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Technically Recoverable Shale Oil and Shale Gas Resources:

South Africa

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Executive Summary

Introduction

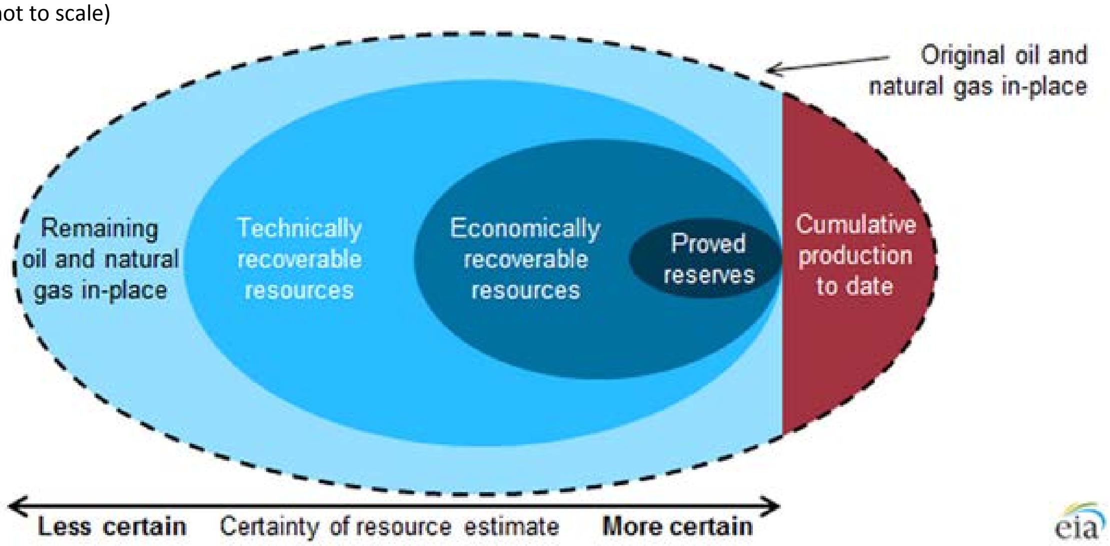
Although the shale resource estimates presented in this report will likely change over time as additional information becomes available, it is evident that shale resources that were until recently not included in technically recoverable resources constitute a substantial share of overall global technically recoverable oil and natural gas resources. This chapter is from the 2013 EIA world shale report [Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States].

Resource categories

When considering the market implications of abundant shale resources, it is important to distinguish between a technically recoverable resource, which is the focus of this supplement as in the 2013 report, and an economically recoverable resource. Technically recoverable resources represent the volumes of oil and natural gas that could be produced with current technology, regardless of oil and natural gas prices and production costs. Economically recoverable resources are resources that can be profitably produced under current market conditions. The economic recoverability of oil and gas resources depends on three factors: the costs of drilling and completing wells, the amount of oil or natural gas produced from an average well over its lifetime, and the prices received for oil and gas production. Recent experience with shale gas and tight oil in the United States and other countries suggests that economic recoverability can be significantly influenced by above-the-ground factors as well as by geology. Key positive above-the-ground advantages in the United States and Canada that may not apply in other locations include private ownership of subsurface rights that provide a strong incentive for development; availability of many independent operators and supporting contractors with critical expertise and suitable drilling rigs and, preexisting gathering and pipeline infrastructure; and the availability of water resources for use in hydraulic fracturing. See Figure 1.

Figure 1. Stylized representation of oil and natural gas resource categorizations

(not to scale)



Source: U.S. Energy Information Administration
Note: Resource categories are not drawn to scale relative to the actual size of each resource category. The graphic shown above is applicable only to oil and natural gas resources.

Crude oil and natural gas resources are the estimated oil and natural gas volumes that might be produced at some time in the future. The volumes of oil and natural gas that ultimately will be produced cannot be known ahead of time. Resource estimates change as extraction technologies improve, as markets evolve, and as oil and natural gas are produced. Consequently, the oil and gas industry, researchers, and government agencies spend considerable time and effort defining and quantifying oil and natural gas resources.

For many purposes, oil and natural gas resources are usefully classified into four categories:

- Remaining oil and gas in-place (original oil and gas in-place minus cumulative production at a specific date)
- Technically recoverable resources
- Economically recoverable resources
- Proved reserves

The oil and natural gas volumes reported for each resource category are estimates based on a combination of facts and assumptions regarding the geophysical characteristics of the rocks, the fluids trapped within those rocks, the capability of extraction technologies, and the prices received and costs paid to produce oil and natural gas. The uncertainty in estimated volumes declines across the resource categories (see figure above) based on the relative mix of facts and assumptions used to create these resource estimates. Oil and gas in-place estimates are based on fewer facts and more assumptions, while proved reserves are based mostly on facts and fewer assumptions.

Remaining oil and natural gas in-place (original oil and gas in-place minus cumulative production). The volume of oil and natural gas within a formation before the start of production is the original oil and gas in-place. As oil and natural gas are produced, the volumes that remain trapped within the rocks are the remaining oil and gas in-place, which has the largest volume and is the most uncertain of the four resource categories.

Technically recoverable resources. The next largest volume resource category is technically recoverable resources, which includes all the oil and gas that can be produced based on current technology, industry practice, and geologic knowledge. As technology develops, as industry practices improve, and as the understanding of the geology increases, the estimated volumes of technically recoverable resources also expand.

The geophysical characteristics of the rock (e.g., resistance to fluid flow) and the physical properties of the hydrocarbons (e.g., viscosity) prevent oil and gas extraction technology from producing 100% of the original oil and gas in-place.

Economically recoverable resources. The portion of technically recoverable resources that can be profitably produced is called economically recoverable oil and gas resources. The volume of economically recoverable resources is determined by both oil and natural gas prices and by the capital and operating costs that would be incurred during production. As oil and gas prices increase or decrease, the volume of the economically recoverable resources increases or decreases, respectively. Similarly, increasing or decreasing capital and operating costs result in economically recoverable resource volumes shrinking or growing.

U.S. government agencies, including EIA, report estimates of technically recoverable resources (rather than economically recoverable resources) because any particular estimate of economically recoverable resources is tied to a specific set of prices and costs. This makes it difficult to compare estimates made by other parties using different price and cost assumptions. Also, because prices and costs can change over relatively short periods, an estimate of economically recoverable resources that is based on the prevailing prices and costs at a particular time can quickly become obsolete.

Proved reserves. The most certain oil and gas resource category, but with the smallest volume, is proved oil and gas reserves. Proved reserves are volumes of oil and natural gas that geologic and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved reserves generally increase when new production wells are drilled and decrease when existing wells are produced. Like economically recoverable resources, proved reserves shrink or grow as prices and costs change. The U.S. Securities and Exchange Commission regulates the reporting of company financial assets, including those proved oil and gas reserve assets reported by public oil and gas companies.

Each year EIA updates its report of proved U.S. oil and natural gas reserves and its estimates of unproved technically recoverable resources for shale gas, tight gas, and tight oil resources. These reserve and resource estimates are used in developing EIA's Annual Energy Outlook projections for oil and natural gas production.

- Proved oil and gas reserves are reported in EIA's U.S. Crude Oil and Natural Gas Proved Reserves.
- Unproved technically recoverable oil and gas resource estimates are reported in EIA's Assumptions report of the Annual Energy Outlook. Unproved technically recoverable oil and gas resources equal total technically recoverable resources minus the proved oil and gas reserves.

Over time, oil and natural gas resource volumes are reclassified, going from one resource category into another category, as production technology develops and markets evolve.

Additional information regarding oil and natural gas resource categorization is available from the Society of Petroleum Engineers and the United Nations.

Methodology

The shale formations assessed in this supplement as in the previous report were selected for a combination of factors that included the availability of data, country-level natural gas import dependence, observed large shale formations, and observations of activities by companies and governments directed at shale resource development. Shale formations were excluded from the analysis if one of the following conditions is true: (1) the geophysical characteristics of the shale formation are unknown; (2) the average total carbon content is less than 2 percent; (3) the vertical depth is less than 1,000 meters (3,300 feet) or greater than 5,000 meters (16,500 feet), or (4) relatively large undeveloped oil or natural gas resources.

The consultant relied on publicly available data from technical literature and studies on each of the selected international shale gas formations to first provide an estimate of the "risked oil and natural gas in-place," and then to estimate the unproved technically recoverable oil and natural gas resource for that shale formation. This methodology is intended to make the best use of sometimes scant data in order to perform initial assessments of this type.

The risked oil and natural gas in-place estimates are derived by first estimating the volume of in-place resources for a prospective formation within a basin, and then factoring in the formation's success factor and recovery factor. The success factor represents the probability that a portion of the formation is expected to have attractive oil and natural gas flow rates. The recovery factor takes into consideration the capability of current technology to produce oil and natural gas from formations with similar geophysical characteristics. Foreign shale oil recovery rates are developed by matching a shale formation's geophysical characteristics to U.S. shale oil analogs. The resulting estimate is referred to as both the risked oil and natural gas in-place and the technically recoverable resource. The specific tasks carried out to implement the assessment include:

1. Conduct a preliminary review of the basin and select the shale formations to be assessed.

2. Determine the areal extent of the shale formations within the basin and estimate its overall thickness, in addition to other parameters.
3. Determine the prospective area deemed likely to be suitable for development based on depth, rock quality, and application of expert judgment.
4. Estimate the natural gas in-place as a combination of *free gas*[1] and *adsorbed gas*[2] that is contained within the prospective area. Estimate the oil in-place based on pore space oil volumes.
5. Establish and apply a composite success factor made up of two parts. The first part is a formation success probability factor that takes into account the results from current shale oil and shale gas activity as an indicator of how much is known or unknown about the shale formation. The second part is a prospective area success factor that takes into account a set of factors (e.g., geologic complexity and lack of access) that could limit portions of the prospective area from development.
6. For shale oil, identify those U.S. shales that best match the geophysical characteristics of the foreign shale oil formation to estimate the oil in-place recovery factor.[3] For shale gas, determine the recovery factor based on geologic complexity, pore size, formation pressure, and clay content, the latter of which determines a formation's ability to be hydraulically fractured. The gas phase of each formation includes dry natural gas, associated natural gas, or wet natural gas. Therefore, estimates of shale gas resources in this report implicitly include the light wet hydrocarbons that are typically coproduced with natural gas.
7. Technically recoverable resources[4] represent the volumes of oil and natural gas that could be produced with current technology, regardless of oil and natural gas prices and production costs. Technically recoverable resources are determined by multiplying the risked in-place oil or natural gas by a recovery factor.

Based on U.S. shale production experience, the recovery factors used in this supplement as in the previous report for shale gas generally ranged from 20 percent to 30 percent, with values as low as 15 percent and as high as 35 percent being applied in exceptional cases. Because of oil's viscosity and capillary forces, oil does not flow through rock fractures as easily as natural gas. Consequently, the recovery factors for shale oil are typically lower than they are for shale gas, ranging from 3 percent to 7 percent of the oil in-place with exceptional cases being as high as 10 percent or as low as 1 percent. The consultant selected the recovery factor based on U.S. shale production recovery rates, given a range of factors including mineralogy, geologic complexity, and a number of other factors that affect the response of the geologic formation to the application of best practice shale gas recovery technology. Because most shale oil and shale gas wells are only a few years old, there is still considerable uncertainty as to the expected life of U.S. shale wells and their ultimate recovery. The recovery rates used in this analysis are based on an extrapolation of shale well production over 30 years. Because a shale's geophysical characteristics vary significantly throughout the formation and analog matching is never exact, a shale formation's resource potential cannot be fully determined until extensive well production tests are conducted across the formation.

Key exclusions

In addition to the key distinction between technically recoverable resources and economically recoverable resources that has been already discussed at some length, there are a number of additional factors outside of the scope of this report that must be considered in using its findings as a basis for projections of future

[1] Free gas is natural gas that is trapped in the pore spaces of the shale. Free gas can be the dominant source of natural gas for the deeper shales.
[2] Adsorbed gas is natural gas that adheres to the surface of the shale, primarily the organic matter of the shale, due to the forces of the chemical bonds in both the substrate and the natural gas that cause them to attract. Adsorbed gas can be the dominant source of natural gas for the shallower and higher organically rich shales.
[3] The recovery factor pertains to percent of the original oil or natural gas in-place that is produced over the life of a production well.
[4] Referred to as risked recoverable resources in the consultant report.

production. In addition, several other exclusions were made for this supplement as in the previous report to simplify how the assessments were made and to keep the work to a level consistent with the available funding.

Some of the key exclusions for this supplement as in the previous report include:

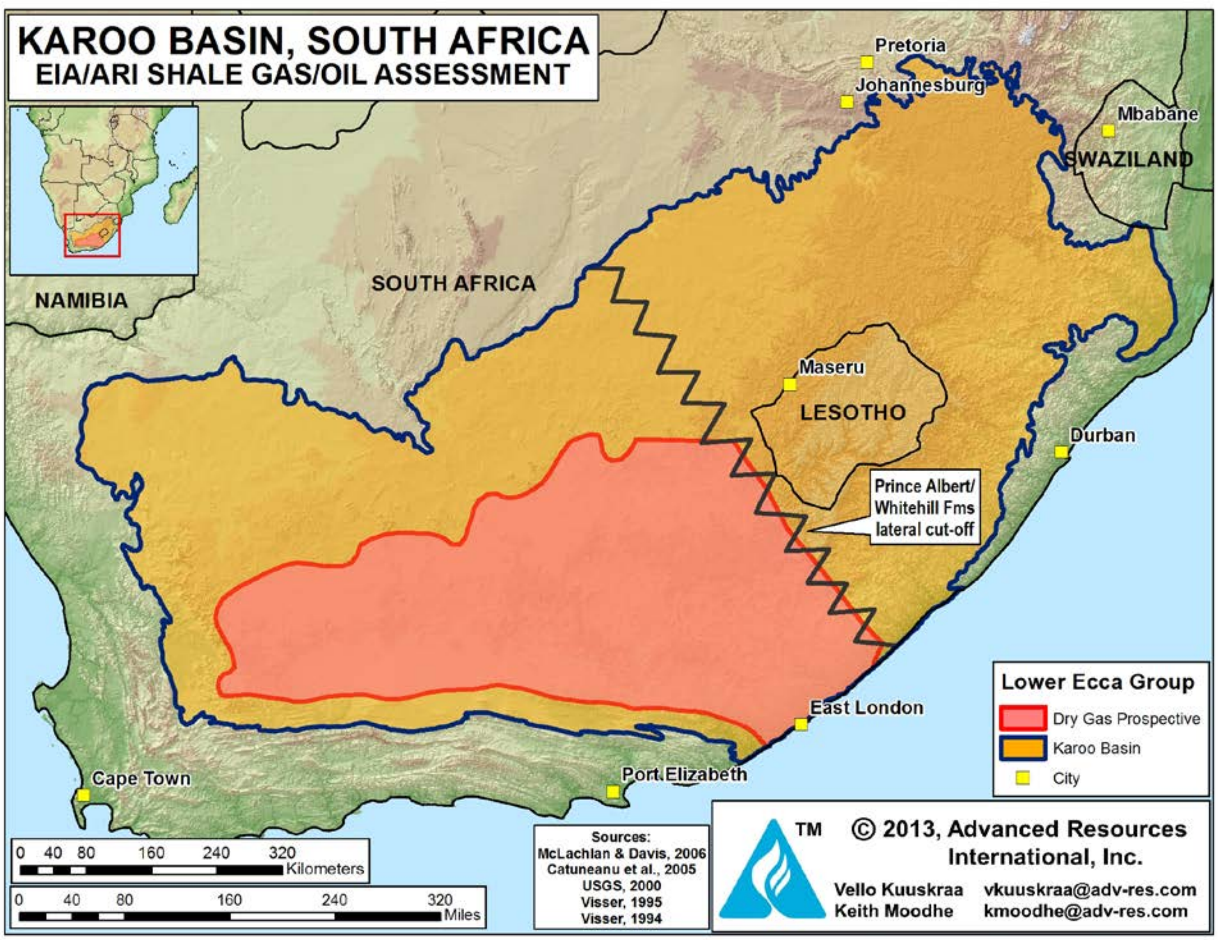
1. **Tight oil produced from low permeability sandstone and carbonate formations** that can often be found adjacent to shale oil formations. Assessing those formations was beyond the scope of this supplement as in the previous report.
2. **Coalbed methane and tight natural gas** and other natural gas resources that may exist within these countries were also excluded from the assessment.
3. **Assessed formations without a resource estimate**, which resulted when data were judged to be inadequate to provide a useful estimate. Including additional shale formations would likely increase the estimated resource.
4. **Countries outside the scope of the report**, the inclusion of which would likely add to estimated resources in shale formations. It is acknowledged that potentially productive shales exist in most of the countries in the Middle East and the Caspian region, including those holding substantial non-shale oil and natural gas resources.
5. **Offshore portions of assessed shale oil** and shale gas formations were excluded, as were shale oil and shale gas formations situated entirely offshore.

XIX. SOUTH AFRICA

SUMMARY

South Africa has one major sedimentary basin that contains thick, organic-rich shales - - the Karoo Basin in central and southern South Africa, Figure XIX-1.[1,2,3] The Karoo Basin is large (236,400 mi^2), extending across nearly two-thirds of the country, with the southern portion of the basin potentially favorable for shale gas. However, the basin contains significant areas of igneous (sill) intrusions that may impact the quality of the shale resources, limit the use of seismic imaging, and increase the risks of shale exploration.

Figure XIX -1: Outline of Karoo Basin and Prospective Shale Gas Area of South Africa



Source: ARI, 2013.

The Permian-age Ecca Group, with its organic-rich source rocks in the Lower Ecca Formation, is the primary shale formation addressed by this assessment. Of particular interest is the organic-rich, thermally mature black shale unit in the Whitehill Formation of the Lower Ecca. This shale unit is regionally persistent in composition and thickness and can be traced across most of the southern portion of the Karoo Basin.[4]

We estimate that the Lower Permian Ecca Group shales in this basin contain 1,559 Tcf of risked shale gas in-place, with 370 Tcf as the risked, technically recoverable shale gas resource, Table XIX-1. We have excluded the Upper Ecca shales in this basin from quantitative assessment because their TOC content is reported to be below the 2% TOC standard used by this resource assessment study.

Table XIX-1: Shale Gas Reservoir Properties and Resources of the Karoo Basin

Basic Data	Basin/Gross Area		Karoo ($236,400\ mi^2$)		
	Shale Formation		Prince Albert	Whitehill	Collingham
	Geologic Age		L. Permian	L. Permian	L. Permian
	Depositional Environment		Marine	Marine	Marine
Physical Extent	Prospective Area (mi^2)		60,180	60,180	60,180
	Thickness (ft)	Organically Rich	400	200	200
		Net	120	100	80
	Depth (ft)	Interval	6,000 - 10,500	5,500 - 10,000	5,200 - 9,700
		Average	8,500	8,000	7,800
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.	Mod. Overpress.
	Average TOC (wt. %)		2.5%	6.0%	4.0%
	Thermal Maturity (% Ro)		3.00%	3.00%	3.00%
	Clay Content		Low	Low	Low
Resource	Gas Phase		Dry Gas	Dry Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		42.7	58.5	36.3
	Risked GIP (Tcf)		385.3	845.4	327.9
	Risked Recoverable (Tcf)		96.3	211.3	82.0

INTRODUCTION

South Africa is a net natural gas importer, primarily from neighboring Mozambique and Namibia. As such, South Africa has given priority to exploration for domestic gas and oil. Shale exploration is initiated via a Technical Cooperation Permit (TCP), which may lead to an Exploration Permit (EP) and eventually to a production contract. The country has a corporation tax of 28% and royalty of 7%, terms that are favorable for gas and oil development.

A number of major and independent companies have signed Technical Cooperation Permits (TCPs) to pursue shale gas in the Karoo Basin, including Royal Dutch Shell, the Falcon Oil & Gas/Chevron joint venture, the Sasol/Chesapeake/Statoil joint venture, Sunset Energy Ltd. of Australia and Anglo Coal of South Africa.

1. KAROO BASIN

1.1 Introduction

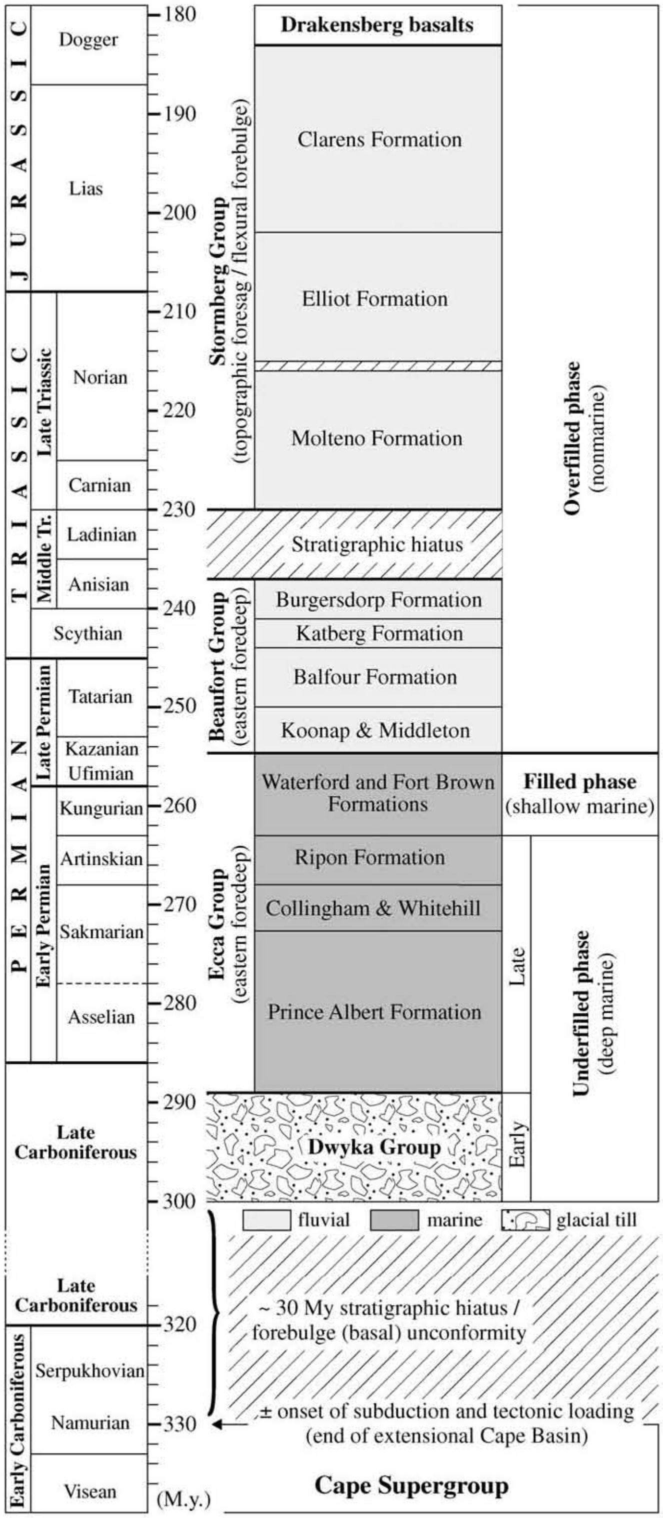
The Karoo foreland basin is filled with over 5 km of Carboniferous to Early Jurassic sedimentary strata. The Early Permian-age Ecca Group underlies much of the Karoo Basin, cropping out along the southern and western basin margins, Figure XIX-1. The Ecca Group contains a sequence of organic-rich mudstone, siltstone, sandstone and minor conglomerates.[5]

1.2 Geologic Setting

The larger Ecca Group, encompassing an interval up to 10,000 ft thick in the southern portion of the basin, is further divided into the Upper Ecca (containing the Fort Brown and Waterford Formations) and the Lower Ecca (containing the Prince Albert, Whitehill and Collingham Formations), Figure XIX-2. The three Lower Ecca formations are the subject of this shale resource assessment.

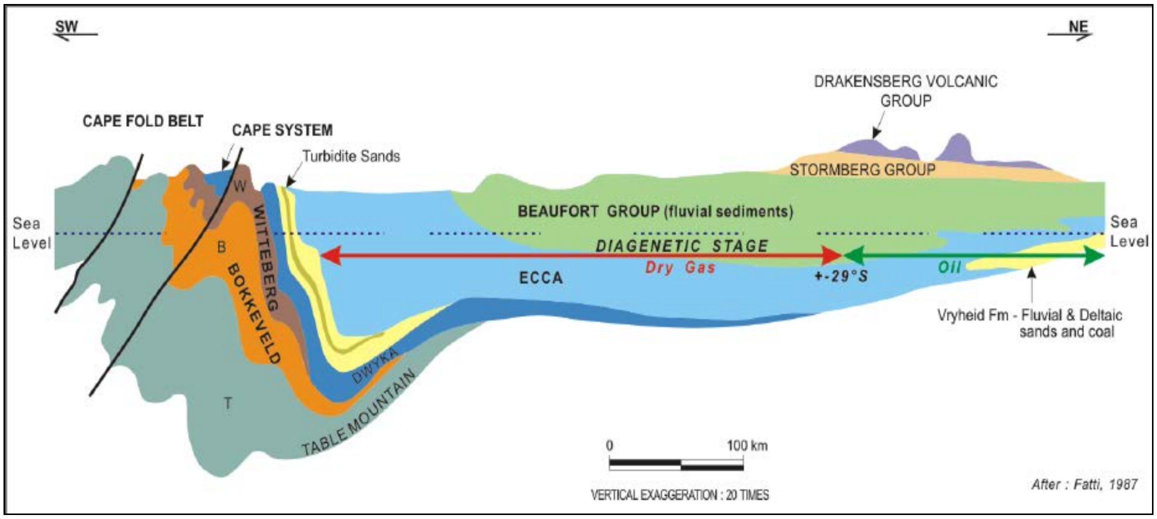
The regional southwest to northeast cross-section illustrates the structure of the Cape Fold Belt of the Ecca Group on the south and the thermal maturity for the Ecca Group on the north, Figure XIX-3.[6]

Figure XIX-2. Stratigraphic Column of the Karoo Basin of South Africa



Source: Catuneanu, O. et al., 2005.

Figure XIX-3. Schematic Cross-Section of Southern Karoo Basin and Ecca Group Shales

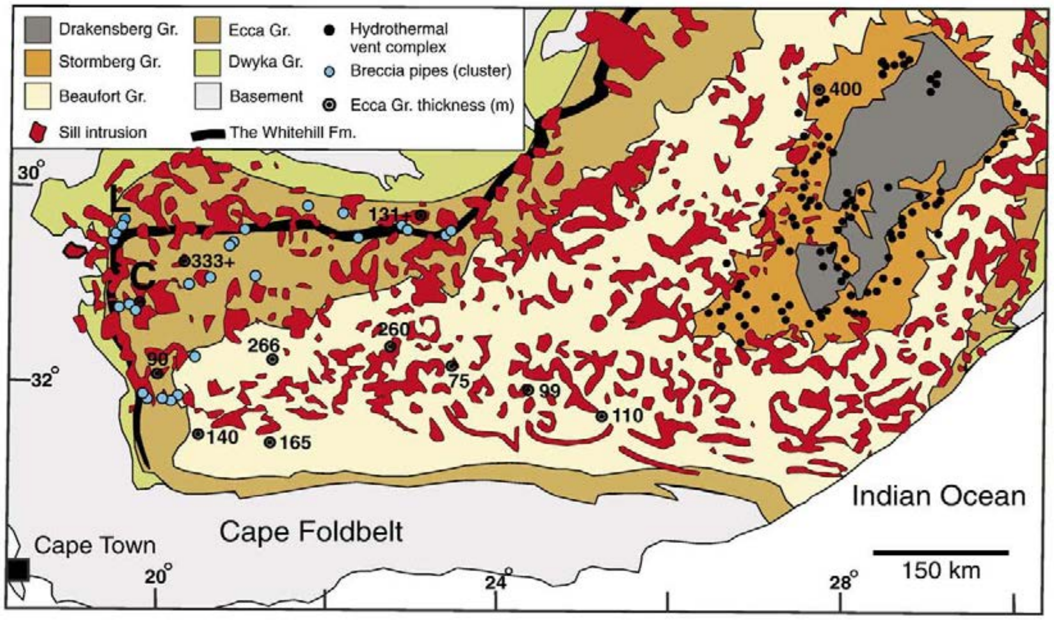


Source: McLachlan, I. and Davis, A., 2006.

Major portions of the Karoo Basin have igneous (sill) intrusions and complex geology, with the most extensive and thickest sills concentrated within the Upper Ecca and Balfour formations.[7] This unusual condition creates significant exploration risk in pursuing the shale resources in the Karoo Basin, Figure XIX-4.[8] (Note that this map reflects the maximum extent of intrusions, which are expected to be less within the target shale formations.) Local mapping indicates that contact metamorphism is restricted to quite close to the intrusions. As such, we removed 15% of the prospective area to account for the potential impact of igneous intrusions and significantly risked the remaining resource.

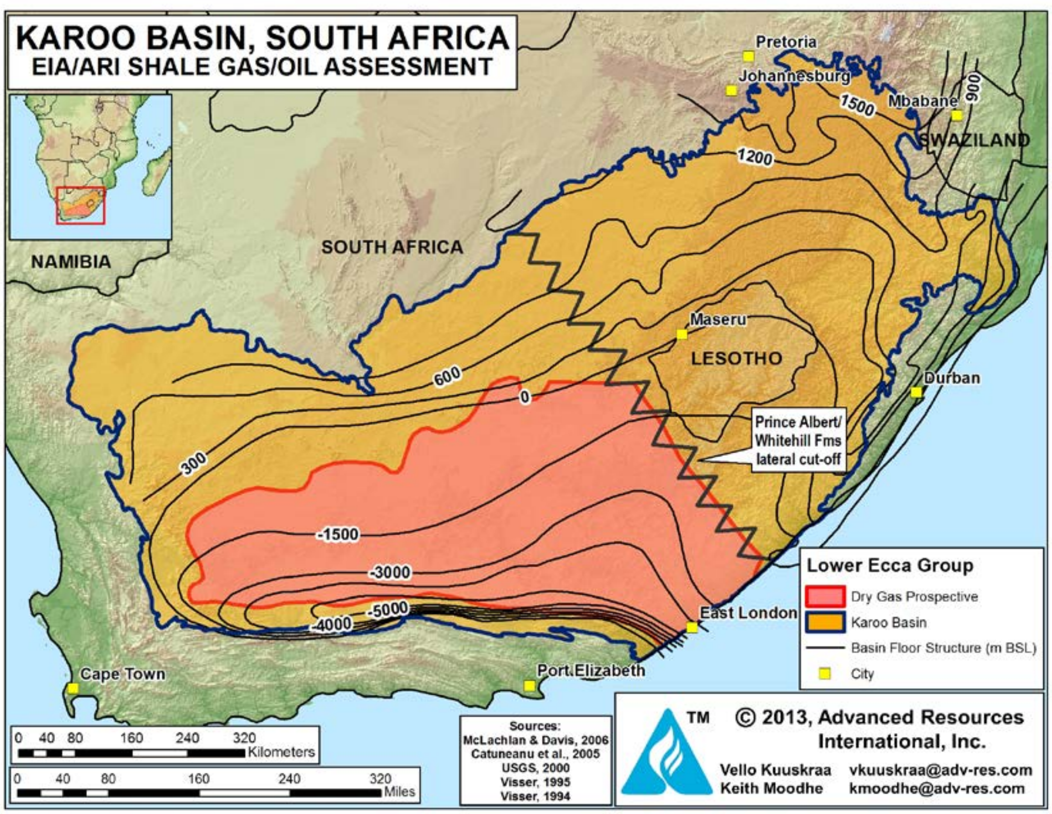
The prospective area for the Lower Ecca Group shales is estimated at 60,180 mi^2, Figure XIX-5. The boundaries of the prospective area are defined by the outcrop of the Upper Ecca Group on the east, south and west/northwest and the pinch-out of the Lower Ecca Group shales on the northeast, Figure XIX-1. The dry gas window is south of the approximately 29^o latitude line. Given the thermal maturity information and the depositional limits of the Lower Ecca shales, the prospective area of the Lower Ecca shales is primarily in the dry gas window.

Figure XIX-4. Igneous Intrusions in the Karoo Basin, South Africa



Source: Svensen, H. et al., 2007.

Figure XIX-5. Lower Ecca Group Structure Map, Karoo Basin, South Africa



Source: ARI, 2013.

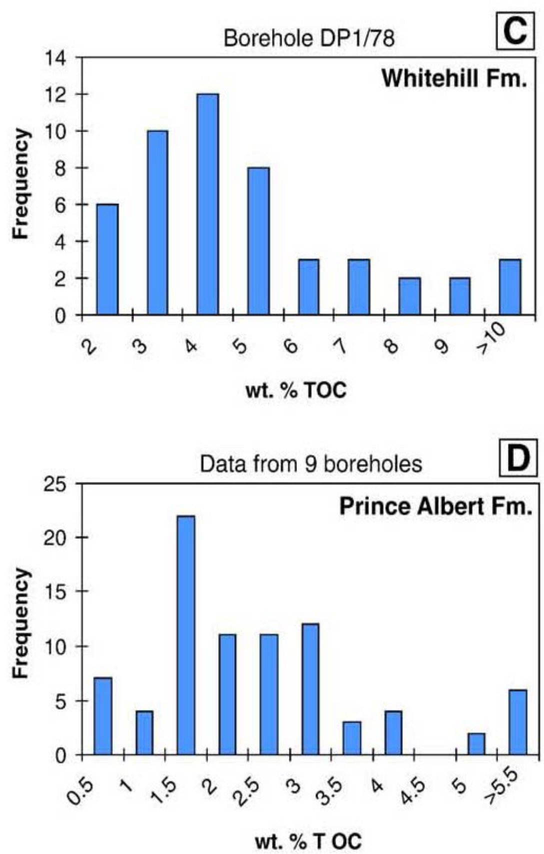
1.2 Reservoir Properties (Prospective Area)

Lower Ecca Shales. The Lower Ecca shales include the thick basal Prince Albert Formation, overlain by the thinner Whitehill and Collingham Formations. Each of these sedimentary units has been individually assessed and is discussed below.

Prince Albert Shale. The Lower Permian Prince Albert Formation has a thick, thermally mature area for shale gas in the Karoo Basin. Depth to the Prince Albert Shale ranges from 6,000 to over 10,000 ft, averaging about 8,500 ft in the deeper prospective area in the south. The Prince Albert Shale has a gross thickness that ranges from 200 to 800 ft, averaging 400 ft, with a net organic-rich thickness of about 120 ft.

The total organic content (TOC) of the Prince Albert Shale within its organic-rich net pay interval ranges from 1.5 to 5.5%, averaging 2.5%, Figure XIX-6.[8] Local TOC values of up to 12% have been recorded.[9] However, in areas near igneous intrusions much of the organic content may have been lost or converted to graphite.

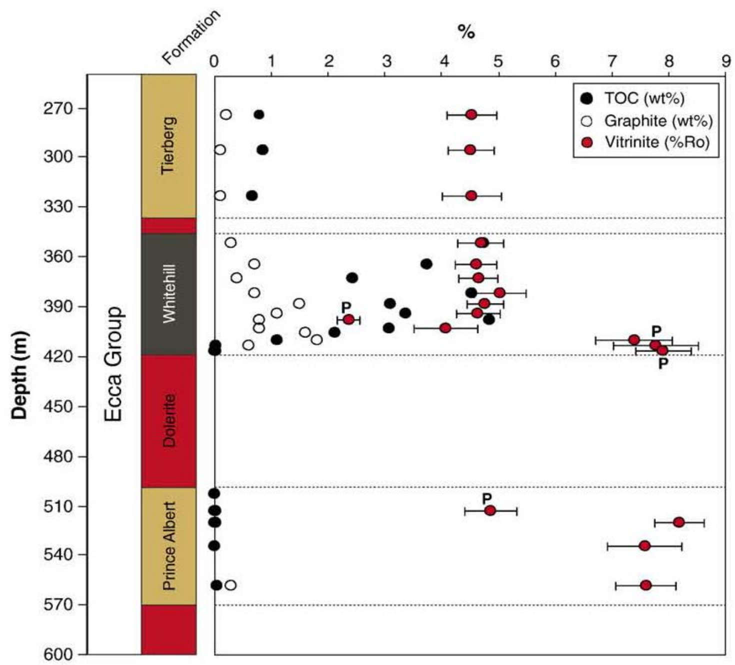
Figure XIX-6. Total Organic Content of Prince Albert and Whitehill Formations



Source: Svensen, H. et al., 2007.

Because of the presence of igneous intrusions, the thermal maturity of the Prince Albert Shale is high, estimated at 2% to 4% R_o, placing the shale well into the dry gas window. In areas near igneous intrusions, the formation is over-mature, with vitrinite reflectance (R_o) values reaching 8%, indicating that the organic content has been transformed into graphite and CO_2, Figure XIX-7. The Prince Albert Shale was deposited as a deep marine sediment and is inferred to have mineralogy favorable for shale formation stimulation.

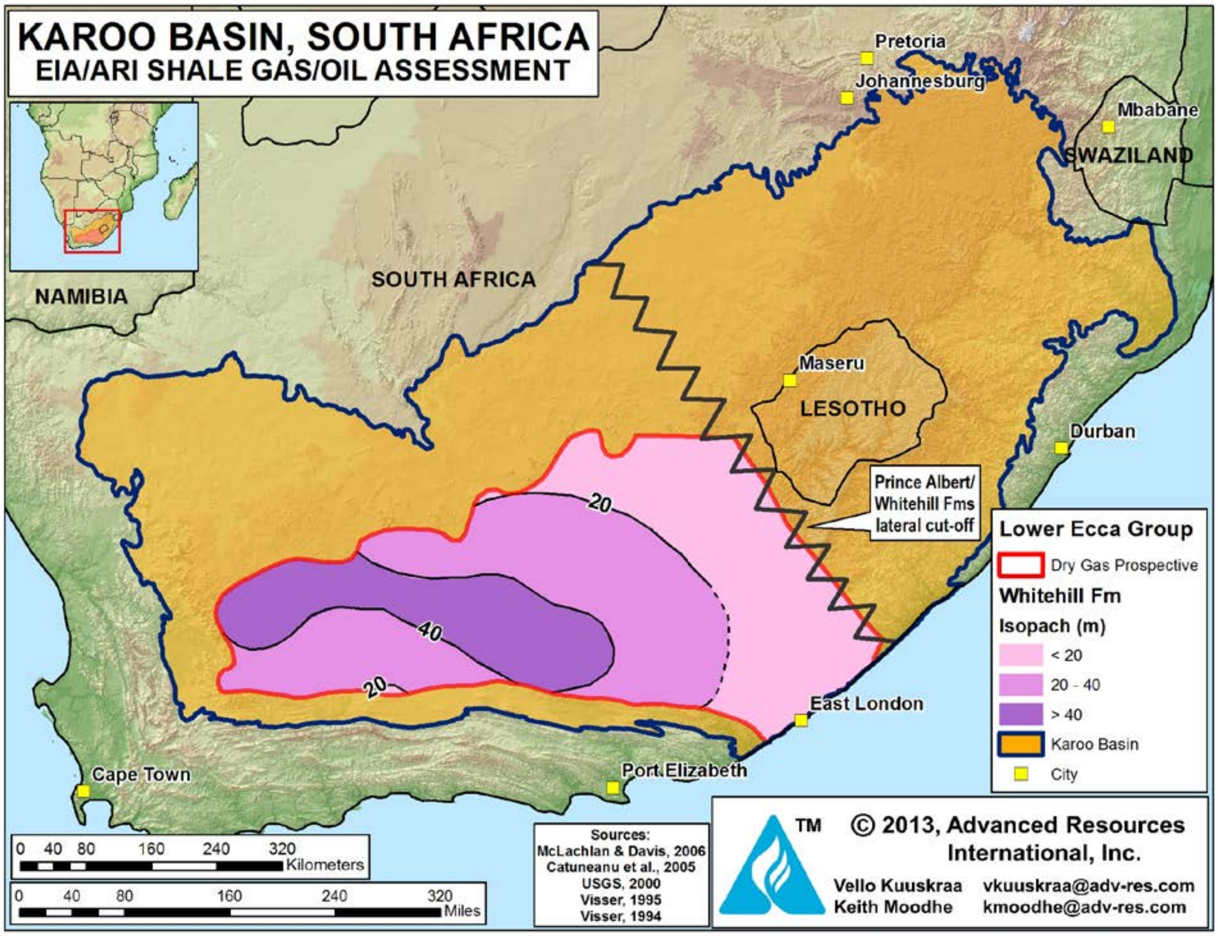
Figure XIX-7. Carbon Loss in Lower Ecca Group Metamorphic Shale



Based on limited well data, primarily from the Cranemere CR 1/68 well completed in the Upper Ecca interval, the Prince Albert Shale appears to be overpressured and has a high thermal gradient.

Whitehill Shale. The organic-rich Lower Permian Whitehill Formation contains one of the main shale gas targets in the Karoo Basin of South Africa. The depth to the Whitehill Shale ranges from 5,500 to 10,000 ft, averaging 8,000 ft in the prospective area. The Whitehill Shale has an estimated gross organic thickness of 100 to 300 ft,[10] with an average net thickness of 100 ft within the prospective area, as shown by the isopach map on Figure XIX-8.[11]

Figure XIX-8. Isopach Map of the Whitehill Formation



Source: ARI, 2013.

The total organic content (TOC) for the Whitehill Shale in the prospective area ranges from 3% to 14%, averaging 6%. Local areas have TOC contents up to 15%.[4] In areas near igneous intrusions, portions of the organic content may have been converted to graphite. The main minerals in the Whitehill Formation are quartz, pyrite, calcite and chlorite, making the shale favorable for hydraulic stimulation. The Whitehill Shale is assumed to be overpressured. The thermal maturity (R_o) of the Whitehill Shale in the prospective area ranges from 2% to 4%, placing the shale into the dry gas window.

The hydrogen and oxygen indexes of the Whitehill Formation indicate a mixture of Type I and Type II kerogen.[9] The Whitehill Shales was deposited in deep marine, anoxic setting and contains minor sandy interbeds from distal turbidites and storm deposits.[12,13]

Collingham Shale. The Lower Permian Collingham Formation (often grouped with the Whitehill Formation) contains the third shale formation addressed by this resource study. The Collingham Formation has an upward transition from deep-water submarine to shallow-water deltaic deposits.[9] The depth to the Collingham Shale averages 7,800 ft within the prospective area. Except for total organic content, the shale has reservoir properties similar to the Whitehill Shale. It has an estimated gross organic thickness of 200 ft, a net thickness of 80 ft, and TOC of 2% to 8%, averaging 4%. Thermal maturity is high, estimated at 3% R_o, influenced by igneous intrusions. The shale is assumed to be overpressured based on data from the Upper Ecca Group.

Upper Ecca Shales. The Upper Ecca Formation extends over a particularly thick, 1,500 m (~5,000 ft) vertical interval in the central and northern Karoo Basin. The Upper Ecca contains two shale sequences of interest - - the Waterford and the Fort Brown. The Fort Brown Formation accounts for the great bulk of the vertical interval of the Upper Ecca. These shales are interpreted by some investigators to have been deposited in a shallow marine environment,[2] although others categorize them as lacustrine.[14]

The organic content and thermal maturity of the Upper Ecca shales are considerably less than for the Lower Ecca shales. The total organic content (TOC) is reported to range from about 1% to 2%. With a thermal maturity ranging from 0.9% to 1.1% R_o, the Upper Ecca shales area is in the oil to wet gas window.[15]

In the materials below, we provide a qualitative description for the Upper Ecca shales. However, because their average TOC is below the 2% criterion set for the study, these shales have been excluded from our quantitative assessment.

The boundaries of the prospective area for the Upper Ecca shales are defined by the outcrop of the Upper Ecca on the east, south and west and the shallowing of the Lower Ecca shales on the northeast. The shale oil window is north of the approximately 29^o latitude line. A significant basalt intrusion area of about 10,000 mi^2 in the center of the prospective area has been excluded. Major portions of the prospective area have igneous intrusions that have locally destroyed portions of the organics, creating significant exploration risk.

Fort Brown Shale. The Fort Brown Shale, as described in the Cranemere CR 1/68 well, is a dark gray to black shale with occasional siltstone stringers. In this well, the Fort Brown Shale exists over a gross interval of nearly 5,000 ft (1,500 m) from 7,012-11,997 ft. Sunset

Energy, the current permit holder in the area surrounding the Cranemere CR 1/68 well, reports that 24-hour DST testing in one interval of the Fort Brown shale, from 8,154-8,312 ft, had a flow rate of 1.84 MMcfd. The well is reported to have blown out at a depth of about 8,300 ft (2,500 m), requiring 10.5 pound per gallon mud to bring the well under control.

The prospective area for the Upper Ecca Fort Brown Shale is estimated at 31,700 mi^2. The Fort Brown Shale in the prospective area has an average depth of 6,000 ft and ranges from 3,000 to 9,000 ft. The shale has an estimated 600 ft of net organic rich thickness, based on using a net to gross ratio of 20% and an average gross thickness of 3,000 ft. The shale has a total organic content (TOC) that ranges from 1 to 2% and an estimated average thermal maturity of 1.1% R_o (based on limited data).

Waterford Shale. The prospective area for the Upper Ecca Waterford Shale is estimated at 20,800 mi^2. The Waterford Shale in the prospective area has an average depth of 4,500 ft, ranging from 3,000 to 6,000 ft. The shale has an estimated 100 ft of net organic rich thickness within an average gross thickness of 500 ft. Total organic content ranges from 1 to 2%, with average thermal maturity, based on very limited data, of 0.9% R_o.

1.3 Resource Assessment

Prince Albert Shale. Within its 60,180-mi^2 dry gas prospective area, the Prince Albert Shale has a resource concentration of about 43 Bcf/mi^2. Given limited exploration data, the risked shale gas in-place is estimated at 385 Tcf. Based on favorable TOC and reservoir mineralogy, balanced by complex geology and volcanic intrusions in the prospective area, ARI estimates a risked, technically recoverable shale gas resource of 77 Tcf for the Prince Albert Shale in the Karoo Basin.

Whitehill Shale. Within its 60,180-mi^2 dry gas prospective area, the Whitehill Shale has a resource concentration of about 59 Bcf/mi^2. While somewhat more defined than the Prince Albert Shale, the exploration risk for the Whitehill Shale is still substantial, leading to a risked shale gas in-place of 845 Tcf. Based on favorable reservoir mineralogy but complex geology, ARI estimates a risked, technically recoverable shale gas resource of 211 Tcf for the Whitehill Shale in the Karoo Basin.

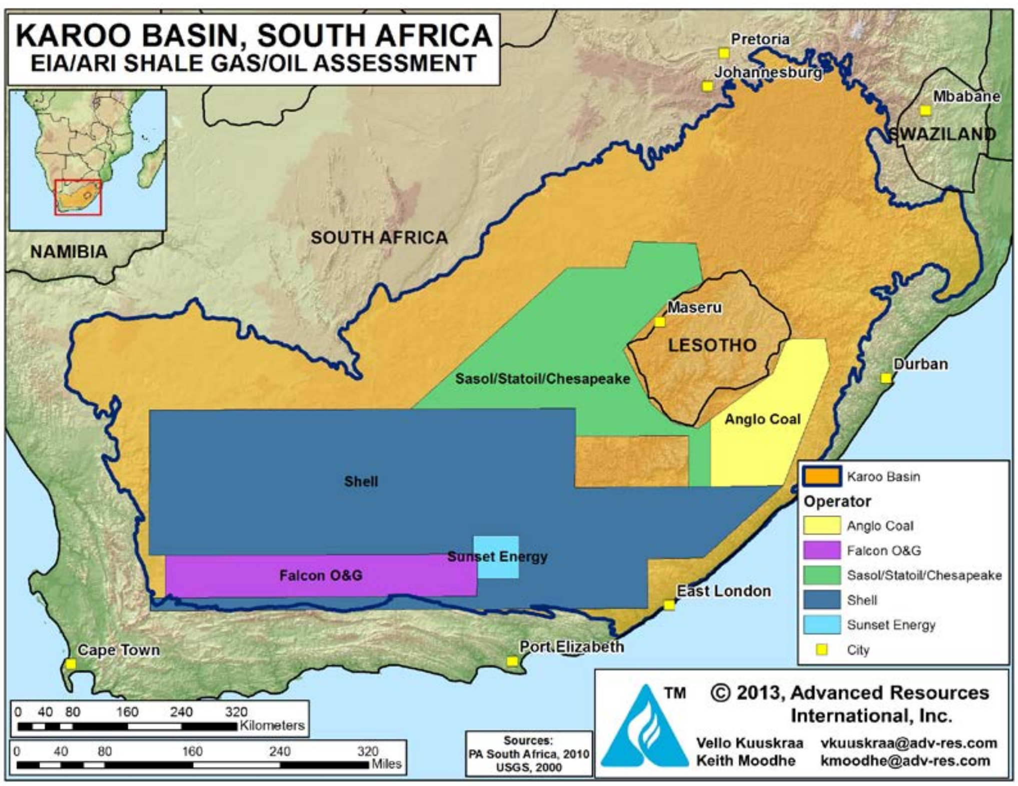
Collingham Shale. With a prospective area of 60,180 mi^2 and with a resource concentration of 36 Bcf/mi^2, the risked gas in-place for the Collingham Shale is estimated at 328 Tcf, with a risked, technically recoverable shale gas resource of 82 Tcf.

Considerable uncertainty surrounds the characterization and assessment of the shale oil resources of South Africa, particularly for the net organic-rich thickness and the vertical and areal distribution of thermal maturity. Shale exploration is just starting in the Karoo Basin and few data points exist, particularly for the Upper Ecca group of formations.

1.4 Recent Activity

Falcon Oil & Gas Ltd., an early entrant into the shale gas play of South Africa, obtained an 11,600-mi^2 TCP along the southern edge of the Karoo Basin. Shell obtained a larger 71,400-mi^2 TCP surrounding the Falcon area. Sunset Energy holds a 1,780-mi^2 TCP to the west of Falcon. The Sasol/Chesapeake/Statoil JV TCP area of 34,000 mi^2 and the Anglo Coal TCP application area of 19,300 mi^2 are to the north and east of Shell's TPC, Figure XIX-9. [16]

Figure XIX-9. Map Showing Operator Permits in the Karoo Basin, South Africa



Source: ARI, 2013.

Recently, Chevron announced that it would partner with Falcon Oil & Gas to pursue the shale resources of the Karoo Basin, starting with seismic studies.[17]

Five older (pre-1970) wells have penetrated the Ecca Shale interval. Each of the wells had gas shows, while one of the wells - - the Cranemere CR 1/68 well - - flowed 1.84 MMcfd from a test zone at 8,154 to 8,312 ft. The gas production, considered to be from fractured shale, depleted relatively rapidly during the 24-hour test. The CR 1/68 well was drilled to 15,282 ft into the underlying Table Mountain quartzite and had gas shows from six intervals, starting at 6,700 ft and ending at 14,650 ft, indicating that the shales in this area are gas saturated.

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