of the basin, whereas our study covered the entire southern part of the main Karoo Basin. Also, these authors concluded that kerogen, which is an important parameter for determining the shale gas potential, was predominantly Type III, whereas our studies showed it to be Type IV.

The data presented here were obtained from three boreholes and three surface localities located in the southern part of the main Karoo Basin (Figure 1), allowing a better understanding of the shale gas potential of the Prince Albert Formation.

Geological setting

Karoo Basin

The Karoo Supergroup sedimentary rocks of the main Karoo basin are thought to have been deposited in a retroarc foreland basin that developed in front of a Permo-Triassic (275 to 245 Ma) fold- and thrust belt, known as the Cape Fold Belt, located along the southern margin of the basin (Johnson, 1991; Johnson et al., 2006; Veevers et al., 1994; Catuneau et al., 1998; Hansma et al., 2016). The basinal foredeep was aligned east-west along the southernmost part of the present Karoo Supergroup outcrop, in which up to 12 km of sediments accumulated in the southeastern part of the basin (Johnson et al., 2006), although Scheiber-Enslin et al. (2015) calculated thicknesses of only 5 to 6 km using two-way-travel-times from historical seismic reflection data. In contrast, Tankard et al. (2009) proposed that the Karoo Basin formed as a result of subsidence of Precambrian basement along crustal faults and that the Cape Fold Belt was only initiated during the Triassic by strike-slip processes. However, Turner (1999) suggested that foreland basin tectonics associated with development of the Cape Fold Belt terminated during the Middle Triassic and was followed by Late Triassic continental extension, which played a major role in late basin development.

Dwyka Group

In the southern and central parts of the main Karoo Basin (Figure 1), shales of the Prince Albert Formation (Ecca Group) overlie the basal rocks of the Karoo Supergroup (Dwyka Group) strata with a sharp to gradational contact (Visser, 1997). Here, the Dwyka Group consists of two formations (Visser, 1986), a lower diamictite-rich Elandsvlei Formation, and a mixed lithofacies – diamictite, mudstone, sandstone and conglomerate known as the Mbizane Formation (Visser et al., 1990). The former occurs south of latitude 30°S and the latter north of this latitude (Visser et al., 1990). In northern KwaZulu-Natal, both formations are present with the Mbizane Formation overlying the Elandsvlei Formation (Visser et al., 1990).

Volcanic tuff beds are present in the upper half of the Elandsvlei Formation in the southern part of the main Karoo Basin and western part of the Kalahari Basin in Namibia and magmatic zircons contained in these beds were used to obtain U-Pb dates ranging from 302 to 290 Ma (Bangert et al., 1999). This led Isbell et al. (2008) to estimate an age of between 312 and 290 Ma for the Dwyka Group, i.e. Late Carboniferous (Moscovian) to Early Permian (Sakmarian) in age (International Commission on Stratigraphy, 2017).

Ecca Group

The Ecca Group consists of a number of formations of Permian age (Johnson et al., 2006) that reflect a variety of marine and marginal marine environments (Figure 2).

The Prince Albert Formation is the lowermost unit of the Ecca Group in the central and southern parts of the main Karoo

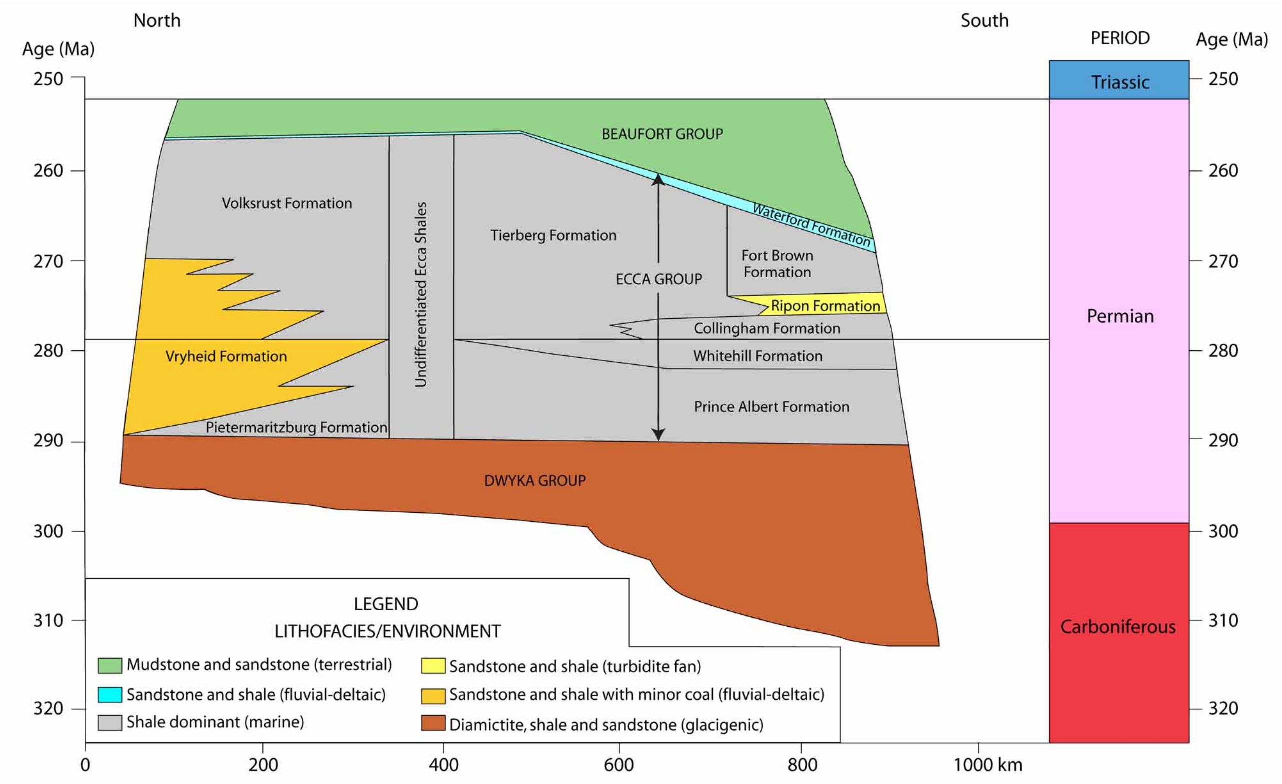

Figure 2. *Distribution in time and space of Late Carboniferous to latest Permian stratigraphic units including lithology and depositional environment in the main Karoo Basin (Kingsley, 1981; Johnson et al., 2006; Cole, 2018, 2019). Chronostratigraphic scale is from International Commission on Stratigraphy (2017).*

Basin (Figure 1) and consists predominantly of dark grey bioturbated shale and subordinate siltstone-dominated rhythmite. It is present in the southwestern and central parts of the main Karoo Basin, southwest of a line drawn from Coffee Bay to Aliwal North to Hertzogville, which coincides with the lateral termination of the overlying Whitehill Formation (Figures 1 and 3; Cole, 2005; Johnson et al., 2006). The lowermost shale of the Prince Albert Formation contains dispersed dropstones in places (Cole, 2005). The Prince Albert Formation is, in turn, conformably overlain by black, carbonaceous, non-bioturbated shale of the Whitehill Formation with a sharp contact (Cole and Basson, 1991; Cole, 2005).

In the region northeast of Kimberley (Figure 3), the Prince Albert Formation contains siltstone and sandstone beds which are grouped into two upward-coarsening cycles (Cole and McLachlan, 1991). Also in this area, the overlying black shales of the Whitehill Formation become dark grey and contain siltstone and rhythmite, with the result that they become indistinguishable from the lithologies of the Prince Albert Formation (Cole and McLachlan, 1991). Both these formations grade laterally north-eastward into the heterolithic and coal-bearing Vryheid Formation (Faure and Cole, 1999; Cole, 2015). Sandstones of the Vryheid Formation pinch out south of a line from between Dealesville, Ladybrand and Harding (Figure 3) into a shale-dominated succession (Cole and McLachlan, 1991) referred to as undifferentiated "Ecca Shales" (Figure 2; Johnson et al., 2006). These shales occur towards the south and southwest as far as the lateral boundary of the Prince Albert and Whitehill formations, where the distinctive black shale of the Whitehill Formation is used to separate the dark grey shales of the underlying Prince Albert Formation and overlying Tierberg Formation (Figure 2; Cole and Basson, 1991).

Prince Albert Formation

The Prince Albert Formation is Early Permian (Artinskian to early Kungurian; International Commission on Stratigraphy, 2017) in age, based upon the following radiometric dates. Bangert et al. (1999) obtained U-Pb dates of 289.6 ± 3.8 Ma and 288 ± 3 Ma from magmatic zircons extracted from two interbedded tuff horizons in the basal part of the formation in the southern part of the main Karoo Basin. Werner (2006) obtained comparable dates of 290.9 ± 1.7 Ma and 279.1 ± 1.5 Ma from tuff horizons respectively in the basal and uppermost parts of the Prince Albert Formation in the Karasburg Basin of southern Namibia.

The Prince Albert Formation is generally between 100 and 300 m thick, but is anomalously thick (497 m) in borehole SC 3/67 south of Graaff-Reinet, in contrast to only 59 m in borehole SFT2, which was drilled 71 km further southeast for the African Earth Observatory Network (AEON) from the Nelson Mandela University in Port Elizabeth (Figure 3). In the Douglas area, marine fossils (i.e. cephalopods, bivalves, brachiopods and

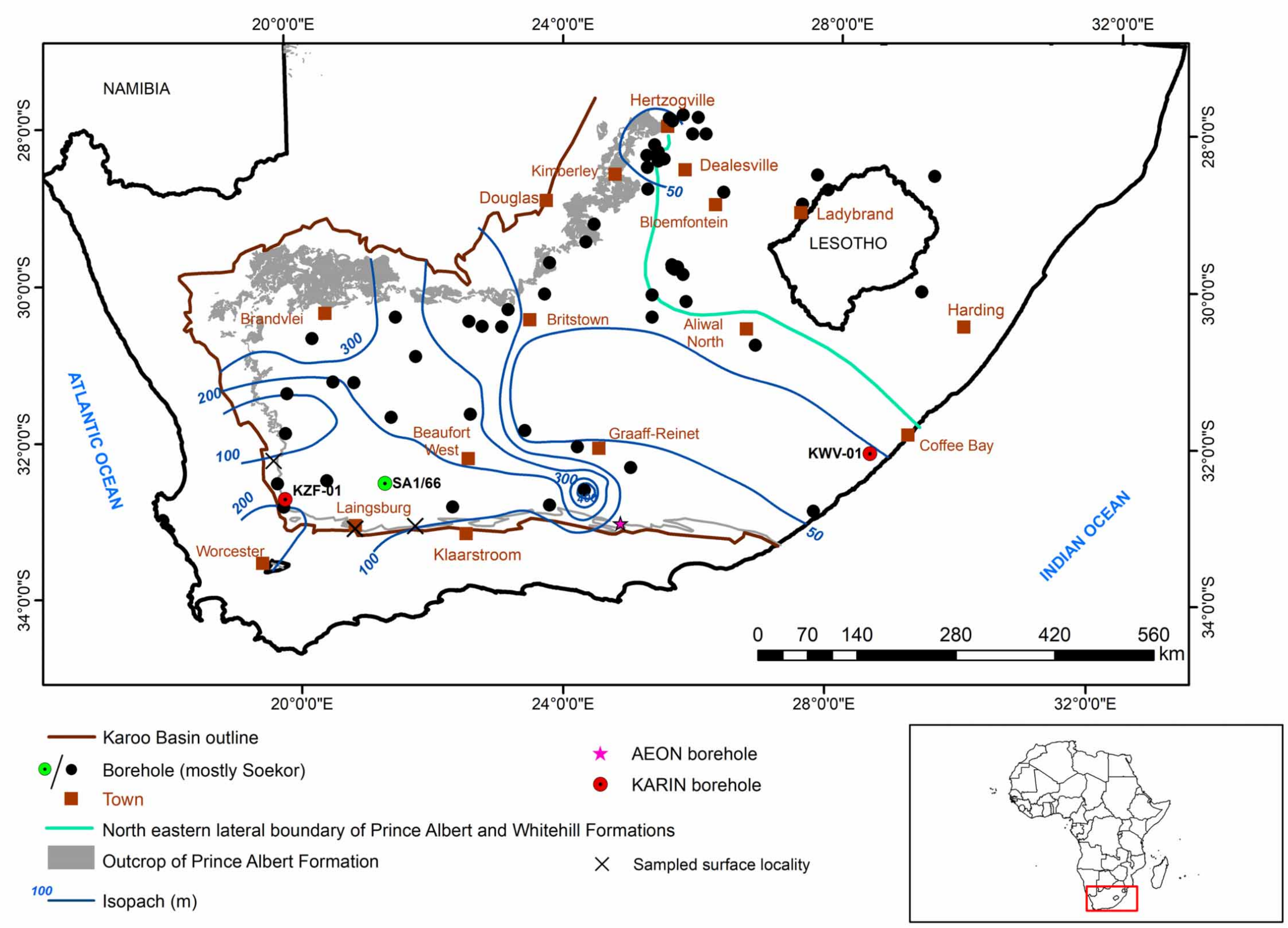

Figure 3. *Distribution and isopach map of the Prince Albert Formation in the main Karoo Basin, South Africa, showing the position of deep boreholes. Sampled boreholes KZF-01 and KWV-01 are indicated by red circles and SA 1/66 by a green circle.*

Table 1. Prince Albert Formation shale samples. Localities are shown in Figure 3.

Location	Sample number	Latitude (decimal degrees S)	Longitude (decimal degrees E)	Depths (m)
BH KZF-01,	HM57 V	32.8418	19.8258	439.61 - 439.95
Tankwa	HM58* x V			440.81 - 441.17
	HM60*			479.72 - 480.10
	HM66*			515.36 - 515.69
	HM68x			523.53 - 523.76
	HM69x V			529.60 - 529.86
	HM70*			537.14 - 537.44
	HM79x V			588.54 - 588.73
	HM81*			600.48 - 600.70
	HM82x V			606.74 - 606.91
	HM85x V			624.40 - 624.72
	HM88x V			639.29 - 639.61
	HM89*			645.45 - 645.76
	HM90x V			651.52 - 651.84
BH KWV-01,	HM94x V	32.2453	28.5856	2309.05 - 2309.37
Willowvale	HM95*			2311.98 - 2312.36
	HM96x V			2315.08 - 2315.37
	HM97*			2317.59 - 2317.88
	HM98*			2320.40 - 2320.73
	HM99x V			2323.39 - 2323.72
	HM100*			2326.70 - 2327.00
	HM101x V			2329.56 - 2329.87
BH SA 1/66,	HM125* x	32.6746	21.3335	2785.74 - 2788.78
Merweville	HM126* x			2793.51 - 2798.59
Prince Albert	HM40 V	33.22164	21.7723	61
outcrop	HM42 V	33.2216	21.7723	56.7
	HM43 V	33.2216	21.7723	51
	HM48V	33.2213	21.7724	38.4
Tankwa	HM24 V	32.3456	19.6709	120
outcrop	HM34 V	32.3598	19.6934	135
Laingsburg	HM3 V	33.2413	20.8651	144
outcrop	HM6 V	33.2409	20.8650	121

Note: BH = borehole. Borehole depths are from surface; outcrop depths are from below base of Whitehill Formation.
* samples selected for mercury porosimetry.
x samples selected for Rock-Eval pyrolysis.
V samples selected for vitrinite reflectance.

palaeoniscoid fish), coprolites, wood and spores have been recorded from near the base of the Prince Albert Formation (McLachlan and Anderson, 1973). Oelofsen (1986) found a fossil shark from near the base of the formation north of Klaarstroom, and Visser (1994) reported the presence of sponge spicules, foraminifera, radiolarians and acritarchs from within the basal five metres of the succession at Laingsburg (Figure 3).

The Prince Albert Formation is considered to have been deposited in a marine environment, more specifically in a basin-plain to -shelf setting within a basin that opened towards the southwest (Visser, 1994). The marine conditions probably coincided with the final deglaciation event of the Dwyka Group (Visser, 1991, 1994, 1997). Phosphatic nodules and lenses occur in the southern part of the basin (Visser, 1991) indicating that water depth was probably between 250 and 400 m (Bühmann et al., 1989), but shallowed towards the north, northeast and east where such nodules are absent (Visser, 1994). The prevalence of shale indicates that suspension settling of mud was the dominant sedimentary process, whereas the subordinate siltstone-dominated rhythmite may represent tractional fall-out from turbidity currents (Visser, 1991; Johnson et al., 2006). In the region northeast of Kimberley, the upward-coarsening cycles of mudstone, siltstone, rhythmite and sandstone were interpreted to represent a deltaic environment, with the sediments being derived from an adjacent northerly provenance (Cole and McLachlan, 1991).

Methods

The shale gas potential of the Prince Albert Formation was investigated in the southernmost part of the main Karoo Basin from three selected boreholes (KZF-01, KWV-01 and SA 1/66) and three outcrop sections.

Assessment of porosity, density and bulk density measurements was made in order to evaluate the physical properties. The thermal maturity of the shale was investigated using Rock-Eval pyrolysis and vitrinite reflectance analyses. Surface samples were only analysed for vitrinite reflectance, as weathered samples such as these, would not give reliable results for the other tests employed on the borehole samples. The samples are listed in Table 1.

Mercury Porosimetry

Twelve core samples were collected from boreholes KZF-01, KWV-01 and SA 1/66 for mercury porosimetry, including volume porosity, bulk density and skeletal density measurements (Table 1). These analyses were completed at MCA services in Cambridge, UK. A Micromeritics AutoPore V (9620) instrument was used for the collection of mercury intrusion data using mercury of 99.999% purity and applying a mercury contact angle of 140 degrees and surface tension of 480 dynes/cm^2.

Samples were degassed prior to analysis, for a minimum of two hours under vacuum at a temperature between 25°C and 150°C depending on sample stability. Samples were prepared for the mercury penetrometer, such that sufficient sample mass is provided for analysis or the penetrometer bulb is as full as possible, without causing obstruction to mercury flow. A blank correction was applied using a reference analysis of the actual penetrometer under the same analytical conditions. The penetrometer was previously calibrated in duplicate for volume, using the method detailed by Micromeritics (ASTM International, 2018). For the calculation of density and porosity, the assembled penetrometer is weighed with and without mercury (before and after completion of the low pressure stage of analysis).

Sample evacuation was conducted up to pressures of 50 micrometre of mercury (µmHg). Intrusion data are collected in the approximate applied pressure range 0.3 to 60,000 pounds per square inch (psi) with equilibration occurring after 10 seconds. Maximum mercury intrusion limits are set to 0.01 mm per gram (mL/g) or lower to ensure collection of a reasonable number of data points in regions of mercury intrusion. Low pressure analysis is typically conducted to 45 psi, unless sample pore size distribution demands an alternative pressure.

Rock-Eval

Twelve shale samples from boreholes KZF-01 and KWV-01 (Table 1) were analysed by means of a Rock-Eval 6 pyrolyser by the Indian Institute of Technology in Mumbai, India. Two samples from borehole SA 1/66 were analysed by Chesapeake Energy in the United States of America (Table 1).

Rock-Eval pyrolysis is a technique that is used to identify the maturity and petroleum potential of organic material. Crushed material was analysed by a Rock-Eval 6 pyrolyser, which thermally decomposes organic matter in the sample by means of a step-heating process in an inert atmosphere. During pyrolysis, the amount of hydrocarbons released (S_1 and S_2) was measured with increasing temperatures (up to 750°C). S_1 relates to the free hydrocarbons and these are released at temperatures up to 300°C. S_2 are the generated hydrocarbons and hydrocarbon-like compounds and these are released at temperatures between 300 and 650°C. Generated CO_2 represents the S_3 component and is released at temperatures of 300 and 750°C over a longer period of time. Following completion of pyrolysis, any remaining carbon is residual carbon and is termed S_4.

Total organic carbon (TOC) is an important parameter for evaluating shale gas resources (Kuuskraa et al., 2011). TOC content was calculated from the results of Rock-Eval pyrolysis using the following equation (de Kock et al., 2017):

$$\text{TOC (wt\%)} = \frac{0.082(S_1+S_2)+S_4}{10}$$

The Rock-Eval pyrolysis method of calculating TOC can be subject to error due to the S_1 and S_2 peaks becoming diminished in very thermally matured sediments. The calculated TOC did not include inorganic carbon as this was measured separately.

Vitrinite reflectance

Vitrinite reflectance is an indicator of thermal maturity, which is useful to the understanding of the tectonic history of the basin and determining the boundaries between diagenesis, catagenesis and low grade metamorphic stages (Dow, 1977). A total of twenty samples were selected from outcrop and core (Table 1) of the Prince Albert Formation. Vitrinite reflectance measurements were undertaken at the University of Johannesburg. The technique uses microscopic determination of oil-polished surfaced blocks to identify vitrinite found within the shale samples. The technique uses the ASTM standard test method D7708 (ASTM International, 2014).

A Zeiss petrographic microscope was used with a 50X oil immersion objective for refracted light and fluorescence intensity measurements. It was fitted with two digital cameras. The reflectance system was calibrated using two standards, namely 3.240 cubic zirkonia and 5.20 strontium-titanate together with immersion oil for a refractive index of 1.518. Where the reflectance readings were primarily below 3, a third standard was included, namely 0.900 yttrium-aluminium-garnet (YAG).

“Hilgers Fossil Diskus” software was used to identify vitrinite and bituminite macerals. From the organic matter present within the sample, random vitrinite reflectance (Ro random) measurements were collected (ASTM international, 2014). The mean and standard deviation were calculated as a reflectance percentage using between 20 and 100 vitrinite counts per sample, and then plotted as a histogram (Figure 4).

Results

Mercury Porosimetry (Porosity)

In borehole KZF-01, the Prince Albert Formation shale sample HM 81 (Table 1), had the highest porosity of 3.345% at a depth of 600.48 m (Tables 1 and 2). Porosity measurements in borehole KWV-01 range between 0.154 (HM95) and 0.078% (HM100) for depths between 2311.98 m and 2327 m (Tables 1 and 2), but there is no consistent trend with increasing depth. In borehole SA 1/66 samples HM125 and HM126 had poor permeabilities, 0.000066 and 0.000138 mD respectively, although the porosity of HM126 was higher (5.6%) in contrast to 1.9% in HM125 (Table 2). The porosity of shales decreases rapidly with burial and subsequent depletion of interstitial pore water (Roswell and De Swart, 1976). Hence, porosity measurements of the Prince Albert Formation in borehole KWV-01 are lower than in borehole KZF-01 due to deeper burial and the presence of a 19 m thick dolerite sill 12 m above the Prince Albert

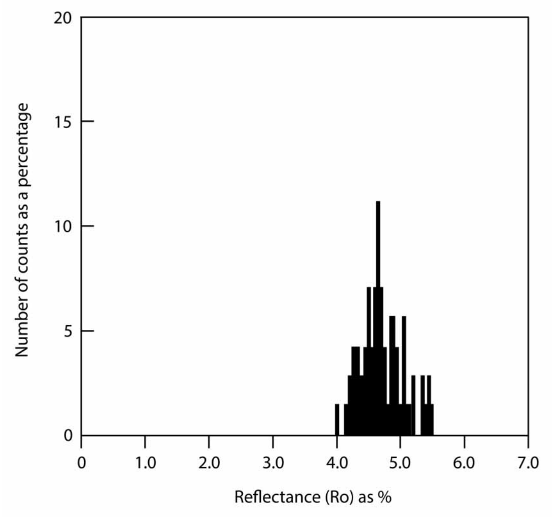

Figure 4. *Example of vitrinite reflectance data plotted as a histogram for shale sample HM99 of borehole KWV-01 taken between depths of 2323.39 and 2323.72 m with a reflectance mean of 4.696% and standard deviation of 0.335%.*

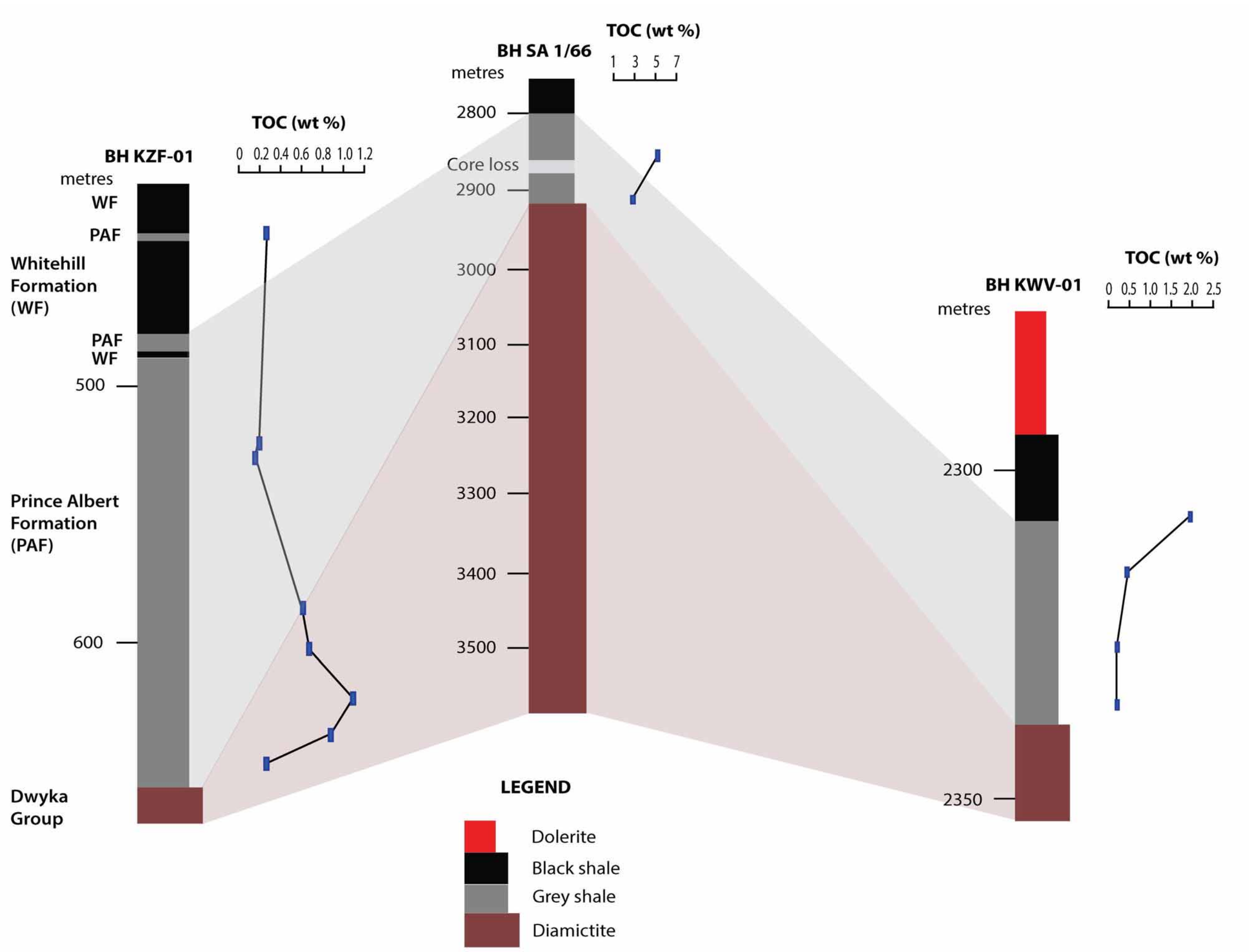

Figure 5. *Lithological logs of boreholes KZF-01, SA 1/66 and KWV-01 showing the total organic carbon (TOC) content of the Prince Albert Formation.*

Formation (Figure 5). Porosity measurements of KWV-01 (Table 2) decrease with increasing distance from the dolerite sill. This is because contact metamorphism of shale adjacent to the dolerite increases the porosity by potential fracturing associated with the emplacement of the dolerite sill (Chevallier et al., 2001).

Bulk densities, which includes the pore space within the shale, range between 2.185 and 2.400 g/mL, whereas the skeletal densities, which excludes the pore space, range between 2.227 and 2.402 g/mL for boreholes KZF-01 and KWV-01. Bulk density measurements of borehole SA 1/66 range between 2.521 and 2.686 g/mL, but no skeletal density measurements were recorded. In addition, the high porosity shales of borehole KZF-01 display lower bulk densities compared to the low porosity shales of borehole KWV-01 (Table 2).

In Table 2 pore volume and pore area distribution were used to calculate the porosity of samples. Samples from borehole KWV-01 have insufficient porosity volumes to allow for the identification of permeability parameters and the further calculation of permeability. Moderate permeability values in most of borehole KZF-01 (0.13 to 2.79 mD) suggest compaction and cementation of the shale with minor pore interconnectivity (Cao et al., 2015).

Rock-Eval and TOC

The type of hydrocarbon potential was assessed using a plot of S_2 values against TOC measurements (Prezbindowski, 2010) and the type of kerogen was determined from a plot of hydrogen index (HI) against oxygen index (OI) (Prezbindowski, 2010). The results are displayed in Figure 6 and indicate that the kerogen is type IV, which only has a potential to generate inert gases. These results are in contrast to previous studies where Type II and Type III kerogens were also reported for the Prince Albert Formation (Ferreira, 2014; Geel et al., 2015; Chere et al., 2017; Baiyegunhi et al., 2018). The production of inert gases depends on overburden thickness, tectonic processes such as uplift, fractures and faults, which cause the migration and accumulation of these inert gases (Nazeer et al., 2018).

In borehole KZF-01, TOC ranges between 0.18 and 1.12 wt%, in KWV-01 between 0.2 and 2.27 wt% and in SA 1/66 between 2.76 and 4.87 wt% (Table 3). Some of these values exceed the minimum qualifying value of 2 wt% for economically viable shale gas resources as defined by Kuuskraa et al. (2011). However, for organic matter to generate hydrocarbons, the carbon has to be associated with hydrogen, normally with a hydrogen index exceeding 150 mg/g (Dembicki, 2009). None of the samples exceed this value (Table 3). Tmax values range between 298°C and 453°C (Table 3). Twelve of these samples are less than 435°C, which indicates immaturity and the remaining two are between 435°C and 470°C reflecting maturity (Peters and Cassa, 1994). These results are in disagreement with the above findings concerning maturity and are probably dubious values mainly because of very weak S_2 peaks in overmature samples (Dellisanti et al., 2010).

Vitrinite reflectance

The vitrinite reflectance values of outcropping shale samples of the Prince Albert Formation in the Tankwa and Prince Albert areas are all less than 3% (Figure 7), possibly in the dry gas window (Figure 8; Tissot and Welte, 1984). This contrasts with core samples from boreholes KZF-01 and KWV-01, where the reflectance values are between 3.8 and 4.9% (Figure 7), which lies within the epimetamorphic zone (Figure 8; Tissot and Welte, 1984). However, the low reflectance values of outcrop samples are probably a result of alteration by surficial weathering and erosion. Reflectance values >3.5% should not always be considered as areas with high thermal maturity as the Marcellus and Utica shales in the U.S.A both produce gas with higher reflectance values (Popova, 2017a, 2017b). Geel et al. (2015) reported reflectance values of between 3.08 and

Table 2. Pore volume, area, bulk density, skeletal density, porosity and permeability of samples of the Prince Albert Formation from boreholes KZF-01, KWV-01 and SA 1/66.

Borehole	Sample number	Median pore diameter (μm) using volume	Median pore diameter (μm) using area	Average pore diameter (μm)	Bulk density (g/mL)	Skeletal density (g/mL)	Porosity (%)	Permeability (micro-Darcy)
KZF-01	HM58	0.291	0.004	0.021	2.325	2.332	0.270	<0.05
	HM60	229.913	0.007	0.332	2.256	2.291	3.131	0.396
	HM66	283.146	0.007	0.143	2.205	2.236	3.05	1.159
	HM70	209.419	0.005	0.056	2.199	2.227	2.447	0.438
	HM81	149.785	0.004	0.052	2.185	2.228	3.345	2.791
	HM89	160.999	0.015	0.168	2.267	2.280	1.014	0.126
KWV-01	HM95	12.907	0.363	2.378	2.298	2.301	0.154	*SNB
	HM97	7.022	0.948	2.809	2.308	2.311	0.134	*SNB
	HM98	1.833	0.178	0.560	2.321	2.324	0.120	*SNB
	HM100	8.108	0.556	1.912	2.400	2.402	0.078	*SNB
SA 1/66	HM125	-	-	-	2.686	-	1.9	0.000066
	HM126	-	-	-	2.521	-	5.6	0.000138

*SNB: Samples HM95, HM97, HM98 and HM100 have insufficient porosity (pore volume and pore size distribution).

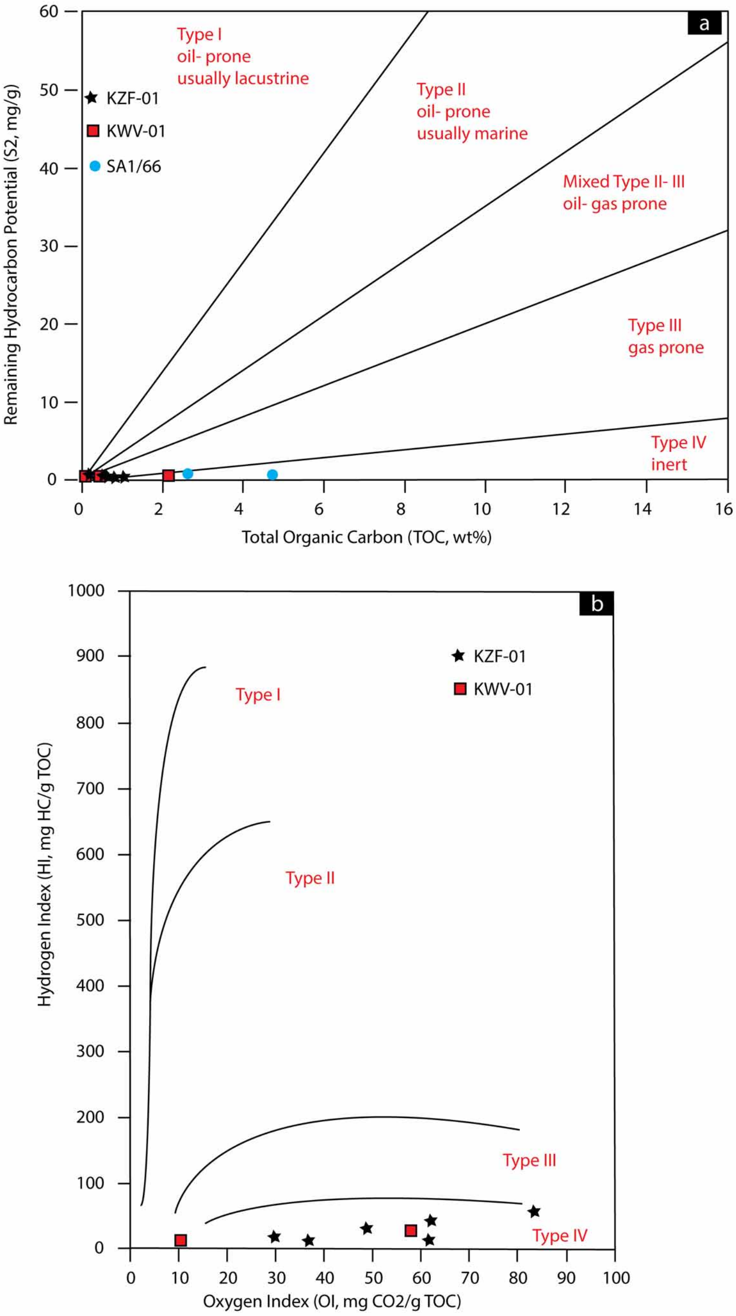

Figure 6. *(**a**) Kerogen potential plot and (**b**) HI versus OI plots on the modified Van Krevelen diagram (Dembicki, 2009) of samples indicating the kerogen type.*

4.90% and Baiyegunhi et al. (2018) values of between 3.12 and 3.84% for borehole samples of the Prince Albert Formation in the southeastern part of the main Karoo Basin.

Discussion and conclusion

Results of this study indicate that samples located outside the "sweet spots" for shale gas in the southern part of the main Karoo Basin (Figure 1) are overmature with low S_2 and hydrogen index values and thus indicate no potential for shale gas (Figure 6). In borehole KZF-01, which is located close to the Cape Fold Belt, tectonism may have resulted in the destruction of porosity and permeability within shales of the Prince Albert Formation affecting the storage and migration properties of the shale. Borehole KWV-01 is located in the region of the Karoo Basin, where dolerite intrusions are prevalent within the Karoo Supergroup, including the Prince Albert Formation (Duncan and Marsh, 2006). Dolerite sills (19 m and 149 m thick respectively) occur some 12 m and 112 m above the Prince Albert Formation in borehole KWV-01 and have reduced the shale gas potential as a result of contact metamorphism. In KWV-01 the top of the Prince Albert Formation lies at a depth of 2307.81 m and at least another 5000 m of

Table 3. Results of Rock-Eval analysis and vitrinite reflectance of borehole samples.

Sample and borehole	S_1 (mg/g)	S_2 (mg/g)	S_3 (mg/g)	S_4 (mg/g)	Tmax (°C)	TOC (wt%)	HI	OI	Vitrinite Reflectance (%)
KZF-01									
HM57	-	-	-	-	-	-	-	-	3.58
HM58	0.08	0.14	0.74	2.61	304	0.28	50	264.30	4.32
HM68	0.04	0.09	0.13	1.99	310	0.21	42.90	61.90	-
HM69	0.07	0.11	0.15	1.65	302	0.18	61.10	83.30	4.53
HM79	0.07	0.08	0.23	6.18	304	0.63	12.70	36.50	4.57
HM82	0.14	0.24	0.34	6.68	453	0.70	34.30	48.60	4.25
HM85	0.18	0.19	0.69	10.90	299	1.12	17	61.60	4.61
HM88	0.15	0.17	0.27	8.74	436	0.90	18.90	30	4.48
HM90	0.07	0.11	0.36	2.55	298	0.27	40.70	133.30	4.32
KWV-01									
HM94	0.27	0.28	0.23	22.25	301	2.27	12.30	10.10	3.97
HM96	0.09	0.15	0.30	5.00	302	0.52	26.80	57.70	5.10
HM99	0.10	0.13	0.38	1.81	307	0.20	65	190	4.69
HM101	0.08	0.12	0.37	1.84	303	0.20	60	185	4.91
SA 1/66									
HM125	0.12	0.09	-	48.53	305	4.87	1.90	-	-
HM126	0.12	0.72	-	26.91	320	2.76	26.10	-	-

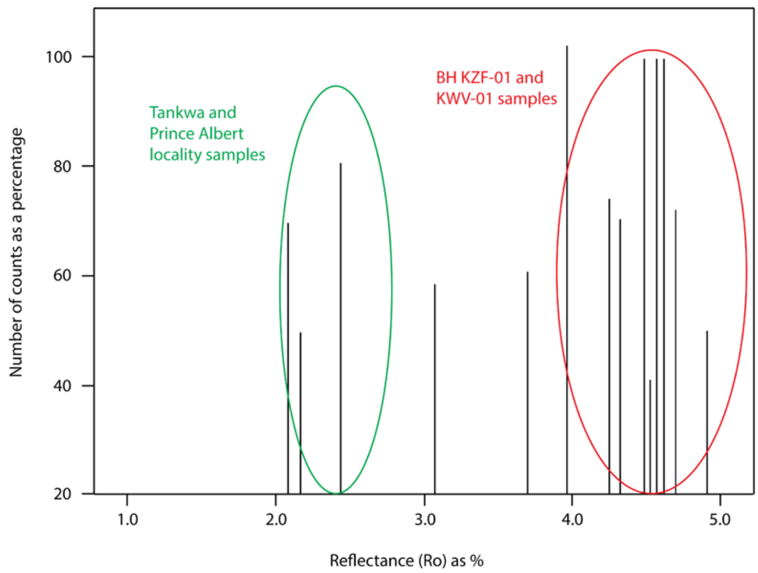

Figure 7. *Histogram of vitrinite reflectance data of Prince Albert shales from boreholes KZF-01 and KWV-01 and outcrops in the Tankwa and Prince Albert areas.*

overburden comprising the Beaufort, Stormberg and Drakensberg Groups was probably present before erosion took place (see Johnson et al., 2006, p. 465, Fig. 4; see Duncan and Marsh, 2006, p. 505, Fig. 4). This would place the Prince Albert Formation in the metamorphic zone with no potential for generating dry gas, together with the destruction of temporarily generated hydrocarbon (Rowsell and De Swardt, 1976). This is supported by vitrinite reflectance values of between 3.97 and 5.10% which fall within the epimetamorphic and metamorphic zones (Figure 8). TOC values are relatively low in boreholes KZF-01 and KWV-01, but in borehole SA 1/66, the TOC and porosity values are comparable with those of the gas-producing Marcellus and

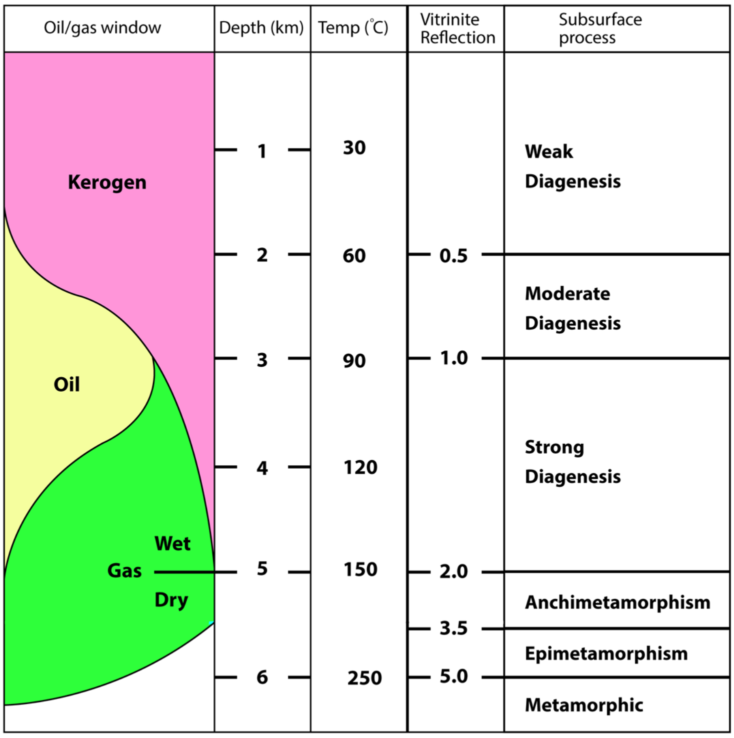

Figure 8. *Hydrocarbon generation and vitrinite reflectance indices plotted against depth of burial (Tissot and Welte, 1984).*

Table 4. Prince Albert Formation shale compared with the gas-producing Barnett and Marcellus shales in the USA.

	Prince Albert Formation, main Karoo Basin S.A (this study)			**USA (Bruner and Smosna, 2011)**	
Parameters	**KZF-01**	**KWV-01**	**SA 1/66**	**Barnett (Fort Worth Basin)**	**Marcellus (Appalachian Basin)**
TOC (wt%)	0.53	0.79	3.81	2-6	1-10
Kerogen type	Type IV	Type IV	Type IV	Type II	Type II and/or Type III
Vitrinite reflectance (%)	4.33	4.67	-	1-2	1-4
Tmax (°C)	338	303	313	465	475
Shale porosity (%)	2.01	0.12	3.75	1-6	1-6

Barnett shales in the United States (Table 4; Bruner and Smosna, 2011). However, the results of Rock-Eval pyrolysis indicate a low hydrogen index and a Type IV kerogen (Figure 6). The low hydrogen index implies that much of the organic matter is not bound to hydrogen and that much of the organic carbon is classified as “dead carbon” (de Kock et al., 2017). The poor hydrocarbon generation potential is also shown by the low value of S_1 and S_2 combined, which do not exceed 0.84 mg/g (Table 3), and fall within the poor quality range of Dembicki (2009).

Variable porosity values suggest that viable conditions for shale gas might exist in the “sweet spot” areas, which ideally should have permeability measurements between 1 to 10 mD, overburden of less than 3500 m, TOC greater than 3 wt% and high hydrogen indices.

In view of this, the Prince Albert Formation has little to questionable economic shale gas potential.

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