STATE OF THE ART: FRACKING FOR SHALE GAS EXPLORATION IN SOUTH-AFRICA AND THE IMPACT ON WATER RESOURCES

Report to the
Water Research Commission

by

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WRC Report No. KV 294/11
ISBN 978-1-4312-0225-6

February 2012

Obtainable from

Water Research Commission
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Gezina, 0031

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The publication of this report emanates from a project titled *State of the Art: Fracking for Shale Gas Exploration in South-Africa and the Impact on Water Resources* (WRC Project No. K8/986/1)

Executive Summary

This report attempts to summarize the current knowledge on hydraulic fracturing in the public domain as well as give a review of South Africa's regional geology and geohydrology. The observation and findings made in this work is neither totally comprehensive nor exhaustive since very little data is available in the public domain on hydraulic fracturing in South Africa.

The report attempts to address issues which arise from a scientific perspective point, i.e. geology, geohydrology and possible contamination matters. Since geology plays such a pivotal role in the development of shale gas in the Karoo an extensive section was included to highlight possible challenges. A number of case studies from international sources were also presented to illustrate risk areas and assist with possible monitoring processes. In the monitoring section different scenarios were evaluated, which might have an effect on the environment or the regulatory body. Finally, recommendations were made in the instance if hydraulic fracturing is considered as a possibility to be used in South Africa.

The main concerns regarding hydraulic fracturing can be summarised in the following figure in which highest environmental impact issues are highlighted in red.

Subsequently these concerns were addressed in a systematic methodology which highlighted the likelihood of it occurring. Migration of fluid, surface spills and water use posed the most probable points of impact. The application of good management practices would significantly reduce these events from occurring. Additionally monitoring by the regulatory body would ensure a continuation of good practices.

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Conversion of Units

Due to the nature of the oil and gas industry different units are commonly used than that which is acceptable, thus the following conversions will be required during the reading of this report.

1 Barrel US Oil = 158.99 litres

1 Barrel US liquid = 119.24 litres

1 Bar = 0.99 atmospheres

1 Feet = 30.48 cm

1 cubic feet = 0.02832 m^3

1 Acre = 0.41 hectare

1 Pounds/cubic inch = 27.68 g/cm^3

Chapter 1 Scope of Work

1.1 Aim of Document

The document is intended to report on the following key issues regarding gas exploration and development through deep well drilling and hydraulic fracturing. The following key issues are:

- The shale gas reservoir potential in the main Karoo basin and any other potential areas of interest.
- The location relative to and relationship between the shale gas reservoirs and the Karoo aquifer systems.
- Potential impacts associated with hydraulic fracturing and associated processes.

This report is thus subdivided into five chapters which deal with the five aims, listed below, identified from the above key issues.

1. The current state of knowledge of potential shale gas reservoirs in the Karoo Basin.
2. Review on shale gas development and hydraulic fracturing potential on South Africa's Karoo Basin and groundwater resources, including the natural and artificial hydraulically fractured systems.
3. The shale gas reservoir interactions with groundwater reserves.
4. International case studies of shale gas development and hydraulic fracturing and associated impacts on both groundwater and surface water reserves.
5. Recommendations on the potential impacts of South Africa's water resources and suggested monitoring, treatment and management, including institutional arrangements, options into shale gas development.

To assist in this investigation a number of groundwater and related reports have already been

by the WRC and are listed in Table 1-1 with the key findings highlighted in

Table 1-2. Some of the reports deal directly with issues of concern and was used to highlight specific impact zones that occur in the Karoo.

Table 1-1 List of WRC projects related to groundwater and surface issues which might be impacted by gas exploration.

Title	Report #
Experimental measurement of specific storativity by the determination of rock elastic parameters	KV 184/07
Exploitation potential of Karoo aquifers	170/1/91
Field and laboratory investigations to study the fate and transport of dense non-aqueous phase liquids (DNAPLS) in groundwater	1501/5/08
Flow conceptualisation, recharge and storativity determination in karoo aquifers, with special emphasis on Mzimvubu Keiskamma and Mvoti-Umzimkulu water management areas in the Eastern Cape and KwaZulu-Natal provinces of South Africa	1565/1/10
Hydrogeological and isotopic assessment of the response of a fractured multi-layered aquifer to long term abstraction in a semi-arid environment	565/1/01
Hydrogeology of fractured-rock aquifers and related ecosystems within the Qoqodala dolerite ring and sill complex, Great Kei catchment, Eastern Cape	1238/1/04
Hydrogeology of the Main Karoo Basin: Current Knowledge and Future Research Needs	TT179/02
Karoo aquifers: Deformations, hydraulic and mechanical properties	936/1/04
Karoo aquifers: Their geology, geometry and physical properties	487/1/98
Manual for site assessment at DNAPL contaminated sites in South Africa	1501/2/08
Manual on pumping test analysis in fractured-rock aquifers	1116/1/02
Regional Characterization and Mapping of Karoo Fractured Aquifer Systems – An Integrated Approach Using Geographical Information System and Digital Image	653/1/02
The Influences of Dolerite Sill and Ring Complexes on the Occurrence of Groundwater in Karoo Fractured Aquifers: A Morpho-Tectonic Approach	937/1/01
A Groundwater Planning Toolkit for the Main Karoo Basin: Identifying and quantifying groundwater development options incorporating the concept of wellfield yields and aquifer firm yields	1763/1/11
Measurement of the bulk flow and transport characteristics of selected fractured rock aquifer systems in South Africa.	on-going
Field investigations to study the fate and transport of light non-aqueous phase liquids (LNAPLs) in groundwater(S)	on-going

Table 1-2 Key findings of WRC projects related to Table 1-1.

Title	Findings
Experimental measurement of specific storativity by the determination of rock elastic parameters	Storativity determination
Exploitation potential of Karoo aquifers	Recharge variability
Field and laboratory investigations to study the fate and transport of dense non-aqueous phase liquids (DNAPLS) in groundwater	Transport scenarios
Flow conceptualisation, recharge and storativity determination in Karoo aquifers, with special emphasis on Mzimvubu Keiskamma and Mvoti-Umzimkulu water management areas in the Eastern Cape and KwaZulu-Natal provinces of South Africa	Conceptual model on occurrence and flow dynamics
Hydrogeological and isotopic assessment of the response of a fractured multi-layered aquifer to long term abstraction in a semi-arid environment	Recharge variability
Hydrogeology of fractured-rock aquifers and related ecosystems within the Qoqodala dolerite ring and sill complex, Great Kei catchment, Eastern Cape	Influence of dolerite structures on ecosystems
Hydrogeology of the Main Karoo Basin: Current Knowledge and Future Research Needs	Review
Karoo aquifers: Deformations, hydraulic and mechanical properties	Heterogeneity of aquifer parameters
Karoo aquifers: Their geology, geometry and physical properties	Heterogeneity of aquifer parameters
Manual for site assessment at DNAPL contaminated sites in South Africa	Delineation methodology
Manual on pumping test analysis in fractured-rock aquifers	Determination of aquifer parameters
Regional Characterization and Mapping of Karoo Fractured Aquifer Systems – An Integrated Approach Using Geographical Information System and Digital Image	GIS evaluation of aquifer location
The Influences of Dolerite Sill and Ring Complexes on the Occurrence of Groundwater in Karoo Fractured Aquifers: A Morpho-Tectonic Approach	Influence of dolerite structures on aquifers
A Groundwater Planning Toolkit for the Main Karoo Basin: Identifying and quantifying groundwater development options incorporating the concept of wellfield yields and aquifer firm yields	Delineate high yield and resource potential
Measurement of the bulk flow and transport characteristics of selected fractured rock aquifer systems in South Africa.	Bulkflow properties and estimation
Field investigations to study the fate and transport of light non-aqueous phase liquids (LNAPLs) in groundwater(S)	Characterisation and assessment approaches

1.2 Methodology

The procedure employed in this document will concentrate on seven main focus areas which should cover the most critical points as it pertains to South Africa. Due to the lack of information available to South Africans it was envisaged that a systematic balanced approach on hydraulic fracturing would be best. In order to perform this task the following key points were reported on:

1. Literature survey of local and international case studies on the impact of gas exploration on groundwater and surface water bodies. The research will include the geology, geohydrology and chemical (natural and induced) environments.
2. A survey of the geology of the Karoo area will be presented to illustrate the extent, thickness and depth of the Whitehill Formation. This will aid in assessing the vulnerability of the area to impacts of hydraulic fracturing might have on the system.
3. A geohydrological assessment of borehole yields, volume and occurrence of groundwater in the study area will be developed to estimate possible influences of hydraulic fracturing on the system. Secondly it will act as a rough estimate of the type and class of water resource that might be affected.
4. An estimate based on carbon content on possible gas production from the White Hill Formation and the impact it will have on the environment.
5. Surface water and groundwater interactions will be focused on to estimate the change from a natural system to industrial and hydraulic fracturing procedures on these resources. An estimate of recharge and rainfall patterns will be reported to give a rough estimate in fluxes in the area as well as subsurface zones which will be developed for gas production.
6. Determine monitoring options – leniency versus zero tolerance. Impacts of accidental spillages and surface developments on groundwater and surface water bodies.
7. Formulate recommendations from the proposed study to affect decision making processes.

Chapter 2 Introduction

This document is a collection of reports and journal articles which have been assimilated to give a coherent perspective on the proposed shale gas exploration and exploitation in the Karoo.

The announcement that gas exploration will take place in the Karoo has raised both concern and elation. The excitement is partly due to the creation of employment prospects while the concern is driven by a fear that the pristine way of life in the Karoo area might be destroyed. This report will not focus on these aspects but only on the gas development process and the associated impact this might have on the environment. One major concern that has been raised is the influence of hydraulic fracturing on groundwater resources and the top most geological strata in the Karoo (Späth, 2010).

Hydraulic fracturing was developed in the United States of America in the late 1940s to assist in the stimulation of oil and natural gas wells (Howard and Fast, 1970, van Poolen et al., 1958, Montgomery and Smith, 2010). The number of wells that incorporates hydraulic fracturing increases by the day since oil and gas production is increased by this technique (Montgomery and Smith, 2010).

Due to present energy shortfall in South Africa, the requirement for new energy sources have gained new momentum and part of this new focus is on shale gas in Karoo type formations. There are currently a number of companies that have exploration rights to investigate natural gas resources in Karoo type formations (Figure 2-1). The most interesting aspect of this is that the area available for natural gas development is substantially larger than just the Karoo, with exploration areas covering six of the nine provinces in South Africa. A five-spot pumping test in the Waterberg has been operated since 2004 by Anglo Operations (Raseroka and McLachlan, 2008) and 20 boreholes have been drilled in the main Karoo since the beginning of 2008 to test for coal-bed methane production potential (Raseroka and McLachlan, 2008). Since most of the exploration rights for natural gas resource has been allocated for shale gas development (Figure 2-1) a short description of the exploration and development techniques will be presented in the next section and Chapter 3.

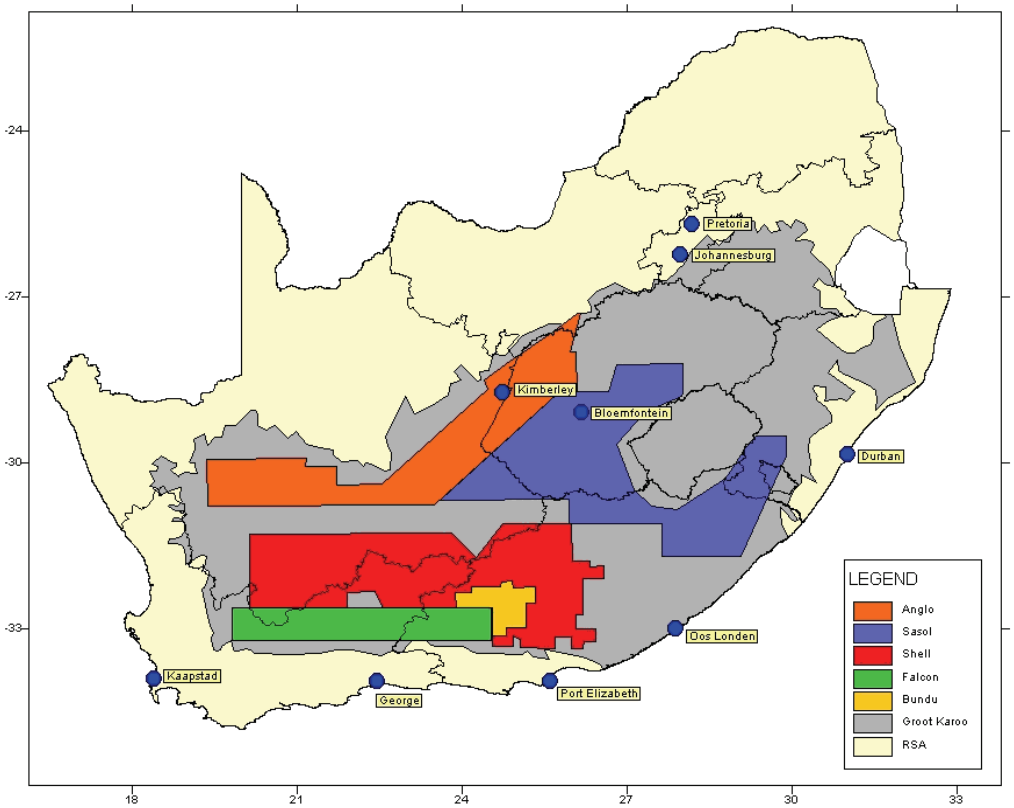

Figure 2-1 Regional map of South Africa showing the exploration rights and companies associated with these permits.

2.1 Gas Establishment and Distribution

2.1.1 Shale Gas Applications in South Africa

The Shale Gas project aims to target the carbonaceous shales of the Ecca and Dwyka Groups, but the stratigraphic units in question vary in lithological makeup along strike as one proceeds from the Cape to the Free State/KwaZulu-Natal regions. The project team's early thinking was to only target zones of the Whitehill formation of the lower Ecca, which is a carbonaceous shale unit characterized by its distinctive white weathering in outcrop. During the initial study, a set of parameters were created to site potential areas of interest as set out below:

1. Depth constraint → min. 300 m-max. 1 500 m
2. Areas devoid of or with the smallest concentration of dolerites.

3. Thickness of source rocks preferably ± 100 m or more.
4. Area of targets covering at least 1 000 km^2.
5. Favourable structural features for possible gas traps.

The above parameters were used to delineate areas in the Northern and Western Cape provinces and coupled with geophysics, the early study produced two possible target areas near the town of Carnarvon.

However, as more was learnt of shale gas exploration and exploitation in the USA, the approach to the present Shale Gas project was modified. The distribution of the Whitehill Formation with its marine setting led to further investigation into the dynamics of the Main Karoo Basin and other stratigraphic units equivalent to the Whitehill to extend the potential target areas. A revised set of source rocks were identified with the main target zone now identified as carbonaceous shales of the Lower and Upper Ecca Group with subordinate interest in the Dwyka Shales (Figure 2-1). The source formations have been extended to include the following:

1. Whitehill Formation (Cape region)
2. Prince Albert Formation (Cape region)
3. Volksrust Formation (Free State and KZN regions)
4. Vryheid Formation (Free State and KZN regions)
5. Pietermaritzburg Formation (KZN region)
6. Dwyka Shales (All regions, where shallow enough)

The research into the Shale Gas deposits of the USA led to a revised set of geochemical and petrophysical parameters that are based on the criteria set by Jarvie (2008) to include the following:

1. Total Organic Carbon and its composition (dead carbon, free gas, etc.) → 1% or more.
2. Kerogen Type → Determines hydrocarbon types as well as adsorption/desorption properties.
3. Vitrinite reflectance and T_{max} (maximum temperatures that rocks were subjected to during hydrocarbon production) → Thermal Maturity with reflectance values of 1,35 to 2,5, T_{max} values vary and can be very high (between 400°C and 580°C as seen in the Barnett Shale).
4. Rock Eval Hydrogen Index <100.
5. Porosities and other physical properties related to gas flow.

6. Calculations of hydrocarbon generation, expulsion and retention.

From a South African perspective, the Rowsell and De Swardt's study of the maturation indices pertaining to the Karoo Basin can be used to identify areas prospective for gas generation (as from Figure 2-2):

1. Temperature Range → ±130°C to 170°/180°C.
2. Vitrinite Reflectance of 1,35-2,5.
3. CR/CT Ratio of about 0,85 to 0,94.
4. Total Organic Carbon and its composition (dead carbon, free gas, etc.) → 1% or more.

2.2 Geology and Gas Plays

From the abundant Internet sources of information on gas-producing shales in the World, it is apparent that these shales are organic-rich with gas producing shales containing total organic carbon values between 3 and 12 percent (Internet, 2007). In South Africa, shales containing significant organic carbon are restricted to the Ecca Group of the main Karoo Basin, smaller basins in the northern part of South Africa and to the Bokkeveld Group in the southernmost part of South Africa (Rowsell and De Swardt, 1976).

Shale gas is defined as gas generated from organic-rich shale. The target gas is methane, which is an energy source and can be used for the production of fuels as in the Mossgas process or as a power source for electricity generation. Methane is a dry gas and represents the final stage of hydrocarbon thermal maturation. Organic-rich shales were originally muds deposited in marine or lacustrine basins, the organic material being derived mostly from algae, spores and pollen. These muds became buried and lithified over tens to hundreds of millions of years and generated various hydrocarbons with increasing depth of burial and increasing temperature (Figure 2-2). Between 2 and 4 km burial depth, oil is produced, between 4 and 5 km, wet gas is produced and between 5 and 6 km, dry gas, including methane, is produced. Deeper burial results in low-grade metamorphism, the termination of hydrocarbon generation and the formation of graphite from the organic material. In South Africa, shales of the Bokkeveld Group have undergone low-grade metamorphism and no longer have a capacity for hydrocarbon generation (Rowsell and De Swardt, 1976). However, the comprehensive investigations of Rowsell and De Swardt (Rowsell and De Swardt, 1976) using numerous widely-spaced deep core samples in the main Karoo Basin indicate that the Ecca Group shales have a potential to generate dry gas south of approximately latitude 29°S (Figure 3-1). Further north, the shales have been less deeply buried and have a potential for oil generation except where younger igneous dolerite intrusions have locally increased the thermal maturity leading to the generation of dry gas (Rowsell and De Swardt, 1976). In the smaller basins in the northern part of South Africa, namely Springbok Flats, Ellisras, Tshipise and Tuli, the maximum thickness of the Karoo Supergroup strata is approximately 4 km in the Tuli Basin (Brandl, 1981) and the Ecca Group organic-rich shales have not been buried sufficiently to reach a level of thermal maturity capable of generating dry gas. Therefore only the Ecca Group shales in the main Karoo Basin south of latitude 29°S have a potential to generate dry gas and are the principal subject of this report.

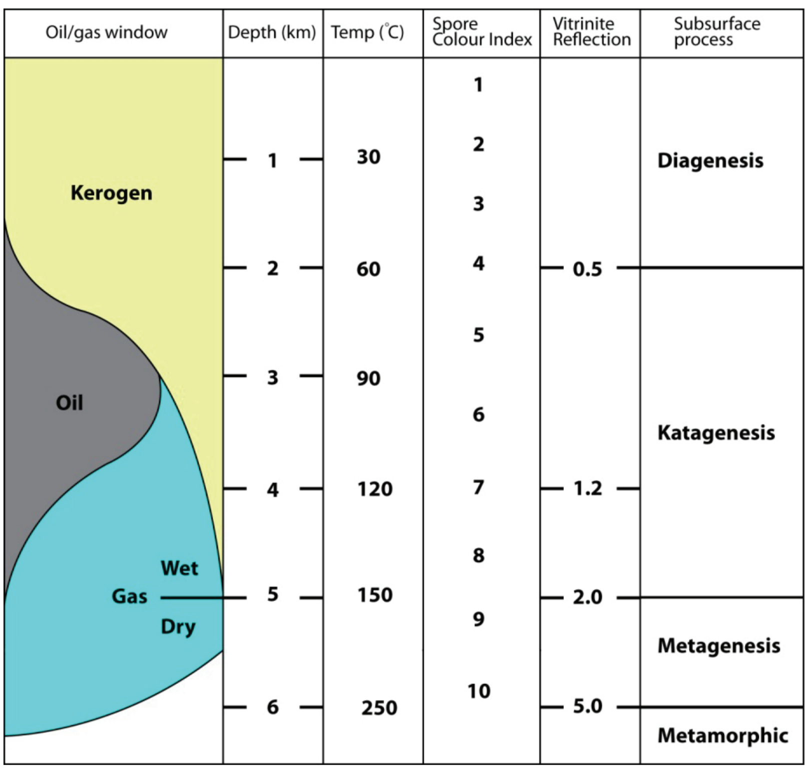

Figure 2-2 Hydrocarbon generation thermal maturation indices and maturation stages plotted against depth of burial after (Tissot and Welte, 1984).

2.3 Exploration and Development of Shale Gas Resources

2.3.1 Well Construction

Drilling for gas starts off in the same way as a water production borehole, in which a wellbore casing or conductor casing is installed to stabilise the unconsolidated sediments near the earth's surface. Drilling is continued vertically and casing is installed until a depth is reached where all viable aquifer systems (potable water) cannot be affected (GWPRF, 2009). Once this point is reached drilling is continued for a few meters and cement is then pumped into the casing followed by water. This is done to push the cement out through the bottom of the casing and back up into the spaces between the surface casing and the wellbore or annulus until it is entirely filled with cement. In the USA, most states require the surface casing to be fully cemented before drilling can be continued (Zoback et al., 2010).

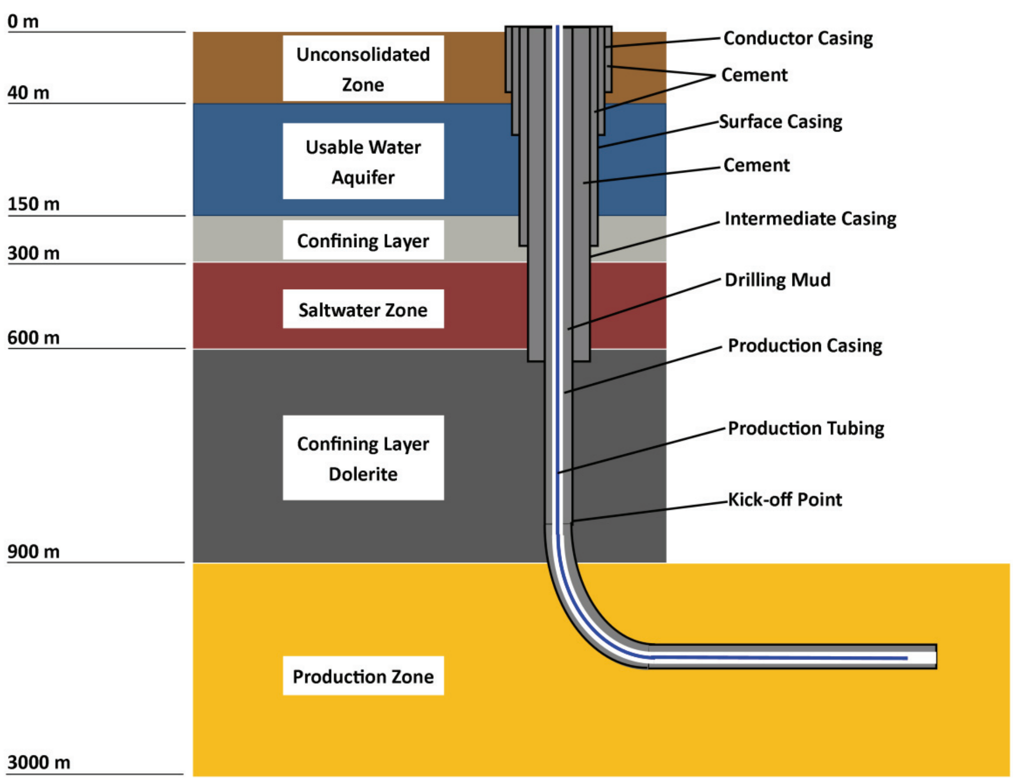

Figure 2-3 Conceptual model of borehole drilling arrangement for gas exploration.

Once the surface casing is in place a blowout preventer system is installed to avoid any encountered pressurized fluids from rising up the borehole and going through the space between the drill pipe and the surface casing. At this stage the cement behind the casing is allowed to settle and drilling is continued for another three to six meters. The borehole is then pressurised and checked for integrity before continuing the drilling program. As the vertical drilling is continued intermediate casing is inserted to stabilize the deep borehole (Figure 2-3). The intermediate casing also serves to isolate and separate brines and hydrocarbons which might be trapped in the sub-surface, thus preventing borehole interference, natural gas contamination and protection of surface aquifer systems (GWPRF, 2009).

At the kick-off point drilling techniques are applied to force the drilling to occur in a horizontal direction through the production zone. Horizontal drilling can be done in such a way that the horizontal borehole can stretch from a few meters to as much as three kilometres in a specific direction (Zoback et al., 2010). This can significantly increase the contact between the borehole and the shale formation. Once the horizontal borehole has reached its target extend, production casing is installed and cemented into place to prevent leaking. Subsequently the production casing is punctured at selected points where the hydraulic fracturing process will take place.

2.3.2 Hydraulic Fracturing

The technique is commonly used to enhance the production of low permeability formations such as tight sands, coal beds, and deep shales. Hydraulic fracturing is a technically complex process and is usually performed by highly specialised work units. If the horizontal boreholes are quite long, the hydraulic fracturing needs to be conducted in stages. The starting point is commonly located at the tip of the borehole (furthest point) and successively hydraulic fracturing is done towards the vertical position. After each hydraulic fracturing process the perforation interval is isolated such that only a single subsection of the borehole is hydraulically fractured at a given moment.

Hydraulic fracturing is done by pumping fracturing fluid at increased pressures through the perforations in a section of the casing. The chemical composition of the fracturing fluid, as well as the rate and pressure at which it is pumped into the shale, are tailored to the specific properties of each shale formation and, to some extent, each borehole due to differences in volume (Figure 2-4). When the pressure increases to a sufficient level, it causes a hydraulic fracture to open in the rock, propagating along a plane more or less perpendicular to the path of the borehole direction (Zoback et al., 2010, Witherspoon et al., 1980). The hydraulic fractures are typically intended to propagate horizontally for about 100 to 300 meters away from the borehole in each direction and vertically for the thickness of the shale. Operators monitor and control the fracturing pressure to prevent vertical propagation beyond the thickness of the gas-producing shale layer (Zoback et al., 2010, GWPRF, 2009).

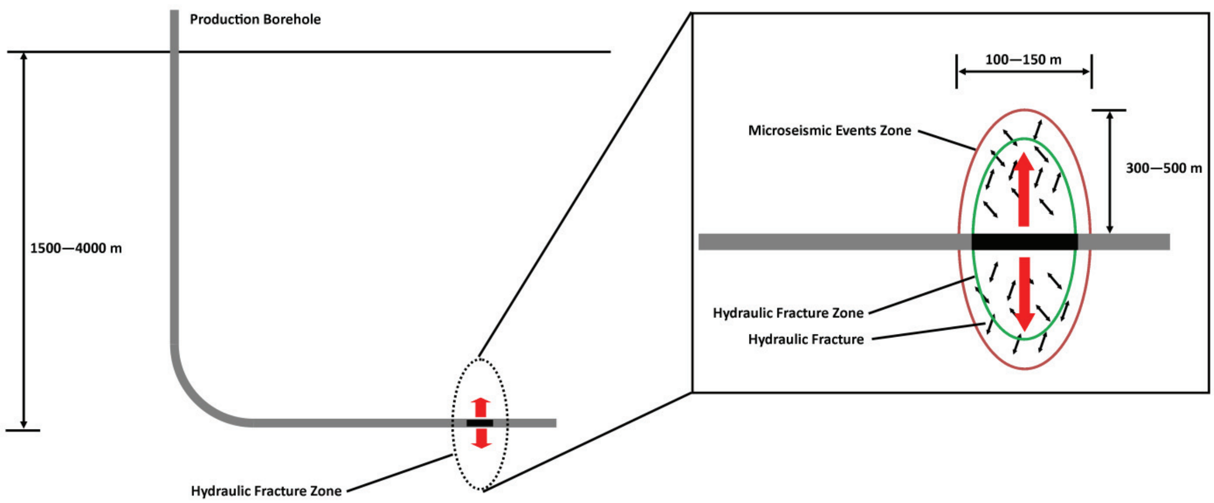

Figure 2-4 Hydraulic fracturing process producing hydraulic fracture zones perpendicular to borehole. Green ellipse indicates effective fracture zone while the red ellipse represents microseismic signiture.

2.3.3 Step-by-step Guide on Hydraulic Fracturing

1. Select drilling site after extensive surveillance/studies including geology, geohydrology, structural geology, seismic geophysics and magneto telluric geophysics.
2. Build entrance roads to site.
3. Clean drilling pad (usually between 1 and 2 hectares), construct waste water ponds and set up drilling rig. A pit is then dug close to the drill site and lined with thick plastic to prevent any potential soil contamination. All the rock, soil and mud removed from the well site can then be placed in the pit to prevent the contamination of the soil and water table.

4. Drill vertical or horizontal borehole and install casings. When the borehole is drilled through a groundwater aquifer, multiple layers of cement and steel casing are used to ensure the integrity of the wellbore and provide an impermeable barrier between the well and the water source.
5. Remove drilling rig and get ready for hydraulic fracturing process. Perforate walls of deep borehole with a perforation gun in the direction of anisotropic forces. Insert hydraulic fracturing pumps. Hydraulic fracturing fluid is then pumped down at pressures more than 400 bar the borehole into the target shale reservoir, creating small fractures in the rock (fracture lengths usually < 100 m). The fractures are held open by grains of sand that are mixed into the hydraulic fracturing fluid, allowing the natural gas to escape from the tight rock and flow up through the well. Hydraulic fracturing fluid is typically comprised of approximately 98-99.5 percent water and sand, and 0.5-2 percent chemical additives.
6. Remove hydraulic fracturing pump and contain the flow-back water in waste pits or tanks.

   Typical classes of parameters present in flow-back fluid are:

   i. Dissolved Solids (chlorides, sulphates, and calcium)
   ii. Metals (calcium, magnesium, barium, strontium)
   iii. Suspended solids
   iv. Mineral scales (calcium carbonate and barium sulphate)
   v. Bacteria - acid producing bacteria and sulphate reducing bacteria
   vi. Friction Reducers
   vii. Iron solids (iron oxide and iron sulphide)
   viii. Dispersed clay fines, colloids & silts
   ix. Acid Gases (carbon dioxide, hydrogen sulphide)
7. Install the “christmas” tree gas head (well head).
8. Rehabilitate the well pad.

Chapter 3 Karoo Basin Geology

3.1 Parameters Controlling the Shale Gas in the Main Karoo Basin

The objectives of this study are to assess the potential of the Ecca Group shales to viably produce gas (methane) in the main Karoo Basin using hydraulic fracturing procedures at depths of between 1.5 and 4 km. A second objective is to assess the effects of intrusive dolerites on the gas-generating potential of the shales, since these dolerites are present over about 390 000 km² of the main Karoo Basin underlain by the Ecca Group (Svensen et al., 2007) and are only absent in the southernmost part of the basin, south of approximately latitude 32°30'S. The dolerites would have heated the adjacent shales to a probable maximum temperature of 1000°C, resulting in pyrolysis and a reduction of organic carbon (Rowsell and De Swardt, 1976; Svensen et al., 2007). The dolerites intruded the Permian (290-253 Ma) Ecca Group shales over a relatively short period (0.5 million years) dated at 183 Ma (Riley et al., 2006; Svensen et al., 2007).

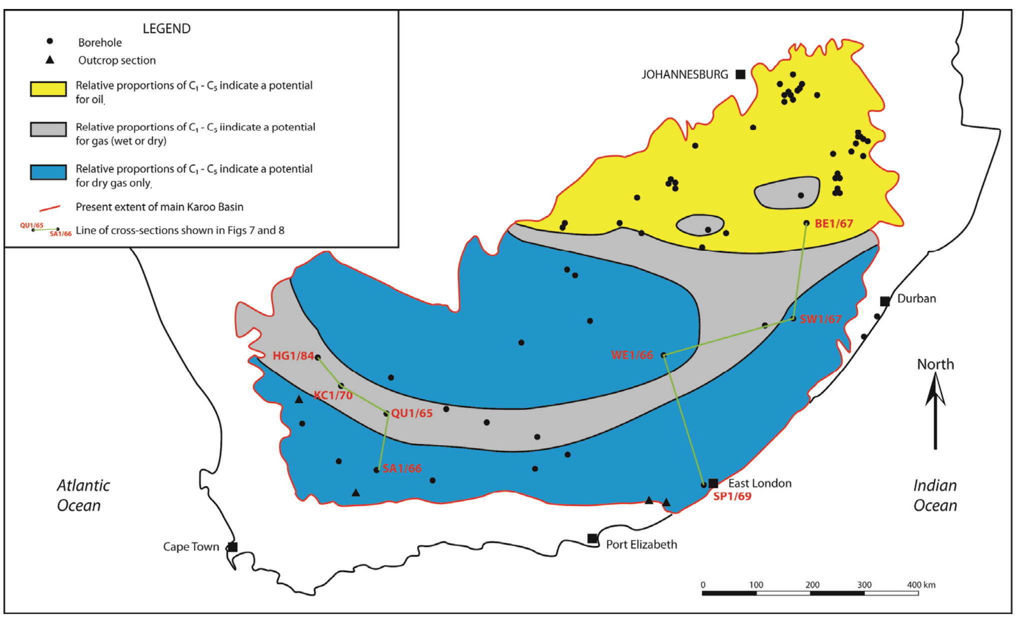

Figure 3-1 Hydrocarbon potential of mainly Ecca Group shales in the main Karoo Basin based upon the relative proportions of the constituent gases, C1-C5 (methane to pentane). Taken from Fig. 14 of Rowsell and De Swardt (Rowsell and De Swardt, 1976).

Total organic carbon within the shale is an important parameter, since there is a linear relationship between total organic carbon and gas content, as in the Barnett Shale in the Fort Worth Basin of Texas (USA) (Report, 2005). Thickness is also important, as most of the gas produced is from areas where the shale is between 90 and 183 metres thick (Internet, 2007). However, more recently, it has become technically possible to produce gas from shale units as thin as 10 to 15 metres (De Wit, 2011). Within the main Karoo Basin, there are reports of natural gas occurrences both at surface and at intervals in the deep boreholes drilled by Soekor (now called the Petroleum Agency of South Africa) between 1965 and 1977. Furthermore, varying quantities of gas were obtained by desorbed gas analysis undertaken by Soekor on Ecca Group shale samples retrieved from the deep borehole cores (Rowsell and De Swardt, 1976).

It was found that only the lower Ecca Group shales within the dry gas window south of latitude 29°S have comparable total organic carbon contents to those of producing shales elsewhere in the world (Internet, 2007). The upper Ecca Group shales, namely the Tierberg Formation (Viljoen, 2005), average only 1.2 percent organic carbon (Cole and McLachlan, 1994), which is significantly lower than the 3 to 12 percent range applicable to producing shales (Internet, 2007). The Dwyka Group also contains black shales with between 0.1 and 4.3 percent total organic carbon, averaging 1.9 percent (Cole and Christie, 1994, Cole and McLachlan, 1994). However, these shales are thin and restricted, being interbedded with diamictite and sandstone, with the thickest shales (50 to 60 m) occurring in only 3 out of 45 deep boreholes investigated. The lower Ecca Group comprises black, organic-rich shale of the Whitehill Formation (Cole and Basson, 1991) overlying dark grey shale of the Prince Albert Formation (Figure 3-2; (Cole, 2005). The Whitehill Formation pinches out northeastwards along a line stretching from Hertzogville in the Free State to Coffee Bay in Eastern Cape Province (Cole and McLachlan, 1994). Northeast of this line, the Whitehill Formation correlates with the middle part of the sandstone-dominated Vryheid Formation and the Prince Albert Formation grades into shale of the Pietermaritzburg Formation (Figure 3-2). In the area between Coffee Bay and Harding, the Whitehill and Vryheid Formations are separated by a continuous shale succession (Figure 3-3; (Johnson et al., 2006)).

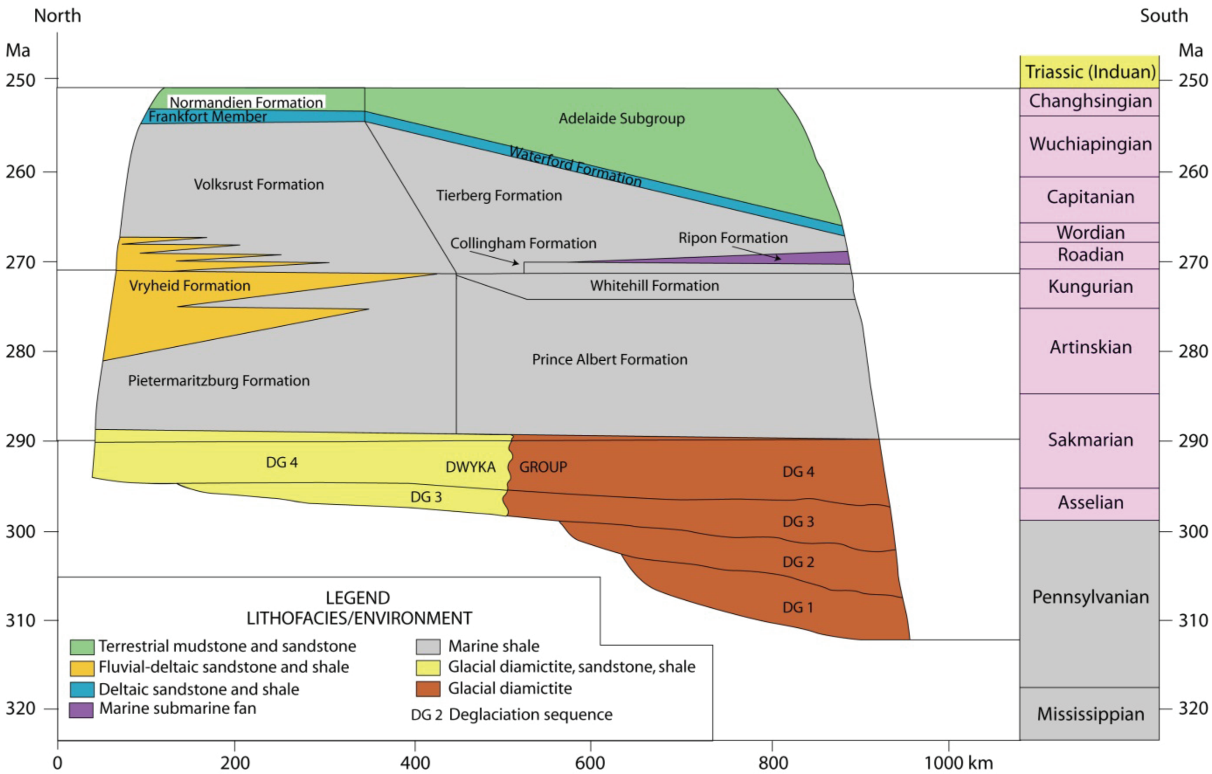

Figure 3-2 Distribution in time and space of the Dwyka Group, Ecca Group and Adelaide Subgroup in the main Karoo Basin, South Africa, showing lithofacies, environment and stratigraphic relationships. Modified from Fig. 7 of Veevers et al. (Veevers et al., 1994). The geologic timescale is from Gradstein et al. (Gradstein et al., 2004).

Shale isopach maps of the Whitehill Formation and lower Ecca Group were drawn for the Karoo Basin south of latitude 28°S. Since hydraulic fracturing is normally undertaken at least 1500 metres below the shallow groundwater aquifers, which are often utilised by farmers and communities (Internet, 2010), maps showing the depth to the top of the Whitehill Formation and lower Ecca Group were compiled. The disposition of dolerite intrusions in each of the two sedimentary units was shown by means of isopach and dolerite percentage maps. The sedimentary succession, including dolerites, is illustrated in two north-trending cross-sections derived from the deep boreholes in the western and eastern parts of the main Karoo Basin (Figure 3-1).

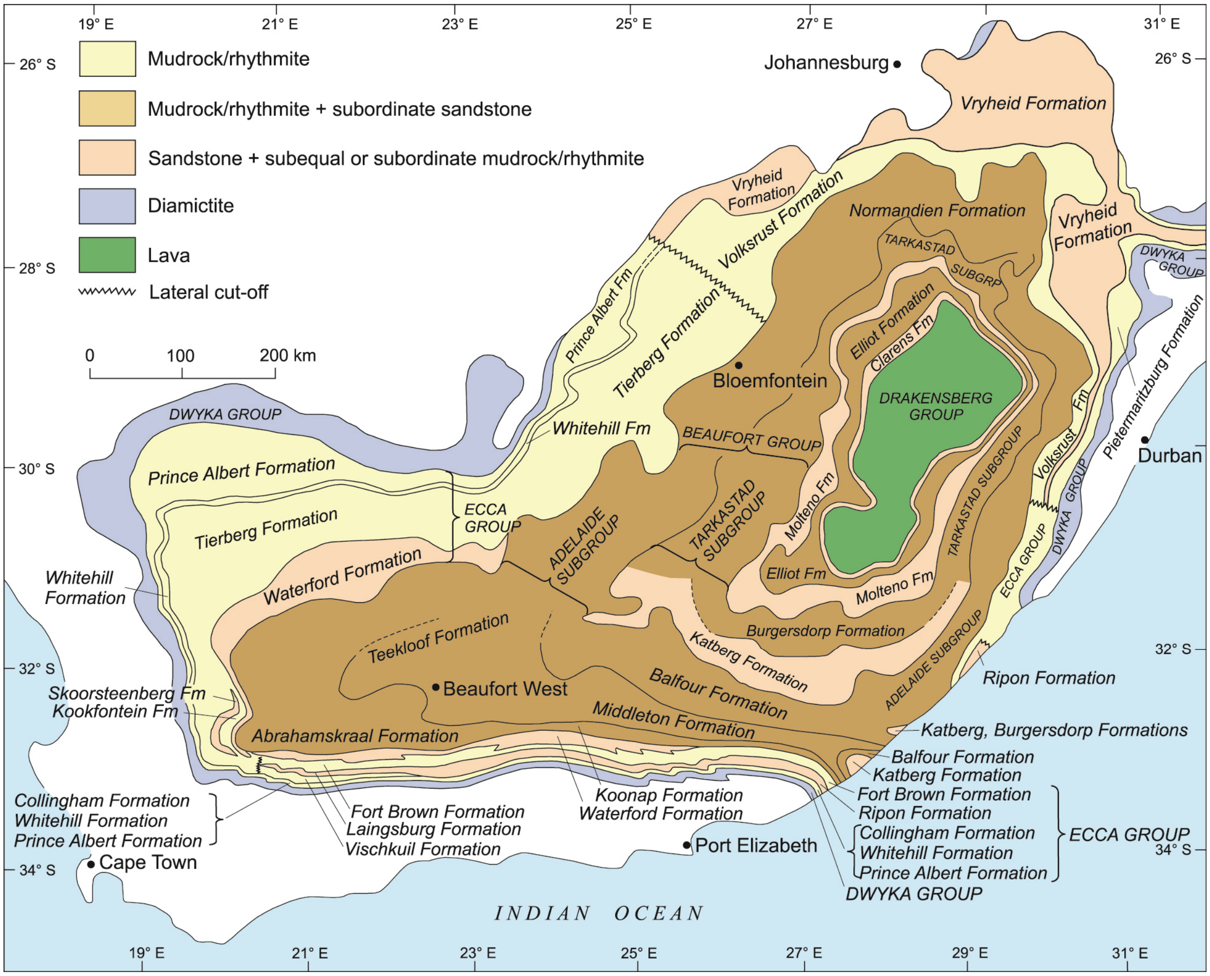

Figure 3-3 Areal distribution (schematic) of lithostratigraphic units in the main Karoo Basin. Taken from Fig. 3 of Johnson et al. (Johnson et al., 2006).

3.2 Distribution of Shale Gas Potential in the Main Karoo Basin

The distribution of mainly Ecca Group shales having a potential to produce dry gas in the main Karoo Basin south of approximately latitude 29°S (Figure 3-1) was delineated by Rowsell and De Swardt (Rowsell and De Swardt, 1976) using the results of desorbed gas analysis on core samples from the deep Soekor boreholes. The gaseous hydrocarbons (methane to pentane) are absorbed on to the fine-grained constituents of shales and can be desorbed by low-temperature acid hydrolysis (Rowsell and De Swardt, 1976). Samples yielding high proportions of C_1 gas (methane) and C_2/C_1 (Ethane/Methane) relative to C_3/C_1 (Propane/Methane) indicate a potential for dry gas. The trend of increasing maturity due to increasing depth of burial southwards across the basin is supported by the results from other parameters, namely vitrinite reflectance, CR/CT ratios, illite crystallinity and spore colour index. For dry gas generation, vitrinite reflectance values should be between 2 and 5 percent (Figure 2-2). In the main Karoo Basin south of latitude 29°S, values for shale of the Ecca and Dwyka Groups vary between 1.75 and 4.39 percent (Rowsell and De Swardt, 1976). Branch et al. (Branch et al., 2007) measured vitrinite reflectance values between 3.5 and 5.3 percent for shale of the Whitehill Formation and between 4.0 and 6.4 percent for shale of the Prince Albert Formation in borehole SA1/66 in the southwestern part of the basin some 60 km north of the basin margin (Figure 3-3). These correspond to the dry gas and metamorphic maturation stages (Figure 2-2), which indicates that shales in the southern extremity of the present basin are over-mature and can no longer generate dry gas. CR/CT ratios (residual, non-volatile carbon after pyrolysis to total carbon in the kerogen or organic material) gives an indication of the ability of the shale to produce additional amounts of hydrocarbons if heated to sufficiently high temperatures with lower ratios corresponding to higher potential. The results more or less correspond to the findings of the desorbed gas analysis (Rowsell and De Swardt, 1976). Illite crystallinity or Kübler index is a measure of the width in millimetres of the 10 Å diffraction peak at half its height. It gives an indication of the maturity level of the shale with decreasing indices corresponding to increasing maturity (Rowsell and De Swardt, 1976). The results of Soekor's investigations indicate a trend of increasing Kübler index or "crystallinity" from south to north across the Karoo Basin in shales of the Ecca and Dwyka Groups. In the southern part of the basin, south of approximately 30°S, the average indices are less than 4 and correspond to the metagenesis stage and possible preservation of dry gas (Figure 2-2). Spore colour index is a measure of palynological thermal maturity and is based on the colour of recognisable organic matter such as spores in transmitted light. The colour changes from pale yellow in the immature zone through various shades of orange, red and brown to dark brown or black in the metagenesis stage (Rowsell and De Swardt, 1976). The then Geological Survey of South Africa (now called the Council for Geosciences) and Soekor (now called PetroSA) determined spore colours in shales of the Ecca and Dwyka Groups from 23 boreholes in the central and southern Karoo between 1976 and 1987. The spore colour scale of Barnard et al. (1976), which ranges from 1 to 10, was used and this was calibrated against other thermal maturation indices, namely temperature and vitrinite reflectance (Figure 2-2). In the southern part of the Karoo Basin, spore colour indices in shales of the Ecca Group were all estimated at 9, which correspond to the dry gas generation stage (Figure 2-2). Dolerite intrusions have resulted in an increase in the spore colour index from adjacent shales with thicker sills resulting in indices of 10 corresponding to the metagenesis/metamorphic transition (Figure 2-2).

Gas can be trapped in the shales in three ways (Internet, 2011): 1) within pore spaces of the shale; 2) within vertical fractures in the shale: and 3) adsorbed onto mineral grains and organic matter. Most gas that has been recovered by means of hydraulic fracturing is from the pore spaces (Internet, 2011). Gas is definitely present in shales of the Ecca Group and, to a lesser extent the Dwyka Group as shown by several recorded natural gas occurrences (Krol and Weinert, 1966) and the release of varying amounts of gas from the desorbed gas analyses of Soekor (Rowsell and De Swardt, 1976). The deep drilling programme of Soekor between 1965 and 1977 intersected numerous low volume, high pressure gas pockets, predominantly in fractured shale of the Ecca Group (Van Vuuren et al., 1998). Methane was the predominant gas in the Soekor boreholes south of about 30°S, but north of this latitude in boreholes LA1/68, WI1/72 and GL1/67, it formed less than 10 percent of the total gas measured and occurred in fractured shale close to dolerite intrusions. The Krol and Weinert (Krol and Weinert, 1966) data was obtained from surface springs and boreholes and shows variable proportions of methane in Ecca Group shales and Dwyka Group diamictite and shales with higher values (> 60 percent) normally occurring in shale in close proximity to dolerite, possibly due to fracture porosity trapping the gas, the fractures being caused by the heating effects of the dolerite on the adjacent shale (Rowsell and De Swardt, 1976). Gas from the desorbed gas analyses could represent either gases generated *in situ* or those which have migrated. Soekor's measurements gave variable but low quantities of gas generated from samples of the Ecca Group shales. The lowest average quantity was 0.185 ml/kg from samples of Ecca Group shale in borehole KD1/71 west of Carnarvon and the highest average quantity was 16.83 ml/kg from core samples of Fort Brown Formation (Upper Ecca Group) shale between depths of 2148 and 3645 metres in borehole CR1/68, 75 km southeast of Graaff-Reinet (Rowsell and De Swardt, 1976).

3.2.1 Whitehill Formation

The Whitehill Formation contains the highest total organic carbon contents and presumably has the highest potential for generating dry gas. In the southern part of the basin, values of between 3 and 7 percent have been measured (Rowsell and De Swardt, 1976), but in one deep borehole, QU1/65, a maximum of 14.8 percent was obtained (Cole and McLachlan, 1994). In the Hopetown-Hertzogville region between latitudes 28°S and 29°30'S, an average total organic content of 3 percent with a maximum of 14.7 percent was obtained (Cole and McLachlan, 1994). The shales are thickest (> 30 m) in the south-central part of the basin, but pinch out northeast of a line from Hertzogville to Coffee Bay

(Figure 3-4). Depocentres with up to 72 metres of strata are present near Calvinia, Laingsburg and Graaff-Reinet. However, it is relatively thin compared with the producing Barnett Shale (15-300 m; (Report, 2005)) and the Marcellus Shale (12-270 m; (Internet, 2011)) in the United States. A depth to the top of the Whitehill Formation map shows that it is only deeper than the minimum proposed depth of 1500 metres for hydraulic fracturing (Internet, 2010) in the southern and southeastern part of the basin (Figure 3-5). Dolerites commonly intrude the Whitehill Formation (Figure 3-6-Figure 3-8) (Cole and McLachlan, 1994) and have thermally-destroyed the gas-generating potential of the adjacent shale by transforming the organic carbon to carbon dioxide, methane and graphite (Svensen et al., 2007). The Early Jurassic dolerite intrusives form sill and ring-like structures, which are generally saucer-shaped with an inner sill at the bottom, an arcuate inclined sheet on the periphery, and an outer sill on the rim (Chevallier and Woodford, 1999). The sills and inclined sheets range in thickness from a few metres to 200 metres and the dykes are normally between 2 and 10 metres wide and 5-30 kilometres long, but can be up to 80 kilometres (Duncan and Marsh, 2006). An isopach map of dolerite within and/or adjacent to the Whitehill Formation is shown in Figure 3-9. Dolerites exceeding 100 metres in thickness occur in the Aliwal North area and in excess of 50 metres in the regions of Calvinia, Britstown and northeast of Kimberley. The percentage of dolerite in the Whitehill Formation is shown in Figure 3-10 with over 75 percent dolerite being present in the Aliwal North and Britstown regions and over 50 percent in the regions of Calvinia and northeast of Kimberley. The width of destruction of the organic carbon in the shale is variable with some authors estimating only a quarter of the sill thickness and others twice the thickness (Rowsell and De Swardt, 1976, Cole and McLachlan, 1994). Thicker sills result in a proportionally-thicker zone of destruction, as shown in a deep borehole east of Calvinia where an 83 m-thick sill beneath the 72 m-thick Whitehill Formation has significantly reduced the organic carbon resulting in the formation of graphite (Svensen et al., 2007). It is therefore likely that in areas with greater than 50 percent dolerite, the Whitehill Formation no longer has a potential to generate dry gas. This eliminates the Aliwal North region from the southern and southeastern part of the basin where the depth to the top of the Whitehill Formation is greater than 1500 metres (Figure 3-5). The most promising area to source gas from the Whitehill Formation is south of the southern limit of dolerite intrusion, but north of the Cape Fold Belt (~ 30 km north of the southernmost exposures (Figure 3-10)), where the shales tend to be overmature and graphitic. A few small (~ 10 km^2) dolerite-free areas covering the Whitehill Formation are present in the greater part of the Karoo Basin intruded by dolerite (Cole and McLachlan, 1994). These areas are probably located between adjacent dolerite sill and ring-like structures, but thin sills are commonly present in the overlying Tierberg or underlying Prince Albert Formations (Figure 3-8).

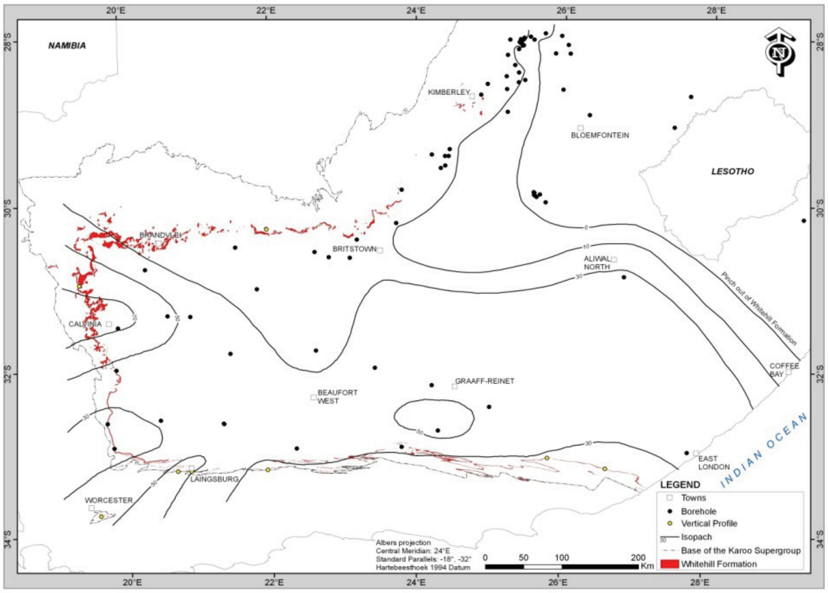

Figure 3-4 Distribution and shale isopach map of the Whitehill Formation in the main Karoo Basin. Surface exposure of the Whitehill Formation is shown.

3.2.2 Lower Ecca Group

The Lower Ecca Group comprises a Prince Albert Formation southwest of a line from Hertzogville to Coffee Bay and a Pietermaritzburg Formation northeast of this line, but separated by a block of dark grey shale in a wedge-shaped area between Bloemfontein and Coffee Bay (Figure 3-2 and Figure 3-3; (Johnson et al., 2006)). Total organic carbon in the Prince Albert Formation varies between 0.35 and 12.4 percent with an average of 2.4 percent, whereas that in the Pietermaritzburg Formation averages 2 to 3 percent (Cole and McLachlan, 1994, Rowsell and Connan, 1979). An isopach map of the shale was compiled after removing dolerite and minor sandstone beds (Figure 3-11). It is thickest (200-497 m) east of Lesotho and in a southeast-trending zone from Brandvlei to Graaff-Reinet and is over 100 metres thick south of about latitude 29°S (Figure 3-11). These thicknesses are comparable with the producing Barnett Shale (15-300 m; (Report, 2005)) and Marcellus Shale (12-270 m; (Internet, 2011)). A depth to the top of the Lower Ecca Group map shows that it is deeper than the minimum proposed depth of 1500 metres for hydraulic fracturing (Internet, 2010) southeast of a line from Ficksburg to north of Laingsburg (Figure 3-12). Dolerites intrude the Lower Ecca Group (Figure 3-6 and Figure 3-7) and have thermally-destroyed the gas-generating potential of the adjacent shale as described above. Dolerites with composite thicknesses exceeding 100 metres occur beneath southern Lesotho and adjacent parts of South Africa and between Calvinia and Brandvlei (Figure 3-13). A maximum composite dolerite thickness of 261 metres was recorded in borehole SW1/67, east of Lesotho. The percentage of dolerite in the Lower Ecca Group is shown in Figure 3-14 with over 40 percent dolerite being present in an area centred on Aliwal North and in a smaller area east of Calvinia. However, proportionally, the ratio of dolerite to shale is significantly less than that for the Whitehill Formation, where several areas have a percentage dolerite exceeding 50 percent (Figure 3-10). Compared with the Whitehill Formation, the width of destruction of the organic carbon in the shale varies between a quarter of the sill thickness and twice the thickness (Rowsell and De Swardt, 1976, Cole and McLachlan, 1994). In a borehole east of Calvinia, the organic carbon in 70 metres of shale of the Prince Albert Formation overlaid and underlain by dolerites 83 metres and 112 metres thick respectively, has been completely destroyed (Svensen et al., 2007). It is probable that the destructive effect of dolerite on the shale occurs for a distance of at least the thickness of the sill. Despite the Lower Ecca Group containing more than 40 percent dolerite in some areas, a small portion of the shale will most likely have a potential to generate dry gas. In the region southeast of a line from Ficksburg to north of Laingsburg, where the top of the Lower Ecca Group is deeper than the minimum proposed depth of 1500 metres for hydraulic fracturing (Internet, 2010), shale having the best potential for dry gas lies in an east-trending zone between 30 km north of the southernmost exposures and 50 km north of the southern limit of dolerite intrusion (Figure 3-12 and Figure 3-14).

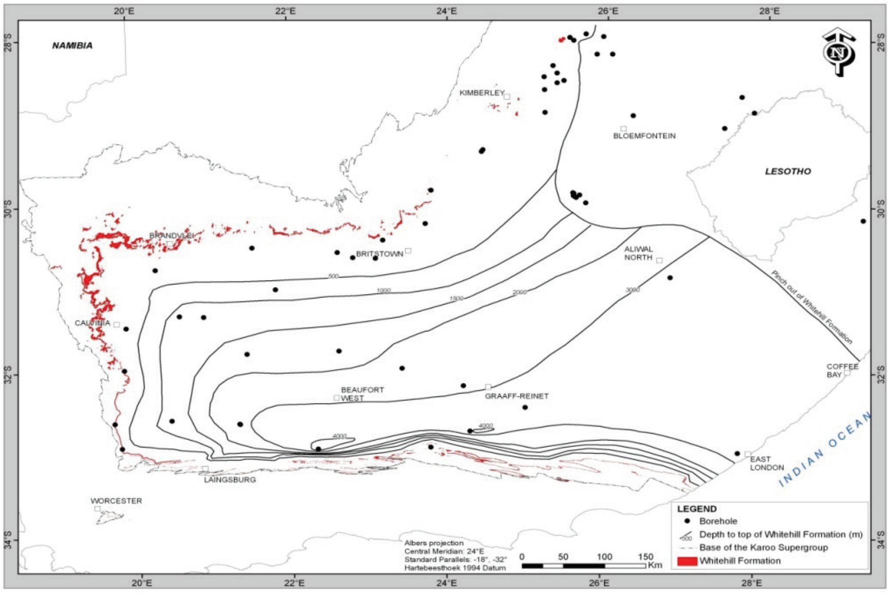

Figure 3-5 Map showing depth to top of Whitehill Formation in the main Karoo Basin. Surface exposure of the Whitehill Formation is shown.

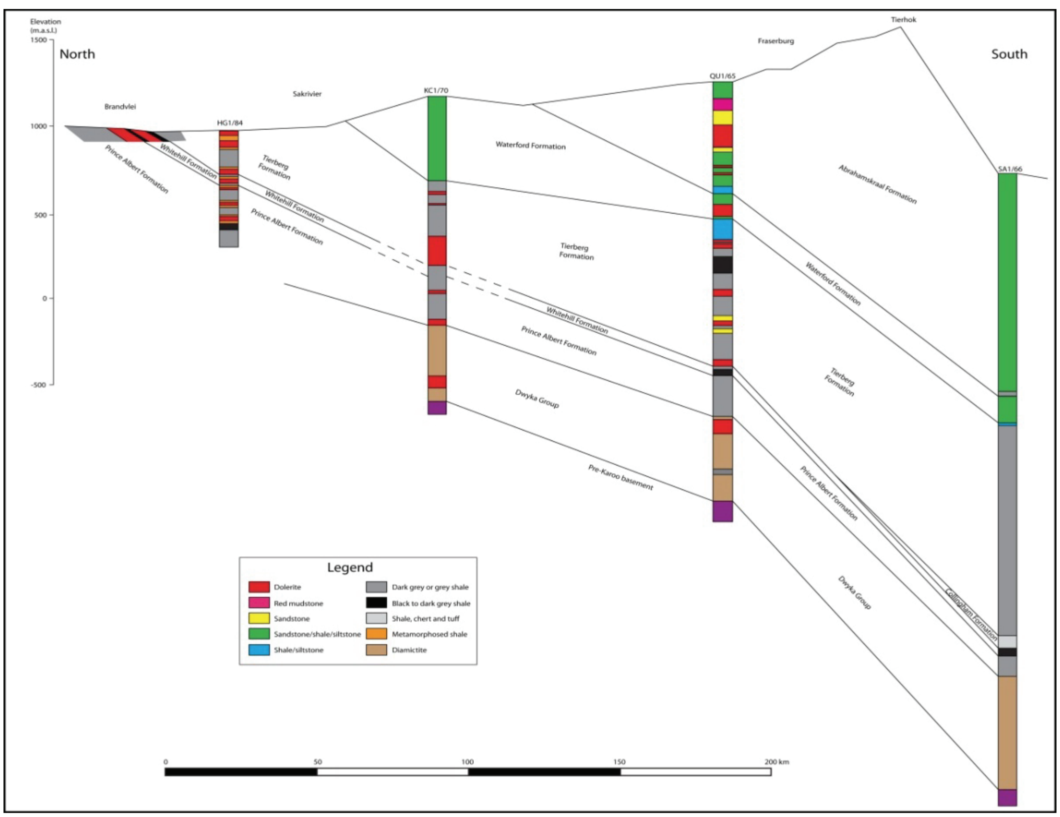

Figure 3-6 North-south cross-section across Beaufort, Ecca and Dwyka Groups in western part of main Karoo Basin using the logs of four deep boreholes. Cross-section shows lithology, including younger dolerite, stratigraphy and exposures of Whitehill Formation and dolerite near Brandvlei.

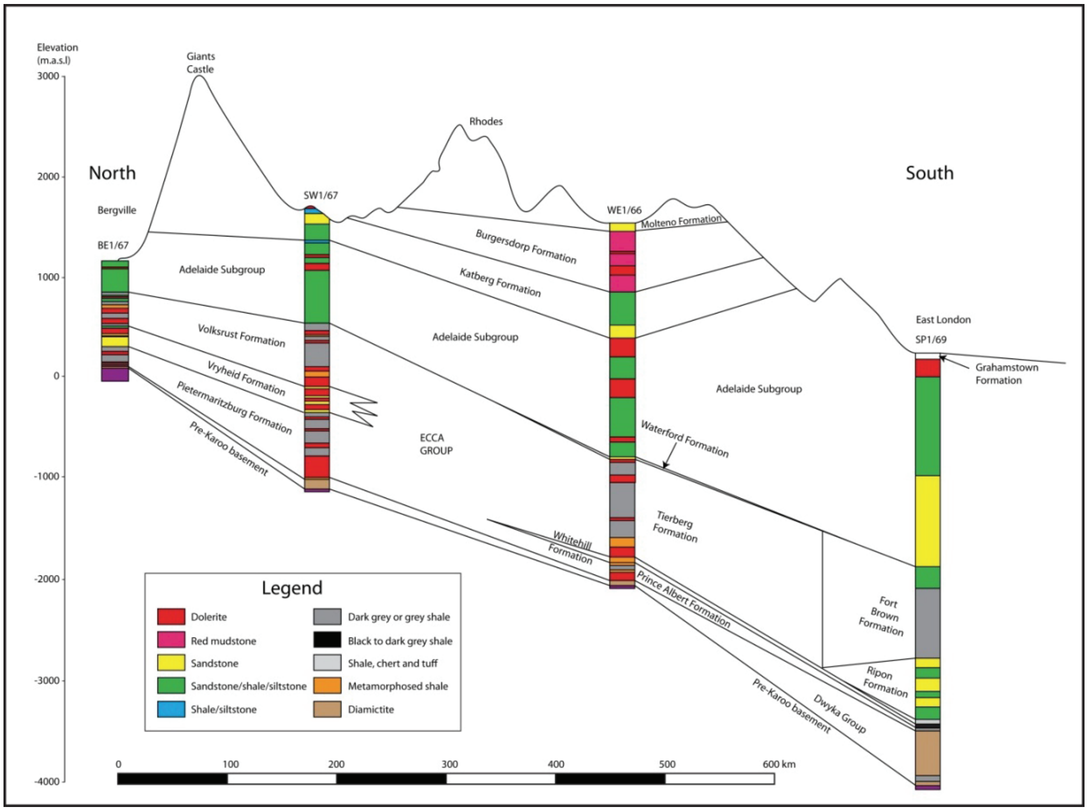

Figure 3-7 North-south cross-section across Beaufort, Ecca and Dwyka Groups in eastern part of main Karoo Basin using the logs of four deep boreholes. Cross-section shows lithology, including younger dolerite, and stratigraphy.

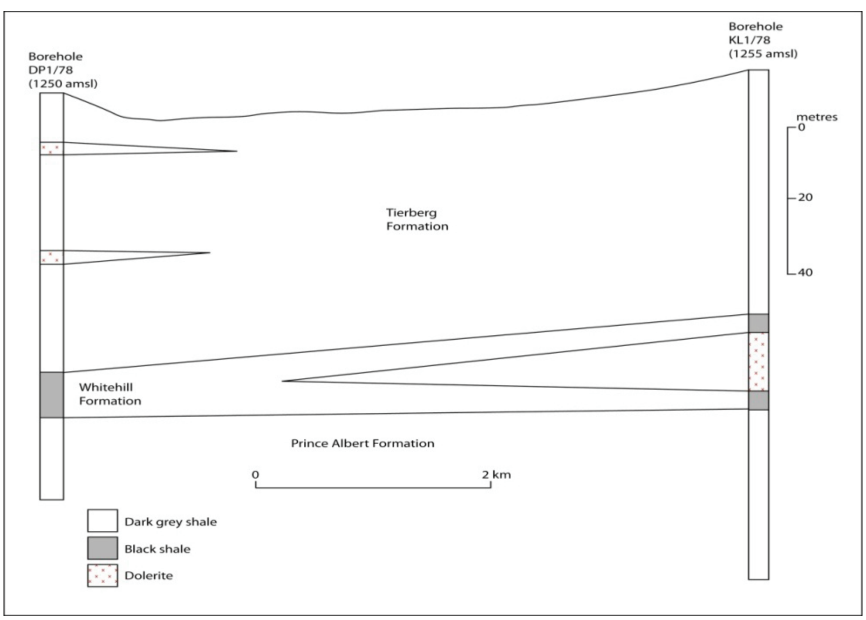

Figure 3-8 Cross-section between boreholes DP1/78 and KL1/78 some 75 km southwest of Kimberley showing localised pinch-out of an extensive dolerite sill in the Whitehill Formation.

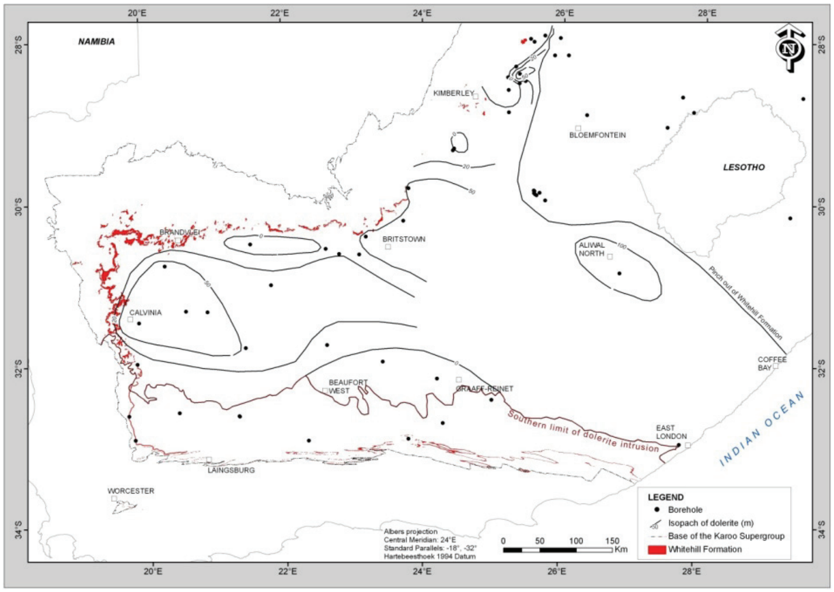

Figure 3-9 Isopach map of dolerite thickness within and adjacent to the Whitehill Formation in the main Karoo Basin. The southern limit of dolerite intrusions in the basin is shown.

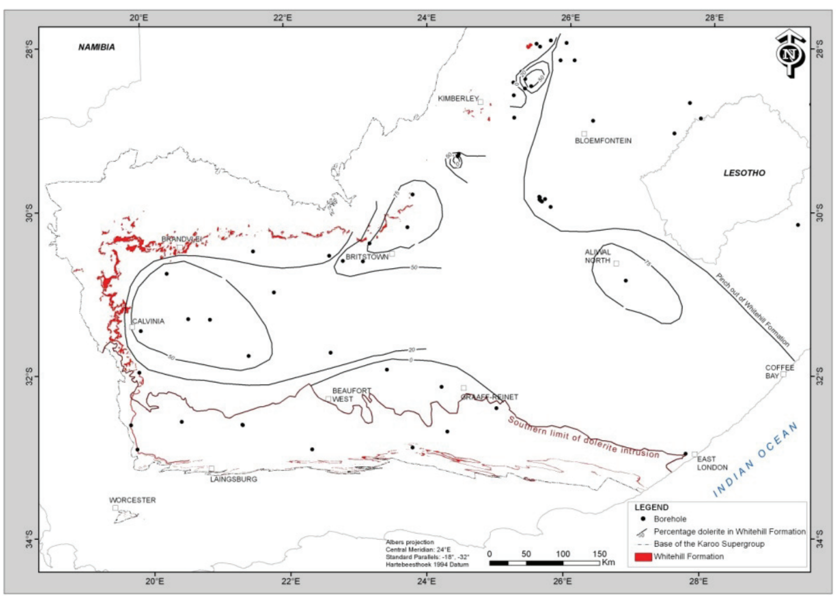

Figure 3-10 Percentage dolerite map within and adjacent to the Whitehill Formation in the main Karoo Basin. The southern limit of dolerite intrusions in the basin is shown.

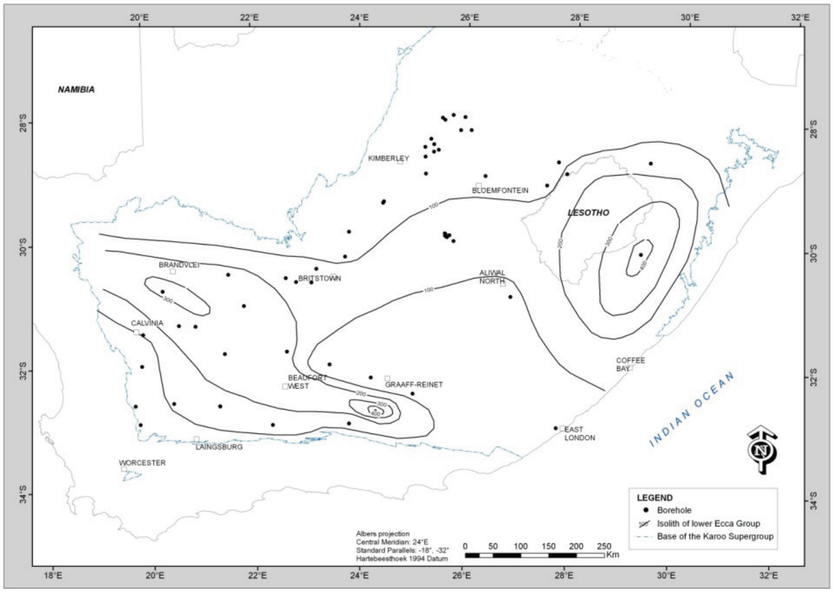

Figure 3-11 Distribution and shale isolith map of the Lower Ecca Group, here represented by the Prince Albert and Pietermaritzburg Formations, in the main Karoo Basin.

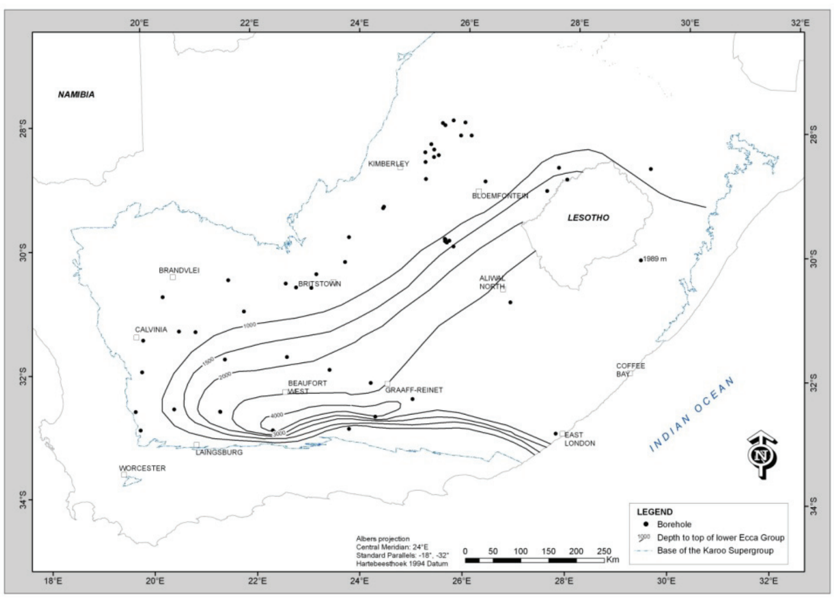

Figure 3-12 Map showing depth to top of Lower Ecca Group, here represented by the Prince Albert and Pietermaritzburg Formations, in the main Karoo Basin.

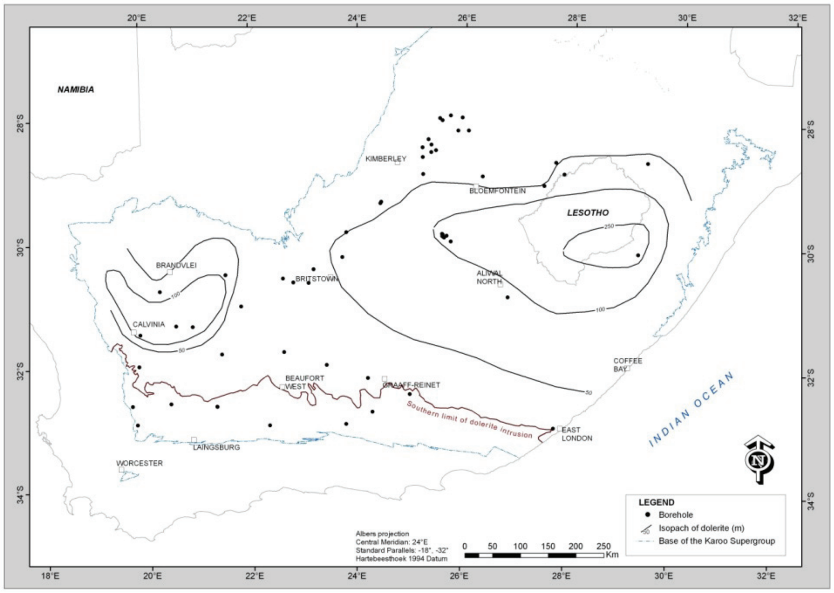

Figure 3-13 Isopach map of dolerite thickness within the Lower Ecca Group in the main Karoo Basin. The southern limit of dolerite intrusions in the basin is shown.

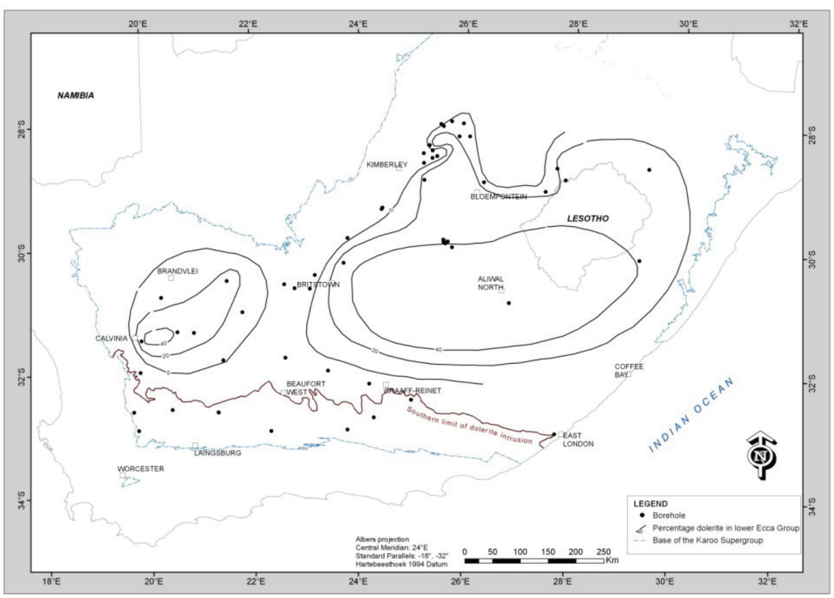

Figure 3-14 Percentage dolerite map within the Lower Ecca Group in the main Karoo Basin. The southern limit of dolerite intrusions in the basin is shown.

3.3 Geological Factors Affecting Hydraulic Fracturing

3.3.1 Role of sediment lithology on fracture, fluid and gas migration

3.3.1.1 Fracture migration

Hydraulic fracturing typically happens at depths greater than 1500 m for the recovery process to be efficient. This overlying 1.5 km generates a considerable amount of vertical pressure. The likelihood of a vertical fracture generated by a perforation power source (done with a gun barrel and calculated to only propagate a few or ten of metres in the formation) extending to the upper part of the succession is very unlikely. Out of the 15000 hydraulic fracturing wells drilled in Texas for the past 10 years, no such incident has ever been reported. After perforation, hydraulic fracturing will open the fractures and increase the propagation. Once again the pressure used for injection exceeds the combined lithostatic pressure and cohesive strength of the formation. The lithostatic pressure is nearly equivalent to the downward pressure exerted by the total formation column above the hydraulic fracturing point.

3.3.1.2 Potential hydraulic fluid migration due to hydraulic fracturing

The stack of sedimentary strata above the targeted formation in the Karoo consists of a succession of shale, mudrock, sandstone and dolerite. Each of these rock-types are generally characterised by low matrix transmissivities / permeability (between 0.5 and 50 m^2/day) (Dondo et al., 2010a). These values were obtained from pump tests carried out on Karoo aquifers less than 200 m deep. Matrix transmissivities at greater depth would therefore be expected to be even less than these values. Dolerite matrix has also been found to be quite impermeable (Rowsell and Connan, 1979).

Under such conditions, migration of hydraulic fluid is most likely going to be considerably retarded. Deep hydrogeological investigations and groundwater modelling will have to be completed during the initial exploration step into shale gas, in order to prevent such problems being encountered.

3.3.1.3 Gas leakage

Possible contamination of drinking groundwater associated with shale gas extraction has been reported from the Marcellus shale, in Pennsylvania, USA (Osborn et al., 2011, Revesz et al., 2010). These methane concentrations have been found to be substantially higher close to gas-wells (between a few hundred meters and 1 km) than the regional natural concentration. These contaminations are more likely to be due to leakages related to the construction of the boreholes than to seepage through the shales. Strong regulations have been put in place by the State authorities to prevent such a problem from reoccurring.

The targeted sources in the Karoo are overlaid by very thick and tight shale deposits, such as the Tierberg Formation, up to 800 m thick that would prevent any natural gas from escaping. Caution should; however, be taken especially since other artificial routes can be created for the gas to escape, e.g. along the dolerite dyke and sill systems.

3.3.2 Drilling in a dolerite sill environment

3.3.2.1 Dolerite sill/ring complexes and ground water

Many of the areas where the shale formations have the potential to represent a good prospective target for exploration are also characterised by multiple dolerite intrusions. Drilling in a dolerite sill environment will face challenges that can be overcome if sufficient investigation is carried out on these intrusive structures at depth. There is sparse information on the structure of deep dolerite sills and associated deep groundwater and water strikes in the Karoo lithostratigraphic formations. All available data comes from groundwater exploration drilling at shallow to medium depth (< 300 m).

Several Water Research Commission projects (Botha and Cloot, 2004, Botha et al., 1998, Chevallier et al., 2001, Chevallier et al., 2004a, Chevallier et al., 2004b, Chevallier and Woodford, 1999, Woodford and Chevallier, 2002, Nhleko, 2008) have shown that flat fractures associated with lithological contacts or dolerite sills are rewarding targets for groundwater exploration in the Karoo in term of strikes and yields. The Department of Water Affairs and Forestry (now called DWA) drilled many exploration percussion rotary boreholes on dolerite structures between 1979 and 2004. Boreholes could be drilled to a maximum depth of 300 metres, which was the technical limit of the drilling rigs. Several groundwater strikes were intercepted at that depth. Below this depth, the presence of deep water strikes in the Karoo formations and associated dolerite, their yields and the composition of the water are still a matter of debate.

A Water Research Commission project was undertaken at the Qoqodala dolerite ring system, which has intruded the Early Triassic Burgersdorp Formation (Beaufort Group), in the Great Kei catchment, northeast of Queenstown, Eastern Cape, in order to investigate the water flow associated with a sill/ring complex (Figure 3-15) (Chevallier et al., 2004a). The aim of the project was to test the hydromorphostructural model (saucer-shaped intrusion) of dolerite rings established by Chevallier (Chevallier et al., 2001).

Exploration drilling was located across the southern rim of the Qoqodala dolerite ring complex (Figure 3-16). The Department of Water Affairs (DWA) drilled a total of 12 exploration percussion rotary boreholes between March 2002 and June 2003 leading to a total drilling depth of 2655 metres for the 12 boreholes (shown in Figures 3-17 and 3-18).

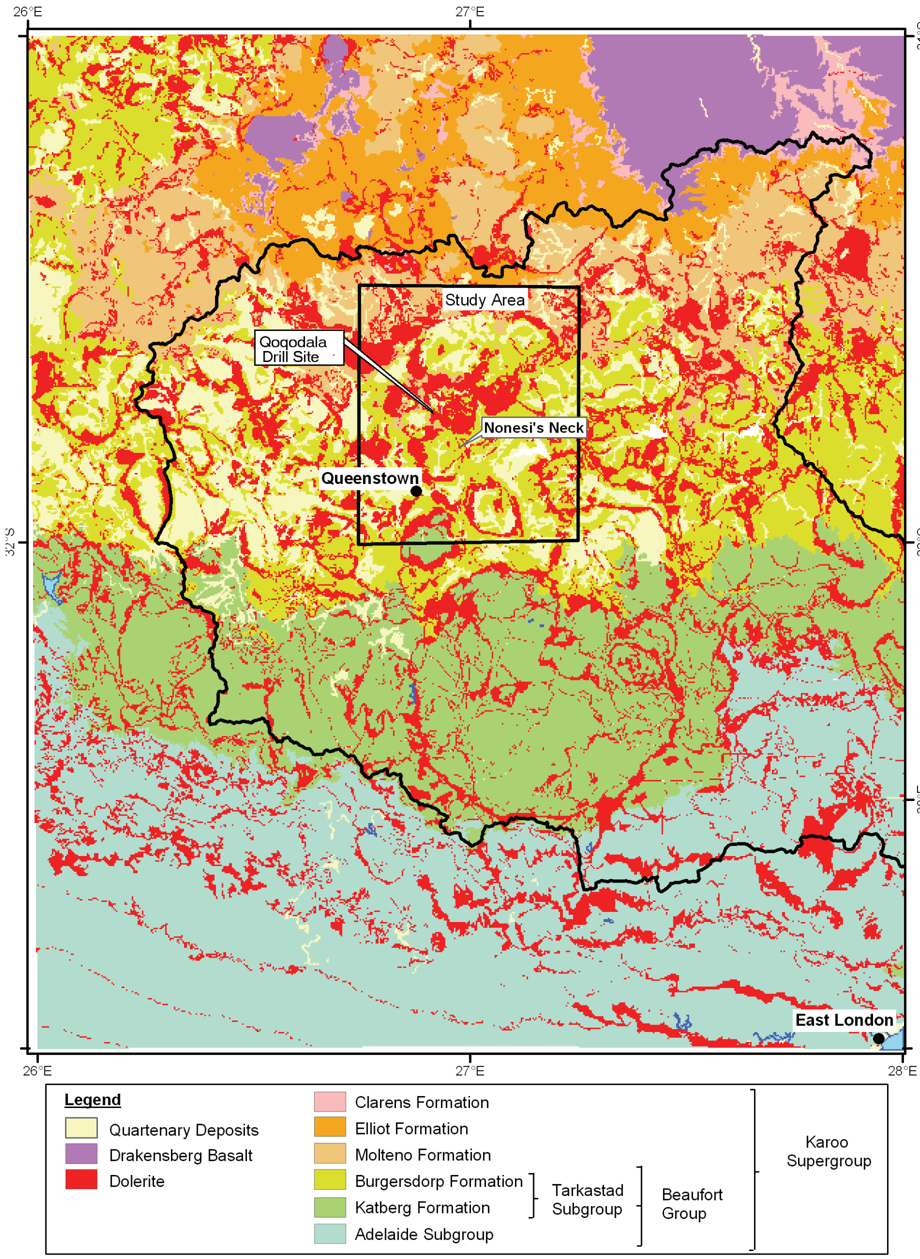

Figure 3-15 General Geology of the Great Kei Catchment showing the dolerite sills and rings and the location of the Qoqodala ring complex selected for exploration drilling (Chevallier et al., 2001).

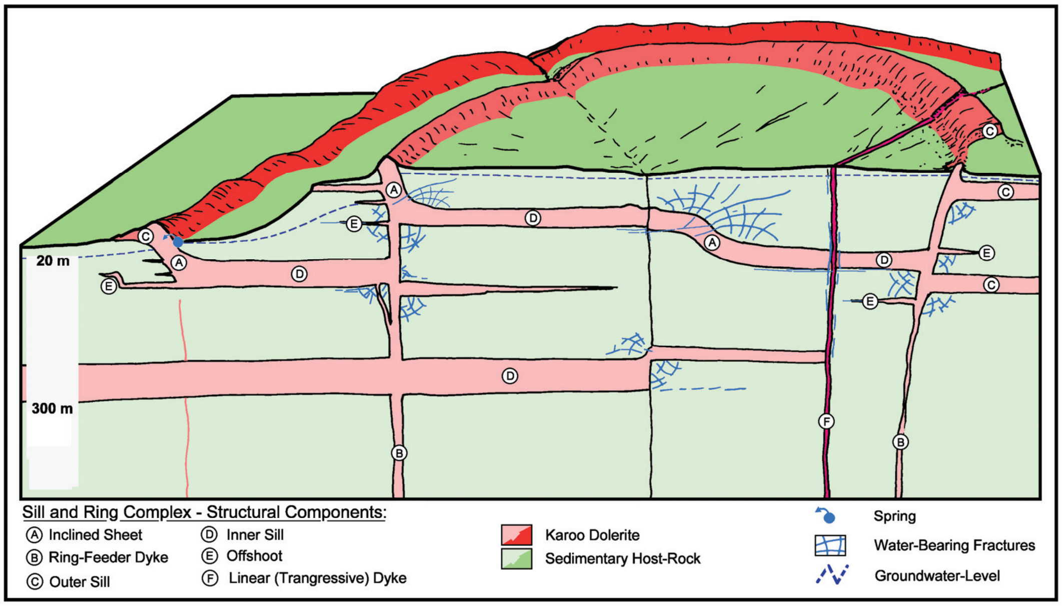

Figure 3-16 Hydro-morpho-tectonic model of Karoo dolerite sill and ring complexes (Chevallier et al., 2001) showing the saucer-shape and complexity of the dolerite plumbing system and associated fractured aquifers.

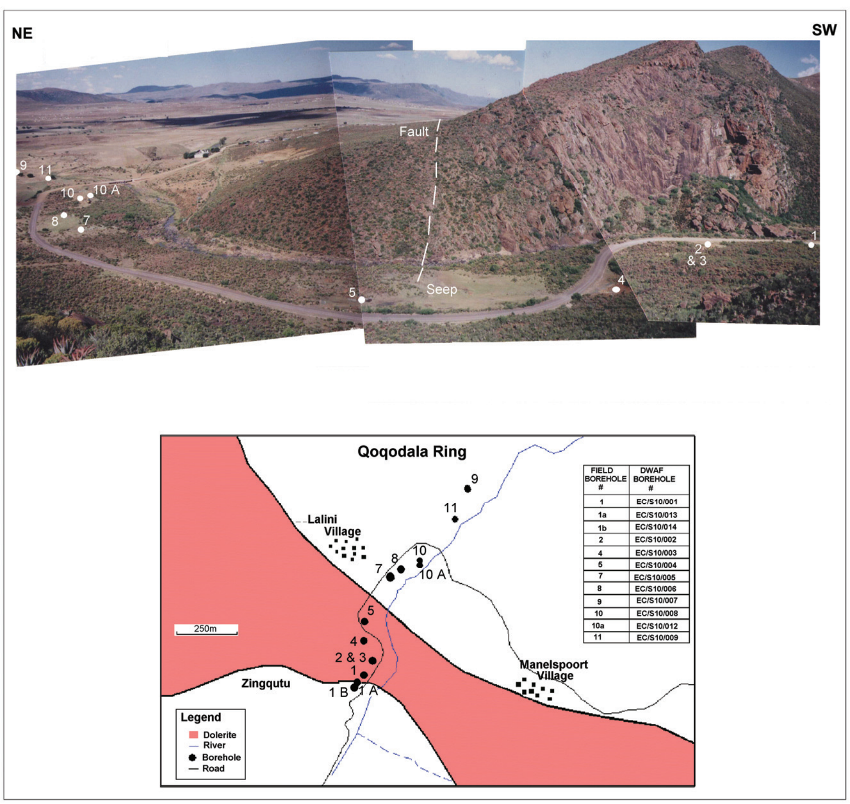

Figure 3-17 The Qoqodala exploration drilling site. The 1.5 km-long profile straddles the inclined dolerite sheet. 12 exploration boreholes were drilled across the structure.

The cross section shown in Figure 3-18 was compiled from geological logging, video camera data, geophysical logging and completed by a Time Domain Electromagnetic survey (TDEM), especially for deep structure detection. The profile shows a very thick dolerite inclined sheet linking different sills. The back of the inclined sheet between the two upper sills is structurally very complex with several dolerite offshoots and water strikes. A major sandstone bar with interbedded shale has been displaced by the inclined intrusion. Water strikes and fractures mainly occur at lithological contacts (dolerite contacts or sandstone contacts). The sandstone seems to be the most water saturated lithological unit, and the video camera recording showed it to be the most fractured.

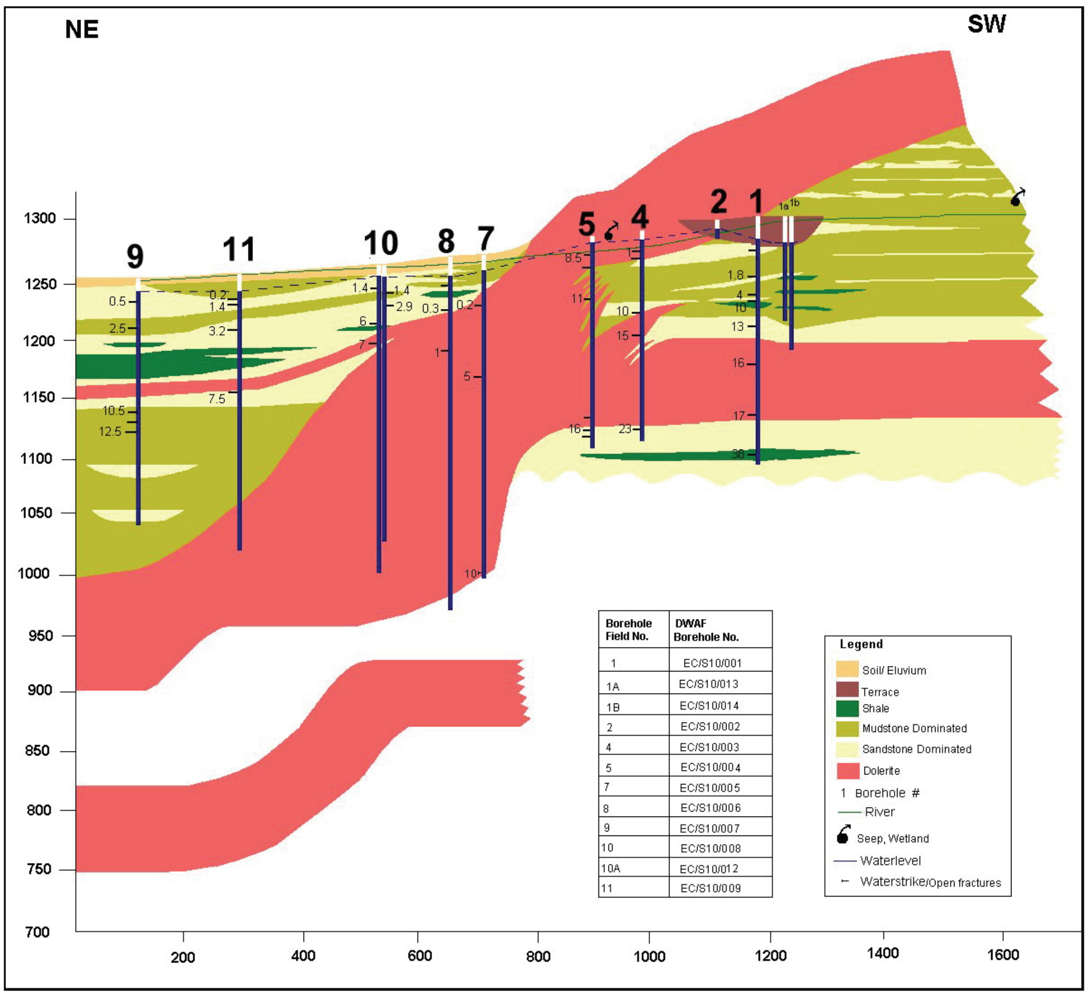

Figure 3-18 Geohydrological profile at Qoqodala exploration drilling site. Water strikes and fractures are present at lithological contacts.

The top fractured-rock aquifer lies between -20 and -60 m. Water movement within this aquifer has been seen from a video camera in borehole 1, where the water disappears into a horizontal fracture at a depth of 54 m. A series of water-bearing fractures occur at different depths below and at the base of the sills. The deepest aquifer (250 m depth) occurs at the bottom of the Qoqodala sill / inclined sheet. It has been intercepted by borehole 7. At the bottom of the hole the water is turbid and could be coming out of a fracture. The water is warm (24°C) and is moving up the borehole. Boreholes drilled into the upper aquifer unit generally strike a relatively large number of low-yielding water interceptions, whereas infrequent, discrete, higher yielding water interceptions are typical of the deeper aquifer units.

Drilling of the exploration boreholes BH-1, -4, -5, -7 and BH-8 resulted in an artificial connection between the various aquifer units. It is postulated that the drilling of BH-1, -4 and BH-5 resulted in a downward flow of groundwater.

The Qoqodala site shows that the Karoo aquifers in the dolerite sill/ring environment are compartmentalised and multifractured aquifers, at least down to 250 m. Several water strikes can be intercepted during drilling and artificial connection between aquifers can be created. If drilling occurs in a dolerite sill environmental, strict precautions should be taken to avoid the creation of an artificial "plumbing system" from one borehole to the other and loss of shallow groundwater into deep fracture systems. This would then indicate that good borehole construction and testing methods should be used.

3.3.2.2 Hydraulic injection tests along shallow dolerite sills (< 300 m)

The Qoqodala exploration site has been used to test the groundwater movement around dolerite intrusions. Injection-type tests were conducted on borehole BH-1 using the Department of Water Affairs' hydraulic-fracture rig. The objectives of the tests were to gain information on the fracture connectivity and flow dynamics within the zone of intersection of the inclined sheet and outer-sill. Digital water level recorders were initially inserted in BH5 and BH7, as well as in borehole BH1B. Water levels in the remaining observation boreholes were collected by hand throughout the testing programme. In BH1, the packer was set at 139.50 m for both injections. Note that in all cases, the water was injected below the packer and the injection varied from 5 to 60 bars depending upon the transmissivity and degree of connectivity of the fractures being tested.

During injection tests in borehole BH1, the piezometric levels in BH5 and BH7, situated 300 and 483 metres away, rose by 0.40 and 0.04 m, respectively (Figure 3-19 and Figure 3-20). This confirms the continuity of this fracture system at the base of the sill and inclined sheet, since it extends from BH1 through to BH4, BH5 and BH7. The water level in borehole BH1B, situated some 57 metres away from BH1, did not respond to the injection tests as it does not penetrate the fracture system at the base of the outer sill. This indicates that the two aquifers (namely top fractured and below the sill) are not connected – although as already mentioned an 'artificial' hydraulic connection has been created via BH4 and BH5.

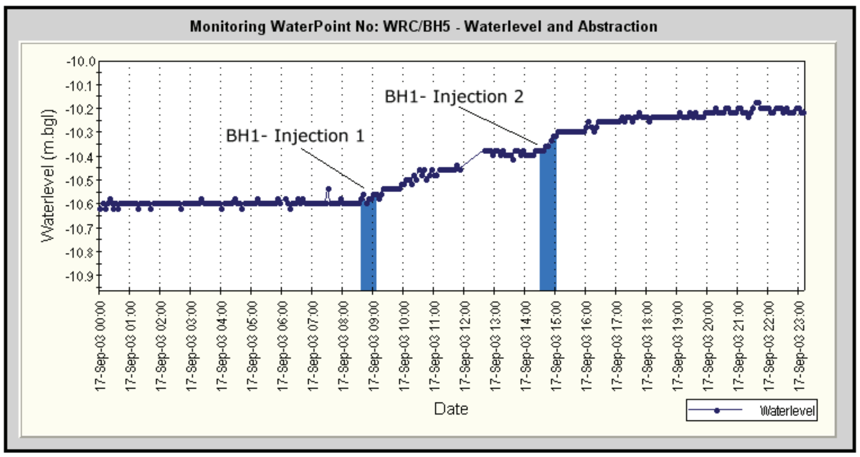

Figure 3-19 Waterlevel response in BH5 due to injection in BH1.

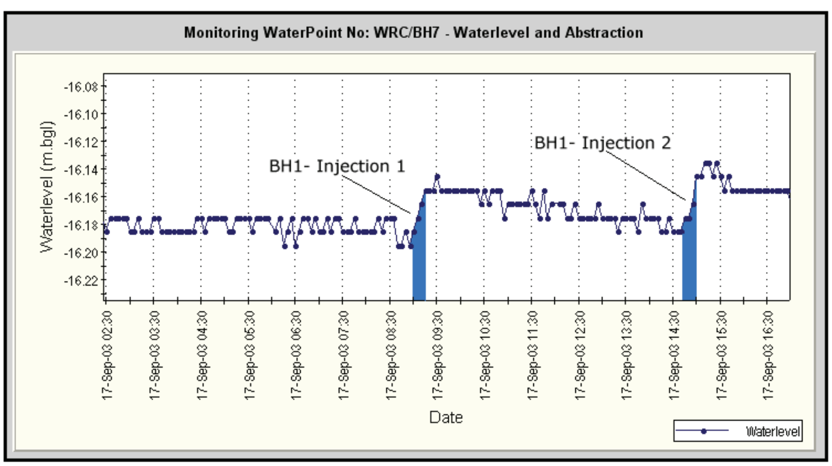

Figure 3-20 Waterlevel response in BH7 due to injection in BH1.

The tests show that open fractures can extend for hundreds of meters at the base of dolerite sills, at least to a depth of 250 meter. These semi-deep aquifers are confined and not linked to the shallow fractured aquifers. However vertical and horizontal drilling can create artificial connections between these aquifers and leaking of hydraulic fluid or gas.

3.4 Horizontal drilling in a dolerite dyke and fault environment

3.4.1 Dolerite dykes

Horizontal drilling for hydraulic fracturing can be done over few kilometres and might therefore intercept a dolerite dyke. A regional hydrogeological investigation of the Karoo dykes has been undertaken by the Water Research Commission (Woodford and Chevallier, 2002, Woodford and Chaevallier, 2002). The Karoo basin is intruded by a network of dolerites that appear to be dense at the regional scale (Figure 3-21). At lower scales, the spacing is often around 1 km and the connectivity is therefore very low. The majority of dolerite dykes range from 3 to 15 m in thickness. Long dykes (500 km to 800 km) can be very thick. The E-W dyke north of Victoria West attains a thickness of 65 m in places. Dykes thinner than 3 m, are usually limited in length. Dolerite dyke dips range from vertical to 70°.

Dolerite dykes have been the preferred target for groundwater by many practitioners and farmers. Several WRC projects have been carried out on dolerite dykes (Woodford and Chevallier, 2002, Dondo et al., 2010a) with the support of exploration drilling from the Department of Water Affairs to verify the yield capacity of dolerite dykes and their ability to form preferential conduits.

Many water strikes were typically intercepted at depths down to 70 m. They are found at the contact dyke-sediment and in the sediment away from the dyke (Figure 3-22). Below 70 m very little water strikes were intercepted alongside the dyke.

The situation is however different for dykes that display structural complexity (i.e. off sets, en-échelons, change of shape). Water strikes are found to a depth of 250 metres, which is the maximum depth of the boreholes (Figure 3-23). Most of the strikes are found in the sediment away from the dykes. These water strikes seem to be associated to horizontal or transgressive oblique fractures cross-cutting the dyke and extending into the sediment. These fractures correspond to cooling joints or horizontal offset along t he dykes. Thermal joints have formed in the intrusion, perpendicular to the cooling surface and in the adjacent sediment. The distance along which the country rock is affected by thermal jointing varies from one to a few metres depending on the thickness of the intrusion.

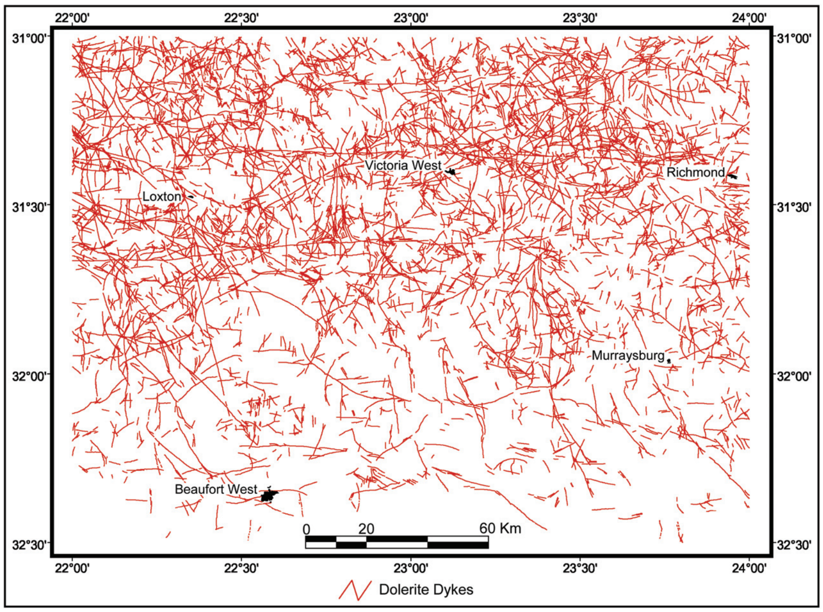

Figure 3-21 The dolerite dykes and associated fractures between Victoria West and Beaufort West. Note the two long E-W regional dykes north and south of Victoria West. (Woodford and Chevallier, 2002, Woodford and Chaevallier, 2002)

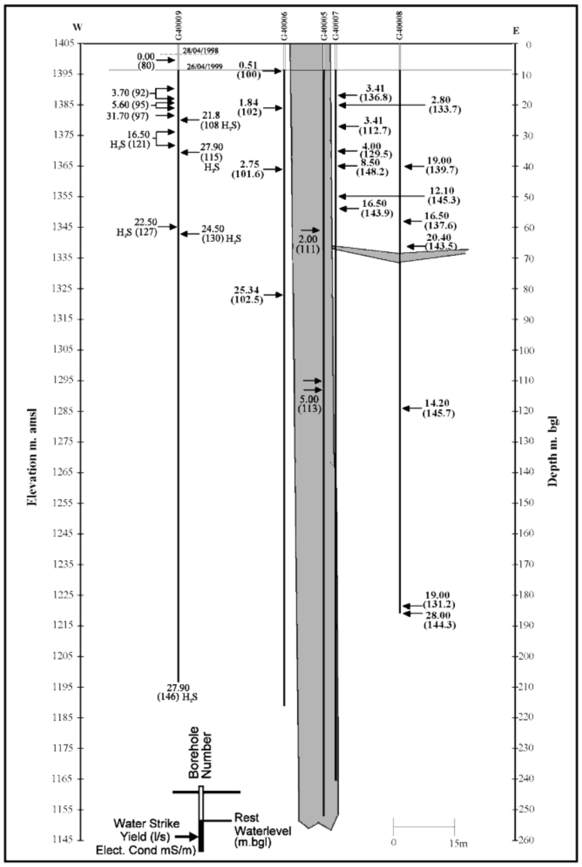

Figure 3-22 Geohydrological profile of a NNW trending dolerite dyke south of Loxton. Many water strikes were intersected in the first 70 m in the sediment and at the dyke-sediment contact. Below 70 m no water strikes were intersected alongside the dykes. (Woodford and Chevallier, 2002)

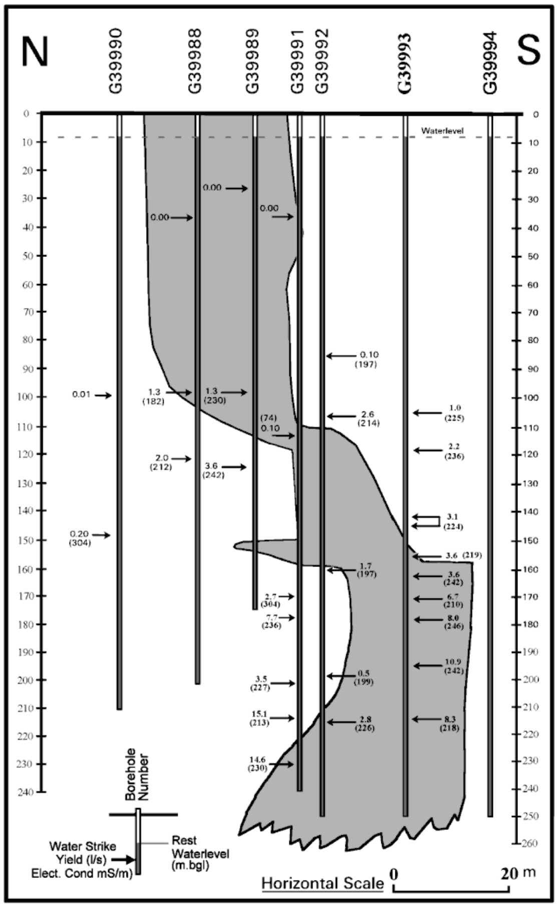

Figure 3-23 Geohydrological profile of an E-W trending dolerite dyke southwest of Loxton. The water strikes intersected alongside the intrusion are horizontal fractures transgressing from the dyke to the sedimentary rock.

At depths below 300 m no information is available on dolerite dykes, whether they extend down to the basement or whether they are strata bound as a result of lateral propagation (and not vertical) inside the same sedimentary pile. In the latter case they would be rootless.

The key question is: can dykes act as vertical conduits for groundwater flow or hydraulic fluids? From the examples cited above it is clear that many water strikes between 0 and 70 m (i.e. in the weathered zone) are found at the contact dyke-sediment whereas below 70 m less water strikes are found along transgressive fractures. The main mechanism of flow dynamics at depth and around dykes is associated with sub-horizontal fractures. These fractures are not linked to one another and collect water from the matrix. The influence of dolerite dykes on vertical groundwater circulation at depth seems therefore very small. The T-values from different case studies also show that permeability of the dykes is too low to allow for major flow in the dykes themselves. These fractured aquifers are also very confined and will prevent hydraulic fracturing along horizontal drilling to affect or contaminate a whole range of individual fractures, especially if hydraulic fracturing takes place at depths greater than 1500 metres.

3.4.2 Kimberlite fissures

Kimberlite fissures are deep-rooted, being generated at the base of the craton some 30 to 40 km deep and could possibly be intersected by horizontal drilling.

Kimberlite fracture swarms consist of parallel fissures and associated joints or fractures. Each swarm can be divided into sub-swarms of smaller size (Figure 3-24). Within each sub-swarm the fissures are always closely spaced (approximately 10 to 50 m apart). The fissures are 0.5 to 4 m wide and often show strong upwarping of the surrounding Karoo beds. In outcrop the Kimberlite intrusion is often inconspicuous and only visible as stringers of highly decomposed Kimberlite (green-ground) or micaceous calcrete (yellow ground). Fresh hypabyssal Kimberlite is usually encountered after drilling through 12 to 60 m of weathered zone. Parallel regional jointing often accompanies the fissures.

The fact that swarms can be subdivided into sub-swarms points to a vertical hierarchy within the fracturing system at depth, i.e. fissures, dykes, parental dykes and larger bodies. Kimberlite areas should therefore be considered in any exploration drilling.

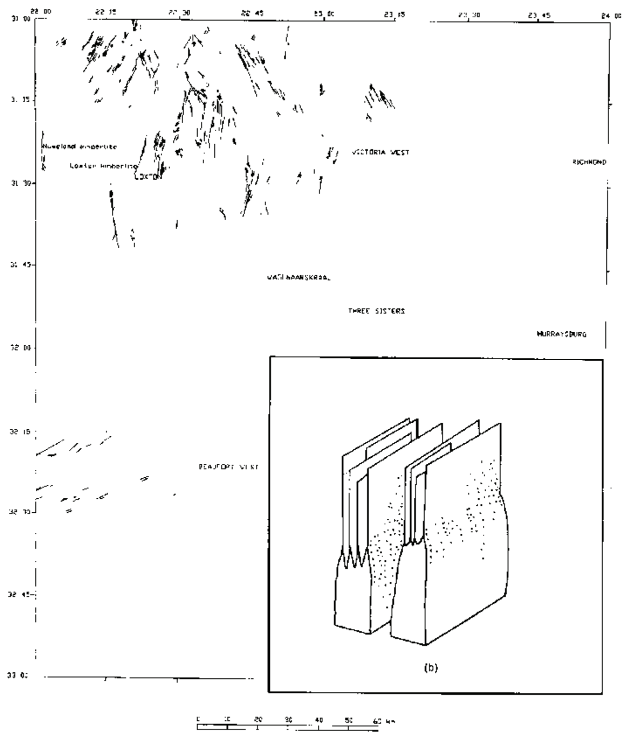

Figure 3-24 Kimberlite Swarms and Sub-Swarms of (a) the Victoria West-Beaufort West area (b) proposed Vertical Geometry of a swarm (Woodford and Chevallier, 2002).

3.4.3 Geological Faults

A casual observation of the 1:250 000-scale geological maps produced by the Council for Geoscience, South Africa, indicate that faults with strike lengths of more than 5 km, commonly intersect the Karoo strata in the region of the main Karoo Basin south of latitude 32° 45’ (Hill, 1993). A seismic profile between Prince Albert and Fraserberg (south of the dolerite line) shows that at depth these faults are listric thrusts associated with the development of the Cape Fault Belt (Lindeque et al., 2007). These faults could play an important role in deep groundwater circulation and migration of hydraulic fluid (Figure 3-25).

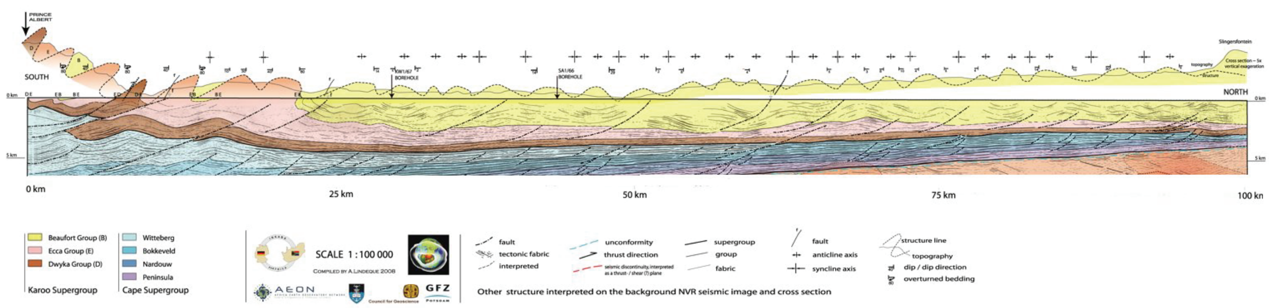

Figure 3-25 Seismic profile across the Southern Karoo, from Prince Albert to Fraserberg, showing the deeply rooted listric thrusts (down to 5 km) associated with the development of the Cape Fault Belt (Lindeque, 2008)

North of the dolerite line most of the faults present are mainly associated with dolerite. Here, sills have caused uplift of the sedimentary rocks and the displacement is usually closely associated with the thickness of a specific sill. There is however evidence that some of the dolerite dykes could be associated with pre-existed faults, which provided passages for the dolerite intrusions (Hill, 1993).

3.5 Deep water-bearing systems and shale gas (< 600 m)

Knowledge and information on deep water-bearing (aquifer) systems in the Karoo Basin is limited to the warm water springs in the main Karoo Basin. There are about 16 naturally-occurring warm water (thermal) springs (26-41°C) in the main Karoo Basin south of latitude 28 degrees, with a few more occurring further north (Figure 3-26; Kent, 1949). These springs provide evidence of natural connections between "deep groundwater" and the surface. These waters originate at a maximum depth of between 450 m and 1 150 m, as calculated from the geothermal gradient and the surface temperature of the waters (Figure 3-26).

Taking the immense size of the main Karoo Basin into consideration, there is in real terms, very limited natural connection (leakages) between deep circulating and shallow (surface) groundwater. All the waters are according to Kent (Kent, 1949) are originally meteoritic and mainly deviate in composition due to differences in different compositions of the different rock lithologies associated with the spring, indicating also the presence of connate (old) water. The waters of the central and eastern Karoo have NaCl as the prominent constituent with total dissolved solids ranging from 496 mg/l to 754 mg/l. A few springs are, however characterised by high $NaHCO_3$ and SO_4 contents, e.g. Stinkfontein, south of

Beaufort West and the spring at Cradock. Biogenic methane is one of the main gases commonly associated with the hot springs in the main Karoo Basin and in some instances constitutes the only gas present. The other gases present are mainly H_2, N_2, He and Ar.

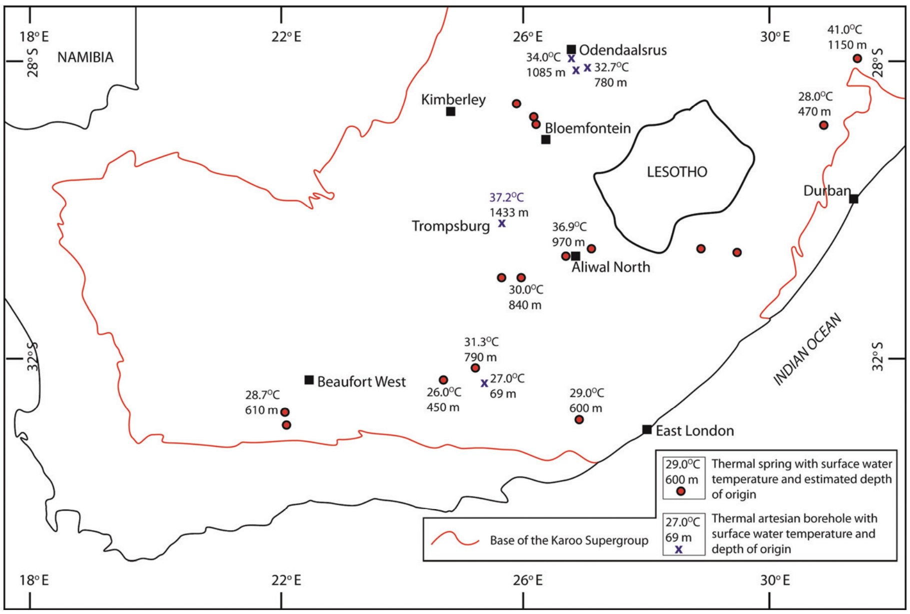

Figure 3-26 Distribution of thermal springs and thermal artesian boreholes in the main Karoo Basin south of latitude 28°S.

Although these deep waters flow as springs to the surface, no known negative contamination of the surface waters are known. In terms of quality, below 1000 m water quality quickly deteriorates due to extensive contact time with geological formations which can be a result of an extended infiltration time or the rate of water movement in the subsurface. Only one site at Aliwal North had a flow of 3821 cubic metres in 24 hours with the others varying between only tens to hundreds of cubic metres in 24 hours (Kent, 1949). A special feature of the Karoo is the presence of dolerite dykes and sills, which significantly reduce the permeability of the formation due to its un-weathered state below 30 to 40 m depth.

Although contamination could be possible, any negative influence of these spring waters on surface water and/or shallow aquifers is apparently very limited and if it does occur it is restricted to a very small area.

3.5.1 *Metal and Radioactive Elements in Shale*

Concerns were also expressed on the mobilization of radioactive elements such as uranium and other elements such as heavy metals derived naturally from the shales during the fracturing process and that could be brought to the surface with the fracturing water. Studies done on the fine-grained sedimentary rocks of the Karoo Supergroup and especially on the formations under discussion, clearly indicates that these shales are not enriched in any of the possible “dangerous” elements (Danchin, 1970, Hofmeyr, 1971, Zawada, 1988, Cole and McLachlan, 1994, Viljoen, 2004). However, further mineral identification would be recommended during the initial exploration and drilling phase for shale gas so that appropriate measures are taken in turns of minimising mobilisation and disposal if present in the backflow fluid.

3.5.2 *Induced seismicity*

Induced seismicity can be caused by hydraulic fracturing. The energy released during hydraulic fracturing can generate earthquakes, most of which are generally only detectable by sensitive seismological instruments (Phillips et al., 1998, Li, 1996).

During hydraulic fracturing experiments (for geothermal purposes) in 2003 by Geodynamics Ltd in Australia, over 2 700 small induced earthquakes were recorded over a period of several weeks. Most of these were less than Magnitude (M) 1.0 and only three of these earthquakes were over Magnitude (M) 3.0. As the induced earthquakes were small and occurred at depth, they were usually not felt at the surface. After the hydraulic fracturing process ceased, the fluid pressure in the rock fractures decreased and the incidence of induced earthquakes dropped off dramatically (Baisch et al., 2006).

According to Geoscience Australia (Baisch et al., 2006) the likelihood that hydraulic fracturing will generate earthquakes that are felt at the surface can be minimized by:

- Careful geological mapping prior to the development of the fracturing to identify any large existing faults (these should be avoided to reduce the risk of larger earthquakes);
- Control of water injection rate – reduced injection rate produces fewer earthquakes (Baisch et al., 2006);

- Control of fracturing depth – the deeper it is, the less likely small earthquakes will be felt at the surface;
- Produce fracture networks of smaller vertical extent, which may result in smaller earthquakes.

Although each site will be site specific, in general, current evidence suggests that there are very low risks associated with hydraulic fracturing-induced seismicity. With the appropriate management, induced seismicity should not be regarded as an impediment for hydraulic fracturing. In North America, earthquakes induced by hydraulic fracturing for shale gas have not exceeded Magnitude (M) 3.0 (De Wit, 2011).

Seismic monitoring options can be utilized. A seismograph network must be employed before fracturing commences to define a baseline. This network must be maintained and monitored throughout the process.

Chapter 4 Case Studies

4.1 Review of Local and International Case Studies

Very few case studies are present in the literature which can be seen as objective, most of the studies are either motivated by industrial or private interests. This is most notable is the recent document produced by the EPA (EPA, 2011) in which the following key points are stated:

“As the use of hydraulic fracturing has increased, so have concerns about its potential impact on human health and the environment, especially with regard to possible effects on drinking water resources. These concerns have intensified as hydraulic fracturing has spread from the South and West to other settings, such as the Marcellus Shale, which extends from the southern tier of New York through parts of Pennsylvania, West Virginia, eastern Ohio, and western Maryland.” (EPA, 2011)

“The overarching goal of this research is to answer the following questions:

i. Can hydraulic fracturing impact drinking water resources?
ii. If so, what are the conditions associated with the potential impacts on drinking water resources due to hydraulic fracturing activities? ” (EPA, 2011)

This clearly illustrates that there is much confusion as to the impact of hydraulic fracturing on groundwater resources as well as communities in the proximity of these production boreholes. Secondly, the report does not indicate the presence of real published case studies to highlight the benefits or hazard of hydraulic fracturing in communities. In most instances of reports or investigations in an area no baseline information is available to proof without a doubt that hydraulic fracturing is the cause of the problems in the area. Due to the high impact of these studies and the lack of real monetary support for these projects the EPA (EPA, 2011) has proposed to do a thorough investigation. The case studies given in this section will concentrate on the scientific merit of the research reported and highlight the most relevant findings.

1. A report on uranium solubilisation has recently been released from the University of Buffalo in the USA (Fortson et al., 2011). The report dealt with the possible mobilisation of uranium during

the hydraulic fracturing process; however the concentrations of hydrochloric acid used was higher than the levels typically used during hydraulic fracturing. This does not exclude the possibility of high concentration gradients being formed in the hydraulic fracturing fluid which could lead to the tested scenario. The following results were reported by the authors: "*Six shale samples were analyzed and total organic content (TOC) varied between 3.13 wt% and 8.55 wt%. Hydrocarbons were unevenly distributed, as shown by varied intensity of hydrocarbons throughout the elemental maps. Uneven distributions of uranium were also present in samples with concentrations ranging from 10.2 ppm to 53.4 ppm.* ***<u>Preliminary results indicate that uranium is physically and chemically associated with hydrocarbons.</u>*** *High concentrations of barium, ranging from 902 ppm to 2000 ppm, also exist within the samples. Barium is more evenly distributed within the samples.*"(Fortson et al., 2011). Interestingly from this study the following conclusions were derived "*This study shows that metals in* ***<u>wastewater produced</u>*** *during natural gas development of the Marcellus Shale may be a concern.*"

2. A study investigating methane contamination of drinking water that is associated with hydraulic fracturing has indicated a possible link (Osborn et al., 2011). The following results were reported by the authors: "*Methane concentrations were detected generally in 51 of 60 drinking-water wells (85%) across the region, regardless of gas industry operations, but* ***<u>concentrations were substantially higher closer to natural-gas wells</u>*** *(Fig. 3). Methane concentrations were 17-times higher on average (19.2 mg CH4 L−1) in shallow wells from active drilling and extraction areas than in wells from nonactive areas (1.1 mg L−1 on average; P < 0.05; Fig. 3 and Table 1).*"(Osborn et al., 2011). The study data included isotopic and chemical results; however no historic data was presented which could indicate possible changes over the development cycle of the gas fields.
3. Review reports dealing with hydraulic fracturing has been given at various conferences and meetings (Zoback et al., 2010). In general consultants give summary reviews that do not contain any negative information as this might influence their company profiles (Arthur et al., 2008). One specific report highlights the problems with official state reports in the USA "*The Environmental Protection Agency, the Ground Water Protection Council and the Interstate Oil & Gas Compact Commission all have found hydraulic fracturing nonthreatening to the environment or public health. As displayed on the Energy in Depth Web site (http://www.energyindepth.com/), the* ***<u>GWPC's survey of state energy regulatory agencies found no documented cases of contaminated drinking water linked to hydraulic fracturing</u>***."

This is contradictory to reports from the local citizenry as indicated by newspaper reports and the EPA study launched in 2011 (EPA, 2011).

4. Penn State University recently obtained a research grant to focus on landscape changes associated with gas exploration activities, since this might have an impact on the ecosystem in the affected areas (PU, 2011). One of the main aims of the study will be to develop land management practices and monitoring programs to reduce the Marcellus disturbance footprint.
5. The Queensland Government in Australia have increased the regulatory requirement for hydraulic fracturing during gas exploration. New compulsory measurements include ten business days written notice to landowner of any drilling, hydraulic fracturing or certain exploration techniques. In addition the companies must supply a detailed report to the government about **hydraulic fracturing** activities – including the **composition of all fluids used in each well** and potential impacts on water aquifers (Hinchliffe, 2011).
6. A report filed by the USA Committee on Energy and Commerce Minority Staff highlighted the current problem with hydraulic fracturing fluids "*Hydraulic fracturing has opened access to vast domestic reserves of natural gas that could provide an important stepping stone to a clean energy future. Yet questions about the safety of hydraulic fracturing persist, which are compounded by the* ***secrecy surrounding the chemicals used in hydraulic fracturing fluids****. This analysis is the most comprehensive national* ***assessment to date of the types and volumes of chemical used in the hydraulic fracturing process****. It shows that between 2005 and 2009, the 14 leading hydraulic fracturing companies in the United States used over* ***2,500 hydraulic fracturing products containing 750 compounds. More than 650 of these products contained chemicals that are known or possible human carcinogens, regulated under the Safe Drinking Water Act, or listed as hazardous air pollutants****.*" (Waxman et al., 2011)

4.2 Environmental and Geohydrology of the Karoo Area

In this section two types of environments will be presented. Firstly, shallow aquifer systems (< 300 meters below surface) and finally deeper water carrying formations will be discussed. Since hydraulic fracturing might pose a risk to the surface aquifers and regional water bodies the most prominent factors will be presented that could affect these systems from a climatological perspective.

4.2.1 Climatic factors

The influence of climatic conditions on recharge and water usage have been investigated recently in WRC reports (Dondo et al., 2010b, Xu et al., 2007, Bredenkamp et al., 2007, Meyer, 2005), these reports all indicate that the process of groundwater recharge in South Africa is a highly complex problem. To illustrate this point a few maps were compiled showing different processes. A recent thesis by Dr. Van Wyk (Van Wyk, 2010) on groundwater recharge highlighted the effect of rainfall volume versus intensity when it comes to the volume of recharge. In Figure 4-1 the mean annual precipitation and rainfall concentration percentages is shown. The average annual precipitation in South Africa is ca. 500 mm, which is significantly less than that observed for the world with a value of 860 mm. Firstly, the mean annual precipitation in South Africa increases from the arid west to the tropical east. High precipitation values are observed along the eastern section extending into the north of South Africa. Comparing this mean annual rainfall pattern with the mean annual rainfall concentration it can be deduced that the northern section of South Africa has significantly more intense rainfall events (thunder storms). In contrast the southern half of South Africa and the eastern coastal section has a moderate continuous rainfall pattern.

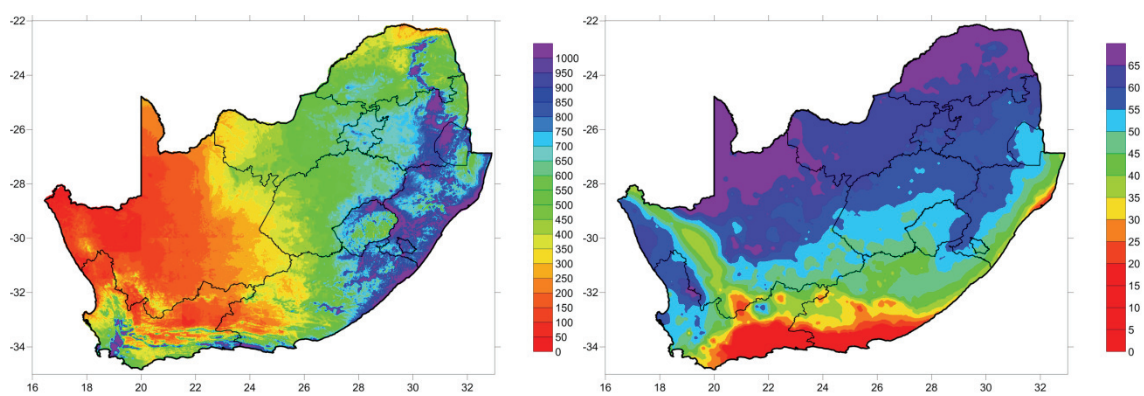

Figure 4-1 Mean annual precipitation (left hand, mm) and mean annual rainfall concentration as a percentage of total (right hand, %) of South Africa (Schulze et al., 1997).

It is expected that if episodic recharge does occur, it will generally be associated with high intensity rainfall events as noted previously (Van Wyk, 2010). Interestingly, the Karoo type aquifers are associated with high intensity rainfall areas which should increase recharge in these areas, however due to the low rainfall volumes it is expected that recharge would be in the order of a few millimetres per annum.

A second environmental factor that influences aquifer systems is the mean annual temperature and the associated mean annual evaporation potential (Figure 4-2). The average South African temperature range during the summer months is between 24-20^{o}C while during the winter time it ranges from 10-17^{o}C. The average temperature only decreases along the mountainous central belt and associated highlands, as indicated in Figure 4-2. This trend is not reflected in the evaporation potential with relatively low evaporation potentials along the eastern and coastal area (< 2 m) while inland and to the west the evaporation potentials is higher (> 2 m). This observation can be related to both the mean annual rainfall volume and mean annual temperature. It is expected that areas with high annual temperatures and evaporation potentials should be more reliant on groundwater sources, since aquifers are less vulnerable to these factors and thus represents a more constant source of water.

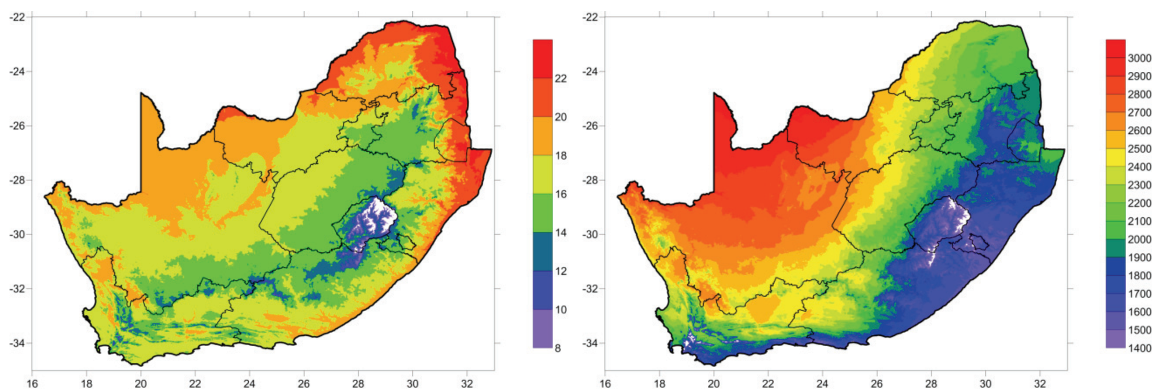

Figure 4-2 Mean annual temperature (left hand, ^{o}C) and mean annual evaporation potential (right hand, mm) of South Africa (Schulze et al., 1997).

Finally, the general rainfall patterns of South Africa are shown in Figure 4-3, illustrating the season progression and the major rainfall seasons. The seasonality of rainfall will also change the effective recharge observed in an aquifer, since lower evaporation potentials are dominant during the winter season allowing for pools to form which can recharge over a longer timeframe.

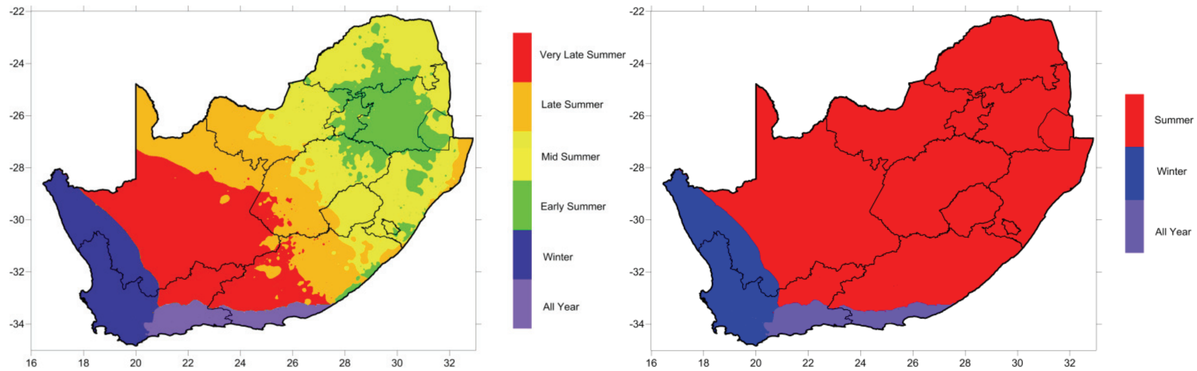

Figure 4-3 Generalised areas as a function of rain seasons in South Africa (Schulze et al., 1997).

In the next paragraph regional hydrogeological South African maps will be presented. The main focus is to supply a group of maps that will illustrate water resource directed management options and the impact it can have on South Africa's water resources.

4.2.2 Hydrogeological factors

The majority of South African aquifers are found in hard rock geological formations, as noted previously the geological structure would have an impact on the transport properties of the aquifer. In regard to bulk flow parameters various estimations of transmissivity and storativity values have been attempted, however no satisfactory results have been obtained that could be applied in groundwater management (Murray et al., 2011). One major complicating factor is the presence of dolerite dykes and sills, which infiltrated the Karoo Supergroup during the early Jurassic period. The irregular distribution of high and low permeability zones complicates the effective estimation of regional groundwater flow parameters (Figure 4-4).

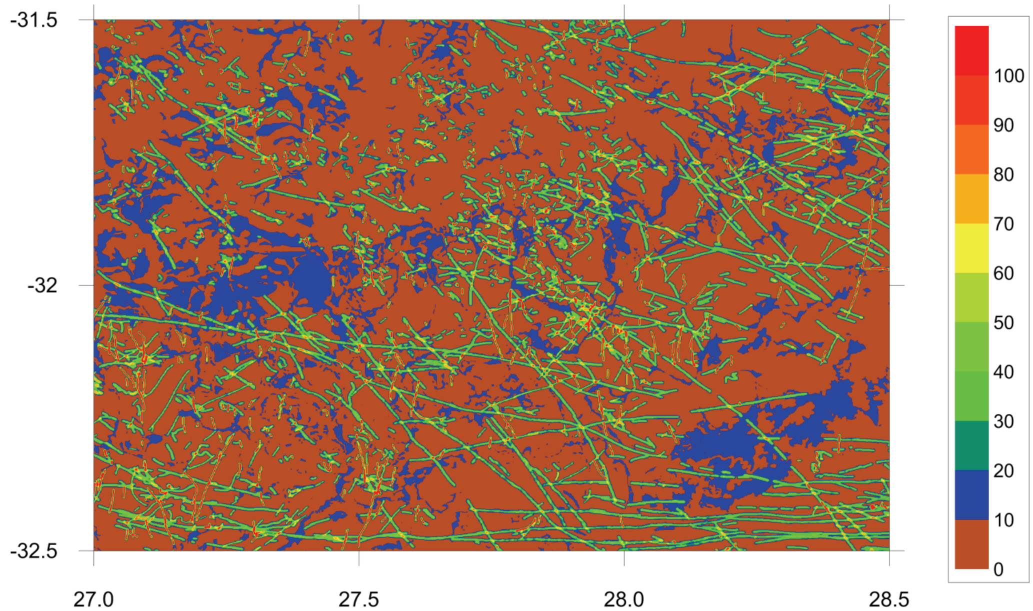

Figure 4-4 A regional map showing a subsection of the Karoo Supergroup with blue patterns indicating sills while green to red represents dykes in the area (Murray et al., 2012).

The estimation of transmissivity values have been done using various methods, i.e. conversion of borehole yield and pump test data (Figure 4-5). It is clear from the figures that different transmissivity values were obtained, this stems from the underlying observations used in determining the values. The first set of transmissivity values were calculated from borehole yields which would indicate a long-term average scenario. The maximum transmissivity that could be observed for this map was 44 m^2/d. In contrast if pump test data is used, maximum transmissivity values were observed in the range of 400-500 m^2/d. The discrepancy between the maximum values indicates that there might be a biasing factor in one of the methods or the methodology of obtaining the data itself.

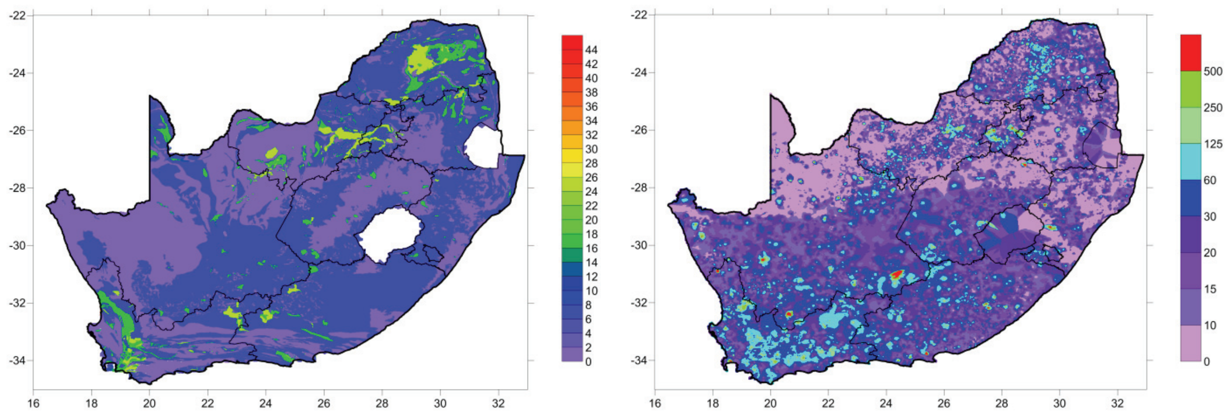

Figure 4-5 Estimated transmissivity values (m^2/d) for South Africa. Left-hand side constructed from reported borehole yield data points and right-hand side from the Groundwater Resource Directed Management (Dennis and Wentzel, 2007) Database.

Turning to storativity values for South Africa very little reported data exists which can be used for calculations. In general storativity values for the Karoo Supergroup is estimated to be in the range of 10^{-3}-10^{-5}. Considering the map (Figure 4-6) this assumption for South Africa holds, since 95 % of South Africa's aquifers is located in the Karoo Supergroup formations (Botha et al., 1998).

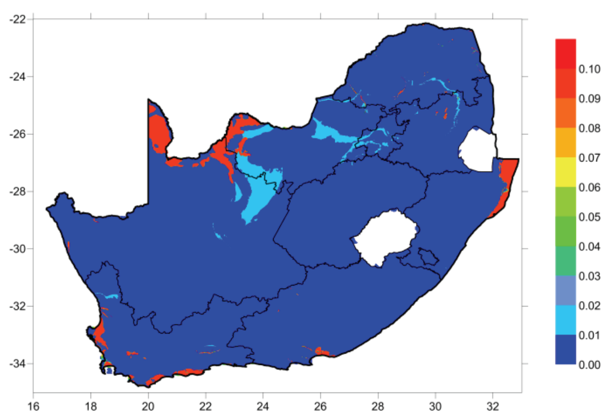

Figure 4-6 Estimated storativity values for South Africa (Dennis and Wentzel, 2007).

4.2.3 Deep Water Bearing Systems and Shale Gas

4.2.3.1 Conceptual Model

To effectively discuss the deep water bearing system, a conceptual model of the area is required. In order to classify an aquifer system, it must firstly be able to produce potable or reasonable quality water. Secondly, it must yield water at an acceptable rate such that it can be applied for human or aquatic use. Typically, aquifer systems occur within the first three hundred meters below surface, Figure 4-7. Below this zone water quality quickly deteriorates due to extensive contact time with geological formations which can be a result of a prolonged infiltration time or the rate of water movement in the subsurface. A special feature of the Karoo is the presence of dolerite dykes and sills, which significantly reduce the permeability of the formation due to its un-weathered state (Table 4-1).

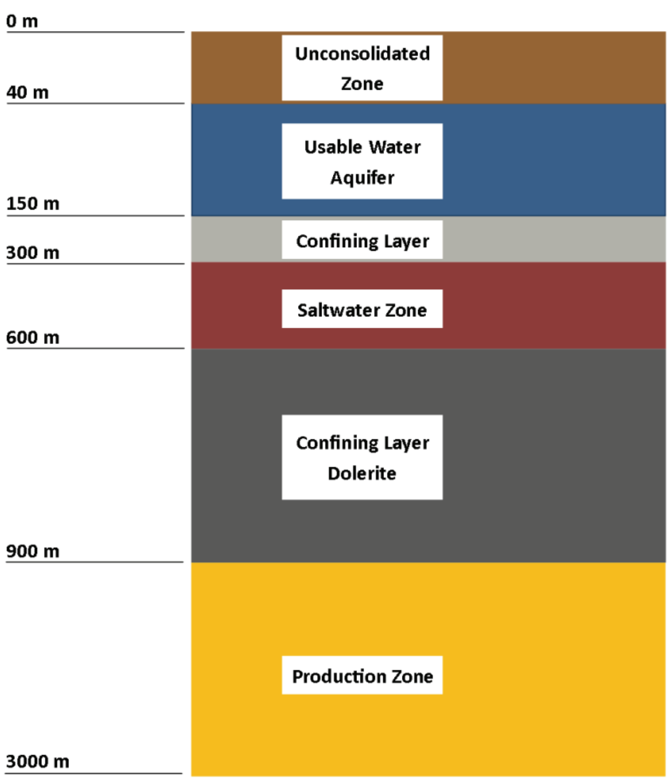

Figure 4-7 Conceptual model of the geology of the area and the associated depths of generalised strata.

Table 4-1 Conceptual understanding of formation type and the relationship between porosity and hydraulic conductivity.

Formation	% Porosity Range	K (m/d)
Unconsolidated	**3—30**	**0.01—100**
Aquifer	**3—30**	**0.01—100**
Confining	**$1x10^{-4}$—10**	**10^{-4}—10^{-8}**
Saltwater	**$1x10^{-4}$—10**	**10^{-4}—10^{-6}**
Dolerite	**$1x10^{-8}$—5**	**10^{-5}—10^{-8}**
Production	**$1x10^{-8}$—10**	**10^{-4}—10^{-6}**

It can be observed from Table 4-1 that the porosity of the system in general decreases with depth; however the most notable fact is the change in the hydraulic conductivity which decreases by orders of magnitude with depth. The decrease is due to the relatively slow geological processes that take place at depth and the reduction of weathering progression. It is expected that the dolerite intrusion sections will generally be sills; however it does not exclude dykes intruding the host rock to the surface (Figure 4-4).

Overall it is expected that if a dolerite dyke intrudes that it originated from a sill structure. The processes involved in the intrusion of the dolerite formation are two-fold in the Karoo type sediments. Firstly, thin dykes (< 10 meters wide) have a faster cooling down tempo than larger dyke structures. This results in fractured baked zones that have high hydraulic conductivity values. The slower cooling dyke structures tend not to exhibit these fractured baked zones and have thus low hydraulic conductivity zones. It is not expected that a dyke would weather aggressively at depths greater than one hundred meters. For the purpose of the conceptual model this depth is increased to three hundred meters, since it is expected that the average geological formations at this depth would have low permeabilities.

If dolerite sills are present in an area at depths of three hundred meters or more that this structure would be a highly impermeable barrier, except if major faulting is present in the region. The overlying shale formations would then act as traps for the released gas or water in these formations. Typically the production zone for natural gas development is below the dolerite region and thus would have a low permeability area directly above the respective sites (Figure 3-16).

4.3 Surface Water and Groundwater Interactions

4.3.1 Environmental Impacts of Hydraulic Fracturing

The concerns over hydraulic fracturing centre on a few main issues: (1) migration of gas, (2) migration of fracturing fluids, (3) water use, (4) management of produced water, (5) surface spills and (6) identification of chemical additives (Figure 4-8). Each issue is addressed in turn below.

1. *Migration of gas or fracture fluids.* A major concern in natural gas development is the prevention of migration of gas or other fluids out of the reservoir and into overlying strata, particularly fresh water aquifers. In cases where this has occurred, it has been the result of well construction problems and not of hydraulic fracturing itself. At depths of about 610 meters or less, fractures propagate horizontally due to the natural stress regime of the rock. This confines the fractures to the gas reservoir. At greater depths, fractures may propagate vertically; however, characteristics of overlying rock layers prevent fractures from extending above the top of the gas reservoir. The installation of steel pipe ("casing"), encased in cement, is key to preventing migration of gas or fluids. Michigan regulations require that each oil and gas well have a casing and cementing plan that will effectively contain gas and other fluids within the wellbore, whether related to fracturing or not. Surface casing must be set a minimum of 35 meters into the bedrock and 35 meters below any fresh water zones and cemented from the base of the casing to the ground surface. Before fracturing or other operations can take place to complete a well for production, an additional string of production casing must be set to the depth of the reservoir and cemented in place. Depending on depth, additional protective casing may be required. To provide additional protection for aquifers and well integrity, the Department of Environmental Quality (DEQ) imposes a permit condition for wells in shallow reservoirs prohibiting hydraulic fracturing within 15 meters of the base of the surface casing. In addition, Instruction 1-2011 requires reporting of volumes, rates, and pressures (including pressure immediately outside of the pipe used to inject the fracturing fluid). Also, DEQ staff check wells in the vicinity to assure there are no wells or other features that could serve as conduits for unwanted movement of fracturing fluids.

Figure 4-8 Main concerns regarding impacts of hydraulic fracturing on the environment.

2. *Water use.* A fracture treatment of a typical Antrim gas well (located in Antrim, Michigan) requires about 50 000 gallons (189 m^3) of water. In the emerging Utica/Collingwood Shale gas development, the amount of water needed to fracture a horizontal well may be up to 5 000 000 gallons (18927 m^3) or more. To put this in perspective, 5 000 000 gallons (18927 m^3) is the volume of water typically used by eight to ten acres of corn during a growing season. Withdrawal of water for oil and gas operations is exempt from the requirements of Michigan's water withdrawal statute; however, Instruction 1-2011 requires the operator to perform the same water withdrawal impact assessment as any other user of large volumes of water. It also requires installation and monitoring of an observation well if there is a freshwater supply well

within one-quarter mile. The DEQ will not approve a withdrawal of water for hydraulic fracturing if it is likely to cause a significant adverse impact to groundwater or surface water.

3. *Management of produced water.* Proper management of produced water is essential in protecting public health and the environment. In Michigan, produced water must be managed and disposed of according to strict rules specifically applying to those fluids. The fluids must be contained in steel tanks and transported to disposal wells where they are injected into deep rock layers that are isolated from fresh water supplies. The disposal wells are licensed by both the DEQ and the U.S. Environmental Protection Agency, and must be tested periodically to assure well integrity. Instruction 1-2011 requires reporting of the volume of flowback water recovered after a hydraulic fracturing operation.
4. *Surface spills.* Spills of chemical additives or flowback water can have adverse environmental or public health impacts. Michigan requires secondary containment under tanks, wellheads, and other areas where spills may be most likely. If a spill does occur, it must be reported immediately to the DEQ, and all spills must be promptly recovered and cleaned up according to strict requirements.
5. *Identification of chemical additives.* Instruction 1-2011 requires oil and gas operators to provide to the DEQ copies of all Material Safety Data Sheets (MSDSs) for additives used in hydraulic fracturing. The MSDSs include information on physical characteristics, toxicity, health effects, first aid, reactivity, storage, disposal, protective equipment, and spill response. The DEQ will post the MSDSs on the Department's web site for public review. While the details on some of the chemical compounds used in hydraulic fracturing are exempted from disclosure on the MSDSs under federal law, the MSDSs will provide enough information for the DEQ to track and monitor spills.

Michigan's laws and rules effectively protect water and other natural resources as well as public health and safety from potential adverse effects of hydraulic fracturing. The DEQ has more than 50 staff employed in enforcing these state requirements. To date, only two productive Utica/Collingwood Shale gas wells have been drilled in Michigan and the potential for more extensive development is unknown; however, the DEQ is taking a proactive approach in addressing large-scale hydraulic fracturing as well as other issues associated with deep shale gas development.

4.3.2 Additional Risk Factors (Bourgoyne, 2004)

4.3.2.1 Upward Fluid Migration through Hydraulic Fracture

Upward fluid migration through cement channels has also been responsible for a number of blowouts. Fluid seeping around the casing can cause erosion of the borehole-casing annulus, which eventually could lead to a collapse around the well. Proper design and planning of cement jobs are basic requirements to prevent upward gas migration around the casing. For this reason, a great deal of effort has been exerted by the petroleum industry to reduce the tendency for channels to form in the cemented annulus during cementing operations. Rock strength is a function of its structure, compaction and type. Rock tensile strength varies in both vertical and horizontal directions. The forces tending to hold the rock together are the strength of the rock itself and the in-situ stresses on the rock. High-pressure fluid, resulting from the well control operation generates hydraulic pressure at the wellbore wall or in the pore spaces of the rock. If the pressure increases, the force applied by the fluid pressure in the rock will become equal to the forces tending to hold the rock together. Any additional pressure applied will cause the rock to split or fracture (Martinez et al., 1990). Thus, from a macroscopic point of view, hydraulic fracturing occurs when the minimum effective stress at the wellbore becomes tensile and equal to the tensile strength.

In terms of well control operations, hydraulic fracturing may lead to the serious risk of allowing upward fluid migration through the fracture. The result can be upward migration of the pressured fluid through the fracture if the fracture is not being confined by a layer with a higher horizontal stress, and if the permeability of the rock matrix surrounding the fracture is not great enough to dissipate the high pressure.

4.3.2.2 Upward Fluid Migration through Shear Failure

Rock failure caused by shear stress can occur, for instance, when an impermeable formation overlays a permeable formation. In this case, massive shear failure due to the flow of highly pressured formation fluid can occur in the permeable formation before causing fracture of the overlying impermeable strata. The consequences of such massive failure include increase of sand production from the shear-damaged permeable formation and even compaction of these intervals (Walters, 1991).

4.3.2.3 Upward Fluid Migration through Fault Planes

Existing fault planes crossing impermeable and sealing layers have been reported as responsible for upward fluid migration which ended in the formation of craters (Walters, 1991, Adams and Thompson, 1989, Adams and Kuhiman, 1991). Flow through the fault planes will depend on many factors such as normal stress in the fault planes and permeability of the fault-plane-filling sediments. Possible mechanisms of flow through faults include:

1. The high-pressured fluid wedges open an existing fault plane at a pressure below that which will cause fracture of the sealing layer; and
2. Increase of permeability due to induced shear dilatancy within the fault plane by the high pressure (Walters, 1991).

Some operators reported that they had seen evidence that naturally occurring gas migration through faults are sometimes the source of a shallow gas flow event when the well bore intersects the fault plane. Gas seeps seen along fault-lines at the seafloor are evidence that such gas migration routes are common.

4.3.2.4 Caving

In this work, caving is defined as the collapsing of solids within and surrounding the well. This collapsing can be by borehole wall failure due to shear failure as the result of the reduction of the hydrostatic pressure in the wellbore, or by tensile failure due to excessive fluid production rate.

4.3.2.5 Potential Water Related Impacts

1. The amount needed for hydraulic fracturing (5 million gallons/frac)
2. Loss of well (aquifer) water through disruption or contamination
3. Gas migration causing methane contaminated water
4. The fate of the produced water (“treated” at publicly owned treatment works)
5. Degradation of water quality in local streams and rivers
6. Degradation of drinking water quality

4.3.2.6 Land usage

1. Large amount of acreage needed for well pads and impoundments
2. As long as a well can be "restimulated", the well pad will remain active
3. Leased areas (former private and public lands) become restricted access
4. Public lands and parks no longer "public" as they are off limits due to safety

4.3.2.7 Exposure to toxic chemicals (spills, aquifer contamination)

1. Hydraulic fracturing fluids
2. Produced water contaminated with organics, salts, heavy metals, and naturally occurring radioactive materials (NORMs)
3. Failed or improper casings lead to aquifer contamination through leakage

4.3.2.8 Traffic and road degradation

1. Significant increase in trucks and vehicles cause road and bridge deterioration
2. Trucks may exceed weight and height limits

4.3.2.9 Noise

1. Heavy equipment, increased traffic,
2. Low frequency sounds during hydraulic fracturing
3. Compressors and compressor stations

4.3.2.10 Air pollution

1. Increased vehicle traffic
2. Well flaring
3. Release of VOC's from well installations (condensate tanks are vented by design)
4. Compressor stations
5. Well blow outs

4.3.2.11 Property devaluation

1. Mortgages and home equity loans jeopardized by presence of wells
2. Mine subsidence insurance compromised or negated
3. Land owner ultimately responsible for taxes and environmental damage

4.3.2.12 EMS and emergency procedures

1. Evacuation plans must be in place for populated areas (a single well blow out can affect more than 1 mile radius)

Chapter 5 Monitoring Options

The question that should be raised is what should be monitored? Should the hydraulic fracturing process itself be monitored, long term monitoring of the surrounding area or a combination. It is the viewpoint of the authors of this document that the process should be monitored throughout, but that the most intensive monitoring should occur during the hydraulic fracturing process. This is necessary since the use of highly toxic substances are required to assist in the fracturing process, additionally high pressures are required which necessitates careful monitoring of the flow back from the borehole.

Considering the chemicals used during the hydraulic fracturing process a dilemma exists, the drilling companies does not want to make known proprietary chemicals which might increase production. On the other hand, the citizen of the area has a right to protect themselves from harmful chemicals and the possibility of legal recourse. A recent investigation by the House of Representatives in the USA (Waxman et al., 2011) found that a list of 750 chemical compounds were used from 2005 to 2009. A more alarming statistic from the investigation was: "Between 2005 and 2009, the oil and gas service companies used hydraulic fracturing products containing 29 chemicals that are (1) known or possible human carcinogens, (2) regulated under the Safe Drinking Water Act for their risks to human health, or (3) listed as hazardous air pollutants under the Clean Air Act. **These 29 chemicals were components of more than 650 different products used in hydraulic fracturing.** The BTEX compounds – benzene, toluene, xylene, and ethylbenzene – appeared in 60 of the hydraulic fracturing products used between 2005 and 2009. Each BTEX compound is a regulated contaminant under the Safe Drinking Water Act and a hazardous air pollutant under the Clean Air Act. Benzene also is a known human carcinogen. **The hydraulic fracturing companies injected 11.4 million gallons of products containing at least one BTEX chemical over the five year period.** In many instances, the oil and gas service companies were unable to provide the Committee with a complete chemical makeup of the hydraulic fracturing fluids they used. **Between 2005 and 2009, the companies used 94 million gallons of 279 products that contained at least one chemical or component that the manufacturers deemed proprietary or a trade secret**."(Waxman et al., 2011).

It should be noted that recent reports on Light Non-Aqueous Phase Liquids(LNAPLs) and Dense NAPLs produced by the Water Research Commission has dealt with this topic of chemical components (Usher et al., 2008). In most instances hydraulic fracturing liquids can be identified as either an LNAPL or DNAPL and recommendations from these reports should be followed if possible. A second observation is that due to the hazardous nature of the chemicals used and safety regulations in South Africa a different decontamination procedure should be followed at these drilling sites.

By means of an illustrative example it is possible to get a rough estimate of the extent of chemical usage in hydraulic fracturing. It has been stated that a vertical hydraulic fracturing process requires 1 x 10^6 litres of fluid; in contrast a single horizontal hydraulic fracturing process requires 10 x 10^6 litres of fluid. A pamphlet recently released by Energy in Depth gave a generic summary which stated the percentage composition of hydraulic fracturing fluid as reported by the Department of Energy (EID, 2010, GWPRF, 2009). If these values are taken as a lower limit then the following deductions can be made from Figure 5-1. Water and sand component of the hydraulic fracturing process constitutes 99.51% of the total volume used.

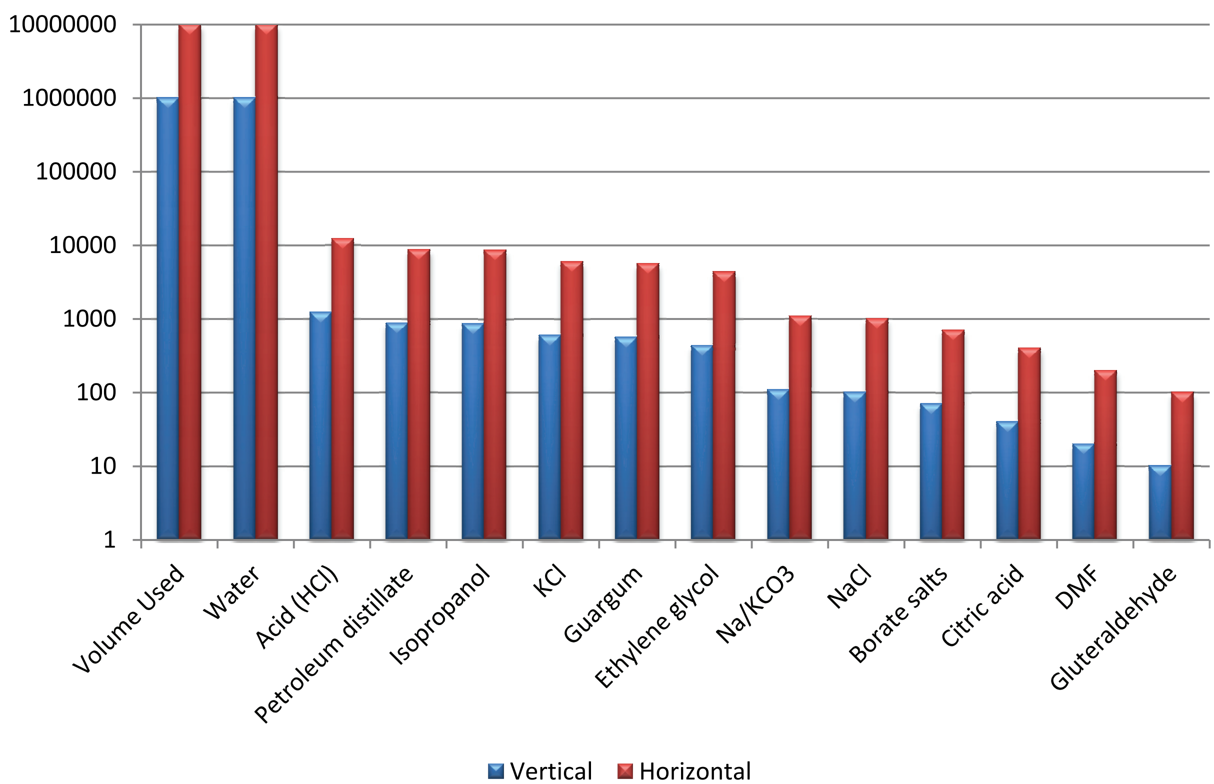

Figure 5-1 Mass and Volume of Chemical Compounds used in Hydraulic Fracturing.

Additives employed in the vertical or horizontal fracturing is present in scales approaching ton scale. Chemicals that are of special concern in large quantities are the acid phase, petroleum distillate and isopropanol. The acid phase is composed of hydrochloric acid and is usually part of the first phase of fluids to be injected into the borehole. The reader is reminded that this mobilises heavy metals in the host rock formation, as it is determined by concentration (Fortson et al., 2011). Petroleum distillates and isopropanol is listed chemicals of concern (carcinogens, safe drinking water act SDWA regulated chemicals and hazardous air pollutants in the USA) (Waxman et al., 2011). Other chemicals that are also classified as chemicals of concern are ethylene glycol, dimethyl formamide (DMF) and hydrochloric acid. If these components are added together then more than 3410 and 34100 litres of chemicals of concern is injected into a borehole to develop a vertical or horizontal hydraulic fractured borehole, respectively. These values represent a single hydraulic fracturing event and the whole process is repeated if another section is hydraulically fractured. It is important to note that it is assumed that the additives represent 0.49% of the total volume, but it can be as high as 2.00% in some instances, depending on circumstances. This would effectively quadruple the volumes mentioned in Figure 5-1 for the additive components.

5.1 Scenario 1 Leakage of Hydraulic Fracturing Fluid through the Well Casing

Consider a scenario in which a hydraulic fracturing solution is used. The assumption in this scenario is that the total mixture, as presented in Figure 5-1, is injected into the system as a total unit. Under the assumption that the additives represent 0.49% and that a horizontal borehole is hydraulically fractured (10×10^6 litres of fluid). If under these circumstances 1% of the total volume seeps into the surrounding aquifer system, through the protective casing well constructs in the upper sub-surface area, it would represent a volume of 1×10^5 litres of fluid. This volume would consist of 99.51% water and sand and the remainder 0.49% would be additive. The result would be the release of 490 litres of contaminants per hydraulic fracturing event. This is a sizeable amount of hazardous chemicals in the subsurface. The main question would be if this is a detectable volume over the total duration of the hydraulic fracturing event, i.e. the release of 1×10^5 litres of fluid from a total of 1×10^7 litres of fluid? This could pose serious hazards to the environment, especially if it is considered that the recharge in the Karoo aquifer systems is generally low and the amount of water present is generally used for human and livestock consumption.

5.2 Scenario 2 Backflow Event of Hydraulic Fracturing Fluid onto Land Surface

Consider a scenario in which a hydraulic fracturing solution is used. The assumption in this scenario is that the total mixture, as presented in Figure 5-1, is injected into the system as a total unit. Under the assumption that the additives represent 0.49% and that a horizontal borehole is hydraulically fractured (10×10^6 litres of fluid). If under these circumstances 1% of the total volume is released onto the surrounding surface area, it would represent a volume of 1×10^5 litres of fluid. This volume would consist of 99.51% water and sand and the remainder 0.49% would be additive. The result would be the release of 490 litres of contaminants per hydraulic fracturing event. If this is allowed to infiltrate the top most aquifer it could represent a significant risk due to the hazardous nature of the chemical compounds present in the hydraulic fracturing fluid. Two studies on the effects of non-aqueous phase liquids have been done in South Africa and in each case it was illustrated that harmful effects can be found in the environment if it is not properly remediated (Usher et al., 2008).

5.3 Scenario 3 Produced Water after Hydraulic Fracturing Event into Collection System

A recent report released by Hayes (Hayes, 2009) gave a reasonable perspective on produced water quality and quantities from a Marcellus shale gas well that has been hydraulically fractured. In this report only horizontal well systems have been investigated due to the scope of the project. Results are collated for six boreholes in the area that has undergone hydraulic fracturing and the volumes used during the process and the backflow water produced (Table 5-1). The percentage of backflow to hydraulic fracturing volumes is also reported to illustrate the variability of the volumes produced during the backflow events. It is clear from Table 5-1 that the volume of water produced can be as little as 1 506 087 litres or as much as 4 082 794 litres with percentage values ranging from 11 to 53 percent of total injected hydraulic fracturing fluid. It should be kept in mind that the backflow water not only consists of hydraulic fracturing fluid but also of chemicals that were produced from the geological formation in which the hydraulic fracturing event took place, thus resulting in a mixture of hydraulic fracturing fluid and shale chemical constituents. The average constituent concentrations are reported in Figure 5-2.

Table 5-1 Reported fracturing and backflow volumes from Hayes report (Hayes, 2009).

Site	Total Hydraulic Fracturing Volume (L)	Total Backflow Water from Well (L)	% Backflow to Hydraulic Fracturing Volume
Site C*	23 248 077	2 542 366	11
Site D	3 361 627	1 778 273	53
Site E	8 505 821	4 082 794	48
Site F	12 400 214	2 768 446	22
Site G	19 701 865	2 969 406	15
Site K*	11 252 167	1 506 087	13
All Sites			
Max	23 248 077	4 082 794	11
Min	3 361 627	1 506 087	53
Average	13 078 295	2 607 895	27

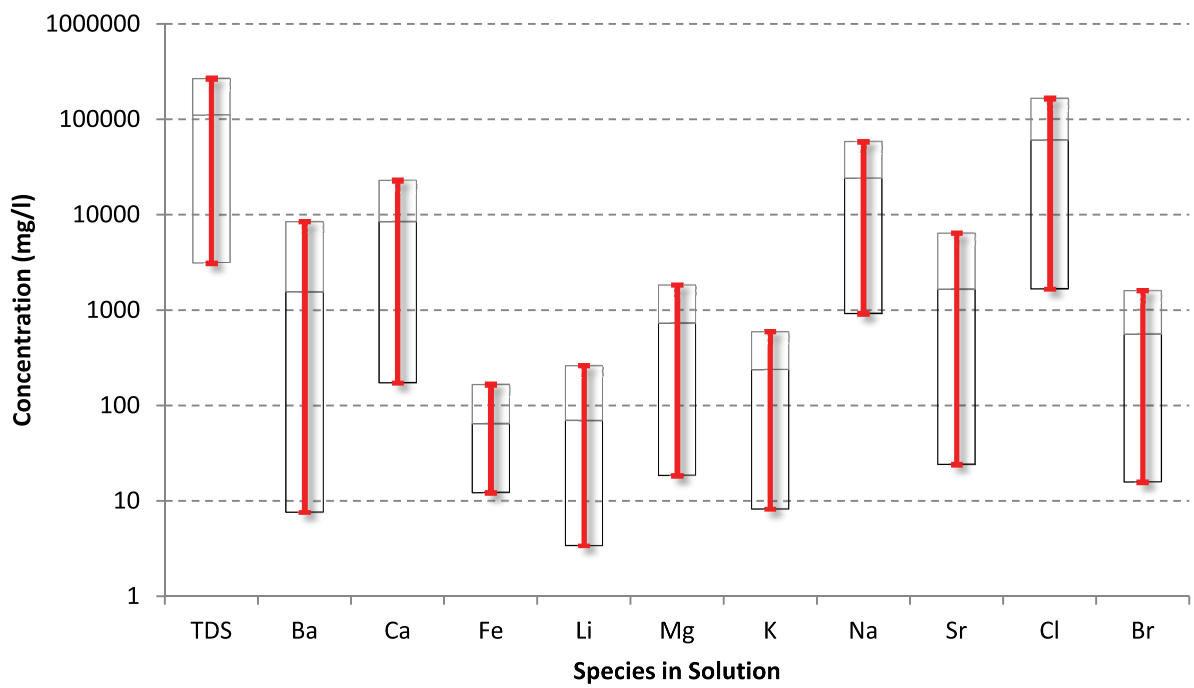

Figure 5-2 Average distribution of sampled sites chemical components.

The average chemical salt loading in the return water was in excess of a 110 000 mg/l and the average volume of return water was approximately 2 600 000 litres. Considering these values an expected salt load produced from a single well would be in the range of 286 tons of material, which would require adequate disposal regulations since the waste would contain materials classified as harmful to the environment (Sr, Ba, Li, Cl and Br). A further consideration in processing the material would be the quantity of salts produced during a specified time period. Data reported by Hayes (Hayes, 2009) were analysed to derive salt loads at reported day intervals at which chemical sample analysis were performed (Table 5-2). It is clear from the data that salt loading values vary considerably over production time and that no singular analysis can be used to determine when the most salt from the hydraulic fracturing borehole would be produced. Secondly, salt loads vary from as little as 57 tonnes to 530 tonnes at 90 day, indicating that a significant quantity of salts is produced from each of the respective boreholes. The cumulative salts produced from these six wells are in the order of 1 900 tonnes which should be disposed of in an environmentally sound methodology.

Table 5-2 Cumulative salt loads in tons at day X for the respective sites (Hayes, 2009).

	Day			
	1	5	14	90
Site C*-	13	75	186	304[a]
Site D-	4	38	183[a]	298
Site E	39	142	227	261
Site F	32	171	209	370
Site G	13	137	269	530
Site K*-	17	34	35	57[a]
a Values indicate estimated values from linear regression model				

Since all of the data which is available from hydraulic fracturing events are based on the Marcellus shale areas in the United States of America a question arose to the effect as how the Karoo shales compare the Marcellus shale. In order to investigate this question, Whitehill samples were collected from the Geological Department at the University of the Free State and subjected to a leaching test in acid. The results obtained are reported in Table 5-3 under the heading of Karoo. To draw a comparison between the shales the average chemical analysis of produced water from the Hayes report (Hayes, 2009) and average composition of shales (Hem, 1985) were included. Due to different analysis methodologies and production environments these values could not be directly compared, instead ratios of the major elements were used to determine if a possible correlation did exist (Table 5-4). In general a good correlation existed between the reported sample compositions in the Hem and Karoo data, with all results of the ratios within the same order when compared to each other. In contrast the Hayes report differed notably in the Ba/Ca, Ba/Li and Ba/Mg ratios which could possibly indicate that the use of hydraulic fracturing additives might have changed the chemical character of the produced water or that a substantial difference exists in the geological formation. Interestingly the remainder of the ratios are within an order of each other, especially the Ba/Sr, Ba/Na and Sr/Na ratios. This could possibly indicate that similar chemical properties in the produced water can be expected from the Karoo type shales in which the hydraulic fracturing events will take place. However, it should be kept in mind that without hydraulic fracturing field data these values can only be assumed to indicate possible chemical species. This clearly indicates that a test site should be established to determine the quantity and quality of the backflow water over an extended time period.

Table 5-3 Reported composition of shale samples obtained from various sources.

Source	Element (mg/l)							
	Ba	Ca	Fe	Li	Sr	Mg	K	Na
Hem[1]	250	22500	38800	46	290	16400	24900	4850
Hayes[2]	1552	8451	64	70	1650	728	237	24043
Karoo[3]	2.7	2400	770	1	3.2	308	50	50
1. Hem report USGS (Hem, 1985); 2. Hayes report GTI (Hayes, 2009); 3. Karoo Sample leached in lab with HCl acid								

Table 5-4 Ratios of chemical compositions from reported shale samples.

Source	Element (mg/l)						
	Ba/Sr	Ba/Ca	Ba/Li	Ba/Mg	Ca/Mg	Ba/Na	Sr/Na
Hem[1]	0.86	0.01	5.43	0.02	1.37	0.05	0.06
Hayes[2]	0.94	0.18	22.17	2.13	11.61	0.06	0.07
Karoo[3]	0.84	0.01	2.70	0.01	7.79	0.05	0.06
	1. Hem report USGS (Hem, 1985); 2. Hayes report GTI (Hayes, 2009); 3. Karoo Sample leached in lab with HCl acid						

5.4 Scenario 4 Gas Seepage Due to Micro-pathways in Casing Strings

During the construction of a gas producing borehole, casing is installed to protect groundwater resources and allow for an efficient hydraulic fracturing method. For the period of cementing of the casings, two main problems can arise. Firstly, loss of circulation of cement in surface casing or non-return to surface. In this instance cement is pumped in to set a string, with a typical inner and outer difference in drill zone or string of one inch, a total volume of 100% plus 20% of cement is used. If the cement does not return to surface after this volume is pumped into the borehole to set the casing, a loss of connection can be assumed (i.e. subterranean cavitation or fracture zones or voids). In all cases the subsurface should be logged to ensure that the drilling platform is still stable. If a return to surface is observed within the volume limit a typical eight hour waiting period is set aside for the setting of the cement. In Texas the zone of critical cement is 72 hours with a UCS of 12 kpsi. Secondly, if it should occur during the setting time that either a change in geological formation (due to release of anisotropic strain) or secondary gas evolution occurs (trapped gas or gas sand); the creation of micro-pathways through the cement casing can be formed. In this instance gas seepage at the surface might be observed, which would imply that the cement job needs to be redone. It is however not always the case that the micro-fracture will be to the surface and in this instance connectivity between shallow and deeper systems might be created. Detection of this situation could most likely only be detected over an extended time period through monitoring.

5.5 Incident Reports from Pennsylvania Department of Environmental Protection

The following observations were obtained from the Pennsylvania Department of Environmental Protection Website (PennOGWV, 2011). The inspection violation is described for each inspected site that had a violation (PennOGWV, 2011) and resolved violations are noted in a second report (PennOGWR, 2011). A different number of violations were cited by the inspection officers that ranged from minor to major incidents. An abbreviated list of transgression is shown in Table 5-5 and is only included in this document as a guide to observed problems encountered in the Marcellus Shale Gas Exploration project.

Table 5-5 Violation reports from Inspectors in Pennsylvania in regards to the Macellus Shale Gas Development (PennOGWV, 2011) from 1st January 2011 till 16th June 2011.

1	Site constructions differed from the drawings (plans) originally issued on 06/01/2010 (e.g. well pad, impoundment, filter sock, etc.).
2	Failure to implement Special Protection "Best Management Protection" for High Quality or Exceptional Value stream.
3	No well tag.
4	Pit fence fallen down around half of pit, hose with flow back on ground with discharge to soil.
5	Pollution Substance spill along site access road.
6	Pit and tanks not constructed with sufficient capacity to contain pollution substances.
7	Drill cuttings and drill mud on ground (minor amounts).
8	SW-defective cement job, 78.86(a) & 78.81(a)(2)&(3), 0.1 psi at 9 5/8 annulus & 0.2 psi at 5 1/2 annulus, 25% gas at 9 5/8 annulus & 90% gas at 5 1/2 annulus, 10 day response request.
9	Failure to case and cement to prevent migrations into fresh groundwater.
10	Failure to properly store, transport, process or dispose of a residual waste.
11	Well drilled. Rig off location. Crews on site picking up roll off containers. Parrish on site working on wells installing vent lines. Site has been scrated clean. All plastic removed. Observed bubbling approximately 1 ft away from base of well head. Bubbles once every 5 seconds. Also observed bubbling along cellar wall. Rathole not filled in. Violation of 25 Pa Code 78.65(1).
12	Violations noted at this site were due to a 1,500 gallon spill of drilling mud being observed on the surface of the ground outside of the containment area and the site PPC plan was not available for review upon request.
13	MS-flowback fluids overtopping tanks spilling out of open manholes onto ground surface beyond secondary containment, 78.56(a)(1), SWMA 301 & CSL 402.
14	Water bubbling in cellar (2 string). Uncontrolled release of gas. 3% combustible gas reading coming from cellar. Follow-up/further investigation required.
15	Pit has hole in liner and perimeter fence is down, lacking 2 feet freeboard, drilling mud spill on ground, Accelerated erosion due to insufficient site stabilization
16	Found several violations on the pipeline project.
17	Blow out, frac fluid release.
18	Production Fluid release, approximately 500 barrels.
	Total Inspections: 304, Total Violations: 593, Total Enforcement: 86
	Total Penalty Amount: $769,500.00

It is clear from the above citations that proper regulation of the industry is a good safeguard to protect the natural resources in the area. It should be noted that the rate of resolution of incidents is generally high and that remediation efforts usually occur within a few hours to months. Only one long term problem was observed in the data presented and it was a centralised waste pit which was not remediated after nine months. Finally, it should be mentioned that the Pennsylvania Oil and Gas Inspectors are of a limited number (< 10) and a total of 938 boreholes were drilled from 01/01/2011 to 18/07/2011 in the Marcellus Shale Gas Fields only, excluding a further 406 boreholes in other gas fields. In a period of 5 days from 18/07/2011 till 22/07/2011, 32 Marcellus Shale Gas boreholes were drilled. The total of Marcellus gas boreholes drilled from the inception in 2005 is 3522; while non-Marcellus gas boreholes are 19465.

5.6 Conclusion

It is clear from the data presented that no clear data sets exists nationally or internationally as to the effects of chemicals on the environment as it pertains to gas exploration, spillages and leakages (GWPRF, 2009, Harrison, 1983, Fontaine et al., 2008, Revesz et al., 2010). It is proposed that an efficient monitoring setup be installed at these sites to determine if any of these chemicals do reach the groundwater systems and what the impact is of these contaminants are on the environment. Secondly, a baseline study must be conducted prior to any drilling to obtain a representative value of regional water quality which should include stable isotopes as well radioactive isotopes. The contribution of methane, ethane, propane and butane should also be known prior to exploration and gas field development.

Chapter 6 Recommendations

The following recommendations can only be applied if the hydraulic fracturing process is used and allowed by the government of South Africa. Furthermore it is a best practice approach which could be ascertained from the available documents and does not represent a conclusive number of recommendations but only what is deemed as the most critical.

1. No chemicals should be injected into the boreholes without full disclosure of the type of compound used, since it can hamper the monitoring and remediation of these sites. Chemicals should be contained in such a manner that no spillage occurs at the surface which could infiltrate into the subsurface, runoff to local surface water bodies or evaporate into the air. Closed tanker units (20000 litres) that can transport waste water back to purification plant.
2. Waste pits should be avoided as far as possible since it can pose a hazard to the regional groundwater. If it is used, it should be lined in accordance with South Africa's specifications for hazardous waste lagoons, as stipulated in legal requirements for hazardous landfill sites and remediated within three months of final drilling activity. Waste pits should be in operation for less than six months since it will reduce the hazard of infiltration into the subsurface. An adequate water board should be maintained at all times and should be commissioned on the principal assumption of a one hundred year flood event.
3. Drilling should be conducted at least 10 km from any residential areas due to the possibility of chemical exposure (atmospheric, surface contact or hydrologically).
4. Drilling logs should be filed at the Department of Water Affairs and Department of Environmental Affairs, and should be publically available within six months of drilling completion to assist in research and monitoring of the gas field.
5. Only best-practice guidelines should be implemented since the resources are available for the development of gas fields and drilling methods.
6. A pilot study should be done a year in advance in which a monitoring network of boreholes (both shallow and deep) is installed to monitor the impact of hydraulic fracturing on the area.
7. A baseline should be constructed before any drilling is done in an area, this would be for liability disclaimers and liability measures if the contractor is careless. These should include atmospheric, soil, surface water and groundwater (isotopes, macro, micro and metal species)

environments and should be filed at the Department of Water Affairs and the Department of Environmental Affairs. The results must be verified by an independent body with known competency, i.e. academic institution which is unbiased. The data should be made available to the public for effective monitoring of the exploration companies as this is one of the greatest drawbacks in the international arena.

8. All associated drilling footprints, including return water containment structures should be fully remediated to natural levels before the contractor is allowed to leave the site. There are sites internationally which this action has not been taken and the site can pose a health risk to local inhabitants.
9. Waste water containers should be used to store and transport waste water from the site to a suitable water treatment plant that can correctly purify the water.
10. Strict legal licensing restrictions should be applied by the government in which the licence for drilling is leased to the drilling company. Drilling needs to be done on the one-strike standard in which a single incident (spillage of flow back, contamination of surface aquifer or incomplete remediation) will institute immediate legal action and polluter pays principles. In addition the company involved should be held accountable for and should in certain circumstances be banned from drilling in the area as this would ensure that no negligent behaviour is tolerated on site. The Karoo has a relatively low recharge and thus remediation of these areas will be protracted.

Chapter 7 References

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Chapter 8 Appendix

8.1 Reports that can be downloaded from Internet

1. Shale gas: a provisional assessment of climate change and environmental impacts
http://www.tyndall.ac.uk/publications/technical-report/2011/shale-gas-provisional-assessment-climate-change-and-environmental

2. EPA: Draft Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources
http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/upload/HFStudyPlanDraft_SAB_020711.pdf

3. Chemical used in hydraulic fracturing
http://democrats.energycommerce.house.gov/sites/default/files/documents/Hydraulic%20Fracturing%20Report%204.18.11.pdf

4. EIA:World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States
http://www.eia.doe.gov/analysis/studies/worldshalegas/pdf/fullreport.pdf

5. Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs
http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/wells_coalbedmethanestudy.cfm

6. Over 1,000,000 hydraulic fracturing stimulations within the USA without compromising fresh groundwater: True or False?
http://www.gwpc.org/meetings/forum/2010/proceedings/6Engelder_Terry.pdf

7. Addressing the Environmental Risks from Shale Gas Development
http://www.efdsystems.org/Portals/25/Hydraulic%20Fracturing%20Paper%20-%20World%20Watch.pdf

8. Jarvie: Geochemical comparison of shale resource systems
http://www.wwgeochem.com/resources/Final+Jarvie+-+Insight+Dallas+May+2008.pdf

9. Meyers: Environmental Dangers of Hydro-Fracturing the Marcellus Shale
http://www.lhup.edu/rmyers3/marcellus.htm

10. Lafolette: Key Considerations for Hydraulic Fracturing of Gas Shales
http://www.pttc.org/aapg/lafollette.pdf

11. GEIS:Natural gas development activities and high-volume hydraulic fracturing.
http://www.dec.ny.gov/docs/materials_minerals_pdf/ogdsgeischap5.pdf
12. King: SPE 133456 Thirty Years of Gas Shale Fracturing: What Have We Learned?
http://65.38.108.124/attachments/studygroups/11/George_King_SPE%20GCS%20May%202011.pdf

8.2 Gas Units

1 barrel of oil = 159 litre

1 barrel oil equivalent = 6 000 vt^3 = 200 m^3 of gas

1000 CF = 28.3 MCM

Trillion = 10^{12}

1 000 vt^3 gas = MMBTUs (BTU = British thermal unit) = 10^9 BTU

MM=thousand million (billion)

100KPa = 1 bar = 10 m

22.4 litres of any gas = 1 mole; CH4 has 16 g per mole

1 m^3 of natural gas = 0.714 kg

Current crude-oil prize = $106 per barrel

Current gas prize = $4/1000CF

Bottom Hole Pressure (psig)= True Vertical Depth (ft) * Mud weight (ppg) *0.052 Reservoir pressure must be between 10 psia and 20,000 psia

8.3 Shared Properties between the Ecca Shale in the Karoo Basin and the Barnett Shale in Texas

Barnett Shale: each vertical well uses 1 million litres and each horizontal well uses 10 million litres of water.

Table 8-1 Shale data from the USA located in five areas.

Property	Barnett	Ohio	Antrim	New Albany	Lewis
Depth, ft	6,500-8,500	2,000-5,000	600-2,200	500-2,000	3,000-6,000
Gross Thickness, ft	200-300	300-1,000	160	180	500-1,900
Net Thickness, ft	50-100	30-100	70-120	50-100	200-300
Bottomhole Temp °F	200	100	75	80-105	130-170
TOC, %	4.5	0.0-4.7	1-20	1-25	0.45-2.5
$\%R_o$	1.0-1.3	0.4-1.3	0.4-0.6	0.4-1.0	1.60-1.88
Total Porosity, %	4-5	4.7	9	10-14	3.0-5.5
Gas Filled Porosity, %	2.5	2.0	4	5	1-3.5
Water Filled Porosity %	1.9	2.5-3.0	4	4-8	1-2
K_h md-ft	0.01-2	0.15-50	1-5,000	NA	6-400
Gas Content, scf/ton	300-350	60-100	40-100	40-80	15-45
Adsorbed Gas, %	20	50	70	40-60	60-85
Reservoir Pressure, psi	3,000-4,000	500-2,000	400	300-600	1,000-1,500
Pressure Gradient, psi/ft	0.43-0.44	0.15-0.40	0.35	0.43	0.20-0.25
Well Costs, $1,000	450-600	200-300	180-250	125-150	250-300
Completion Costs, $1,000	100-150	25-50	25-50	25	100-300
Water Production, Bwpd	0	0	5-500	5-500	0
Gas Production, Mcf/ton	100-1,000	30-500	40-500	10-50	100-200
Well Spacing, Acres	80-160	40-160	40-160	80	80-320
Recovery Factors, %	8-15	10-20	20-60	10-20	5-15
Gas-In-Place, Bcf/Section	30-40	5-10	6-15	7-10	8-50
Reserves, MMcf	500-1,500	150-600	200-1,200	150-600	600-2,000
Historic Production Area Basis for Data	Wise Co., Texas	Pike Co., Kentucky	Otsego Co., Missouri	Harrison Co., Indiana	San Juan & Rio Arriba Co., New Mexico

8.4 Timeline for Hydraulic Fracturing

8.4.1 Hydraulic Fracturing Technological Milestones in the USA

- Early 1900s Natural gas extracted from shale wells. Vertical wells hydraulic fracturing with foam.
- 1983 First gas well drilled in Barnett Shale in Texas
- 1980-1990s Cross-linked gel fracturing fluids developed and used in vertical wells
- 1991 First horizontal well drilled in Barnett Shale
- 1991 Orientation of induced fractures identified
- 1996 Slick water fracturing fluids introduced
- 1996 Micro seismic post-fracturing mapping developed
- 1998 Slick water refracturing of originally gel- hydraulic fracturing wells
- 2002 Multi-stage slick water fracturing of horizontal wells
- 2003 First hydraulic fracturing of Marcellus shale

- 2005 Increased emphasis on improving the recovery factor
- 2007 Use of multi-well pads and cluster drilling

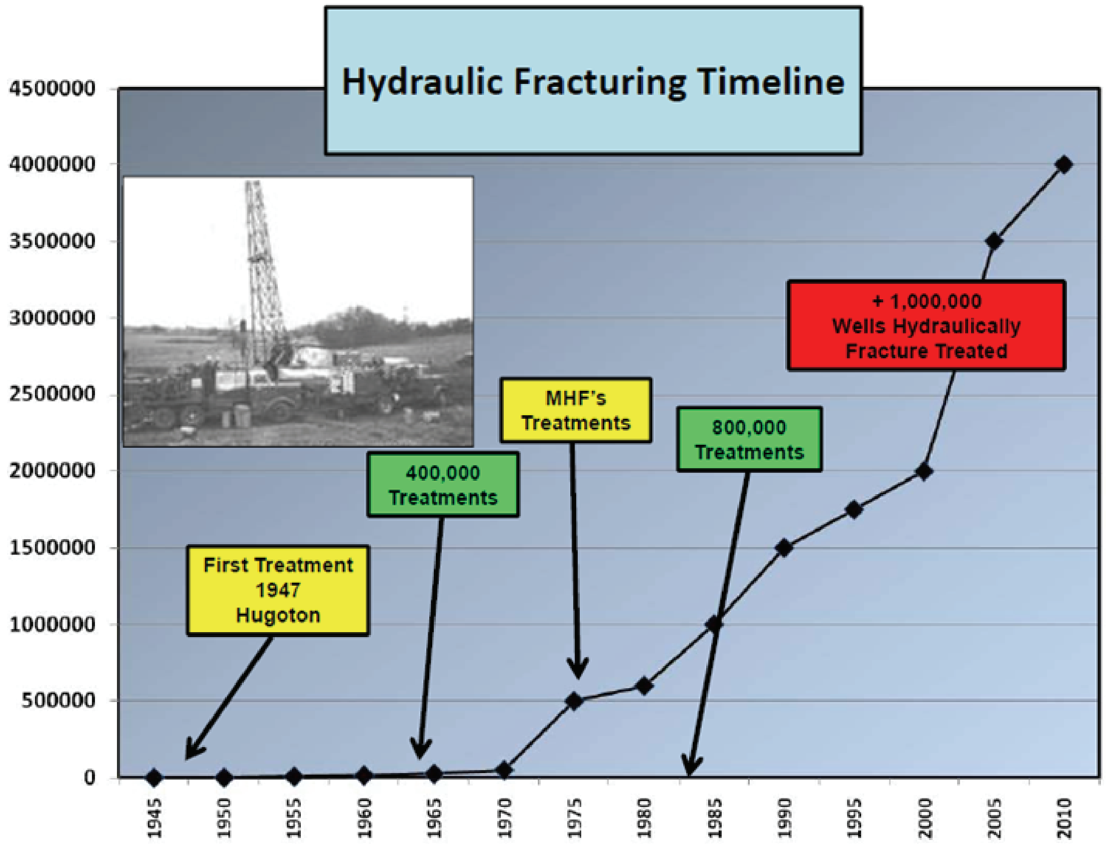

Figure 8-1 Hydraulic fracturing timeline and volumes natural gas produced.

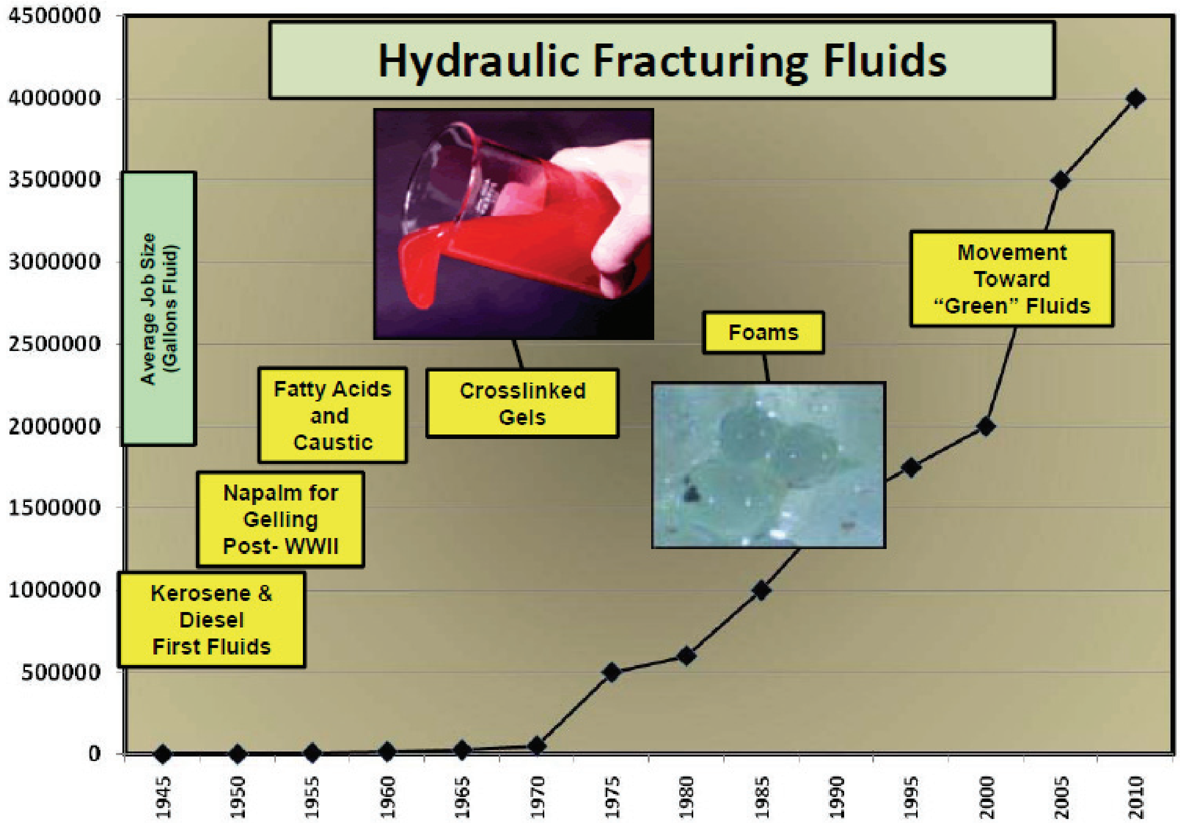

Figure 8-2Hydraulic fracturing timeline and hydraulic fracturing fluids used in the production of natural gas.