CHAPTER 1:
SCENARIOS AND ACTIVITIES

Second Order Draft for Stakeholder Comment

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Executive Summary

There is no history of exploitation of shale gas in South Africa, so this description of potential scenarios and related activities is necessarily hypothetical and based on experience elsewhere, interpreted in the light of what is known about the Karoo petroleum geology, its ecology and social environment. Shale gas, the "unconventional resource" targeted by the petroleum sector, is methane gas trapped in shale formations which have low permeability.[1] The gas is stored or "trapped" under pressure in pore spaces, in existing fractures, and adsorbed on the shale particles. Hydraulic fracturing is the process of applying hydraulic pressure to the shale until that pressure exceeds the formation fracture gradient or fracture pressure. The hydraulic pressure is created using surface equipment to pump hydraulic fluid through perforated well casing into the target shale formation. When the hydraulic pressure exceeds the formation fracture pressure the rock breaks resulting in millimetre-scale fractures. The fractures are kept open by solid particles (typically sand) which is included in the hydraulic fracturing fluid. The trapped methane gas flows out of the shale through the well casing perforations into the wellbore, as long as there is a pressure differential between the source formation and the surface. Produced natural gas has a number of downstream uses, including fuel for electricity generation and for refining to fuels and other hydrocarbon-based products (including diesel, petrol and plastics).

Economically recoverable gas in the study area could range between 5 and 20 trillion cubic feet. It is also possible that no economically recoverable gas reserves might exist. The shales of South Africa's Karoo Basin are known to contain gas. It is uncertain what the magnitude and distribution of the gas reserves are. Igneous dolerite intrusions and the effects of Cape fold processes are believed to have reduced the quantity of gas relative to what originally might have been contained within the shales. Based on limited exploration data, there is reasonable agreement between several assessments that have been made of the presence of shale gas in the Karoo Basin. Indications are that gas is most likely concentrated in the area between the Cape Fold and the Nuweveld mountain ranges.

Three shale gas exploration and development scenarios of increasing magnitude are explored in this chapter, relative to a Reference Case with no shale gas activities. The three shale gas scenarios are: (i) *exploration proceeds, with results indicating that production would not be economically viable* (i.e. all sites are rehabilitated, drilled wells are permanently plugged and monitoring of the abandoned wells is implemented) *(referred to as the 'Exploration Only Scenario')*; (ii) *a relatively small but economically viable shale gas discovery is made, with downstream development resulting in a 1 000 MW combined cycle gas turbine (CCGT) power station (referred to*

[1] Shales are classically defined as "laminated, indurated (consolidated) rock with >67% clay-sized materials" with grain size of <.004mm on the Wentworth Scale (Jackson, 1997).

as the 'Small Gas Scenario'); and (iii) *a relatively large shale gas discovery is made, with downstream development resulting in construction of two CCGT power stations (each of 2 000 MW generating capacity) and a gas-to-liquid plant located either at the coast or in Gauteng (referred to as the 'Big Gas Scenario').* This chapter of the report describes both the reference case and the main shale gas exploration and production activities (or impact drivers) through which the three defined shale gas scenarios would materialise.

The Karoo is changing in response to a number of historic and current influences, independently of shale gas development (SGD), and the resilience to further change varies across the study area. Changes in climate are expected to increase the vulnerability of ecosystems and thereby affect ecosystem services that contribute to social well-being. The effects of this and other change factors will be offset, to varying degrees, by entrepreneurial economic and institutional responses.

The description and quantification of the shale gas-related activities presented in this chapter informs the assessment of ecological and social risk addressed in other chapters. For the shale gas exploration scenario, activities that will manifest as key impact drivers (i.e. those with greatest influence on risk) include the operations of seismic exploration vehicles along networks of survey transects across the study area, clearing of drilling wellpads and crew accommodation sites, the construction of access roads and traffic (especially heavy-duty vehicles using these and public roads throughout operations), rail and road transport of equipment and materials, water use, noise, light and gas emissions, visual impact, generated waste and employment. These activities, plus the installation of gas reticulation and processing infrastructure, will also manifest as key impact drivers for both the small- and large-scale production scenarios; however, their scale will increase significantly relative to exploration, particularly in the case of the large-scale production, or *Big Gas*, scenario.

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CHAPTER 1: SCENARIOS AND ACTIVITIES

1.1 Shale Gas: Introducing the unconventional

Shale gas is a hydrocarbon that consists mainly of methane (CH_4). It is commonly used as fuel for generating electricity, heating and cooking; it can also be converted to liquid fuels, polymers, and other products (Holloway and Rudd, 2013). In order to assess the strategic implications of shale gas development (SGD) within the study area it is necessary to understand what the SGD process life cycle entails, what the main activities are that characterise each stage of the life cycle and how these present as impact drivers that could pose risks to the receiving environment.[2] In turn, an understanding is required of the ecological and social characteristics of the environment in which SGD could materialise. Insight is also required of the petroleum geology of the study area in order to understand where and in what amounts shale gas might occur. It is the aim of this chapter to provide this foundational context for the 17 chapters which follow in this Scientific Assessment.

In the subsurface, hydrocarbon reserves are accumulated or trapped in reservoirs. These reserves are commonly classified by the petroleum sector as either ‘conventional’ or ‘unconventional’. The ‘unconventional’ reserve designation is not strictly a function of geology, but may also be a function of cost to exploit, development and production technology challenges (e.g. requirements for horizontal drilling, hydraulic fracturing) and a suite of determinants of economic feasibility.

Hydrocarbon reserves require four basic components in order to accumulate in the subsurface: (i) source rocks (e.g. organic rich shales); (ii) migration pathways from the source rock; (iii) reservoirs into which hydrocarbon product migrates; and (iv) trapping mechanisms. Conventional hydrocarbon reservesare trapped within interconnected pores and/or fractures in sandstone and limestone rock formations (i.e. the reservoir) with a confining or impermeable boundary that prevents hydrocarbon migration (i.e. the trap). In response to exploration and development operations, the interconnectivity of the pores, or permeability, allows the hydrocarbons to typically flow from the reservoir into a wellbore, without the need for fracture stimulation (Figure 1.1).

Shale gas formations act as a source, a reservoir and a trapping mechanism. The gas is generated from organic material in the shales and trapped within micro pores and existing fractures and adsorbed on the individual particles of shale. Vertical and horizontal drilling of wells and hydraulic fracturing are employed to exploit the shale gas. Unconventional gas is also contained within ‘tight’ or less porous

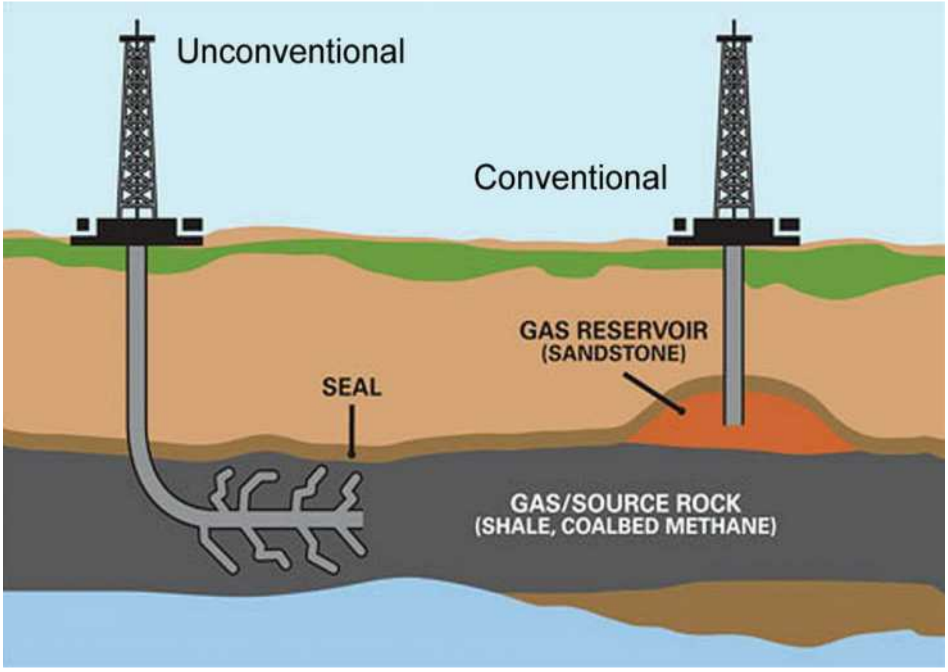
[2] In the Scientific Assessment, the focus is on key activities that present as potential *top order* impact drivers; i.e. those that warrant assessment at the strategic level. It would be the purpose of project level Environmental Impact Assessment to address the many other activities that present as lower order impact drivers.

rock formations that include some sandstones and carbonates (US Energy Information Administration (EIA), 2013). Gas incorporated into coal seams (coal seam gas) also qualifies as an unconventional hydrocarbon product.

Shales may have relatively high porosity but low permeability; therefore, the formation with associated shale gas is stimulated to produce the trapped gas using a technique termed hydraulic fracturing (popularly called ‘fracking’). This process entails typically drilling a well with vertical and horizontal (lateral) sections into a gas-bearing shale formation to achieve maximum exposure of the wellbore to the shale. Sections of the lateral well bore are selectively isolated; fluid pressure in these sections is then increased using surface pumps until the pressure exceeds the shale formation's fracture gradient. Millimetre-scale fractures are created whilst any existing fractures are enhanced within the shale as a result of this hydraulic pressure. The fractures act as pathways for gas to flow out of the shale and into the drilled well (House of Commons Energy and Climate Change Committee, 2011; Holloway and Rudd, 2013). Sand and other materials included in the fracturing fluid prop the fractures open allowing the gas to flow to the surface via the vertical well bores (US EPA, 2012).

Many countries across the globe have gas-rich shale formations (Figure 1.2). In Europe countries have applied a range of policy approaches towards SGD. For example, France and Bulgaria have banned hydraulic fracturing, whilst Poland and the United Kingdom have an ongoing programme of exploratory drilling and testing of hydraulic fracturing (European Commission, 2015). SGD has occurred widely in the United States of America (USA) where shale gas ‘plays’ such as the Barnett and Marcellus formations are important targets for the sector. The onshore USA is unique in that a surface owner may also own the mineral estate (or hold an exclusive development license), unlike most other countries where national governments own the minerals (Kulander, 2013). SGD activities are prescribed, regulated, and enforced at the local, state and federal levels (Williams, 2012). In South Africa the Mineral and Petroleum Resources Development Act (MPRDA, 2002, as Amended in 2008) vests the ownership of the country’s mineral resources, including petroleum, with its citizens. The State acts as custodian of the resources, granting rights to third parties for exploration and exploitation whilst securing benefits for the nation through fiscal arrangements (Norton Rose Fulbright, 2015). The gazetted MPRDA Regulations for Petroleum Exploration and Production (2015) include specific regulations for shale gas exploitation.

Figure 1.1: Schematic comparison between conventional and unconventional gas reserves and extraction techniques (*http://worldinfo.org/2012/01/point-of-view-unconventional-natural-gas-drilling*). Note: conventional gas extraction often involves the establishment of horizontal well sections; also, unconventional gas extraction may involve vertical wells only. It is mainly the hydraulic fracturing process that differentiates the product extraction technique (unconventional versus conventional)



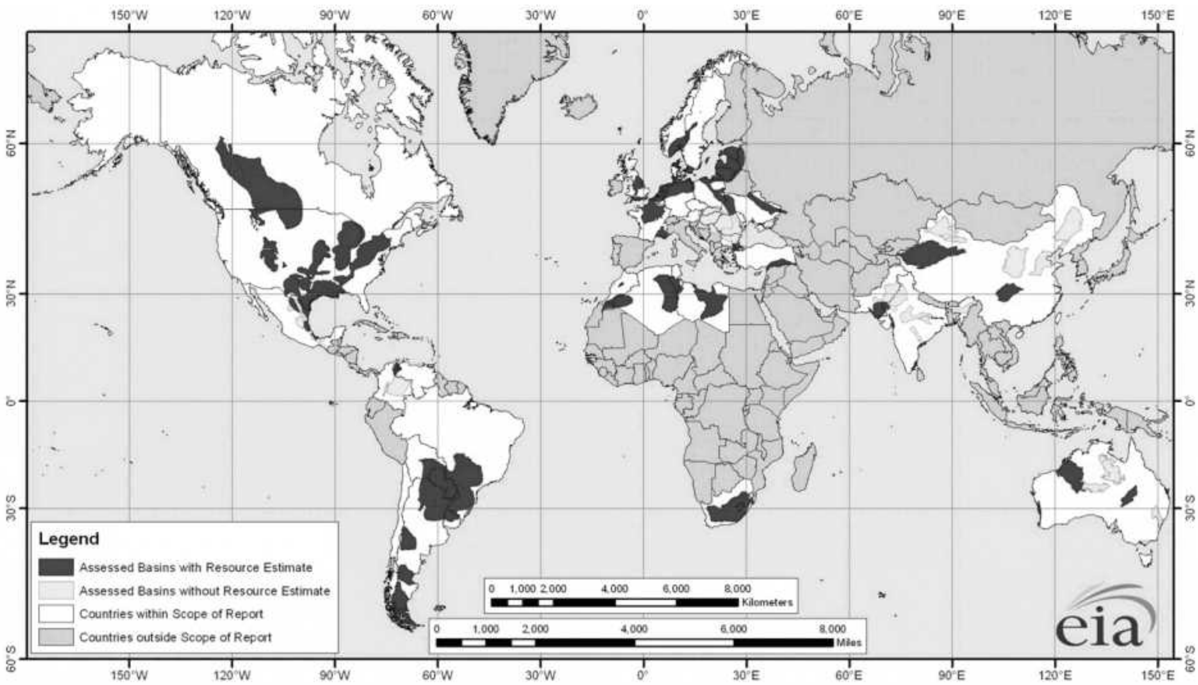


Figure 1.2: World shale gas and oil resources estimated by the US EIA (2013).

As indicated in Figure 1.2 South Africa's shale gas reserves are likely to be concentrated in the sediments of the Karoo Basin. With the exception of SOEKOR's regional oil exploration program in the 1960's (Cole and McLachlan, 1994) there have been no onshore shale gas exploration or production operations undertaken in the country. This implies that the social (including economic) and biophysical attributes of the Karoo are currently unaffected by SGD.

The geology of the study area comprises a succession of sedimentary strata (mainly sandstone, siltstone, mudrock and shale) that attain a maximum combined thickness of some 5 000 m in the south of the main Karoo geological basin. The sedimentary strata represent material deposited by rivers draining into an inland sea over a period of approximately 120 million years, between roughly 300 and 180 million years ago. Much of this timespan brackets the periods in geological time known as the Permian and the Triassic. To the north-east into Lesotho, these strata are overlain by lava intrusions that form the Drakensberg mountains. Except for an area along the southern margin of the study area, dolerite intrusions are widely present elsewhere. The sedimentary and intrusive strata together form the geological Karoo Supergroup.

1.2 The Karoo: Its coupled ecological and social characteristics

1.2.1 Ecological characteristics of the study area

1.2.1.1 <u>Broad-scale ecological context</u>

The areas in which the Karoo shale gas reserves may be concentrated are centred on the Nama Karoo Biome. About 62 % of the study area consists of Nama Karoo and the remainder is made up of Grassland, Succulent Karoo and Albany Thicket biomes. The Succulent Karoo and Fynbos elements are in the west of the study area, Grassland Biome occurs in the eastern part, while Thicket occurs in the south-east. These patterns in biome distribution are explained largely by climatic gradients, especially rainfall seasonality and amount. Geology and soil characteristics serve as secondary local determinants of biome distribution and some of their distinguishing characteristics. According to Cowling and Hilton Taylor (1999) 2 147 plant species, including 377 endemics (plants which grow nowhere else), occur within a core area of 198.5 km^2 within the Nama Karoo Biome. This is less than half the reported total for the less extensive Succulent Karoo Biome, indicating that the broad-scale species richness of the Nama Karoo is relatively poor compared to at least some of the adjacent biomes. Endemism is also relatively low and many species are shared with adjacent biomes.

Within the study area the presence of areas of Thicket Biome in the east and Fynbos in the west increase the total species richness, and it is likely that these areas hold a disproportionate share of the total diversity.

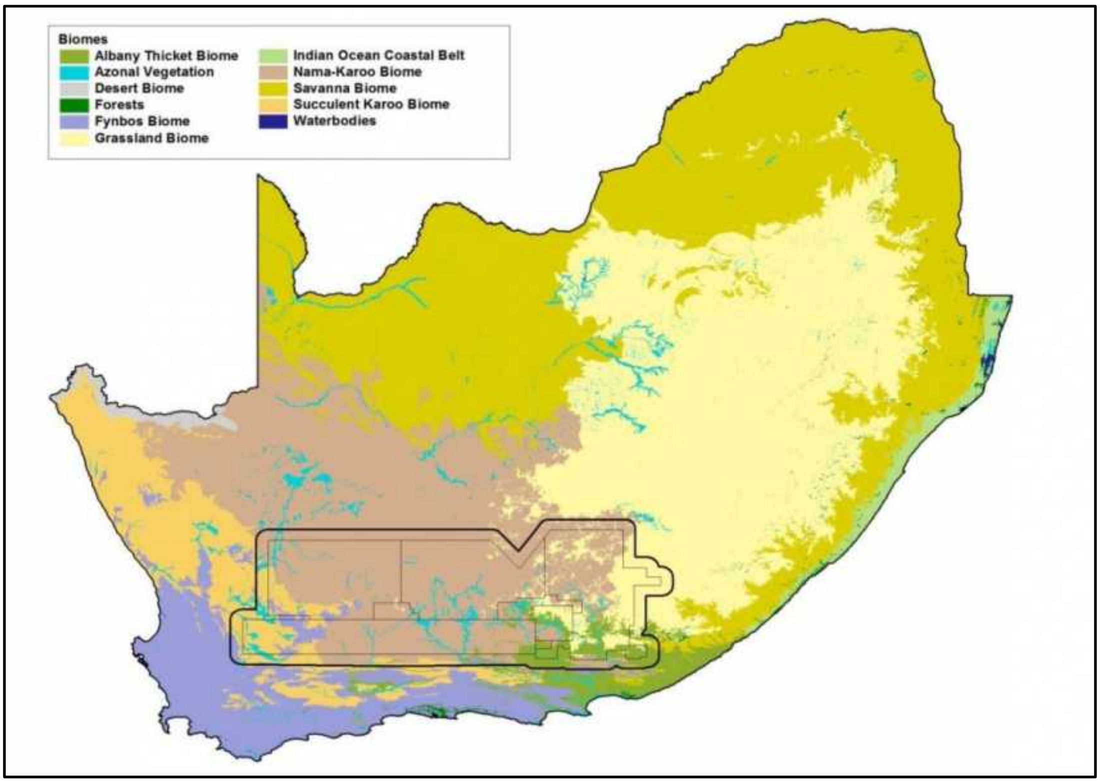


Figure 1.3: Biomes of South Africa (Mucina and Rutherford, 2006), with the study area (including buffer zone) indicated.

1.2.1.2 Surface water

The Karoo is a semi-desert environment, with a mean annual precipitation (MAP) that ranges from 100 mm in the west to 400 mm in the east (Figure 1.4). The median annual runoff is less than 60 mm over most of the study area and falls below 10 mm for much of the western half (Schulze et al. 1997). This assigns a premium value to freshwater resources that are critical, for example, for sustaining local communities and their livelihoods. The western and south-western portions of the study area are not only more prone to extreme but erratic rainfall and associated floods, but also to drought (Figures 1.5 and 1.6).

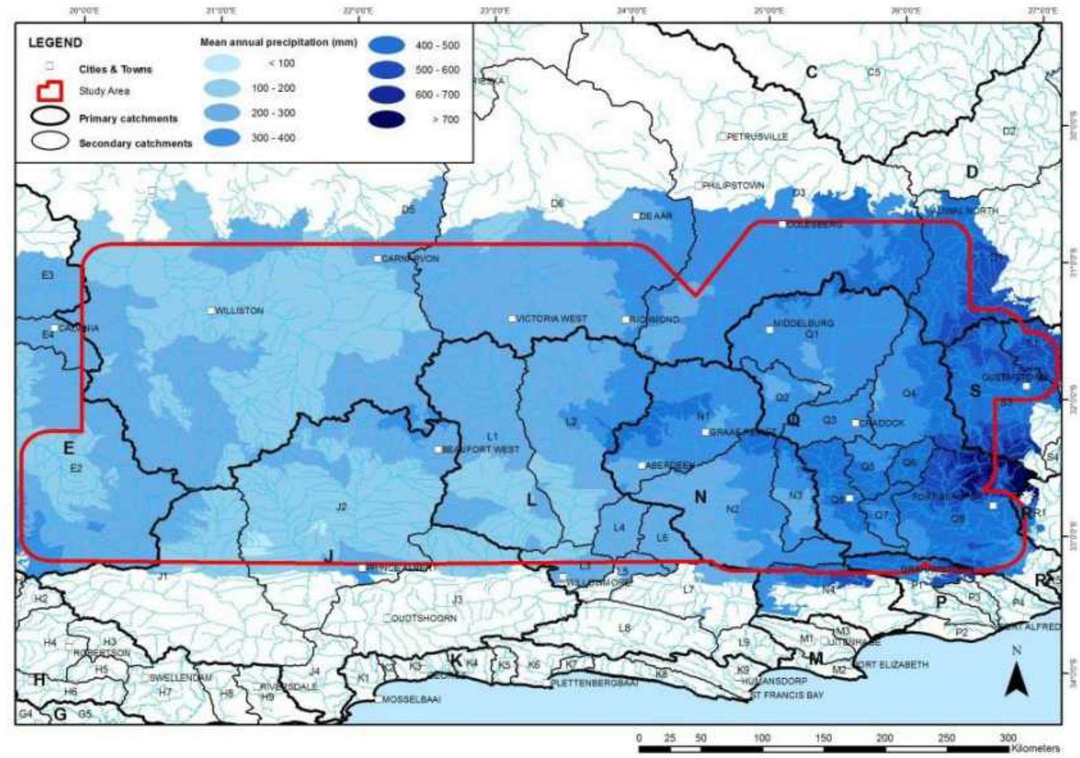


Figure 1.4: Mean Annual Precipitation (MAP) (mm) is the 50 year (1950-1999) average rainfall per Quinary, determined from a 1.7 x 1.7 km grid of MAPs developed by Lynch (2004) with Quinary catchments rainfall determined by techniques described in Schulze et al. (2010)

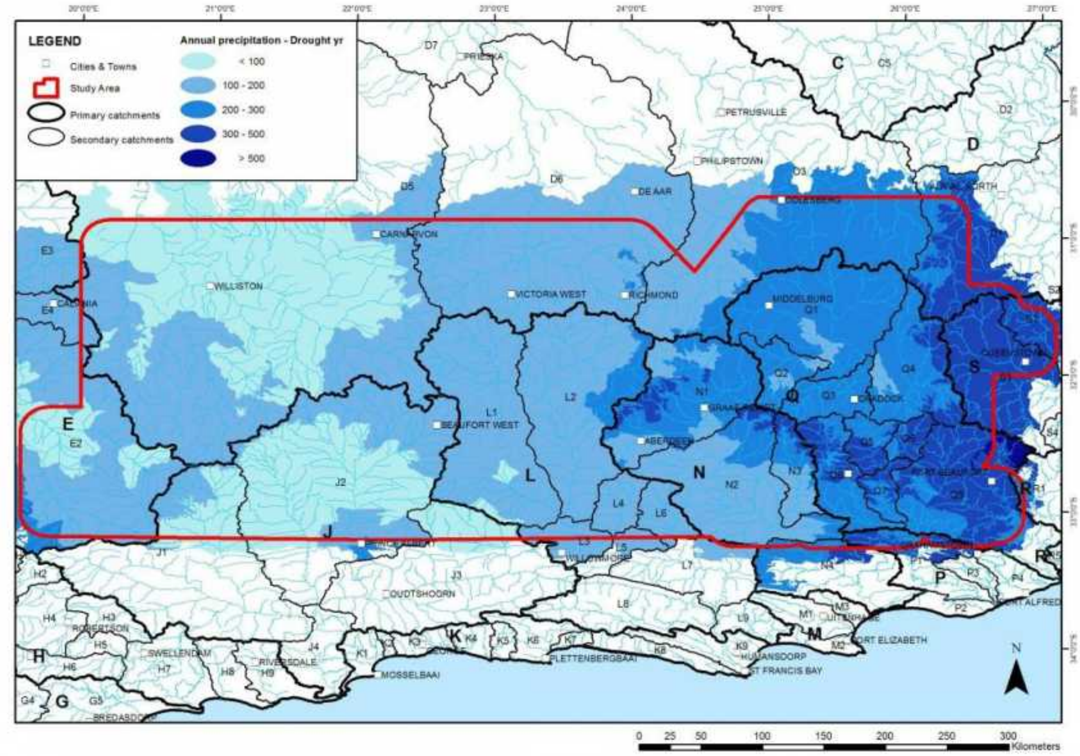


Figure 1.5: Annual Precipitation in a Year with Drought. A year with drought is defined here as one standard deviation below the mean annual precipitation. The map shows a decreasing rainfall gradient from east to west from around 500 mm to under 100 mm per year.

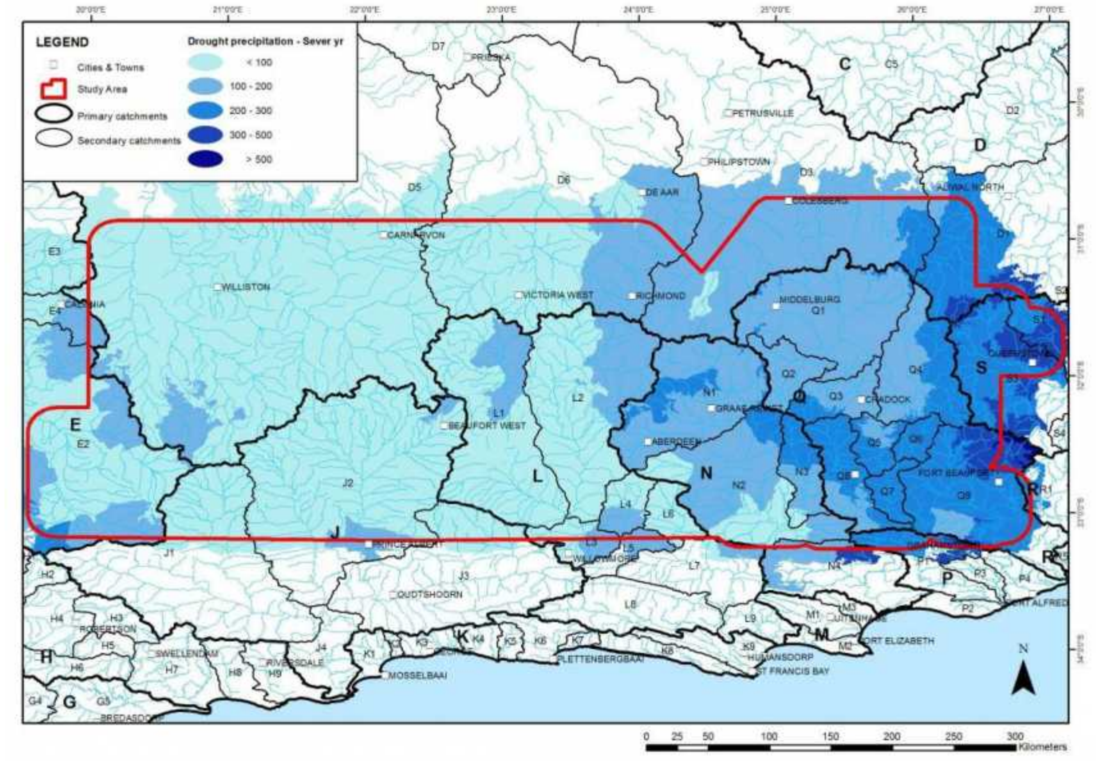


Figure 1.6: Annual Precipitation in a Year with Severe Drought. A severe meteorological drought is defined as 1.5 standard deviations below the mean annual rainfall, and the map shows around 60 % of the study area receiving less than 100 mm in such a year – indicative of the harsh climatic conditions existing in this region.

Set against rainfall data are evaporation rates that also show strong east-west gradients. Large portions of the hotter, western part of the study area experience evaporation rates in excess of 1 800 mm per annum. This reduces toward the cooler eastern part of the study area, although rates are still well in excess of MAP (Figure 1.7).

The Great Escarpment (represented here by the Nuweveldberge) divides the study area into the Lower Karoo in the south, at an elevation of less than 1 000 m, and the Upper Karoo in the north, at an elevation above 1 000 m. The majority of the area north of the escarpment drains northwards via the Riet, Sak, Ongers and Seekoei river systems into the Orange River (and then the Atlantic Ocean), while those areas to the south of the escarpment contribute to the Gouritz, Gamtoos, Sundays and Great Fish River systems that drain into the Indian Ocean. Surface water drainage systems in the study area range from mainly perennial (flowing 11-12 months per annum) in the eastern portion of the study area, to a mixture of ephemeral (flowing for 2-10 months) and episodic (flowing for 0-2 months) interspersed with perennial systems in the western portion.

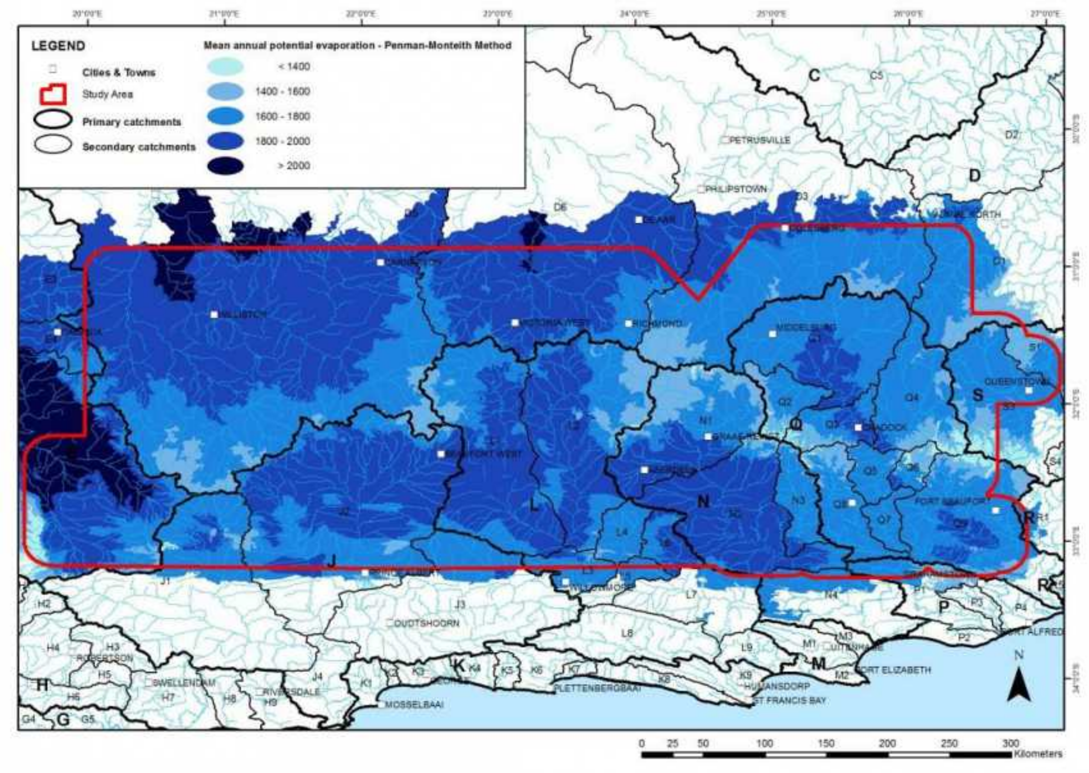


Figure 1.7: Potential Evaporation (PE) is an index of the atmospheric demand of water from a vegetated surface that contains sufficient soil water. PE is directly related to solar radiation and wind, and inversely related to relative humidity. Annual values are high, at generally over 1 600 mm and in parts of the arid west (even > 2 000 mm). The band of relatively lower PE running through the centre occurs over the cooler higher lying east-west mountain range.

Although probably less than half of their extent has been mapped, surface water-associated ecosystems account for about 5 % of the study area. These are largely riparian ecosystems, although there are also some wetlands associated with the endorheic pans of the Bushmanland and Upper Karoo areas.

The sporadic rainfall events result in unreliable and unpredictable surface water runoff to rivers and dams. Soil erosion results in sediment entrainment in runoff and accelerated siltation of dams, with consequent reduction in storage capacity. These factors, coupled with the generally low MAP rates, substantially raise the value of underground water resources, which are relied on for agricultural, domestic and other uses over much of the study area.

1.2.1.3 Groundwater

Groundwater occurs in saturated subsurface strata. The water derives from various sources such as rainwater that infiltrates downward through the unsaturated zone to the water table (rainfall recharge), lateral or vertical inflow from adjacent groundwater systems (subsurface recharge) and inflow drawn from adjacent surface water bodies (induced recharge). Rainfall recharge represents the principal mechanism of groundwater replenishment in the Karoo. In this environment, it is typically assigned a value of 3 % of the average annual rainfall (Van Tonder and Kirchner, 1990).[3] This water is referred to as meteoric water, indicating that it is derived from atmospheric sources.

In the Karoo, there is a critical dependence of farming and human settlements on groundwater. The development and exploitation of groundwater resources for purposes of water supply require the sinking of a borehole into subsurface strata. Where conditions are favourable, shallow groundwater is typically encountered in weathered strata near the surface. At greater depth, groundwater is associated with fractured strata. The influence of dolerite intrusions on the occurrence of groundwater makes these structures the primary targets for the positioning of a successful borehole. The mineralogical composition of dolerite facilitates its detection by means of geophysical techniques. The shallow aquifer (<300 m depth) is well researched and fairly well understood. It supplies local wellfields and farm boreholes. Deep groundwater, including its connectivity with shallow aquifers, is only poorly understood. Methane occurs naturally in groundwater penetrated by a number of boreholes in the study area.

The presence of deep groundwater sources in the Karoo (i.e. far below the usual drilling depth of farm water supply boreholes) is inferred from thermal springs and data collected from a few very deep wells drilled by SOEKOR.

The considerable pressure of the overlying rock mass has the potential to drive some relatively deep groundwater to surface, where there is a pathway for this to occur, resulting in hot springs. If released, the flow of water might reduce over time as the pressure in the deep-seated host strata dissipates through loss to the atmosphere. In instances such as at Aliwal North there is no evidence of a reduction in such flows to the surface over time.

Deep groundwater is referred to as connate (fossil) water if it was trapped in the rock strata when the rock formed millions of years ago, in which case it typically has a high dissolved mineral content and is not replenished naturally. If the deep groundwater derives from meteoric sources, it is referred to as formation water and could be replenished naturally often over long distances from a distal recharge area, which generally makes it less saline than connate water. The temperature of deep groundwater generally increases with the depth from which it rises. Groundwater from the carbon-rich strata of the Whitehill Formation also contains hydrogen sulphide.

Uranium occurs quite commonly in the southwestern part of the Karoo Basin as shallow tabular ore bodies in association with sandstones of the Adelaide Subgroup of the Beaufort Group (Cole,

[3] There will be considerable variation in replenishment factor (%) from place to place and between years, see the Water Chapter 5

1998). The combined extent of these occurrences is sufficient to define the so-called Karoo Uranium (metallogenic) Province, described by Cole et al. (1991) as extending from the north-eastern part of the Western Cape Province across the south-eastern part of the Northern Cape into the southern Free State. Four orebodies were subject to feasibility studies in the late-1970s. One of these, located 42 km west-southwest of Beaufort West, showed an average ore grade of 1.5 kg /t at a depth of 13 m (Cole, 1998). Steyl et al. (2012) report that the results of various geochemical studies of fine-grained sedimentary rocks of the Karoo Supergroup show that the shales are not enriched in possibly ‘dangerous’ elements, including uranium. In the context of SGD these authors do, however, recommend further geochemical characterisation of the shale gas-bearing strata.

Murray et al. (2015) report concentrations in the range 0.002 to 0.041 mg /l in shallow Karoo groundwaters. These authors identified higher uranium and radon concentrations in the ‘shallow’ groundwater than in warm spring-waters rising from a maximum depth of ~1000 m. In a study focussed specifically on the incidence of naturally occurring hazardous trace elements in groundwater nationally, Tarras-Wahlberg et al. (2008) report concentrations of up to 0.539 mg /l in groundwater sampled from old uranium exploration boreholes around Beaufort West and Sutherland and concentrations of <0.016 mg U/l in water supply boreholes in the same area.

1.2.1.4 Ecological patterns and drivers

The study area is characterised by low (<1 m tall) woody shrublands with a variable grass layer. The latter may become dominant on sandy soils or on cooler and wetter landscape units such as mountain plateaus. Trees tend to be restricted to drainage lines and other localised moist habitats (Cowling and Hilton Taylor, 1999). There has been considerable speculation regarding the proportion of grass in the vegetation before European colonisation (Hoffman et al., 1995); however, it is clear that this varies seasonally and over decadal time-scales according to cycles of drier and wetter summer rainfall conditions; which are key drivers of vegetation patterns (Bond et al., 1994; Hoffman et al., 1990).

A key driver of vegetation patterns in South Africa, and especially within the more arid parts of the country, is rainfall (Figure 1.8). The majority of the study area is arid and receives an average of around 250 mm annual rainfall. Some areas such as the Tanqua Karoo, in the rain-shadow of the Cederberg, receive less than 100 mm. Rainfall seasonality is also important. Most of the study area receives the greater proportion of its rainfall in summer, with some winter rainfall-dominated areas occurring along the western margin (Figure 1.8).

Despite the large increase in game farming in recent years, the largest area of the study area is still used for domestic livestock grazing. Grazing by livestock or game is the primary determinant of rangeland condition across the study area (O’Connor and Roux, 1995; Todd, 2006).

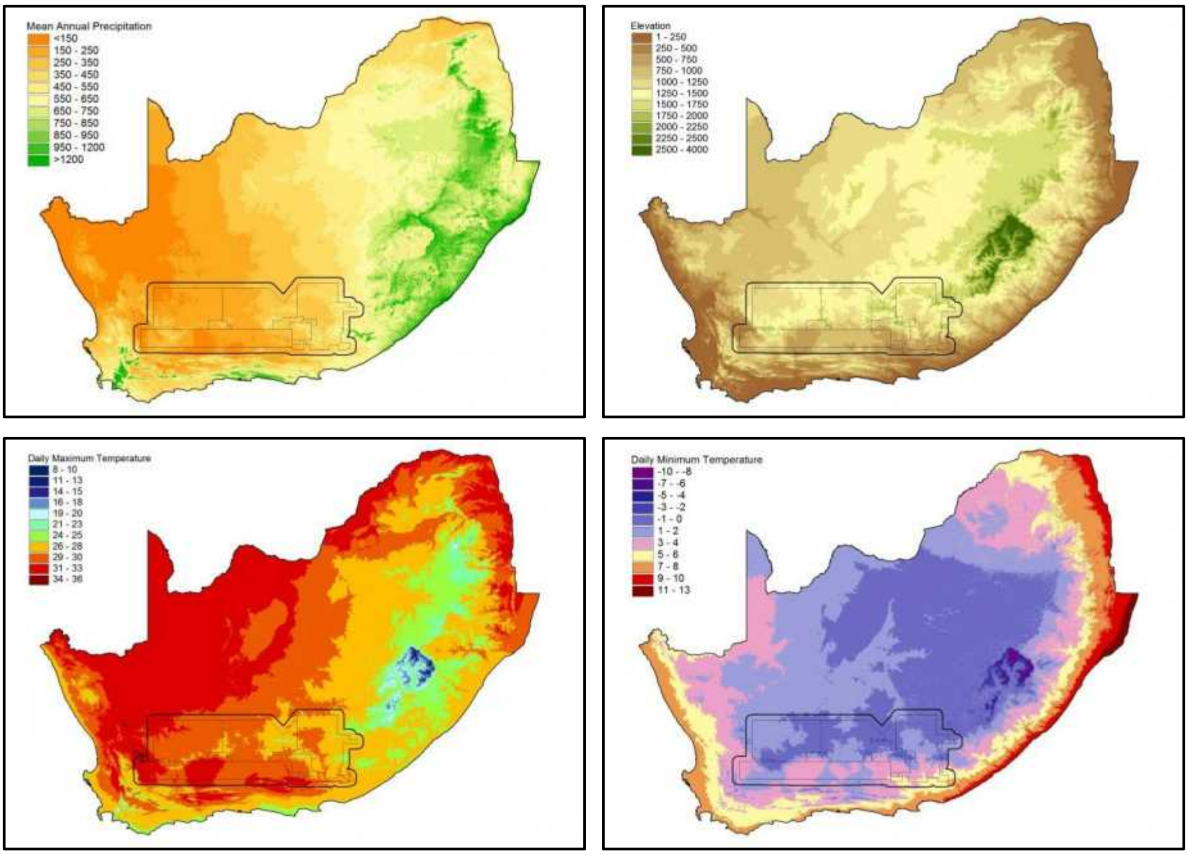


Figure 1.8: Dominant climate and physical drivers of ecological patterns and processes across the Karoo: Patterns of mean annual precipitation, elevation, daily mean maximum temperature for February and daily mean minimum for July (the hottest and coldest months respectively).

1.2.1.5 <u>Land-use effects on ecosystems</u>

Most vegetation types are still more than 98 % intact in terms of structure and composition. The total extent of intensive agriculture is less than 1 % of the total area, restricted to the vicinity of the major rivers (which are typically dry) including the Sundays, Buffels, Gamka, Kariega, Great Fish and Groot Brak. The areas of intensive agriculture are, however, of disproportionate importance to farming enterprises due to their high productivity compared to the surrounding landscape.

Concerns over the degradation of the study area as a result of agricultural practices have strongly influenced agricultural policy over the past century (Hoffman et al., 1999). Game farming has grown rapidly over the past 20 years. Many farming enterprises are mixed, with both game and livestock managed on the same property; in many cases tourism is an important farming enterprise.

1.2.2 Social and economic characteristics of the study area

1.2.2.1 <u>Social and economic responses to a challenging bio-physical environment</u>

Remarkably, the relatively harsh bio-physical environment of the study area does not appear to be a major obstacle to social and economic development.[4] Although the causal factors of current development cannot be stated with a high degree of certainty, an initial suggestion would include: inherited infrastructure and diverse business services; investment capital and creative skills (Ingle, 2010a); land tenure arrangements that facilitate land sales, purchases, investment and consolidation; public sector capacity, whether in provincial departments or municipalities; and human ingenuity in turning local conditions into marketable assets (such as the "space, silence and solitude" of the Karoo (Ingle, 2010b)) through entrepreneurial experience and skill.

1.2.2.1.1 Urban development and planning

The discussion that follows applies to the following geographic sub-regions of the study area (Figure 1.9):

- *Great Karoo*: the arid areas of the Central Karoo District Municipality (DM), Pixley ka Seme DM, the western part of Cacadu DM and the western part of Chris Hani DM; typical towns include Beaufort West, De Aar, Graaff-Reinet, Middelburg and Cradock;
- *Eastern Cape Midlands:* Towns located within commercial agricultural areas, but which are not in the "Karoo proper"; here the environment is less arid and often quite mountainous; the area includes towns such as Sterkstroom, Queenstown, Bedford, Grahamstown, Somerset East and Fort Beaufort (these straddle the eastern parts of Cacadu DM, the western part of Chris Hani DM and the western parts of Amathole DM);
- *Eastern Cape Traditional*: Towns located within communal areas, such as Peddie, Lady Frere, Alice (these straddle the eastern parts of Chris Hani DM and the central parts of Amathole DM); and
- *Sundays River Valley*: *The* intensive agricultural areas near Kirkwood in the southern part of Cacadu DM.

[4] Naturally, there are limits on development imposed by the capacity of key ecosystem goods and services (e.g. water availability; see Sections 2.1.3 and 2.1.4)

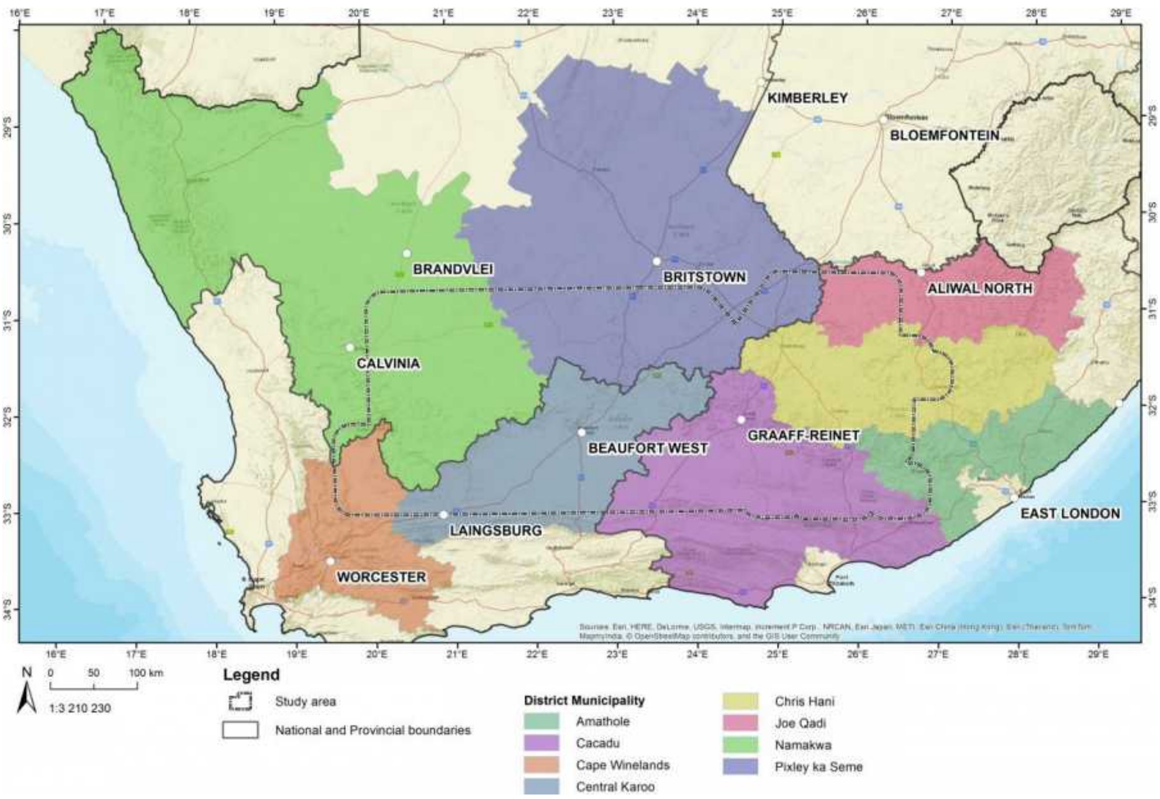


Figure 1.9: Geographic sub-regions included in the study area.

The gross domestic product (GDP) in the study area is generally low when compared to towns and cities located outside the region. Nevertheless, the Great Karoo has shown an increasing economic growth rate (around 4 % per annum, albeit from a low base) and the economic growth rate of the Central Karoo District is now consistently higher than the Western Cape Province (CKDM, 2012: 39). The Central Karoo District, which is classified as a rural development "poverty node", performs significantly better than other poverty nodes elsewhere in the country over a range of indicators (Business Trust, 2007:39). The study area has seen several towns growing in population and economic resilience, while the economies of other towns have dwindled; this is due to a range of dynamics, including new patterns of transport, markets, government services and entrepreneurial innovation (Nel et al., 2011).

Economic strengths vary significantly from the extreme eastern parts of the study area towards the west. In the Great Karoo, commercial agriculture, tourism and commerce are relatively well developed (Lawson et al., 2013). Local economies are more diversified and infrastructure is generally good, including banking, communication and roads. In the Cape Midlands and Traditional Eastern Cape, the towns are generally less developed, with high transport costs, poorly developed markets and poor telecommunications (CHDM, 2010:57). The share of government services as a proportion of regional GDP is relatively low in the Great Karoo (around 10 %) while in the extreme east it is much higher.[5] Levels of unemployment also vary along a west-east axis. In Central Karoo the unemployment rate is about 31 %, whereas in Chris Hani District it is pegged at about 57 % (CKDM, 2012:45; CHDM, 2013:29).

A very high-level generalisation relating to urban development and planning is as follows: *western areas* - more developed and economically diversified, higher levels of employment - contrast with *extreme eastern areas* - less diversified, higher unemployment.

1.2.2.1.2 Population shifts

The Great Karoo has experienced population growth between 1996 and 2011, which in itself is not so remarkable; however, an important phenomenon is that the annual population *growth rate* has increased significantly during this period. This is most likely due to in-migration.

In the extreme east, the study area borders on, and partly encompasses, areas of the Eastern Cape with higher population densities. These areas (part of the former Transkei, with a proportion of land still under tribal authority ownership) have higher densities in terms of settlements. Over the period 1996 – 2011 towns such Queenstown, Alice and Grahamstown (all on the border of, or just outside, the study area) have shown relatively high population growth accompanied by significant out-migration into surrounding rural areas (DST, CSIR, HSRC, 2015). Some of these trends are depicted in Figure 1.10.

Pixley ka Seme District (De Aar area) had a negative growth rate between 1996 and 2001, which became a positive growth rate between 2001 and 2011 (Atkinson, 2015). In contrast, the population in Eastern Cape Traditional Areas is declining in absolute terms, largely due to out-migration, but also possibly due to HIV/AIDS mortalities (CHDM, 2010:37; ADM, 2015:21).

[5] Data in Chris Hani and Amathole District municipalities do not differentiate between government and private community services.

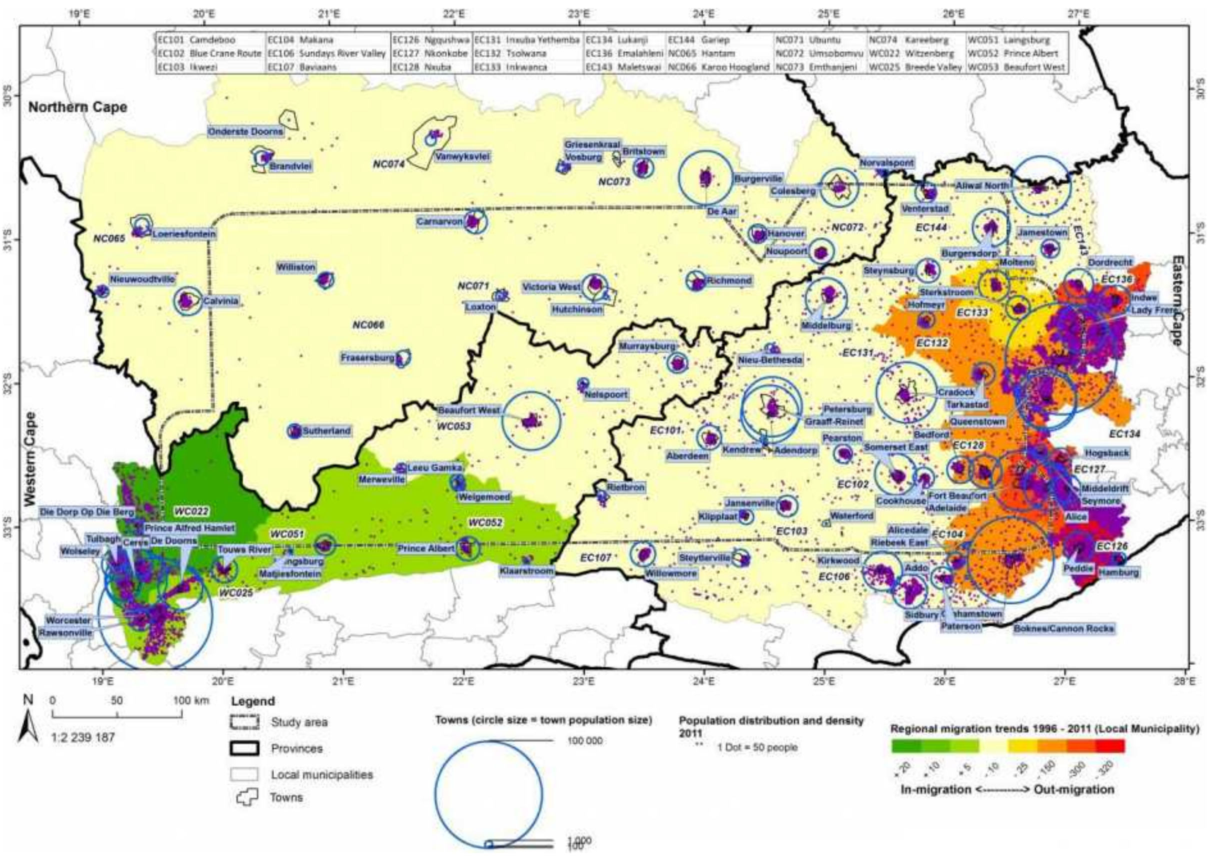


Figure 1.10: Population density, distribution and regional migration trends for Local Municipalities within the study area (Population Distribution Indicator, CSIR (2014))

1.2.2.1.3 Tourism

There are many indications that the Great Karoo is increasingly providing tourism product and growing tourism demand, in terms of ecotourism, interest in historical arts, cultural attractions, astro-tourism, cuisine and other niche markets (Gelderblom, 2006; Saayman et al., 2009; Toerien, 2012; Ingle, 2010b; Table 1.2). Overnighting by people travelling through the Karoo and business tourism also add to the tourism demand. Although not limited to these centres, the Karoo Midlands towns of Cradock and Somerset East have developed significant tourism sectors (Atkinson, 2012). Towards the extreme east of the study area, tourism activity becomes much more isolated (e.g. Hogsback and Stutterheim in Amathole DM) and contributes much less to economic development and diversification.

Tourism is dependent on investment and marketing. In the Great Karoo and Karoo Midlands sub-regions there is significant in-migration of investors (often retirees, or urbanites seeking an alternative quality of life (Ingle, 2013)). This phenomenon is less pronounced towards the eastern extreme of the study area.

1.2.2.1.4 Agriculture

The western areas of the study area are primarily oriented to small livestock (goats, sheep, angora goats) producing a variety of meat, wool and fabric products. Stud farming is also well established, with various regions presenting as hotspots for different stud farming foci (e.g. Middelburg) often with associated business tourism (e.g. buyers attending auctions). In the Karoo Midlands cattle-holding is increasing in scale (Development Partners, 2009:87). Farm sizes are increasing and more efficient farming practices have maintained levels of productivity. There has been a renewed focus in South Africa, and more specifically in the Karoo, on the re-innovation, transformation and lengthening of agricultural value chains for the purposes of more equitable job creation. A shift is underway from agricultural jobs to agri-processing jobs, such as with the wool value chain and the manufacturing of wool products rather than exporting the bulk of raw wool. Also, there has been exploration and introduction of crop types that thrive in arid and semi-arid areas such as the Karoo. A successful example of this is the small rooibos tea farmers case study in the Northern Cape (CASSALD, 2013).

There appears to be significant agricultural capital for investment in the Great Karoo and Karoo Midlands with many farmers diversifying into game farming or privately owned game parks. Hunting is providing increasing levels of revenue to farmers (Development Partners, 2009:118). There is growing mutual support between agriculture and tourism due to farm-stays, ecotourism and hunting.

1.2.2.1.5 Economic sectors compared in key municipalities

The study area is largely defined by an agricultural economy (from a production perspective) and characterised by commercial farms, interspersed with a variety of local and regional service towns, nature reserves and conservation areas (Figure 1.11). For reasons of financial feasibility, farms are quite large. Smaller farming units with intensive agriculture, sustained by irrigation, are established next to major rivers. Towns such as Beaufort West, Graaff-Reinet, Middelburg, Colesberg and Cradock are important regional service towns, accommodating the bulk of the population (DST, CSIR and HSRC, 2015).

More than half of the towns in the study area include around 20 % of households living in poverty, a relative decline in working age population and a decline in formal economic production. This results in increased levels of socio-economic vulnerability (DST, CSIR and HSRC, 2015). Within this context, even though service delivery improvements have been made in many towns, municipal functioning is jeopardised by diminishing economic production and financial viability.

Even though the study area is not a key national economic production zone, it is crossed by important networks of national and inter-regional transport routes carrying a large volume of road and rail freight. It is also crossed by a number of high voltage electricity corridors, with more planned. The economic significance of this is likely to increase in response to the following:

- Large parts of the region fall within areas identified as ideal in terms of horizontal radiance and annual mean wind power for potential solar and wind energy generation (a significant number of green energy projects related to wind and solar energy are under consideration in the area (EDD, 2014));
- Tourism through-traffic will continue to contribute to the economy given the range of natural and cultural heritage and tourism attractions in the region;
- The N1 freight corridor will continue to increase in strategic economic importance; and
- The government's Strategic Infrastructure Programme, which includes plans to upgrade the road/rail/port elements of the Manganese Corridor linked to one or more Eastern Cape ports, and support for greater connectivity between urban and rural areas and between major centres for manufacturing and agri-processing.

These initiatives are expected to provide local job creation and enable regional economic growth (EDD, 2014).

1.2.2.2 Municipal capacity and economic development

There is a difference between municipalities in the western/central and extreme eastern parts of the study area, which is influenced by both a legacy of underdevelopment and current challenges with regard to revenue sources and other factors. For example, Camdeboo Local Municipality has been described as an effectively run municipality with one of the strongest balance sheets of all Eastern Cape municipalities (Development Partners, 2009:153). The IDP for municipalities in Amathole District, for example, convey that they face challenges in areas such as infrastructure maintenance (ADM, 2015:108).

Municipal capacity as a determinant of development will be critical in future as many types of investment (including mining, manufacturing, tourism and potentially shale gas development) depend on municipal capacity. Critical municipal capacity required to implement, monitor and manage complex investments include: waste water treatment, water pollution control, environmental pollution control, air quality management, environmental risk assessments, occupational health and safety assessments, infrastructure safety, including pipelines and tankage, disaster management and noise control (CHDM, 2013:73).

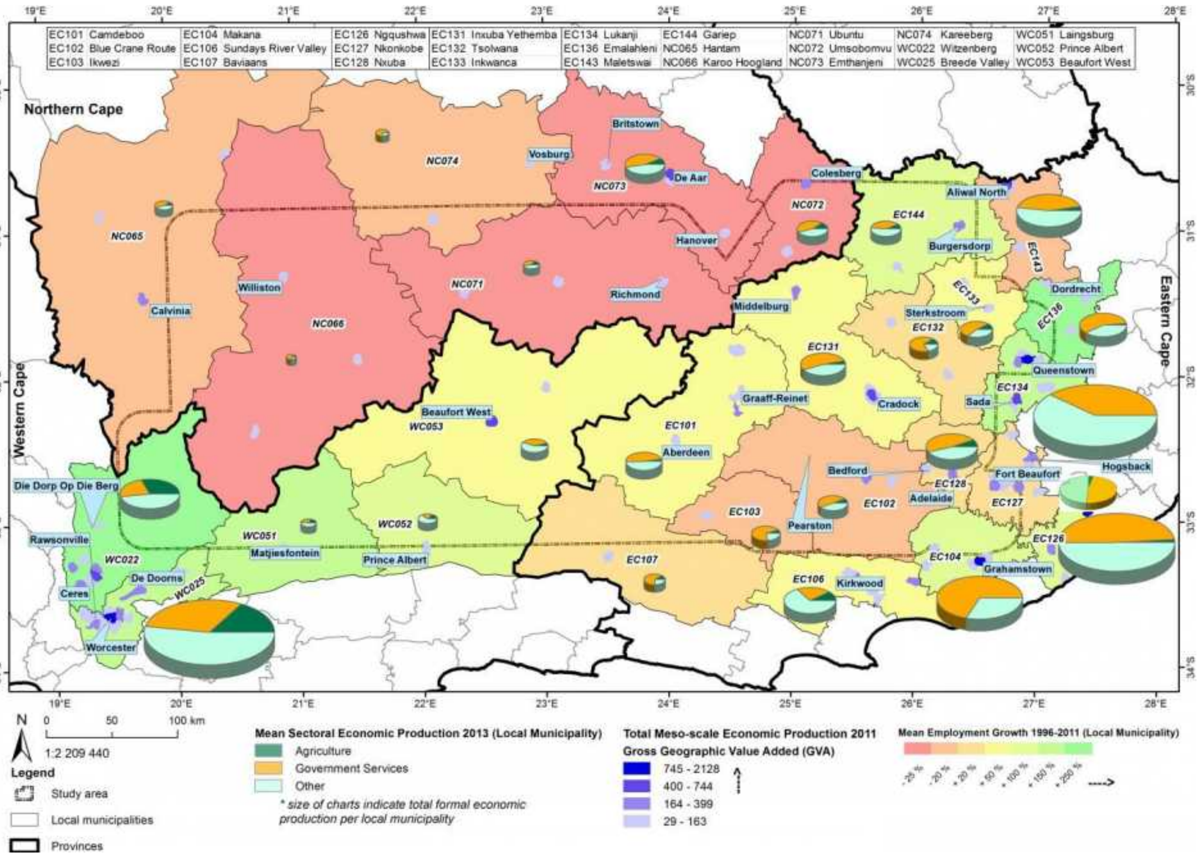


Figure 1.11: Sectoral- and meso-scale economic production and mean employment growth for Local Municipalities within the study area (Economic Production Indicator, CSIR (2014). Note, that although agriculture does not present as making the highest contribution in terms of economic production, it plays a major role in job creation and livelihoods within the study area

1.2.2.3 The social fabric

Social fabric is a collective term for numerous complex and subtle social relationships. A few proxy variables can be used to suggest the strengths and weaknesses of the social fabric in different towns and rural areas in the study area.

One proxy variable is municipal-business collaboration. In some towns, such as Beaufort West and Cradock, a relatively high level of collaboration can be found (Atkinson, 2012); however, this cannot be generalised to other towns. One of the most successful towns is Somerset East where a vibrant Local Economic Development Agency has attracted considerable capital and projects by working closely with the Blue Crane Local Municipality. In contrast, frustration is expressed in the Amathole IDP regarding public apathy in municipal IDP planning processes (ADM, 2015:118). These factors are highly complex and no easy comparisons or generalisations can be made; however, it is highly likely that effective local leadership alliances can strongly boost the fortunes of a town or district.

A second proxy variable is the density of civil society organisations that provide opportunities and support for local people (including the poor). In Beaufort West, for example, numerous local organisations are active, with community membership and participation in church/religious and sports structures being high (Wyeth and Webb, 2002:21, 47).

1.2.3 Scenario 0: Reference Case - Imagined future without shale gas development

In the absence of SGD, which is defined for the assessment as a reference scenario, the most significant drivers of *ecological change* in the Karoo over the next 30 years will be climate change and land-use dynamics. Apart from an increase in average temperature, climate change is likely to result in an increased frequency of extreme events such as drought and floods. These events are deleterious to farming activities and either directly or in concert with land-use and temperature increase will ultimately have negative impacts on biodiversity. There are two land-use effects that are expected to exert most influence on ecosystem integrity: increased game farming, implementation of land reform (not necessarily negative),[6] renewable energy development and uranium mining.

Water resources are sensitive to the impacts of climate change. In the case of surface water, as rain intensities increase, this will translate into greater degrees of flooding, erosion, sediment transport, and therefore higher siltation rates within water impoundments. Groundwater resources are likely to benefit from higher intensity episodic rainfall events, which can allow for above average recharge conditions (Van Wyk, 2010). It is likely that the value of groundwater resources in an increasingly arid Karoo environment will become greater compared to surface water.

In the Great Karoo and Midlands, private land ownership will enable access to finance and associated investment in agriculture, tourism and other rural activities, which in turn stimulate economic multipliers in towns. Cultural and ecological tourism in the Great Karoo and Eastern Cape Midlands will grow steadily, giving rise to further economic diversification. In the extreme east, tourism is expected to remain underdeveloped.

[6] Land redistribution will be relatively limited in the existing commercial farming areas. It is uncertain to what extent land tenure reform may materialise in the traditional areas in the extreme east of the study area.

Projected climate changes for the Karoo

Projections of temperature and rainfall for the Karoo are presented here based on the median (50th percentile) of an ensemble of six dynamically downscaled Global Climate Models (GCMs) (Engelbrecht et al., 2013; Engelbrecht et al., 2009; Malherbe et al., 2013).[7, 8] Change is expressed as an anomaly, which is the difference between the average climate over a period included within the last several decades (1971-2000) and the projected climate in the short- to medium-term (2021 to 2050). The projected changes are based on Representative Concentration Pathways (RCPs), specifically RCP 8.5 and RCP 4.5 Wm-2 scenarios,[9] which assume different paths of development for the world (IPCC, 2013). RCP 4.5 describes a future with relatively ambitious emission reductions, whereas RCP 8.5 describes a future with no reductions in emissions. Emissions in RCP 4.5 peak around 2040, then decline; in RCP 8.5 emissions continue to rise throughout the 21st century (Meinshausen et al., 2011; Stocker et al., 2013).

Temperature

Temperatures are expected to increase between 1 and 1.5 °C (RCP 4.5) and between 1.2 and 1.8 °C (RCP 8.5) over the Karoo region. The increase in temperature is projected to occur in association with an increase in the number very hot days (number of days when the maximum temperature exceeds 35°C).

Rainfall

Projected changes in rainfall are typically harder to detect than that for temperature, but it is likely that South Africa will experience a reduction in annual rainfall amounts and an increase in rainfall variability. Rainfall is expected to decline over the Karoo region, with possible slight increases along the north-eastern border. Some areas of the Karoo may experience a slight increase in extreme rainfall events in the future but this change needs to be interpreted in conjunction with evidence from historical trends in extreme rainfall events. The number of dry days is also expected to increase further indicating a drying trend in the region.

Commercial agriculture will become more sophisticated to ensure access to national and international markets. The marketing of Karoo produce will become more effective, generating higher returns to farmers. Many farmers will diversify into game farming, agri-tourism, hunting and other activities to

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7 A projection is a statement of a possible future state of the climate system, dependent on the evolution of a set of key factors over time (e.g. carbon dioxide emissions).

[8] An ensemble of models refers to a set of individual climate models used to project different (but equally plausible) climate futures.

[9] Cumulative measure of human GHG emissions from all sources expressed in Watts per square meter (Stocker *et al.*, 2013).

increase their economic resilience. It is possible that as tourism develops, more labour-intensive services (such as restaurants and accommodation) will materialise.

Towns will continue to grow as long as social grants are paid. Any reduction or elimination of social grants (e.g. due to fiscal difficulties) will reduce growth in rural towns. It would reduce spending power and thereby undermine local businesses. Renewable energy solutions have become an affordable technology (SAIREC, 2015). Apart from the larger renewable energy national grid extensions, the beyond the grid smaller renewable energy opportunities have made isolated rural communities more self-sustainable.

ICT interconnectivity will become a significant socio-economic development enabler. It will address many of the problems of remoteness as distance becomes irrelevant. The advances in eHealth, eAgriculture, eEducation and even eGovernment (*inter alia*) have the potential of turning around the declining economies of dying towns, potentially reducing the numbers of youth migrating to cities (ITWEB, 2015).

Those towns within effective municipalities are likely to steadily grow their economic base. This will stimulate further rounds of investment. Where municipalities are under capacitated, investment and growth will be less pronounced. Commercial farmers will become primarily urban-based (in terms of where they live), but are expected to develop their farm infrastructure in response to agricultural diversification, also targeting rural tourism. These trends will be less marked in the extreme east of the study area.

For the communal farming areas, there are two sources of economic promise: First, that producer organisations will empower local farmers to become more profitable with their current land holdings; and second, that prosperous local farmers will gain access to more land (through a variety of rental or collaborative schemes) and gradually become commercial farmers.There are significant economic prospects for the arid Karoo, the more temperate midlands and for the communal extreme eastern areas. In some cases, these potentials will be largely achieved if sufficient government and private sector energies can be locked in. In some towns, economic development is likely to remain patchy and vulnerable to economic shocks.

1.3 Petroleum geology in the Karoo

1.3.1 Geological features of the Karoo Basin

The main Karoo Basin is filled with sedimentary formations of the Karoo Supergroup, and covers an area of approximately 700 000 km^2, representing more than half the surface of South Africa. Within the study area, ~87 % of the surface area comprises intercalated arenaceous and argillaceous strata of the Beaufort Group (Figures 1.12 and 1.13). From a flat-lying morphology in its northern part, the basin deepens and the sedimentary succession thickens towards the south-west, up to its interface with the northern margin of the mountains of the Cape Fold Belt (CFB) mountains.

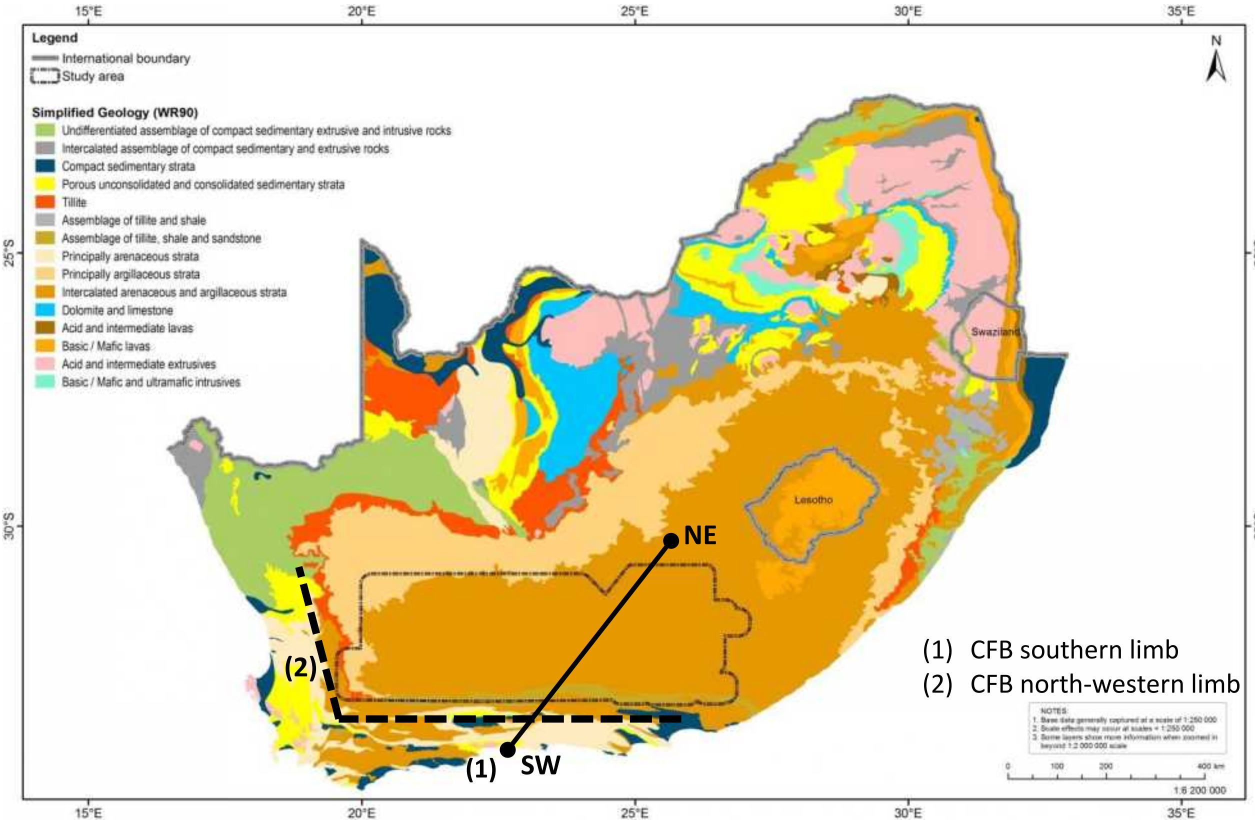


Figure 1.12: Simplified geology of South Africa showing the significant extent of the Karoo Basin (light brown and brown shaded area) deepening from the north-eastern interior to the south-central interior where it abuts against the southern limb of the Cape Fold Belt (CFB); section line SW-NE defines schematic profile in Figure 1.13.

Sedimentary rocks of the Karoo Supergroup

The sedimentary formations are subdivided into groups that reflect variations in depositional environment, rock type (lithology), position in the geological record (stratigraphy) and age (chronology). At the base of the succession, and therefore the oldest, is the glacial deposit (tillite, diamictite) of the Dwyka Group. This is overlain in turn by mainly fine-grained sediments (mudstone, siltstone, shale) of the Ecca Group and, with the inclusion of subordinate sandstone, the Beaufort Group.

SACS (1980) recognizes six distinguishing features between the Ecca and Beaufort groups that collectively are "……. considered to reflect a major change in environment, from deposition in a large body of water, possibly marine, in the case of the Ecca, to generally terrestrial, river-dominated conditions in the case of the Beaufort". Periodic and cyclical deposition is evident in much of the sedimentary column throughout the Ecca and Beaufort groups. Such strata are collectively referred to as rhythmites.

The Ecca and Beaufort groups are themselves subdivided into formations on similar grounds that define the groups. Of direct relevance to this study are the carbon-rich shales of the Prince Albert, Whitehill and Collingham formations at the base of the Ecca Group, which is why they are also referred to as lower Ecca strata.

History of petroleum exploration in the southern Karoo Basin

The Southern Oil Exploration Corporation (SOEKOR) was established in 1965 with the mandate to prove or disprove the existence of economic amounts of oil and gas in South Africa. Seismic surveys were initiated in the southern part of the Main Karoo Basin, and between 1965 and 1972 a total of some 13 000 km of data was acquired (Fatti and Du Toit, 1970). Exploration drilling that was undertaken in the same period demonstrated the presence of gas within the Ecca shales, with minor high pressure, low volume gas shows having been encountered in most of the 12 wells drilled in the southern part of the Karoo Basin (Rowsell and De Swardt, 1976).

In 1976 a comprehensive study was initiated by the Council for Geoscience to investigate the oil-shale potential of the Whitehill Formation on the western flank of the Karoo Basin (Cole and McLachlan ,1994). Sixteen cored boreholes were drilled in the area between Strydenburg and Hertzogville. The study was subsequently extended to include all available borehole logs and cores over the whole extent of the Whitehill Formation, with the logs of 48 borehole and petroleum exploration wells that intersected the Whitehill Formation having been considered. It is these data that form the basis of the majority of shale gas resource estimates for the Karoo that have been made to date.

The Petroleum Agency SA (PASA) acts as regulator for exploration and production activities and is also the custodian of the national petroleum exploration and production database. In 2006 PASA focused on locating and assembling the geological and geophysical data relating to the southern part of the main Karoo Basin. In 2012 the agency also provided an assessment of the potential shale gas resource with a view to determining the reliability of the USA Energy Department's 2011 estimate of 485 trillion standard cubic feet of Technically Recoverable gas; an estimate of a best and a lowest gas resource case was also presented (Decker and Marot, 2012).

Middle to Lower Ecca Group

The Prince Albert, Collingham and Whitehill formations comprise the (Middle to Lower) Ecca group. The formations include carbon-rich shales ranging range in depth below surface from about 300 m to over 3 000 m. They include deep water carbonaceous sediments, with the organic content thereof originating from biological matter that settled out of suspension in a low oxygen environment. The reducing (anoxic) conditions assisted in preserving the organic matter – which explains the origin of the shale gas contained, in places, within the sediments.

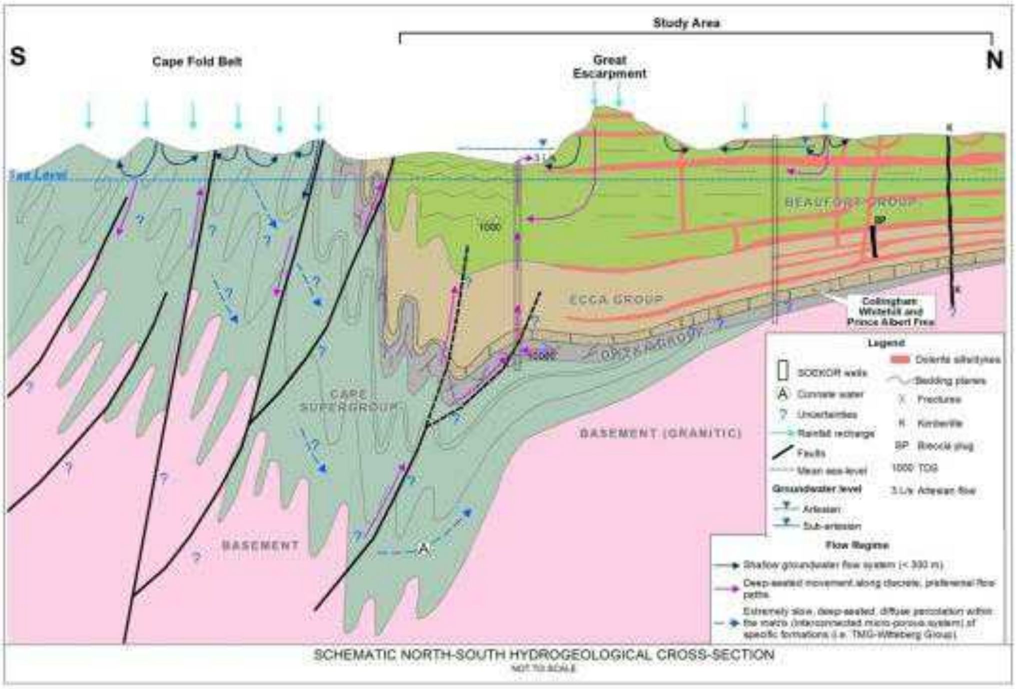


Figure 1.13: Geologic and hydrogeologic profile straddling the study area as shown in Figure 1.12, illustrating the basin-like stratigraphic succession of the Karoo strata overlying older Cape Supergroup and granitic basement rocks (from Rosewarne et al. 2013).

The shales have been severely affected by intense thermal maturation associated with deep burial, the Cape Fold Belt tectonic folding processes and, in a large portion of the southern part of the basin, by intrusion of igneous dolerite. An effect of these factors has been to severely reduce the capacity of the shales to generate gas. The Collingham Formation overlies the Whitehill Formation and forms the top unit of the shale gas target sequence. It varies in thickness from 30 - to 70 m and comprises thin hard bands of dark-grey siliceous mudrock that alternate with very thin beds of yellow weathering tuff. Although it has been regarded as contributing to the potential shale gas reserve of the Karoo Basin, Decker and Marot (2012) and Cole (2014a,b) exclude it due to insufficient data to substantiate the presence of large areas of thick carbonaceous shales expected to incorporate organic carbon at levels greater than 2 %. The formation may, however, have some potential for localised gas development if targeted in tandem with the underlying formations, such as the Whitehill.

The Whitehill Formation directly overlies the Prince Albert Formation. It is black in colour and is thinly laminated highly carbonaceous pyritic shale, which varies in thickness over its entire area of distribution from 10 to 80 m. In the study area its thickness range is less extreme (35 to 43 m). Organic carbon values are consistently high, with up to 17 % total organic carbon and averaging more than 2 % over large areas. It covers an area of 260 000 km^2 of which 66 % (171 811 km^2) lies within the study area. It represents an attractive shale gas exploration target.

The Prince Albert Formation which overlies the Dwyka Group basement to the Ecca Group , is highly variable in thickness (35 - to 150 m) and in the study area is characterised by dark grey carbonaceous, pyritic splintery shale or mudrock. Organic carbon values are high enough over a large enough interval to warrant its consideration as a shale gas target.

Intrusive rocks of the Karoo Supergroup

Development of the Karoo Basin terminated with eruption of the basaltic lava that would form the present-day Lesotho Highlands. Some of the magma rising via vertical fractures and fissures to surface did not reach the surface, finding easier pathways through the horizontally bedded pile of sedimentary strata to solidify as dolerite sills. Dolerite dykes represent solidification in the subvertical to vertical pathways. The presence of these intrusions is recognized internationally as unique to the Karoo (Norton Rose Fulbright 2013), and collectively define the Karoo Large Igneous Province.

Radiometric dating indicates that the sills and dykes were intruded very rapidly within a period of approximately 0.47 million years, or maybe even as a single event. While dykes manifest on the surface as long sinuous bodies forming relatively narrow ridges or depressions, sills form the capping of hills throughout the region (the Three Sisters hills being an example of this). Dolerite is absent along the southern limit of the Karoo Basin within the compressive zone of the Cape Fold Belt where this formative process has prevented the intrusion of sills and dykes. The concentration of dolerite within the study area is illustrated in Figure 1.14 whilst the thickness contours of the percentage of dolerite affecting the Whitehill Formation are indicated in Figure 1.15.

The dolerite structures represent the main targets for scientific groundwater exploration. Dykes in particular are the feature most commonly targeted by landowners for successful water borehole siting, whereas more prominent sill complexes are typically targeted for larger-scale municipal water supply to towns such as at Victoria West (see Chapter 5).

One of the overriding factors used in defining the potential reserves of the Karroo shale gas province has been the perceived negative effect on gas retention of dolerite sills and dykes, especially in the Whitehill Formation. This is a function of both contact metamorphism and gas escape via breccia pipes relating to the intrusion of dolerite sills. These effects are additional to the loss of shale gas that will have occurred along faults during periods of rebound and decompression associated with the Cape Fold structures. In places, the dolerites may provide secondary traps for gas that has migrated out of their source rocks during uplift of the basin and the fall in pressure resulting from the opening up of escape pathways.

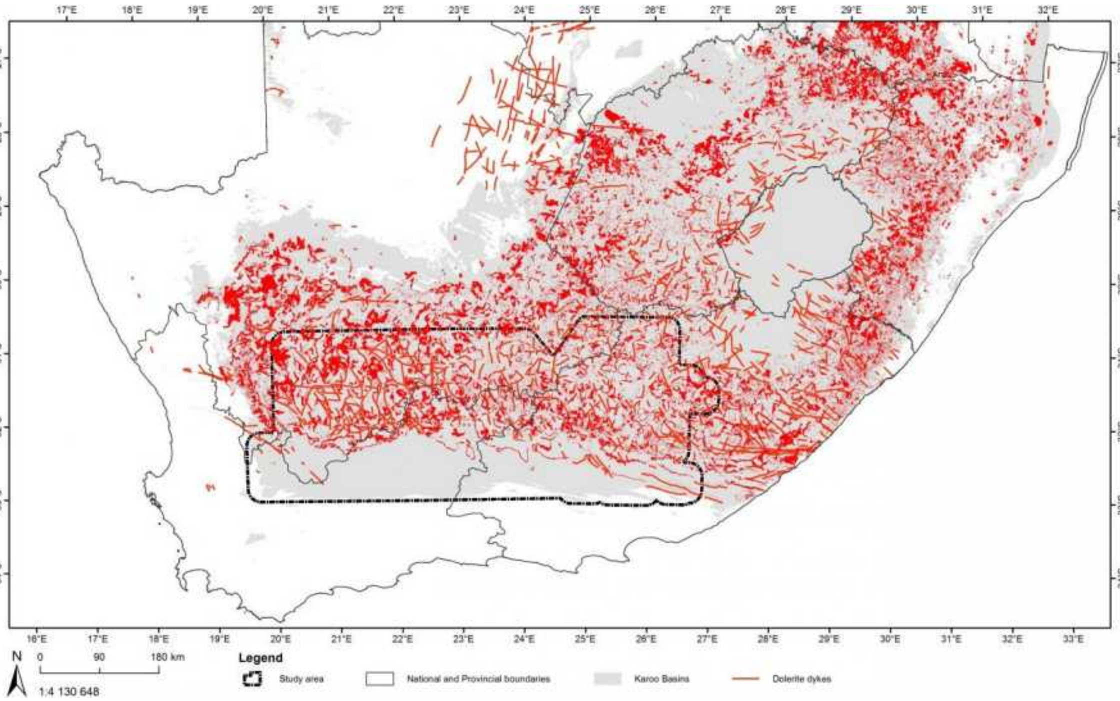


Figure 1.14: Distribution of dolerite dykes and sills in the main Karoo Basin (CGS 2013).

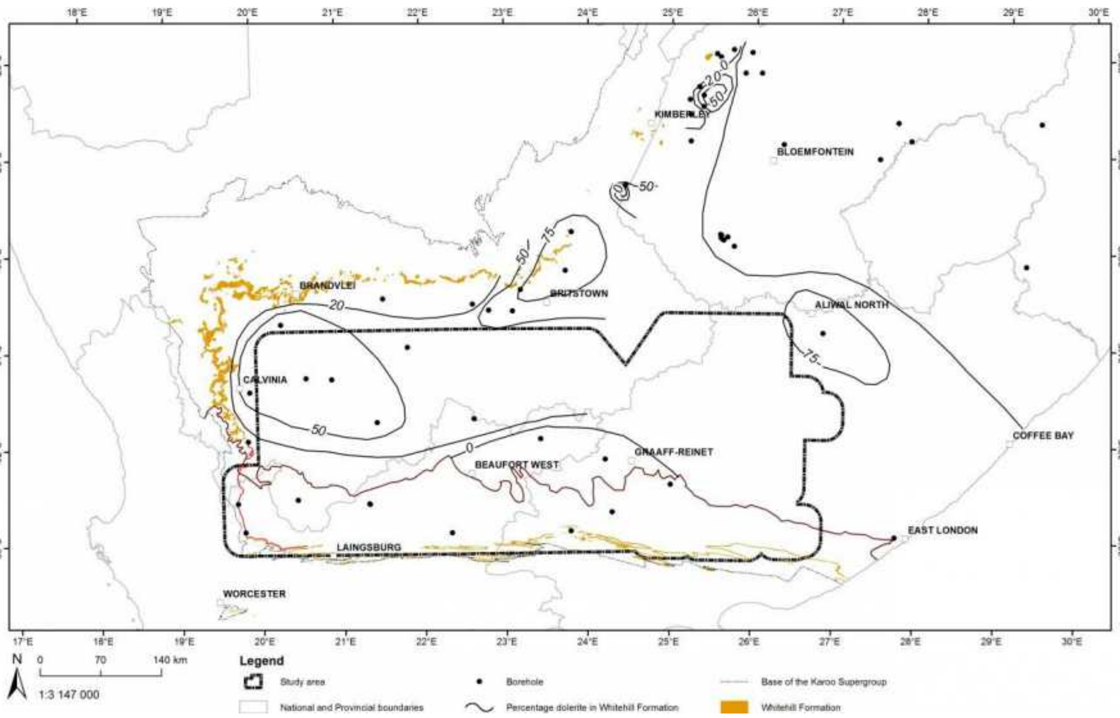
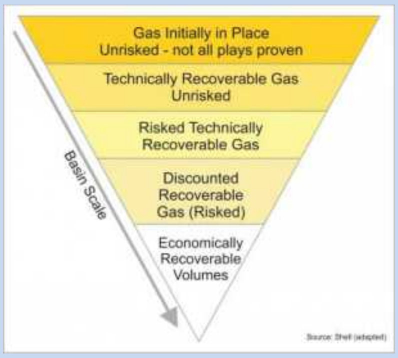


Figure 1.15: Contours of the percentage of dolerite in the Whitehill Formation (CGS 2013).

1.3.2 Shale gas reserve models

A number of attempts have been made to assess the shale gas or petroleum potential of the Karoo carbonaceous shale sequences. In recent years seven different assessments have been made, originating both locally and from the USA. The most significant results of these assessments are outlined here.



Technically recoverable resources represent the volumes of oil and natural gas that could be produced with current technology, regardless of oil and natural gas prices and production costs.

A large number of direct sub-surface measurements (depth, mineralogy, total organic content, thermal maturity, etc.) gathered by current drilling technology need to be undertaken to quantitatively calculate technically recoverable gas reserves (McGlade et al., 2013).

Economically recoverable resources are those that can be profitably produced under current market conditions. The economic recoverability of oil and gas resources depends on three factors: the costs of drilling and completing wells, the amount of oil or natural gas produced from an average well over its lifetime, and the prices received for oil and gas production (US EIA, 2013).

With the growing success of the shale gas industry in North America, the US Department of Energy commissioned a world-wide inventory of shale gas reserves. The results, which were reported by Kuustraa et al. (2011, 2013), are summarised in Table 1.1.

In 2012 the South African Petroleum Agency (PASA) was tasked with providing an assessment of the shale gas reserve of the lower Ecca group of shales within the southern part of the Karoo Basin (Decker and Marot, 2012). In the assessment, account was taken of key geological risk factors (e.g. the implications of dolerite intrusions). The PASA assessment considered three scenarios. Scenario 1: that gas was producible from all three of the target zones (Prince Albert, Whitehill and Collingham formations); Scenario 2: that the Collingham Formation would not be prospective; and Scenario 3: that only the Whitehill Formation would contain sufficient gas to be productive. The results of the assessment are summarised in Table 1.2, which presents estimated shale gas volumes that have been adjusted to include only the study area. The areal extent of the three scenarios is shown in Figure 1.16, with the study area superimposed.

In 2014 the South African Council for Geoscience conducted a shale gas reserve assessment as part of a study dealing with the potential impact of hydraulic fracturing on ground water (Cole, 2014b). The approach used was based on contoured values of shale gas variables derived from petroleum exploration wells. For a preferred area of 21 815 km^2, accounting for various limiting criteria (e.g. dolerite content < 20 %), the shale gas reserve estimates provided for the Whitehill and Prince Albert formations are 13 and 72 trillion cubic feet (tcf) respectively.

Table 1.1: US Department of Energy assessment of South African shale gas reserves, reported by Kuustraa et al (2011, 2013).

US Dept Energy Report Date	Main Karoo Basin Risked Gas in-Place (tcf)	Main Karoo Basin Technically recoverable gas (tcf)	World ranking of estimated RSA Reserve
2011	1 834	485	4th largest
2013	1 559	390	6th largest

Notes: tcf = trillion cubic feet of gas; the estimates are cumulative for the Prince Albert, Whitehill and Collingham formations; the lower estimate of shale gas reserve reported in 2013 accounts for the potential negative effects of dolerite intrusions, which were excluded as an influencing variable from the 2011 assessment; the area to which the analysis is applied is considerably smaller than used in estimates made by the South African Petroleum Agency (PASA).

Table 1.2: Different estimates provided by PASA for shale gas reserves contained within the lower Ecca Group of shales (Decker and Marot, 2012). The estimates presented here reflect volumes adjusted to correspond with the study area.

Target formations of the Ecca Group	Prince Albert Whitehill & Collingham formations	Prince Albert & Whitehill formations	Whitehill Formation Only
Risked gas in place (tcf)	1 722	1 408	159
Technically recoverable gas (tcf)	455	377	32

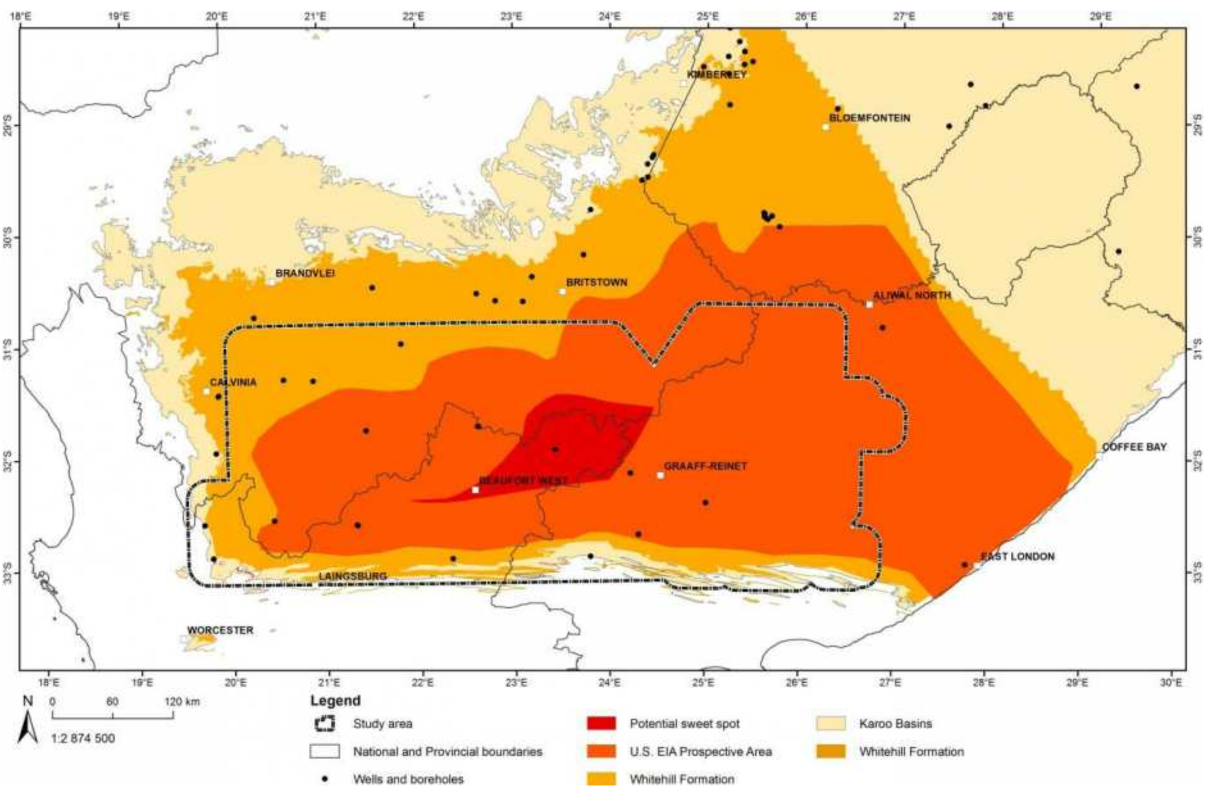


Figure 1.16: Areal extent of the reserve estimates considered by PASA contained within the lower Ecca Group of shales (Decker and Marot, 2012).

Drawing from various sources Geel et al. (2015) prepared a shale gas reserve map for South Africa. Accounting for factors such as reserve maturity and depths and thickness of the Whitehill Formation, the authors define prospective shale gas areas and estimate potential recoverable free gas volumes in the Karoo Basin of between 19 and 23 tcf, with the latter volumes based on gas recovery success factors of 30 and 50 % respectively.[10]

An assessment of shale gas reserve potential was undertaken by PASA as a specific contribution to this Chapter (Mowzer and Adams, 2015). The authors provided both deterministic and probabilistic shale gas reserve evaluations. A distribution curve was generated, with several defined value points identified. In Figure 1.17, P50 is presented as the "best" area of prospectivity, with an estimate of the reserve potential for this area ranging between 36 and 44 tcf.

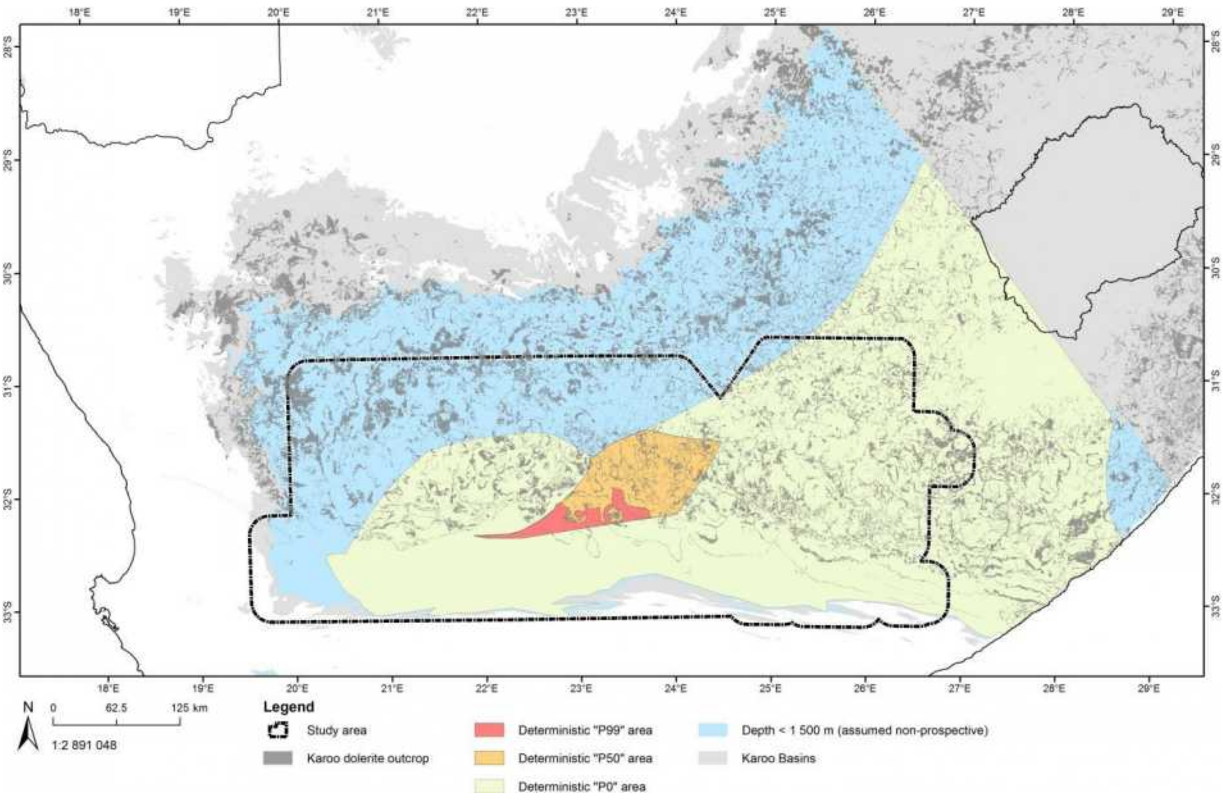


Figure 1.17: Prospectivity map for the Whitehill Formation (after Mowzer and Adams, 2015).[11]

The different approaches adopted for the reserve assessments outlined above make direct comparison of the results difficult. However, to the extent that that this is possible there is reasonable agreement

[10] In the USA, with maturing shale gas technologies, a 20% gas recovery rate from shale is generally assumed, with the number slowly trending higher (Tom Murphy, Penn State University, review comment). Recovery rates of between 30 and 50% may be feasible accounting for expected technological advances between now and when SG E&P could materialise in the SEA study area.

[11] In this context, prospectivity refers to *mineral potential* - based on mineral exploration data - often depicted graphically in map format.

between the results, in that much the same range of 'shale gas in-place' and 'technically recoverable' reserve quantities are presented. Accounting for the study area, where the depth to the top of the Whitehill Formation is at least 1 500 m a reserve estimate can be made for this formation, ranging between 17 tcf and 81 tcf. To this volume of gas can be added what might be contained within the underlying Prince Albert Formation for the same area, which Cole (2014 b) suggests could range between 54 tcf and 72 tcf.

For both formations within the within the study area, where the depth to the top of the Whitehill Formation exceeds 1 500 m, the total technically recoverable shale gas reserve could range between 71 and 153 tcf. Taking a conservative approach regarding estimates of *economically viable* volumes of shale gas that might be available for downstream development and production, the Small Gas and Big Gas scenarios considered for the Scientific Assessment are 5 and 20 tcf respectively.[12]

According to ONPASA (based on information provided for this assessment) approximately 10 % of the total study area could yield technically recoverable concentrations of shale gas. It is further contended by the companies involved that only a fraction of this 10 % is likely to be targeted through relatively few economically viable shale gas developments that proceed from exploration to production. The area most likely to be targeted includes the central and eastern/north-eastern parts of the study area, roughly indicated in Figure 1.18. It is considered most likely that the economically recoverable shale gas reserve quantified above would be contained within the beige- and red-shaded areas indicated in the figure. The red-shaded area within the central part of the study area is considered to have the highest probability of yielding the greatest volume of shale gas, whilst the blue-shaded areas offer the lowest probability.

[12] South Africa's draft unpublished Gas Utilisation Master Plan (GUMP) suggests a conservative estimate for recoverable reserves of Karoo shale gas of 9 tcf. The range assumed for this study (5 – 20 tcf) spans the GUMP estimate.

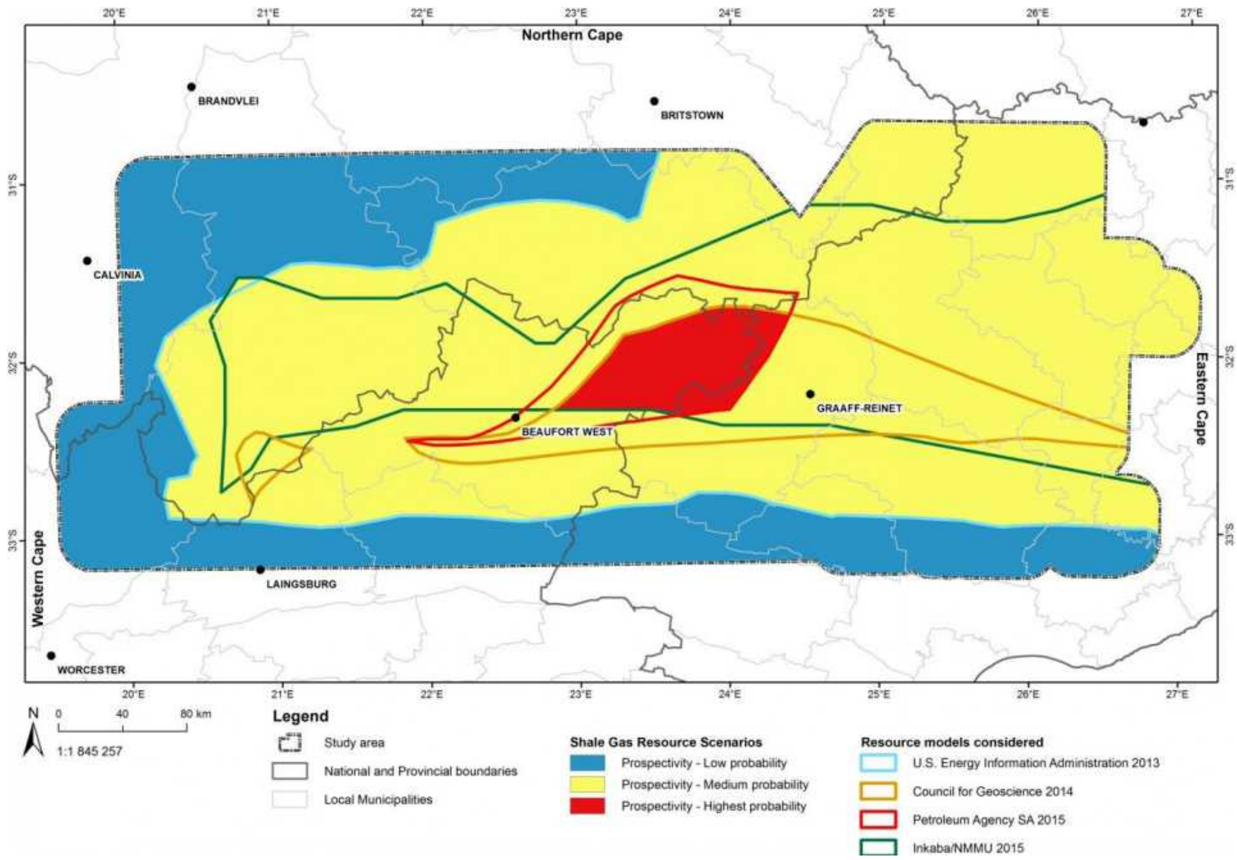


Figure 1.18: SGD prospectivity map for the study area generated by overlaying 4 existing reserve models generated by the U.S Energy Information Agency (2013), the Council for Geoscience (2014), the Petroleum Agency South Africa (2015) and Geel et al. (201) . The solid red polygon, followed by the yellow/beige-shaded area, is considered most likely to yield technically recoverable shale gas.

1.4 Shale gas exploration development and production scenarios

1.4.1 Typical shale gas project lifecycle

Five distinct stages are recognised in a typical lifecycle for a shale gas project (Figure 1.19).[13] These stages progress from geological studies to discovering hydrocarbons to installing infrastructure for producing gas (National Petroleum Council, 2011). Also included is decommissioning at the conclusion of exploration and production, addressing all aspects of environmental rehabilitation. Certain stages lead to a decision, where investment choices are made about whether or not to proceed to the next stage.[14] Decisions are informed by technical and economic criteria, among other factors.

[13] These stages are preceded by permitting and authorisation phases. For example, the MPRDA (Section 5A of Act 28 of 2002/2008) requires environmental authorisations for seismic, exploration, development and production operations (in the form of an Environmental Management Programme or EMPr). Other permits and authorisations also apply.

[14] Internationally, license conditions often impose minimum operational commitments (e.g. a certain number of wells to be drilled), which can require a license holder, for example, to proceed with operations beyond the exploration phase.

Exploration is the first stage in the search for hydrocarbons (shale gas, in the case of this assessment). Amongst other activities, it involves mapping and imaging the sub-surface geological structures, primarily through seismic surveys. Seismic surveys are typically conducted in a phased manner during exploration and also in stages during development of gas fields for production. Regional seismic surveys, usually comprising two-dimensional (2-D) seismic acquisitions, are normally conducted during initial exploration campaigns with the aim of furthering understanding of the sub-surface geological structure and identifying prospective zones for the next phases of exploration. More sophisticated three-dimensional (3-D) seismic surveys are typically commissioned during subsequent stages of exploration and/or development and production planning.[15] The intensity of the surveys (e.g. density of seismic lines that are surveyed on a per km^2 basis) tends to increase for each subsequent stage of seismic exploration, especially as areas are prioritised for drilling.

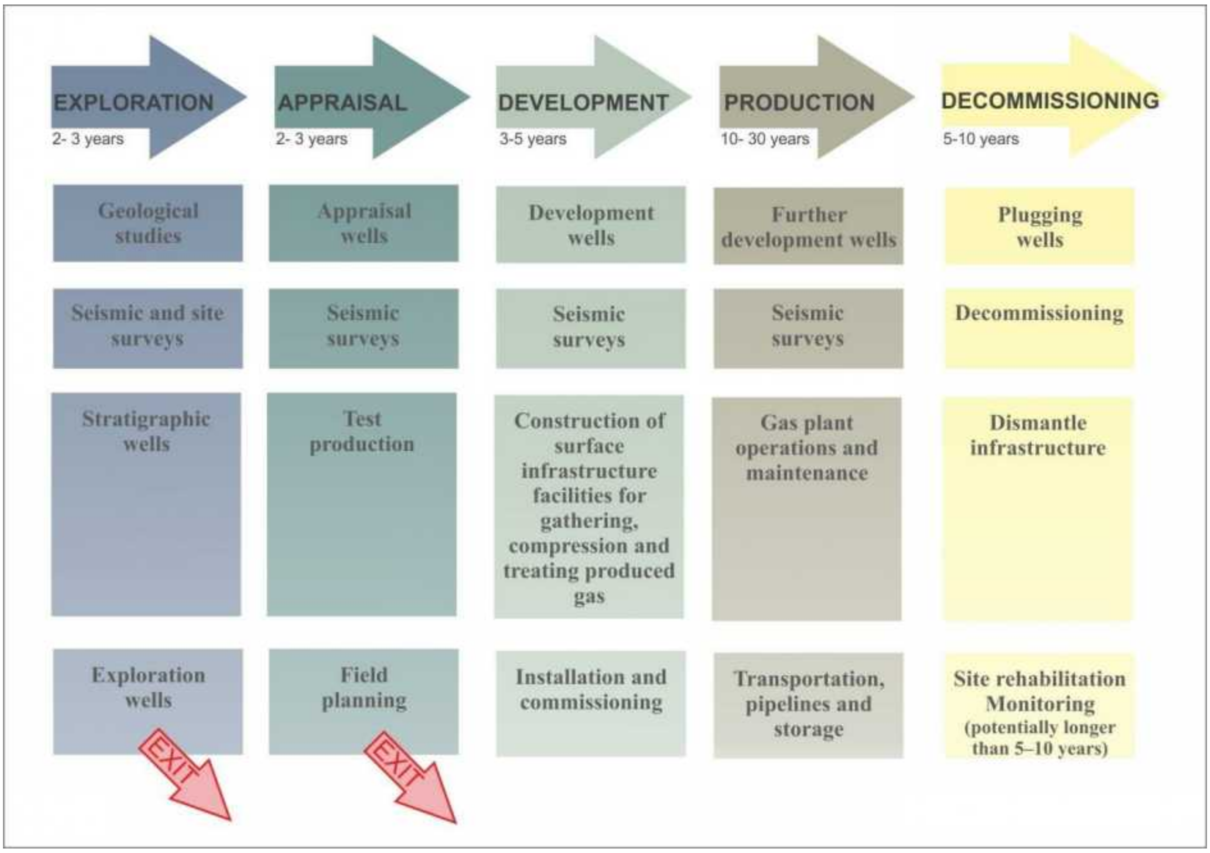


Figure 1.19: Typical life cycle of a shale gas project (adapted from National Petroleum Council 2011)

1.4.2 Imagining shale das development scenarios

There are a number of constraints to knowing whether, to what extent and in what form SGD might materialise within the study area. Most significant in terms of responding to these constraints is the

[15] 3-D seismic can also be used as the initial approach to seismic investigation.

limited understanding of the magnitude and distribution of potential technically recoverable shale gas reserves that could be targeted for exploration, development and production. It is clear that if exploration does not reveal technically recoverable reserves that can be exploited economically, activities will not proceed further and decommissioning will be implemented. If the converse materialises, development may occur, and it could take several alternate forms.

Although there is no way of now knowing what SGD developments will actually materialise, this does not diminish the need for strategic assessment of plausible possibilities to guide future planning. To deal with high levels of uncertainty regarding fundamentally important, but currently unknown determinants of future outcomes of SGD, the use of scenarios provides a platform from which to proceed with the assessment.[16] Three SGD scenarios are proposed, which are additional to the Reference Case Scenario already described (Scenario 0). One scenario identifies the study area as having no potential for shale gas development and production, as might be revealed through extensive exploration and the results of appraisal that do not indicate economic breakeven possibilities (Scenario 1). Another scenario identifies modest downstream SGD potential ("Small Gas") in the central region of the study area where current understanding of the petroleum geology suggests there is greatest probability of a technically recoverable reserve that could be exploited economically (Scenario 2). The final scenario, also located in the central region of the study area, identifies large-scale ("Big Gas") downstream SGD potential (Scenario 3), extending beyond the Small Gas development considered for Scenario 2. An important aim of the assessment Chapters which follow is to consider the risk implications of these scenarios compared to Scenario 0 described in Section 2.3.

The scenarios outlined above provide the basis for the description and quantification of SGD activities that will be presented next. In this regard the prologue to the description of each suite of SGD activities that is described captures the essence of an imagined situation within the SGD sector operating within the study area, playing-out in the future in 2050. The 'run-time' of approximately 35 years from present (2018) allows for the anticipation of plausible established states that might be achieved for the scenarios under consideration.

In the following sections, description of the 'upstream' (i.e. prior) SGD activities associated with each of the three scenarios is structured in a 'cumulative' format: Scenario 2 assumes all the activities that took place in Scenario 1, and Scenario 3 assumes all activities in Scenario 2 (and thus Scenario 1).

[16] According to Illbury and Sunter (2001), scenarios, which deal with uncontrollable determining variables, anticipate *plausible* future situations. Based on current knowledge of the petroleum geology of the study area, the three SG E&P scenarios presented here are considered sufficiently plausible to warrant assessment. Largely due to the probable effect of intrusive dolerite on compromising the integrity of gas that might have been previously been contained within the shale formations (i.e. before the intrusions), it is considered implausible that SGD could materialise beyond what is stated as the Big Gas development scenario (see below).

Through this approach, the activities are presented as an exploration, development and production continuum (Figure 1.19). This approach avoids unnecessary repetition in the description of activities that are common to different scenarios.

Certain of the SGD activities that are described are fundamental to the scientific assessment that follows in later chapters and are expressed and quantified as impact drivers in the sections in which each of the individual scenarios are described. Although the quantification of many of the impact drivers can be anticipated with a relatively high degree of certainty, it is inevitable that assumptions need to be made. Where applicable, these assumptions are expressed in the form of ranges in the quantification of activities. The information that is presented is structured to allow for appreciation of the strategic implications of the SGD activities, both individually (e.g. in the context of a specific scenario) and cumulatively through their association with activities that could follow one after the other across a typical SGD continuum.

1.4.3 Scenario 1: Exploration Only

1.4.3.1 Scenario statement

A scenario that could result from shale gas activities proceeding only as far as the exploration phase can be expressed as follows:

> In 2050 all shale gas activities in the study area have ceased. This follows a period of relatively intensive exploration that was initiated in 2018, which continued until 2025 when it was concluded that the shales within the area contained no economically viable gas reserves. Exploration activities included a limited seismic survey campaign followed by drilling activities, with some hydraulic fracturing, at five targeted locations. Since 2020 a primary focus of South Africa's electricity and petrochemical sectors has been on the use of liquefied natural gas (LNG) imported as feedstock for power generation and liquid fuel production. Also since this time, wind and solar energy projects in the Karoo have continued to make an important contribution to meeting the country's electricity demand. An environmental audit of all shale gas exploration activities in the study area, undertaken in 2048, showed that rehabilitation has fully achieved the targets specified in the project Environmental Impact Assessments and accompanying Environmental Management Programmes. Environmental monitoring will, nevertheless, continue for at least another decade.

The suite of exploration activities contributing to this scenario is discussed below. The discussion is structured to describe the main activities that would be involved, the various assumptions regarding when and where the activities might be scheduled and their quantification as impact drivers.

1.4.3.2 Exploration activities

Exploration activities within a shale gas licence area would be preceded by a number of permitting and authorisation requirements. Important in this regard is the securement of Environmental Authorisation to proceed with exploration projects based on the outcome of Environmental Impact Assessments (EIA) and accompanying Environmental Management Programmes (EMPr) aimed at identifying and ensuring the achievement of impact mitigation and benefit-enhancements to which project proponents commit and are legally bound. These processes address social, health, economic and bio-physical issues of relevance to all exploration projects that are undertaken.[17] With the necessary permits and authorisations in place, a Rights Holder will undertake the scope of exploration that is required. Typically, a considerable lead time is scheduled for mobilisation of contractors and equipment to site.

Exploration field activities within the SGD sector can be broadly differentiated into *seismic acquisition* and *exploration drilling*, which are discussed below.

1.4.3.2.1 Seismic surveying

1.4.3.2.1.1 What seismic surveying entails

The overall objective of a seismic acquisition programme is to identify drilling targets (Robinson and Coruh, 1988; Busanello et al., 2014) with a primary focus on formations expected to yield hydrocarbon product (Nolen-Hoeksema, 2014). Other objectives are to identify the depth and thickness of the shale target, drilling and other hazards (dolerite dykes, faults, breccia pipes), fractures and their density, direct hydrocarbon indicators, (estimate) minimal hydraulic fracture pressure, and to inform the design of additional seismic acquisition and drilling programmes.

A seismic survey is in effect an echo sounding technique (Short, 1992). An acoustic pulse is initiated from a surface location, with reflection occurring at the boundaries of rock layers. This results in the seismic pulse traveling upwards as a reflected wave front. The sub-surface response is recorded by an array of receivers placed on the land surface. Travel time to the reflectors and the velocity of propagation of the reflected acoustic pulse are analysed to develop a picture of the subsurface geology.

There are four basic components of land seismic survey operations (Box 1.1):

- *Location*: planning the location and configuration of a seismic programme.

[17] Application also needs to be made for various licenses pertaining to planned activities; e.g. a Water Use license.

- *Source*: the means of transmitting sound (acoustic) energy into the subsurface.
- *Receivers*: gathering the sound energy as it is reflected by changes in rock properties in the subsurface (typically using geophones).
- *Recorder*: a device for storing received data, which is then downloaded for processing.

Box 1.1: Main components of seismic survey operations (drawing mainly from information provided by Short (1992)).

Location:

Seismic surveys are typically performed on a pre-determined set of accurately geo-referenced 'seismic lines'. These lines are established for an initial regional seismic survey. For areas of specific interest, they are supplemented in follow-up surveys. 'Line-clearing' is the generic term used to describe the process of defining and making accessible the corridors (seismic lines) along which the survey is carried out. The aim is to provide for access of pedestrian and vehicular traffic along the lines and, where necessary, to provide line-of-sight between geo-referenced survey control points and the series of locations where seismic data acquisition is planned. The seismic lines tend to be straight and regularly spaced, although some deviational tolerance can be accepted in gaining access to the data acquisition point (e.g. to avoid a particular landscape feature). In forested and densely vegetated environments, line-clearing can be an intrusive operation with considerable scarring of the vegetated landscape; however, in open environments, where access and line-of sight considerations are not significant constraining factors, there is minimal actual clearing (if any) of vegetation along the lines. In open terrain, the seismic lines tend to bear relatively light loads of traffic involving vehicles used to deploy and retrieve equipment and crews. Where possible, data acquisition points are accessed using existing roads and paths. Specific vehicular driving techniques are employed, such as reversing versus turning around, to minimise environmental disruption.

Mapping is carried out (e.g. in the form of an overlay of the planned seismic lines on cadastral and land use maps) in advance of seismic survey operations. Account is taken of factors such as impassable terrain, restricted access areas (e.g. conservation areas, wetlands) and other obstructions (built areas, rough terrain). Amongst other authorisations involved in planning the location of a seismic survey, land access permission is secured and road-use permits are obtained from the surface owner along with provincial, district and local traffic authorities.

Seismic Sound Source:

During surveys, seismic waves are generated at or near the Earth's surface and travel though the rock formations, potentially up to a maximum depth of 10 km (Nolen-Hoeksema, 2014). In the study area the maximum depth of interest would extend to about 6 km. Land seismic surveys rely primarily on two types of seismic sources: explosives and mechanical sources of vibration (most commonly produced by 'vibroseis' trucks). Surveys may be conducted using one or both approaches to seismic sound source generation, with the choice depending on several factors including geophysical objectives, cost and environmental constraints (Bagaini et al., 2010).

The choice of energy source is critical in data acquisition because resolution quality is largely determined by the source characteristics. A geophysicist would select the seismic source based on the following criteria:

- Penetration to the required depth: a source is selected that produces adequate energy to illuminate the target horizon/s at their particular depths.
- Bandwidth for the required resolution: if high resolution reflections are required to delineate subtle geological features, the source must transmit a broad range of frequencies, from high to low. For shallow targets, explosive sources possess adequate energy and frequency bandwidth; for deeper targets, the longer travel path to a deep reflector requires the selection of a source that has enough energy at the higher frequencies to maintain a broad reflection bandwidth.
- Environment: Areas with sensitive receptors will dictate the buffer and safety requirements and the selection of the source.

There are other technologies that could be used in parallel with seismic surveys (e.g. gravity surveys, magnetic prospecting, magneto-tellurics and passive seismics). The geological information derived from these surveys, some of which are done from aircraft (including drones), is typically complementary to the seismic information derived from conventional methods.

Seismic Receivers:

Seismic waves propagate from the source and travel through geological layers. At the contact from one type of rock to another there is a change in physical properties and it is at these interfaces that some seismic energy reflects back to the surface where seismic receivers (electromechanical devices called geophones) detect the reflected energy (Nolen-Hoeksema, 2014).

Individual geophones are wired together and configured in arrays along a cable. There are two basic types of geophone cable systems: analog- and telemetry-based. The analog systems have a pair of wires for each geophone group and several additional pairs of wires for ‘roll-along’, which allows for setting of the pulses and recording to proceed efficiently (i.e. geophones that have finished recording are picked up behind the shot and moved into position in front of the rolling data acquisition process). If the cables are too long the signal may be attenuated through various causes. These problems are overcome using telemetry systems, which have an analog connection from the geophone group to a processor. The processor or station box amplifies, filters, digitizes and transmits the signal to the recording facility by wire, optical fibre or radio. Hybrids of these two systems can be used to accommodate varying field conditions (Stoker et al., 1997). New wireless systems are evolving and being used, which require little or no need for cabling. In terms of managing environmental impacts, this diminishes the need for clearing lines to lay cables.

Personnel setting up a seismic data collection system, which includes a small recording box, a battery, and an array of geophones). Fibre optic cables laid out in a grid pattern over the survey area transmit the signal from the recording box to the recording truck (Source: Shell)

The seismic source that is triggered and reflected propagates in a pattern that interweaves with the array of receivers. Where the geophone arrays are set up in line with the sound source, this allows for a 2-D profile of the sub-surface geological structure to be generated (i.e. a ‘slice’ through the rock strata). If the source moves around the receiver line, causing reflections to be recorded out of the plane of the in-line arrangement of receivers, generation of a 3-D image is possible (the third dimension being distance, orthogonal to the in-line receiver line; Stoker et al., 1997). For 2-D surveys geophones are deployed in multiples of 100s; for 3-D surveys, deployment is in multiples of 1 000s.

Seismic Recorders:

Once a seismic signal is transmitted and received it is recorded. This trace data along with metadata (e.g. the geographic co-ordinates of the seismic sound sources and receivers) is then transferred to processing centres.

For the areas in which seismic surveys are undertaken, the activities about which insight is necessary for the purposes of this assessment are those related to the generation of the *seismic sound source*.[18] In this regard, the main approaches that would apply to the study area include the shot-point method and the use of vibroseis trucks. Factors that come into consideration when deciding on the energy source include: (i) required energy to obtain adequate information for desired depths; (ii) produced reflection pulse; (iii) convenience and safety; (iv) signal-to-noise ratio; (v) repeatability, and; (vi) total costs (Suarez and Stewart, 2008).

The shot-point method of creating shock wave energy is used, amongst other reasons, in areas where the deployment of vibroseis trucks (see below) is not an option. It would probably be considered for use to some extent within the study area.

The vehicles used for a shot-point seismic programme include a number of truck- or track-mounted drill rigs, a recording truck and several light pickups or stake-bed trucks for transporting crew and light equipment.[19] The drilling rigs create small-diameter holes up to several metres deep (between 3 and 8 m).[20] Different shot-hole depths are associated with different charge sizes that are used. Drilling water, when needed, is obtained from the nearest approved source. To avoid contamination potentially attributable to the explosives that are used, water-bearing zones are sealed with bentonite gravel that is either poured directly down the hole or is placed down-hole in biodegradable cardboard tubes. A light helicopter is often used to move cabling, data boxes, geophones and other light equipment to workers on the ground.

An explosive charge is placed in the hole, which is back-filled with drill cuttings (the material excavated from the shot hole). Before the charge is detonated the fill is tamped down to secure the charge. A ground crew is tasked to work through the area and set off the sources in sequence and retrieve remaining equipment such as geophones, markers, etc. Detonations are often controlled by a radio-controlled unit from a nearby recording truck. Detonations are contained within the hole to force the generated energy downward through the rock strata. As a result, the only sound heard above

[18] Other activities associated with geophysical surveys impinge minimally on the environment.
[19] In some situations, hand augers are used to drill the shot holes
[20] In rugged topography a portable drill may be deployed by light ATV or by helicopter

ground is a dull thud. There is strict adherence to regulations and safety requirements regarding handling and detonation of the explosives that are used.

Vibrator or vibroseis trucks are mobile seismic sound sources (Plates 1.1 and 1.2) designed to do away with the need to drill shot holes and the complex process of detonating explosives, and to reduce safety and security risks relative to the shot-point method. These advantages are, however, offset by other impacts on the environment (e.g. vehicle passage width, which exceeds that of vehicles used for the shot-point method). The trucks can be equipped with special tyres or tracks for deployment in a range of environments, although terrain can impose limits to their operation (e.g. they can't work in steep mountainous areas). They would probably be used at least as extensively as the shot-point method within the study area.

During operations, the vehicle moves into position and lowers the baseplate to the ground. Seismic vibrators fitted to the trucks produce ground motion that propagates into the sub-surface (Bagaini et al., 2010). The vehicle operator can make the piston and baseplate assembly move up and down at specific frequencies thereby transmitting energy through the baseplate and into the ground.

Vibroseis trucks can be employed individually or as a group, often with four or more trucks operating simultaneously. After the prescribed number of sweeps is completed, the baseplates are raised and the vehicles move to the next location, typically a distance of 10-50 m. Productivity, or the number of seismic traces recorded in a given time, is increased by using more than one fleet of vibroseis trucks.

Plate 1.1: Seismic vibration (vibroseis) truck (Source: Shell).

1.4.3.2.1.2 Key impact drivers of seismic exploration

The objective of an initial seismic acquisition programme in the study area would be to contribute to the understanding of the subsurface geology of the Karoo Basin including its depositional environment, the tectonic activity that it has been subjected to and the presence of igneous intrusions including dykes, sills, breccia pipes and hydrothermal vents. The objective would also be to gauge the presence and distribution of potential shale gas plays. Subsequent seismic surveys would support, minimise or eliminate further exploration, including drilling programmes.

Plate 1.2: Ground impression left by the vibrator pad of a vibroseis truck (Source: Shell).

Initial seismic operations would likely be completed in the first 3 years following the issuance of exploration rights (Figure 1.19). This could be followed by subsequent surveys conducted over a number of years, throughout the development and production cycle.[21]

The areas where seismic surveys might be undertaken in the study area are indicated in Figure 1.20 (derived from the information presented in Section 3.2). Only a small fraction (< 1 %) of this area would be impinged upon directly through surveys conducted along quite widely spaced grids (e.g. 10 km spacing for a regional 2-D survey) of seismic lines (< 5 m wide, which is the width of the vehicles that traverse the lines). Exclusion areas indicated in the figure (solid grey-shaded) include municipal areas, conservation areas, wetlands and riparian zones, restricted activity zones and topographically complex landscapes, for example, where slopes exceed 10°.[22] There are likely to be other exclusion areas within the study area, additional to those indicated in Figure 1.20. A closer grid spacing (e.g. 1 km or narrower) would be used for targeted areas, where 3-D surveys are commissioned.

Various towns distributed across the study area would be used to support the seismic survey activities, including offices for project administration, accommodation of personnel (100–200 personnel per campaign), equipment storage and staging areas for equipment destined for deployment in the field and pre-processing and temporary archiving of seismic data. For a proportion of operations, in isolated areas, mobile camps in the immediate vicinity of operations might serve as operational bases for the seismic teams.

As described in Section 4.3.2.1.1 the most likely approaches that would be employed to generate the sound source used in a seismic campaign within the study area would include the shot-point method and the use of vibroseis trucks. Although many activities would be associated with seismic exploration, those to which the status of being key impact drivers can be assigned include the following:

- Clearing of seismic lines (minimal, in the case of the study area; also, minimal if wireless technology is used optimally)
- Vehicle and pedestrian traffic traversing the seismic grid
- Noise emissions

Quantification of key impact drivers is presented in Table 1.3.

[21] Companies generally complete the majority of seismic work relatively quickly so that drilling options can be determined early in the SGD process. They usually commission additional seismic work later when there is need to focus on a specific area/region.
[22] Slopes in excess of 10° would practically be extremely difficult to traverse in the course of seismic operations

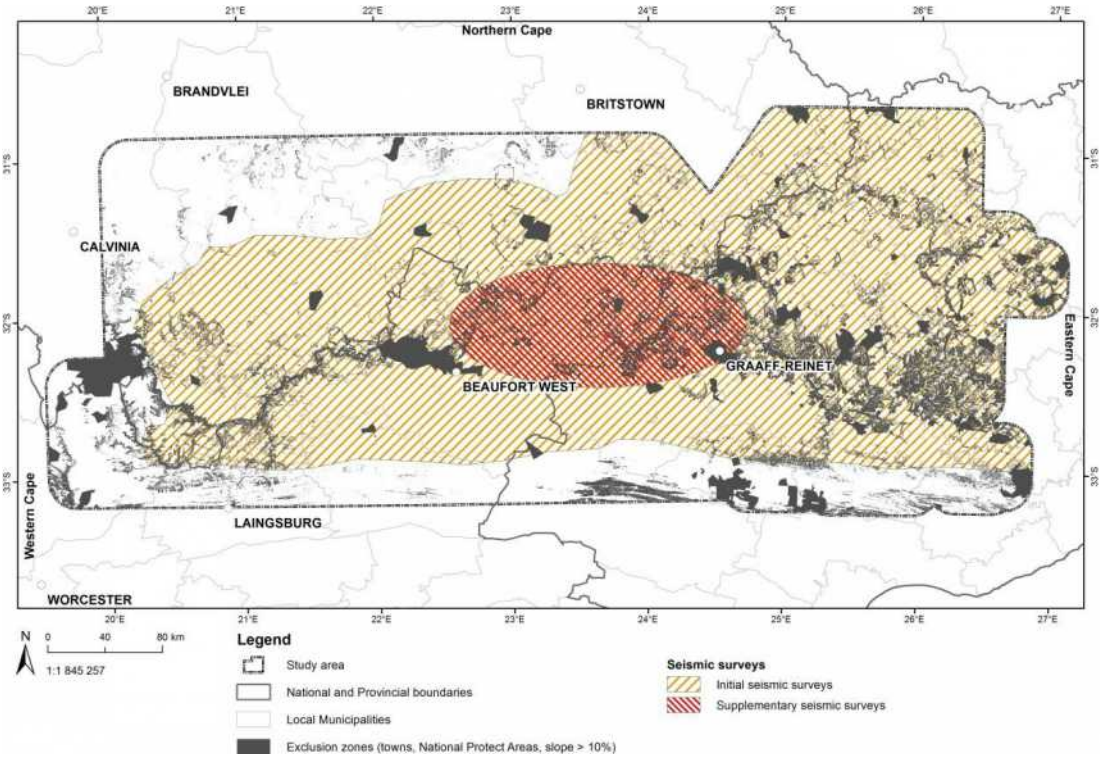


Figure 1.20: Extent of study area that might be affected by exploration activities. There is the possibility that exploration activities may be restricted to identified ‘sweet spots’ and not cover the majority of the area during the initial phases of exploration.

1.4.3.2.2 Exploration and appraisal drilling

1.4.3.2.2.1 What exploration and appraisal drilling entails

Following seismic exploration, establishing the presence and potential yield of hydrocarbon reserves is achieved through drilling, evaluation of drill cuttings and cores, downhole logging and, for some operations, measurement of hydrocarbon flow through extended well testing (e.g. measurement of gas flow following trial hydraulic fracturing).

A typical drilling campaign involves a number of operations. The first entails drilling vertical stratigraphic wells; the next entails appraisal wells, accompanied by hydraulic fracturing and test production.

In terms of drilling location, the first phase of drilling one or more stratigraphic wells is informed by regional geological studies and the results of seismic exploration. For the appraisal phases of drilling, well locations are determined by the combined results of seismic exploration and the results derived from stratigraphic wells. The overall sequence of stages and activities for exploration and appraisal drilling include:

- Site and logistics planning including drilling water supply (if needed) and establishment of groundwater monitoring wells
- Site preparation including drilling of a mousehole (if needed).[23]
- Rig mobilization: move-in; rig up
- Drilling and evaluating vertical exploration wells (to derive key stratigraphic, structural, petrophysical and reservoir information); potentially drill stem testing or possibly conventional well testing
- Drilling, evaluating and completing appraisal wells; hydraulic fracturing and, potentially, production testing
- De-mobilization: drilling rig and ancillary equipment; site restoration; monitoring of wellhead and groundwater well(s)

Site and logistics planning

Detailed baseline information (e.g. regarding surface and shallow groundwater, soils, vegetation and infrastructure) is collected and interpreted in the course of project planning. This typically involves the use of high resolution aerial photography and/or satellite imagery. At this stage, water wells may be drilled for baseline sampling and testing and for subsequent monitoring of potential future contamination of soils and groundwater.

Using this and other information sources, early planning activities include the identification of traffic routes, site access and haul roads. Assessments are also made of road pavement conditions, background traffic volumes, the history of road accidents on the planned project road network and related implications for and attributable to the project traffic volumes. This information is important since drilling programmes involve the transport of personnel and haulage of significant quantities of heavy construction vehicles and equipment and materials to the drill site (some part-distance by rail, but ultimately by road). Examples of equipment and materials include: drilling rigs and ancillary equipment; casing used to line drilled wellbores; chemicals (solid and liquid); compounds used to prepare drilling mud; cementing equipment and material; mobile electricity generators; fuel and lubricants; and temporary accommodation and field office units for crew.

An exploration well site (wellpad) typically occupies an area of up to 2 ha, which contains the drilling rig, portable offices, storage space (for chemicals, fuel and drill muds), plant and equipment areas,

[23] In industry terms, a “mousehole” refers to a hole that is established at the wellpad in order to store pipe joints for quick connection to the drill string. If a shallow aquifer is present, this could be penetrated by the mousehole, and associated environmental risks therefore need to be managed.

parking space for trucks, laydown areas (for drilling pipe and well casing), equipment to process and measure gas produced by the well and water storage tanks and treatment facilities. Additional space may be required for storing excavated sub- and top-soil that would later be used for site rehabilitation.

Separate from the wellpad, approximately 0.5 ha of land is developed for temporary accommodation of the drilling crew.[24] This area is designed and managed as a self-contained facility with sleeping and catering facilities and other amenities and services. The camp is typically located a few hundred metres to a few kilometres away from a wellpad (or cluster of wellpads) where impacts on the local population and environment can be managed effectively (e.g. with due cognizance of project vehicles using public roads for travel between the camp and wellpads).

Gravel access roads are constructed to link the wellpads and crew accommodation to existing road networks, most likely with some upgrades to carry heavy loads and project-related increases in traffic.

Site preparation

Wellpad areas are levelled or shaped to the minimum extent required, for example, to provide for drainage and for positioning temporary site offices, laydown areas and equipment storage. Unless a truck-mounted drilling rig is used (probably only for stratigraphic wells), a re-useable drilling mat will be laid, on which the drilling rig is set up. Above-ground tanks will be positioned for containing water and waste fluids/solids, most likely configured in closed loop format in order to separate solids and fluids – the latter either for re-use or disposal (in the case of waste). Closed loop systems minimise the risk of spills and/or leakage of waste. The areas underneath liquid storage facilities (chemicals, fuel, bulk water and drilling mud containment areas) are lined with impermeable material, the properties of which are in compliance with international best practice standards. Portable containment structures are installed around all tanks in order to contain any accidental spills. The lay-out of a typical drilling pad is illustrated in Plate 1.3.

[24] In the event that operations are located close to towns, the need for temporary accommodation (i.e. camps) diminishes; i.e. staff can be accommodated in the town/s.

Plate 1.3: Illustration of a typical wellpad lay-out with drilling and supporting infrastructure in place (Source: Tom Murphy, Pennsylvania State University, USA).

Drilling of vertical stratigraphic wells

The objectives of drilling a vertical stratigraphic well or set of wells (X-wells in Figure 1.21) are to:

- Correlate stratigraphic and structural records to seismic interpretations;
- Identify freshwater aquifers, drilling hazards and hydrocarbon-bearing zones;
- Confirm predicted organic-rich shale formation packages that might be anticipated, identify new potential target zones and identify existing fractures;
- If encountered, evaluate the thermal maturity, presence/absence of fractures, gas content, gas saturation (free and adsorbed), gas composition, mineralogy, porosity and permeability of the hydrocarbon-bearing shale unit/s (using cores, electric logs and other means).

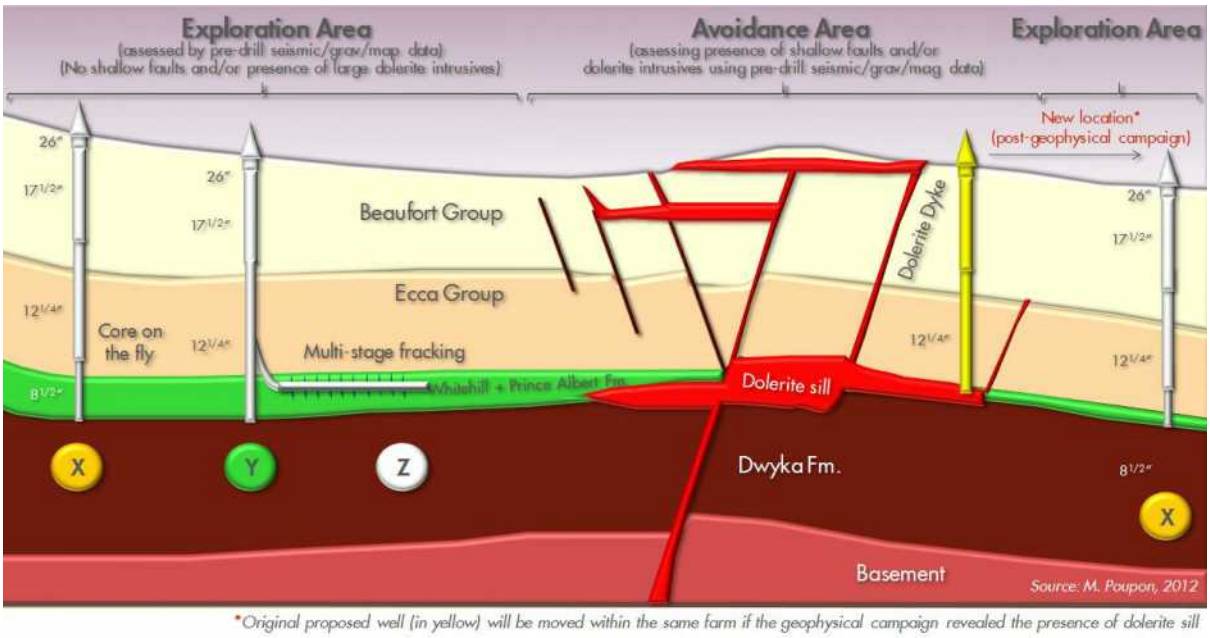


Figure 1.21: A stratigraphic well (indicated by "X") is a vertical well drilled to obtain geological core samples, ideally from the target formation. An appraisal well is a vertical well (indicated as "Y") that is drilled some distance away from the stratigraphic-well so that the characteristics of the formation can be further evaluated and delineated. If the evaluation is positive, a sidetrack may be drilled through the wall of an appraisal well on a curved trajectory, ending with a horizontal section of well bore within the target formation. The horizontal well (indicated as "Z") is subjected to hydraulic fracturing (Source: Shell)

Drilling units (rigs) are powered by either diesel- or gas-fuelled internal combustion engines. For exploration operations, and during the early stages of production operations, diesel-fuelled rigs are used; however, as field gas is produced locally, drilling operations typically transition to the use of this energy resource. Apart from cost considerations (field gas is cheaper than diesel), there are considerable benefits in terms of atmospheric emissions attributable to gas- versus diesel-combustion (see below).

Emitted compound	*Diesel-fuelled engine Emission kg/day*	*% reduction gas vs diesel*	*Gas-fuelled engine Emission kg/day*
CO	10.38	4.3	9.94
NOx	160.13	78.6	34.27
Particulates (< 10 micrometers)	1.675	95.0	0.08
Hydrocarbons	2.345	78.6	0.5

Emissions based on a Caterpillar C32 (or 3512) engine (Source: CAT documentation)

Drilling is initiated by lowering a drill bit through a conductor pipe installed at the surface and by rotating the drill string to which the bit is attached. The rotating bit crushes the rock into small particles or 'cuttings'. These cuttings are flushed from the well as the drilling mud is pumped down inside the drill pipe and back up the outside of the drill pipe in the annular space between the drill pipe and the open hole. The chemical and physical properties of drill cuttings reflect the properties of the geological formations from which they originate (e.g. sandstones, shales); generally, cuttings are relatively inert. The damp cuttings, with residual drilling fluid, are stockpiled temporarily within the drilling works area in impermeable containment facilities. They are subjected to systematic sampling and laboratory analysis with the aim of determining their chemical properties prior to later disposal.[25]

Drilling fluid, often termed 'drilling mud', is used to perform a number of functions including providing hole stability, the entrainment and transport of drill cuttings to surface and circulating drill gas out of the hole. The mudlogger and the mud engineer are responsible for monitoring and analyzing the mud as it is filtered to remove the cuttings and any entrained gas. The mud engineer will measure various mud properties such as its density, fluid loss, rheology, solid content, pH, plastic viscosity and other important variables. The engineer supervises treatment of the mud to meet required specifications before it is circulated back downhole to lubricate and cool the drilling bit and to continue the process of transporting the cuttings to surface. Drilling fluid is prepared through the addition of various compounds and chemicals to water that is supplied to site. [26] The additive used in greatest bulk is barite, which serves primarily as a weighting agent to balance downhole pressure in a well. Other drilling fluid additives fulfil a range of functions such as pH control, corrosion inhibition and de-foaming. For a well drilled, for example, to a depth of 3 500 m (a typical depth assumed for the study area) approximately 1000 m^3 of drilling fluid would be prepared. This would incorporate approximately 300 tonnes of compounds and additives used to formulate the drilling fluid, with water comprising the balance.

In the case of back-to-back drilling of a number of wells in close proximity, drilling fluid would typically be re-used for a number of wells that are drilled. A top-up of approximately 25 % (by volume) of water and drilling fluid compounds would be required for each subsequent drilling operation to account for fluid coatings that remain on stockpiled cuttings and other operational losses.

[25] For example, it may be necessary to adjust the pH of drill cuttings, which may be increased as a result of the chemical properties of the drilling fluid coatings (sodium hydroxide is one of the additives used to increase the pH in order to prevent biological activity within the drilling fluid).

[26] To minimise the risk of environmental pollution potentially attributable to the uncontrolled release of drilling fluid into the environment, industry best practice is to use additives that comply with standards such as those specified in the OSPAR Commission's list of substances considered to pose little or no risk to the environment (PLONOR; OSPAR Commission, 2008). Another example, with specific reference to hydraulic fracturing, is the set of standards applied in Australia (ACOA, 2013).

When the drill bit reaches key depths drilling is stopped and steel casing is run into the open hole and centred within the hole using centralizers. Cement is then pumped down inside the casing and forced out of the bottom and up into the annular space between the casing and the borehole wall until there is a "show" at the surface. The cemented casing then undergoes a mechanical integrity pressure-test to ensure that there is adequate structural integrity at the bottom of the casing or casing shoe. Subsequently, a cased-hole cement bond electric log is run to verify cement bonding along the cemented the casing string.[27] Casing involves setting a series of casing strings of decreasing diameter at increasing depths (Figure 1.22). The purpose of the casing is to provide structural support and integrity to the borehole, allow for deep drilling into high pore pressure formations and to isolate water- and hydrocarbon-bearing formations to prevent cross-contamination. The casing ultimately allows for the safe production of any hydrocarbons found.

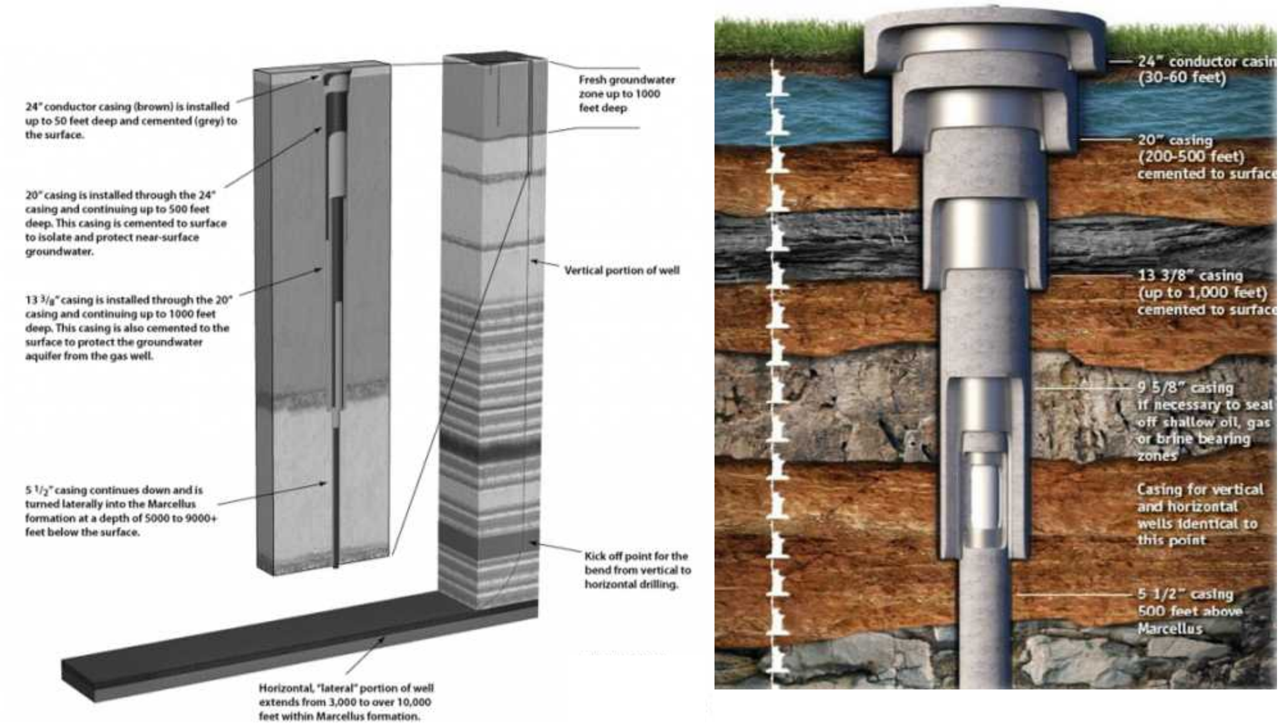


Figure 1.22: General well casing design for SGD operations. Multiple strings of overlapping casing are used to isolate the wellbore from aquifers that are encountered during drilling; these are bonded with cement (Source: Tom Murphy, Pennsylvania State University, USA).

[27] Where they penetrate groundwater zones, wells typically have double, triple, or more overlapping strings of casing, which are bonded with cement, to provide not only structural integrity to a well but to effectively isolate the well bore from the water-bearing formations.

Petrophysical evaluation of the formations penetrated by the well is carried out during the course of drilling operations. This evaluation involves the services of wellsite geologists and mudloggers and the deployment of techniques such as logging while drilling (LWD) and open-hole wireline electric logging. Mudloggers keep a detailed record or log of specific data while drilling that includes: rate of penetration; measurements of mud gas content and type; analysis of drill cuttings to establish formation changes, chemical and physical properties (e.g. rock type and description, apparent porosity, cementation, fluorescence, odour, grain size and friability); pore pressure; drill bit records; mud weight; and hydrocarbon shows. LWD tools are electrical devices installed as part of the drill string and mounted near the drill bit. They are used to record data relating to formation petrophysical properties (porosity, density, resistivity, gamma ray), which are transmitted to the surface in real-time. Open hole wireline logging involves lowering diagnostic tools on an electric cable into the uncased hole. There are a suite of these tools, including: calipers; temperature recording devices; density/neutron/sonic for porosity, gamma ray/Spontaneous Potential/resistivity recorders to indicate rock type and fluid content; Nuclear Magnetic Resonance meters (NMR) for fluid differentiation and gauging production permeability; sidewall core tools for collecting rock samples; formation test tools that record pressures and collect fluid samples; and dipmeters that provide structural information and seismic profile data relating to rock velocities. The ultimate goal is to determine the fluid/gas content in the rock along with the quality and quantity of a hydrocarbon reservoir. This data is key to determining if further well evaluation is necessary and to inform future exploration, development and production decisions and activities.

Appraisal wells

If the results of tests from stratigraphic wells invite further investigation, additional wells are drilled nearby. These wells are planned to yield increasingly detailed information on the properties of the target formation. An appraisal well is created in a similar way as a stratigraphic well with vertical and, typically, horizontal sections. In order to drill horizontally, directional drilling methods are used. A number of horizontal laterals can be drilled from the same vertical wellbore.

On completion of drilling, the rig is removed and the site is prepared for hydraulic fracturing. Well perforating guns, employing directional explosive charges, are lowered inside the cased wellbore by tubing or wireline. Once the guns reach the predetermined depths along the section(s) of the target formation they are discharged to perforate the casing (Figure 1.23). Detonation of the charges punches holes through the well casing and surrounding cement layer into the reservoir rock in the sections of the well bore where gas is expected to be extracted. The perforating guns are then pulled out of the hole to surface where the pumping unit and other equipment are attached to the wellhead; pumping of hydraulic fracture fluid to increase the hydraulic pressure then begins (Plates 1.4 and 1.5). This is done in multiple stages in the horizontal component of the well, with each stage measuring 75 to 100 m in length on average.

The hydraulic fracture fluid is made up of more than 90 % water, with the balance comprising proppant (sized particles, normally sand) and other additives (Figure 1.24).[28] The holder of a right is required to disclose the fluids, chemicals and other additives used in hydraulic fracturing to the competent authority (MPRDA Regulations for Petroleum Exploration and Production, 2015: Chapter 9, Subsection 113). The use of Material Safety Data Sheets is a common means of communicating this information.

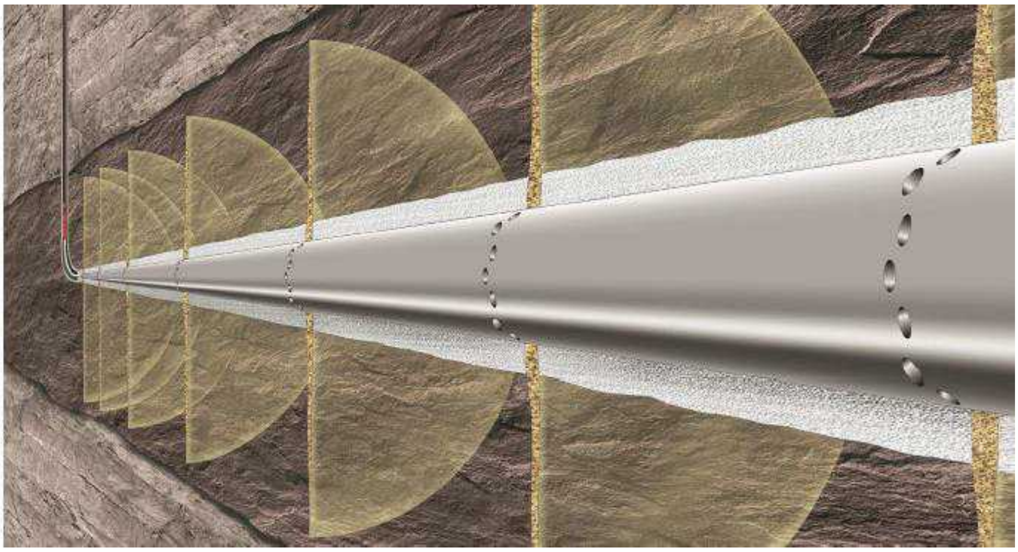


Figure 1.23: Schematic illustration of a horizontal wellbore with perforations through which hydraulic fracture fluid is transmitted into the surrounding shale. (Source: Shell).

[28] Some theory-based research has recently been published, which focuses on the implications of changing the method of fracturing targeted shales using carbon-dioxide as an alternative, or additive, to water (Chandler, 2016). The capacity of the gas to penetrate CO_2-philic nanopores within shales in order to force out lighter petroleum molecules, such as methane, is being investigated. If proven to be implementable in practice, CO_2-based fracturing technology would have significant implications for water use and related waste management.

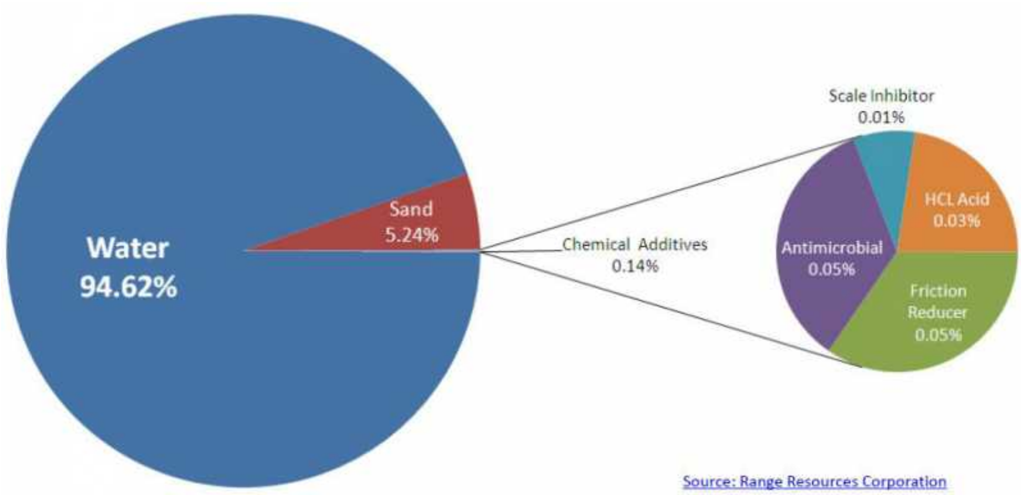


Figure 1.24: Example of the relative composition (% contribution to total volume) of compounds comprising a typical batch of hydraulic fracture fluid (Source: Tom Murphy Pennsylvania State University, USA, citing Range Resources Corporation); as outlined below, other additives may be included

Chemical contaminants associated with SGD

Much of the following section is based on a draft document written by the Environmental Protection Agency of the USA (EPA 2015) on the potential impacts of hydraulic fracturing on drinking water. Note that all of the data used in the EPA document were derived from peer-reviewed papers of government origin, to ensure that they were not influenced by the industry.

Available information indicates that many hundreds of chemicals have been associated with drilling and hydraulic fracturing. Assessing the likely effects of any particular chemical “cocktail” is difficult for the following reasons:

- Most of the information on fracking materials comes from the USA. While laws in most states require disclosure of the content of fracking fluids, this is not true for all states, since the composition is considered to be a trade secret.
- At least 1 173 different chemicals are known to have been used in fracking in different parts of the world. There is no indication as to which combinations might be used in our area of interest in the Karoo, although a broad listing of possibilities has been provided.
- Toxicological data are limited or unavailable for the vast majority of the organic chemicals that are known to be used, or to have been used, in fracking. Thus, the potential effects on human health are very poorly understood (Finkel et al., 2013; Colborn et al., 2011) but have been discussed by McKenzie et al. (2014) and Kassotis et al. (2014). Furthermore, very few published, peer-reviewed epidemiological or toxicological studies are available and the veracity of some publications is questionable.
- What data are available are almost all for individual chemicals, while the effects of chemicals in combination may be greater or less than the effects of each alone.

- EPA (2015) further notes that more than 10 % of the chemicals (134 of 1 173) have also been detected in flowback or produced water.

It is not feasible to describe or even list the hundreds of chemicals involved in the fracking process. Figure 1.25 provides a summary of existing information regarding chemicals used in hydraulic fracturing, highlighting gaps in this regard. A table is also presented in the addendum to this chapter (Addendum A) describing the major uses for which chemicals are employed and, where appropriate, their toxic effects. Unless otherwise indicated, the information contained in the table is taken from EPA (2015).

A number of chemicals are considered so noxious or otherwise problematic that they are currently prohibited from use in South Africa in any hydraulic fracturing activities. These are listed in a second table in Addendum A.

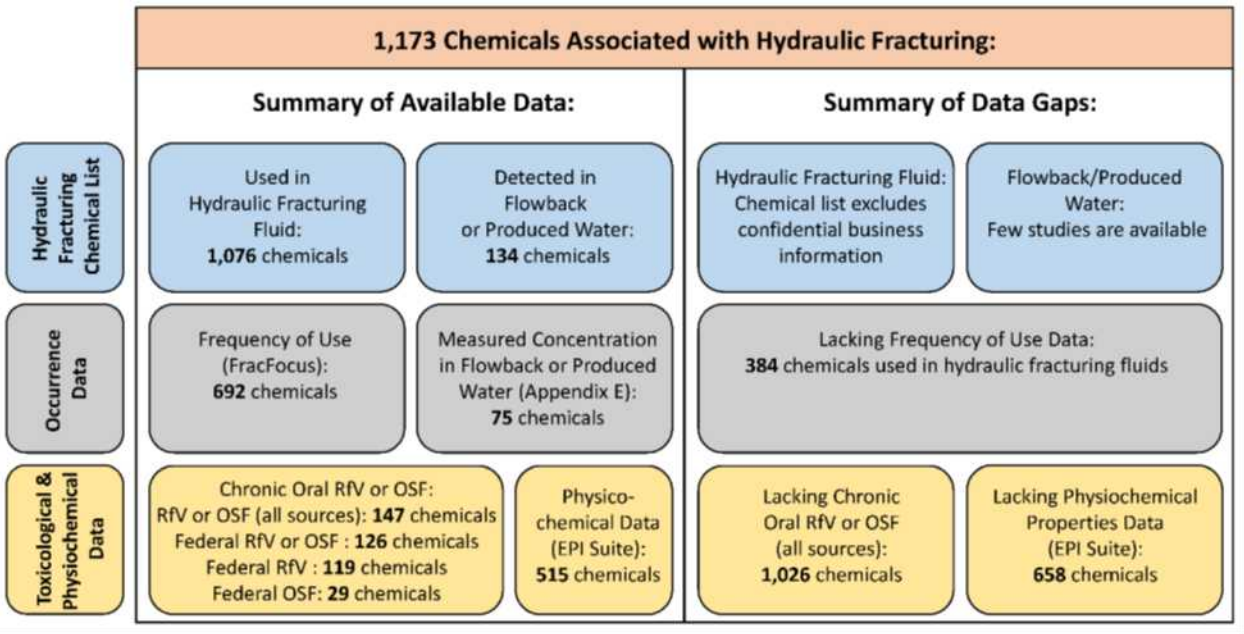


Figure 1.25: Summary information regarding existing data and information gaps regarding the state of knowledge about chemicals involved in hydraulic fracturing processes in the United States (from EPA 2015): RfV = Reference Value, an estimation of an exposure [for a given duration] to the human population (including susceptible subgroups) that is likely to be without an appreciable risk of adverse effects over a lifetime: OSF = oral cancer slope factor, a measure of carcinogenicity

According to an estimate provided by ONPASA, the volume of water used to effect hydraulic fracturing within the study area, for example, within a well comprising a 3 000 m vertical and 1 000 m horizontal section would amount to about 6 000 m^3. Water requirements for hydraulic fracturing can be much higher, with Kargbo et al. (2010) reporting that the volumes used in wells drilled within the

US Marcellus formation, with a 1 500m vertical section and a 980m horizontal section, ranging from 7 700 to 38 000 m^3. Broomfield (2012) reports that vertical shale gas wells typically use approximately 2 000 m^3 of water, whereas horizontal wells typically use between 10 000 and 25 000 m^3 per well. Water requirements reported in the literature for hydraulic fracturing of individual wells range from 10 000 to 30 000 m^3 (Grant and Chrisholm, 2014; Rahm et al., 2012, 2013; Warner et al., 2013; NySDEC, 2015). The volume of water used depends, amongst other factors, on well characteristics (depth, hole sizes and conditions, horizontal lateral length) and the number of fracturing stages within the well.

Although oil and gas developers aim to reduce freshwater consumption through water re-use and use of waste-water from other sources, in current practice freshwater still comprises 80-90 % of the water used for hydraulic fracturing. For example, NySDEC (2015) reports that between only 10 and 20 % of hydraulic fracturing water use comprises recycled wastewater. Re-use involves either straight dilution with fresh water of the flowback wastewater (see below) or the on-site introduction of treatment processes prior to flowback water re-use.

ONPASA has not published information on water supply options to support hydraulic fracturing within the study area. Supply options that could be investigated include:

- Local groundwater in the proximity of wellpads or within shale gas license areas (shallow aquifer or deep fossil water).
- Groundwater/surface water outside the shale gas licence areas.
- Seawater.
- ‘Grey’ water sourced either within or outside the shale gas licence areas.

Proppant is high specification aggregate, usually sand, which is treated and coated with a resin. It can also be produced as ceramic nodules. Sand in the southern Karoo is largely unsuitable for use as proppant because of the high clay content of the local soils, which are derived from shales and mudstones. For this reason, it unlikely that proppant would be sourced locally within the study area for SGD operations. For the scenario considered here, entailing exploration operations only, it can be assumed that proppant would be imported to South Africa and transported to the sites of hydraulic fracturing by road or rail. For the Small and Big gas scenarios outlined in sections 4.4 and 4.5, importation of proppant at the scales required would be uneconomical and it is likely that the product would be manufactured at a location where suitable aggregate can be sourced, for example where sandstones define the local geology, and transported to the study area.

The fracturing fluid is injected down the wellbore at a pressure of between 400 and 600 bar (40 – 60 MPa).[29] The fluid migrates through the perforations in the well casing and cement into the reservoir

[29] The injection pressure required to create fractures depends on the rock's fracture pressure. Normal pressure gradient is about .456psi/ft (1.4941 psi/m) or 0.1013 bar/m. The Whitehill Formation (12 045 ft) at the SOEKOR Cranmere 1/68 well location was drilled with 10.2 ppg mud weight with no reported loss of returns (i.e. no formation breakdown). Based on this depth, the calculated mud hydraulic pressure gradient is 0.53 psi/ft, and the minimum fracture pressure at this depth can therefore be inferred to be 6389 psi or 440

rock to create fractures that are typically 2-7 mm in width, close to the wellbore. The fractures become narrower as they extend outwards for distances of up to about 300 m from the wellbore. The proppant that is pumped into the fractures holds them open when the hydraulic pumping pressure is reduced. The creation of open fractures has the effect of significantly increasing the surface area of rock connected to the main wellbore; gas that is released in the process flows out of the reservoir rock to the surface via the wellbore.

Plate 1.4: Example of an hydraulic fracturing process underway in Appalachia, with the main equipment and facilities involved indicated. (Source: Range Resources Corporation).

bar. The Whitehill Formation should be encountered at greater depths south of the 1/68 Cranmere well, so the fracture pressure should increase.

Plate 1.5: Example of an hydraulic fracturing operation underway, involving a series of wellheads (Source: Tom Murphy, Pennsylvania State University, USA).

Following hydraulic fracturing, surface equipment is installed on the well in order to allow it to be ‘produced’. During initial production, some of the hydraulic fracturing fluid and other entrained material returns to the surface as "flowback". This includes water, fracturing chemicals and gas. Solids are separated from the liquids and gas at a treatment facility on site. This process can also be carried out at a central location to which the flowback is transported, often by road tanker. Graphic illustrations of a produced fluid management system are presented in Figure 1.26 and Plate 1.6 Typically, there is recovery of about 30 % of the volume of fracturing fluid originally injected into the well as flowback; however, recovery volumes can range widely depending on shale characteristics (e.g. between 0 and 80 %: Broomfield, 2012; Grant and Chrisholm, 2014). Sludge (proppant, shale dust, other solids and chemical residues), which can account for around 3 % of the flowback volume, is disposed of at designated approved material waste sites.

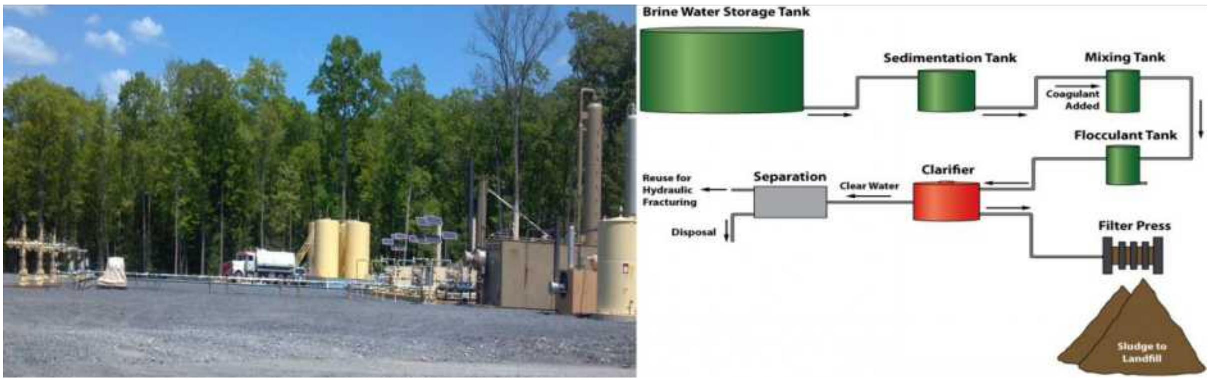


Figure 1.26: Schematic illustration of a produced fluid management system (Source: Tom Murphy, Pennsylvania State University, USA).

Plate 1.6: Example of a closed loop fluid management system (Source: Tom Murphy, Pennsylvania State University, USA).

Flowback fluids are typically saline, with reported total dissolved solids (TDS) values ranging from 10 000 mg/l to 300 000 mg/l (Rahm et al., 2012, 2013). High TDS values indicate that the flowback fluids contain geological formation water or "connate water" trapped in pores of the rock during its geological history. Such water is recovered and treated on surface. The production of connate water can persist for the operational lifetime (5-20 years) of a well (Grant and Chrisholm, 2014), with volumes ranging from 1-2 m^3 per day (Rahm et al., 2013; NySDEC, 2015). Volumes do, however, decline as the well production exhibits the characteristic exponential decline in gas yield as reservoir pressure depletes over time. Since the water has been in prolonged contact with the shale from which it originates, chemical characteristics of the target formation dominate its chemistry, which can also reflect radiogenic properties (Section 2.1.3). The quantity and chemical characteristics of produced water and flowback fluids persist as key uncertainties in terms of management, even in plays where unconventional oil and gas have been produced for a while (Rahm et al., 2013).

In the course of initial well-testing, the produced gas may be flared. Well testing is normally conducted for 30 to 60 days, with flaring undertaken for 30 days or less.

The typical shale gas formation is a pressure depletion reservoir with a characteristic exponential production rate decline over time (Figure 1.27). Production rates and pressure data obtained during well testing are used to calculate an estimated ultimate recovery (EUR) of the well and the field.

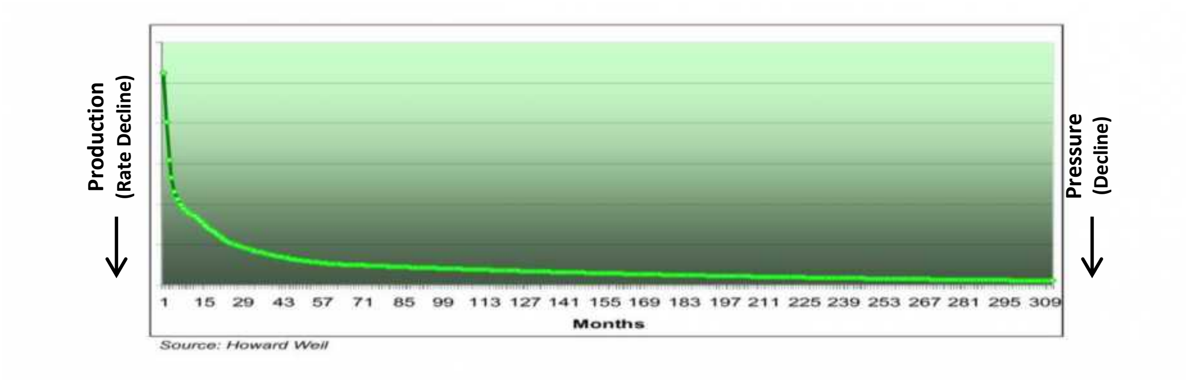


Figure 1.27: Typical Shale Gas Decline Curve (after Benedetto 2008)

On completion of production testing, gas-flow is suspended, surface equipment is disconnected and demobilisation proceeds. The decision to either suspend or permanently decommission (plug and abandon) is based largely on test results. The production test data are, therefore, crucial for decision-making in this regard. Well suspension is effected by closing the valves on the wellhead to prevent product flow to surface (Plate 1.7); gauges are installed to detect possible changes in pressure that could be indicative of a leak. For final decommissioning, cementing of the well bore is undertaken from the furthest point to surface. This aims to ensure that all hydrocarbon- and water-bearing zones are isolated to prevent cross contamination or communication with shallow aquifers or the surface. The issue of well closure/decommissioning is critical and is implemented in accordance with industry best practice as described, for example, by American Petroleum Institute (2009).

Plate 1.7: Surface equipment in place for a suspended well (Source: Tom Murphy, Pennsylvania State University, USA)

If there is full decommissioning, in addition to well plugging, the wellhead and testing and production facilities are removed. Wellpad areas and access roads are rehabilitated to achieve pre-disturbance landform states, with vegetation re-established in accordance with EMPr specifications and relevant prescribed regulations (e.g. regarding species diversity, vegetated ground-cover targets). Baseline environmental studies undertaken in advance of exploration and production provide reference standards to be achieved through rehabilitation. The decommissioned well, along with one or more monitor wells, are routinely inspected in accordance with prescriptive rules and EMPr and EIA commitments to ensure there is no subsurface communication and subsequent groundwater contamination. In this regard, the period of operator liability extends as long as might be necessary (potentially several decades) in order to achieve compliance.

1.4.3.2.2.2 Key impact drivers associated with exploration and appraisal drilling

It is likely that the bulk of the exploration or appraisal drilling activities would be initiated immediately following the completion of seismic surveys and that the activities would be concluded between 5 and 10 years after initiation of SGD operations in the study area (Figure 1.19).

Exploration and appraisal drilling would be undertaken within a small fraction of the area in which the seismic surveys are undertaken (< 5 % in terms of surface area footprint), where information on the petroleum geology indicates there is the greatest potential for encountering technically and economically viable shale gas reserves. Given that such possibilities could extend across a number of license areas, several separate drilling campaigns might be launched. For the purpose of the Scientific Assessment, it is assumed that five campaigns in total will be completed. The notional distribution of these drilling campaigns shows their greater concentration in the central region study area, where current knowledge of the shale gas prospectivity suggests the largest reserves of gas might be encountered (Figure 1.28).

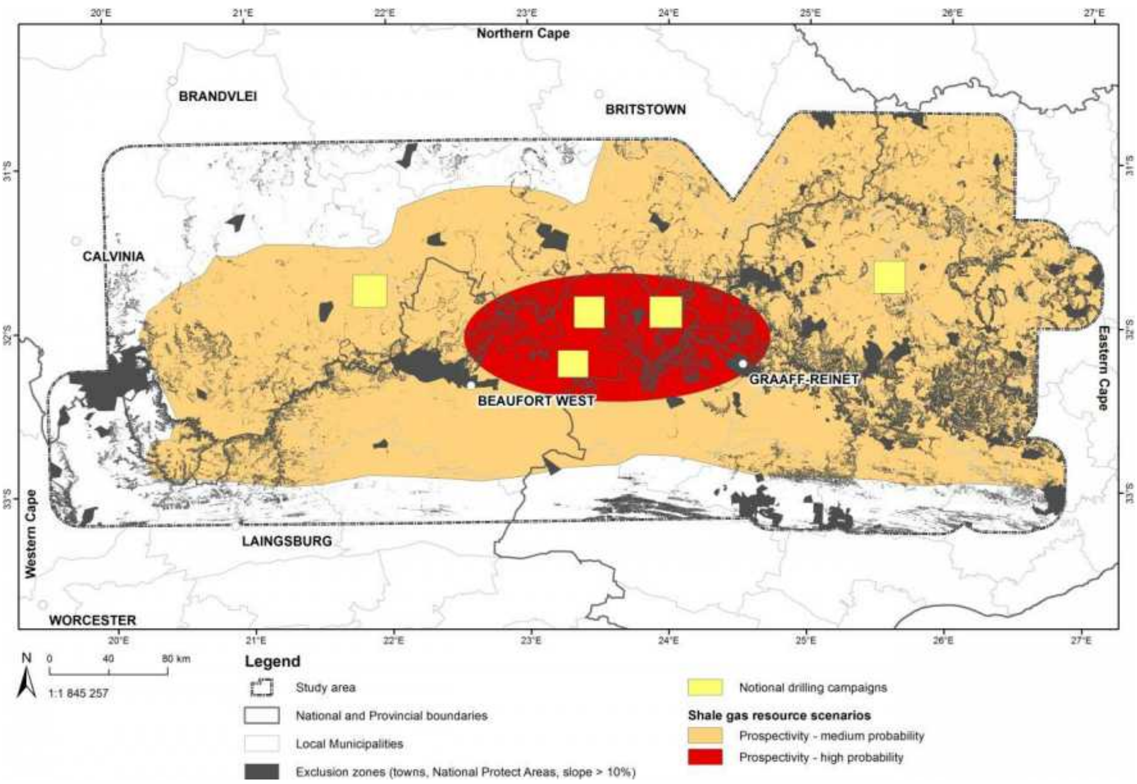


Figure 1.28: Notional distribution of five exploration drilling campaigns that might be commissioned within the study area. The figure simply indicates approximately how large a general target area might be in the case of a drilling campaign; there is currently no idea of where any campaign might be located. Within each square, only a very small fraction of the actual land surface is directly impacted (<5 %), though a larger area would be exposed to noise, visual and light disturbance.

For each drilling campaign, it is assumed that six stratigraphic wells would be drilled from their own individual wellpads. For each campaign, two of the already established wellpads would be used for additional drilling to create two sets of three horizontal wells for hydraulic fracturing; i.e. a total of six horizontal wells drilled from two wellpads, replicated for each of the five exploration campaigns. A schematic indication of how the wellpads associated with these wells might be distributed in an area targeted for exploration drilling is presented in Figure 1.29. Also schematically indicated in this figure are access roads to the wellpads and a facility for crew accommodation. Provision would be made for treating flowback and produced water, entailing modular, contained equipment capable of treating the relatively low volumes of fluid waste generated during operations.

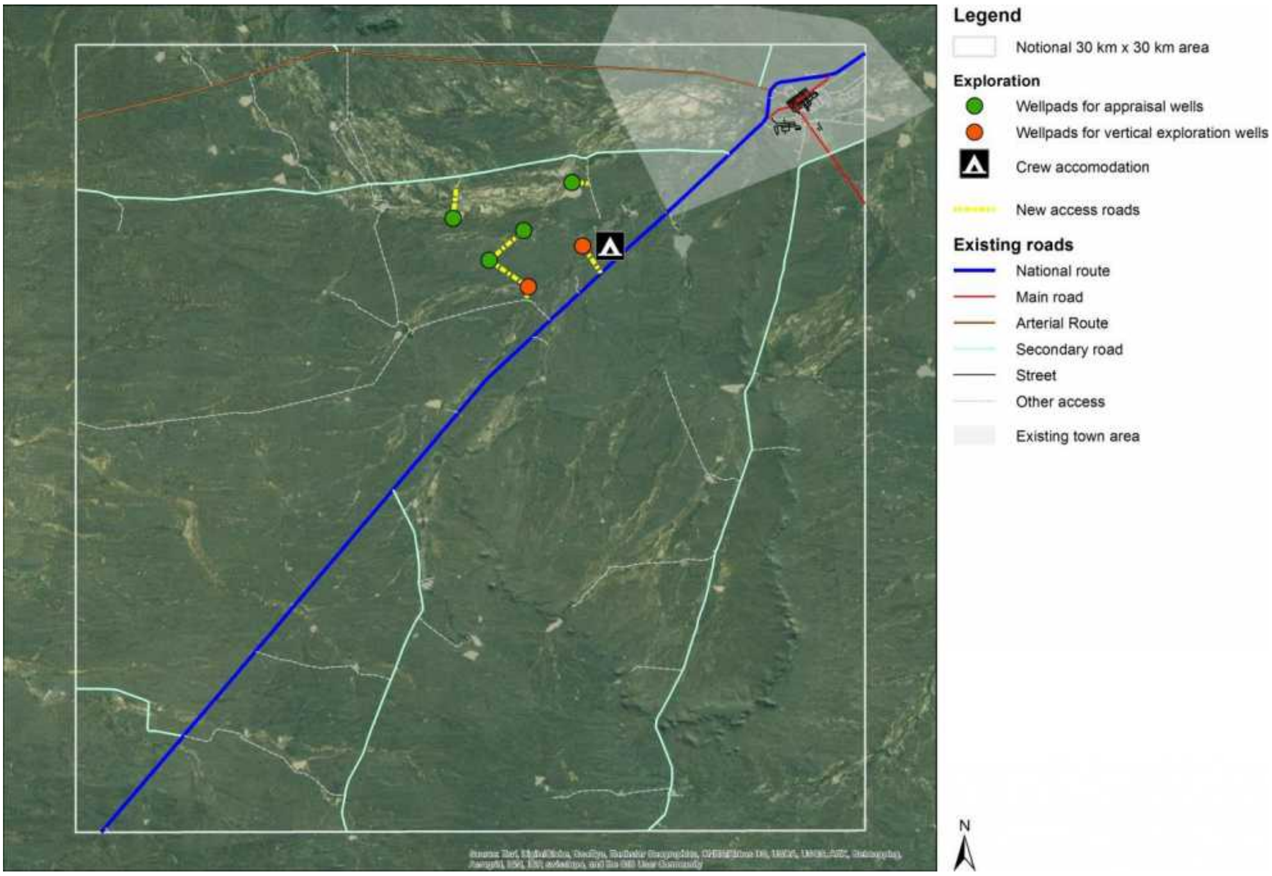


Figure 1.29: Notional schematic depiction of the location of six wellpads (two would be used to drill two sets of three horizontal wells for hydraulic fracturing) and a crew accommodation facility. An area of approximately 30 x 30 km is indicated as being targeted for exploration. Throughout the study area it is assumed that there could be five such initiatives.

Planning, site preparation, drilling, hydraulic fracturing and flow-testing would proceed for each exploration and appraisal drilling campaign, as described in Section 4.3.2.2.1. Although many activities would be associated with each of these project elements, those to which the status of key impact drivers can be assigned include the following:

- Clearing of wellpad areas and the crew accommodation sites.
- Construction of new access roads to wellpads.
- Rail plus road transport to site of drilling fluid compounds (mostly containerised).
- Rail plus road transport to site of well casing.
- Road transport to the site of the drilling rig components (power unit, derrick, etc.).[30]
- Road transport to site of ancillary equipment supporting drilling operations at the wellpads.

[30] It is possible that a single drilling unit could be used for the various exploration campaigns that are undertaken (i.e. shared equipment); alternatively, separate drilling units would be sourced for each campaign.

- Road transport to site of temporary infrastructure and equipment used to establish crew accommodation.
- Transport to site of a truck-mounted drilling unit for creating shallow aquifer water monitoring wells. This unit would probably be mobilised to site during the phase of establishing environmental baseline conditions.
- Sourcing and supply of potable water for domestic use.
- Sourcing and supply of process water to prepare drilling mud and for hydraulic fracturing.[31]
- Process water treatment for recovery (re-use as drilling and hydraulic fracturing fluid) and disposal of process waste (e.g. sludge recovered from flowback) and produced water.
- Drill cuttings disposal.
- Domestic and solid waste management.
- Hazardous waste management (additional to waste process water and solids).
- Flaring of gas during drilling and well-flow testing.
- Noise and light emissions.
- Decommissioning, including removal of equipment and infrastructure from site (primarily by road).
- Employment, personnel logistics, labour negotiations.
- Management of safety, security and medical/health.

Quantification of the main activities comprising seismic exploration and an exploration and appraisal drilling campaign, to which the status of key impact drivers is assigned, is presented in Table 1.3.

[31] The volume of water needed for preparing drilling mud and for hydraulic fracturing for an exploration campaign (Table 1.5) would be relatively small compared to a production programme (Tables 1.6 and 1.7).

Table 1.3: Quantification of key activities/impact drivers associated with seismic survey and exploration and appraisal drilling within the study area (Note: for some quantifications, ranges of values are provided to provide for uncertainties regarding assumptions; e.g. the possibilities that there may or may not be re-use of drilling fluid compounds and water used for both drilling and hydraulic fracturing).

Impact driver	**Unit**	**Factor**	**Total**	**Comments**
Seismic exploration				
Employment provided: Vibroseis truck method seismic campaign	100 personnel	5 exploration areas Duration: Approximately 1 year	500 personnel [32]	Expat specialists: 50%[33] National professionals: 20% National skilled: 10% Local unskilled: 20%
Employment provided: Shot-point method seismic campaign	150 personnel	5 exploration areas Duration: Approximately 1 year	750 [30]	Expat specialists: 50% National professionals: 20% National skilled: 10% Local unskilled: 20%
Establishment of seismic lines	Up to 2 000 km		Up to 2 000 km	90% vibroseis truck method; 10% shot-point method
Density of seismic lines: Regional survey (Vibroseis trucks)	0.25 - 10 km spacing (Note: relatively wide spacing for regional 2-D survey; closer spacing for 3-D survey of specific targeted areas)			90% vibroseis truck method assumed (10% shot-point method; see below)
Vibroseis trucks and shot-point methods: distribution of vibration impact or shot points	20 per km	1 800 km vibroseis method [34] 200 km shot point method	36 000 vibration impact points 4 000 shot points	
Shot-point method: explosive detonated per shot hole	Up to 1kg per shot 20 shots per km	Up to 20 kg per km 200 km	Up to 4 000 kg	
Vibroseis trucks: Vibration impact footprint	5 m^2	20 per km 100 m^2 per km 1 800 km	180 000 m^2 18 ha	

[32] This assumes that each campaign will be separately resourced in terms of personnel. However, there could be collaboration involving sharing of resources, with one campaign scheduled to follow another.

[33] There is currently limited local capacity to undertake seismic, drilling and hydraulic fracturing operations; this implies that these services will need to be contracted in from international sources, initially. The percentage of employed expatriates will decrease over time as local capacity develops.

[34] The assumption made is that the vibroseis method will be employed more extensively than the shot point method (1 800 km compared to 200 km of shot-point method); the quantifications listed here would be adjusted if a different ratio between the two methods materialises.

Impact driver	Unit	Factor	Total	Comments
Vibroseis tyre track width	Up to 2 m tyre width; dual tracks	2 m x 2 tracks 1 800 km	720 ha	Linear effect
Vibroseis trucks in operation: Noise emission	74 dB at 15 m			12 – 24 hr operation
Shot-point method:; Auger drilling operations noise emissions	90 dB at 1 m			12 – 24 hr operation
Vehicle fleet size: Vibroseis truck method	4x Vibroseiss trucks @ 10 t each; 3 x 5 t trucks; 6 x 1t utility vehicles		13 vehicles per fleet	
Vehicle fleet size: Shot-point method	1 x 10 t auger drilling truck; 3 x 5 t trucks; 3 x 1t utility vehicles		7 vehicles per fleet	
Shot-point method: Number of passages per vehicle per seismic line	5 passages by half the fleet	7 vehicles	15 passages per km	
Vibroseis method: Number of passages per vehicle per seismic line	2 passages along each line section by half the fleet	13 vehicles	7 vehicle passages per km of seismic line	
Domestic solid waste produced	0.46 kg per worker per day			See crew sizes per operation
Domestic water use (drinking, sanitation)	0.15 m^3 per person per day			See crew sizes per operation
Sanitary waste produced	0.1425 m^3 per worker per day			See crew sizes per operation
Hazardous waste	1-5 tonnes per campaign	5 campaigns	5 – 25 tonnes	
Exploration and appraisal drilling				
Drilling rigs commissioned	1 rig per campaign	5 campaigns	1 - 5 rigs [35]	
Employment: Drilling campaign	100 personnel per drilling rig	5 campaigns	Up to 500 personnel (see footnote [34])	Expat specialists 20%; National professionals 10%; National skilled 10%; Local unskilled 60%
Drill rig height	40 m			

[35] This range allows for the possibility that drilling rigs and crews might be shared between the different campaigns

Impact driver	Unit	Factor	Total	Comments
Number of wellpads established	6 wellpads per campaign	5 campaigns	30 wellpads	
Access roads constructed to wellpads	1 km per wellpad	6 wellpads per campaign; 5 campaigns	6 km per campaign; 30 km for 5 campaigns	
Wellpad footprint	2 ha per wellpad	6 wellpads per campaign; 5 campaigns	Up to 12 ha per campaign. Up to 60 ha for 5 campaigns	
Crew accommodation camp footprint	1 ha per camp; 1 camp per campaign	5 campaigns	5 ha for 5 campaigns	The size of the camp footprints could be slightly smaller than stated here
Transport of drilling rig, casing and ancillary equipment to and from wellpads	500 truck visits per well drilled (split between 10 t and 20 t trucks)	5 campaigns 12 wells per campaign	30 000 truck visits for 5 campaigns	Extrapolated from and adjusted based on Shell EMPr: (http://southafrica.shell.com/aboutshell/shell-businesses/e-and-p/karoo.html). Golder Associates (2011)
General utility vehicles in operation throughout	Numerous	5 campaigns	Numerous	To be confirmed (tbc) through transport planning study.
Hydraulic fracturing: truck visits per well	500 truck visits per well	Hydraulic fracturing x 6 wells per campaign 5 campaigns	15 000 truck visits for 5 campaigns	Extrapolated from and adjusted based on Shell EMPr: (http://southafrica.shell.com/aboutshell/shell-businesses/e-and-p/karoo.html). Golder Associates (2011)
Drilling fluid water: stratigraphic wells Assumed 3000 m depth (no re-use of water)	825 m^3	4 wells per campaign 5 campaigns	3 300 m^3 per campaign 16 500 m^3 for 5 campaigns	
Drilling fluid water: Vertical wells from which horizontal drilling will be conducted Assumed 3000 m depth (no re-use of water)	825 m^3	2 wells per campaign 5 campaigns	1 650 m^3 per campaign 8 250 m^3 for 5 campaigns	

Impact driver	Unit	Factor	Total	Comments
Drilling fluid water: horizontal wells Assumed 1500 m horizontal (no re-use of water)	450 m^3	6 wells per campaign 5 campaigns	2 700 m^3 per campaign 13 500 m^3 for 5 campaigns	
Drilling fluid water: stratigraphic wells (50% re-use of water)	412 m^3	4 wells per campaign 5 campaigns	1 648 m^3 per campaign 8 240 m^3 for 5 campaigns	
Drilling fluid water: Vertical wells from which horizontal drilling will be conducted (50% re-use of water)	412 m^3	2 wells per campaign 5 campaigns	824 m^3 per campaign 4 120 m^3 for 5 campaigns	
Drilling fluid water: horizontal wells Assumed 1 500 m horizontal (50% re-use of water)	225 m^3	6 wells per campaign 5 campaigns	1 350 m^3 per campaign 6 750 m^3 for 5 campaigns	
Drilling fluid compounds: stratigraphic wells (no re-use)	300 t per well	4 wells per campaign 5 campaigns	1 200 t per campaign 6 000 t for 5 campaigns	
Drilling fluid compounds: Vertical wells from which horizontal drilling will be conducted (no re-use)	300 t per well	2 wells per campaign 5 campaigns	600 t per campaign 3 000 t for 5 campaigns	
Drilling fluid compounds: horizontal wells (no re-use)	150 t per well	6 wells per campaign 5 campaigns	900 t per campaign 4 500 t for 5 campaigns	
Drilling fluid compounds: stratigraphic wells (50% re-use)	150 t per well	4 wells per campaign 5 campaigns	600 t per campaign 3 000 t for 5 campaigns	
Drilling fluid compounds: Vertical wells from which horizontal drilling will be conducted (50% re-use)	150 t per well	2 wells per campaign 5 campaigns	300 t per campaign 1 500 t for 5 campaigns	

Impact driver	Unit	Factor	Total	Comments
Drilling fluid compounds: horizontal wells (50% re-use)	75 t per well	6 wells per campaign 5 campaigns	450 t per campaign 2 250 t for 5 campaigns	
Drill cuttings per stratigraphic well	550 m^3 per well	4 wells per campaign 5 campaigns	2 200 m^3 per campaign 11 000 m^3 for 5 campaigns	
Drill cuttings per vertical well from which horizontal drilling will be conducted	550 m^3 per well	2 wells per campaign 5 campaigns	1 100 m^3 per campaign 5 500 m^3 for 5 campaigns	
Drill cuttings per horizontal well	300 m^3 per well	6 wells per campaign 5 campaigns	1 800 m^3 per campaign 9 000 m^3 for 5 campaigns	
Drilling rig fuel use	1. Diesel: 1 850 gal/day; 7 t /day [36] 2. Natural gas: 257 MMBtu/day; 6.5 t/day oil equivalent [37]	5 rigs 30 days per well 12 wells per campaign 5 campaigns	Total fuel use, 5 campaigns 1. Diesel: 12 600 t 2 Gas: 11 700 t	Approximately 30 days drilling per well
Hydraulic fracturing water: (no-reuse)	15 000 m^3 per well	6 wells per campaign 5 campaigns	90 000 m^3 per campaign 450 000 m^3 for 5 campaigns	
Hydraulic fracturing water: (30% re-use)	10 000 m^3 per well	6 wells per campaign 5 campaigns	60 000 m^3 per campaign 300 000 m^3 for 5 campaigns	
Flowback sludge	Injected volume of fluid per well: approx 15 000 m^3; Flowback: 30% of injected volume (5000 m^3); Sludge: 3% of flowback (i.e. 150 m^3 per well)	6 wells per campaign 5 campaigns	900 m^3 sludge per campaign 4 500 m^3 sludge for 5 campaigns	

[36] Diesel consumption of a drilling rig powered by a Caterpillar C32 or C3512 engine
[37] Natural gas consumption of a drilling rig powered by a General Electric JC 320 Jenbacher engine

Impact driver	Unit	Factor	Total	Comments
Flowback brine	Injected volume of fluid per well: approx 15 000 m^3; Flowback: 30% of injected volume (5000 m^3); Brine: 50% of flowback (i.e. 2 500 m^3 per well);	6 wells per campaign 5 campaigns	15 000 m^3 brine per campaign 75 000 m^3 brine for 5 campaigns	
Produced water	2 m^3 per well per day; 1 year well lifetime	6 wells per campaign 5 campaigns	4 380 m^3 produced water per campaign; 21 900 m^3 produced water for 5 campaigns	Some fraction of this volume may be classed as hazardous
Light emissions				24 hr operational and security lighting; wellpads with development operations underway; crew accommodation areas.
Drilling rig emissions	Diesel-fuelled rig CO: 10.38 kg/day NOx: 160.13 kg/day Particulates: 1.675 kg/day Hydrocarbons: 2.345 kg/day	12 wells per campaign 30 days drilling per well 5 campaigns	Diesel-fuelled rig CO: 3 736 kg NOx: 57 646 kg PM: 603 kg HC: 844 kg	Approximately 30 days drilling per well; 12 wells per campaign.
Hazardous waste (e.g. grease, used engine oil)	1 t per well	12 wells per campaign 5 campaigns	12 t per campaign 60 t for 5 campaigns	
Drilling rig noise emissions	90 dB			24 hrs operations
Flaring during flow-testing: gaseous emissions		6 wells would be flared per campaign	5 campaigns; 30 wells flared	Approximately 30 days flaring per well
Domestic waste	0.46 kg per worker per day			See crew sizes per operation
Sanitary waste	0.1425 m^3 per worker per day			See crew sizes per operation

In the event that none of the exploration drilling campaigns reveals shale gas reserves that are economically viable, the SGD programme within the study area would terminate. Failure criteria would include a discovery with extrapolated results that indicate a reserve magnitude considerably smaller than 5 tcf and/or where appraised gas flow rates from a discovery that is made do not allow for economically viable production. Considerations that could impact this decision include unfavourable gas pricing, high operational costs, technology challenges and complex geological conditions that might be encountered.

Any surface and other disturbances resulting from operations would be rehabilitated in line with EMPr commitments.

If an economically viable discovery is made, the SGD process would advance to further evaluation and potential development of the resource. This would include production through scaled-up drilling, hydraulic fracturing, installation of gas pipelines and processing facilities and other infrastructure. Although an element of exploration would continue to define the extent of potential development (e.g. ongoing 3-D seismic surveys to accurately inform the location of production wells), there would be a general transition away from exploration and appraisal activities towards those more typical of production. This situation is described in Sections 4.4 and 4.5 for Small and Big Gas production scenarios respectively.

1.4.4 Scenario 2: Small Gas

1.4.4.1 <u>Scenario statement</u>

The scenario that could result from SGD proceeding to a small-scale development and production within the study area is expressed as follows:

> In 2050 there is a 1 000 MW Combined Cycle Gas Turbine (CCGT) power station established in the central Karoo. The modular design of the facility allowed for its easy construction and early commissioning. The power station, which has recently undergone refurbishment, is the only downstream project that has materialised within the SGD sector within the study area. The power station makes a relatively small contribution to the country's energy supply mix which, for the Western Cape, is mostly defined by contributions from an LNG-fuelled power station established north of Cape Town and from the region's renewable energy sector.
>
> Shale gas exploration was initiated in 2018. By 2025, exploration and appraisal operations revealed modest, but economically viable shale gas reserves in the central Karoo totalling approximately 5 tcf. This triggered a development programme of early monetisation of the reserve in a directed response to the shortfall in the country's electricity generation capacity at the time.

An environmental audit of all SGD activities in the study area, undertaken in 2048, showed that rehabilitation of areas at abandoned exploration, appraisal and decommissioned production wellpads and the network of decommissioned access roads to these sites has fully achieved the targets specified in the project Environmental Impact Assessments and accompanying Environmental Management Programmes. Environmental monitoring will, nevertheless, continue for at least another decade.

The suite of SGD activities comprising this scenario corresponds largely with those described previously for exploration and appraisal (Section 4.3), but scaled up and supplemented with production-related infrastructure development.[38] The up-scaling process and infrastructure development are discussed below, including a quantification of key SGD activities/impact drivers that would define this production scenario.

1.4.4.2 <u>Key impact drivers of small-scale gas development</u>

For the SGD scenario considered here, development would proceed based on the results of the most successful of the exploration and appraisal campaigns that are undertaken; i.e. it is assumed that development would proceed for a single location situated in the central part of the study area. It is assumed further that all of the activities associated with the development and production scenario would be contained within a single block measuring approximately 30 x 30 km (Figure 1.30).

It is likely that a significant proportion of activities undertaken to support production would be initiated immediately following exploration and appraisal, *inter alia* to accelerate monetization of the gas to offset exploration and production development costs. The construction of production infrastructure (e.g. the initial suite of production wells, the associated gathering pipeline network, gas processing stations) would be concluded in a period of five to ten years (Figure 1.19). Ongoing drilling, completion and testing of production wells and related infrastructure would continue for much of the duration of production, extending over several decades. New wellpads would be developed on a regular basis, whilst existing wellpads would remain operational for several years as additional horizontal wells and/or horizontal laterals are drilled and hydraulic fracturing is undertaken to maintain a supply of gas at the required level (Plate 1.8).

[38] Development and production operations would proceed on the basis of the award of production rights (i.e. conversion of exploration rights to production rights). As for exploration, Environmental Authorisation for operations would be required, based on EIA that is carried out and an approved EMPr. Several other authorisations and permits would apply.

Plate 1.8: Cluster of producing wellheads (Source: Tom Murphy, Pennsylvania State University, USA)

For technical and economic reasons the initial development would target areas which, in the course of exploration and appraisal, promised the highest production rates and ultimate recovery volumes. This would be followed by ongoing expansion into peripheral areas. Production from shale gas wells typically declines rapidly after start-up. Calculations are, therefore, made of the Estimated Ultimate Recovery (EUR) per well, which then determine the number and average spacing of the wells (i.e. number of wells per unit area) and the rate at which they are established. New wells are drilled constantly in order to maintain a particular level of gas production.[39]

Development would commence with the commissioning of supplementary seismic surveys across the production block. In parallel with or immediately following this, access roads and new wellpads would be established to enable drilling of a series of wells aimed at both resource delineation and production. Importantly, a supply of process water would be sourced and, most likely, a central treatment facility designed and constructed to treat the water evacuated from the wells (flowback water, including produced water).[40] Water would be recovered for re-use and the waste separated from the flowback for disposal. A considerably greater volume of hydraulic fracturing fluid would be used in this scenario than during the exploration and appraisal phase (scenario 1).

[39] The regulatory regime may prescribe production rates and, therefore, the rate of establishment of wells, their number and spacing (as is the case in some states in the USA).
[40] Modular water treatment facilities may be provided as an alternative to a central facility.

The drilling and production of wells would proceed at a pace aimed at achieving a targeted rate of gas-flow that can be maintained over time.[41] For the scenario considered here a sustained flow of gas of approximately 172 million standard cubic feet (MMscf) per day would be the target. To achieve this, approximately 550 production wells would be drilled from 55 wellpads (i.e. 10 wells per wellpad).[42] In addition to this total, a relatively small number of resource delineation wells would be drilled. A schematic indication of how the suite of wellpads and associated access roads and other infrastructure might be distributed across a production block is presented in Figure 1.30.

> The fuel consumption of an SGT5 8000H gas turbine with an electricity generation capacity of 1 150 MW is 40 kg/s. Expressed in scf, total fuel consumption over a 35-year operational lifetime would be approximately 2 207 bscf.[1] Assuming an EUR/well of 4.0 bscf (see footnote), the minimum number of wells required to provide for this consumption would total approximately 550. This is the number of production wells assumed for Scenario III. Note that this is less than the number of wells that could theoretically exhaust a shale gas reserve of 5 tcf, which is approximately 1 250 wells. For the assessment, the conservative total of 550 wells is assumed.

At the production sites condensate and produced water would be stripped from any 'wet gas' that is produced and directed into storage tanks. This would be of either a decentralised modular or centralised (Plate 1.6) design. A flare would be installed to provide for safe shut down, depressuring of the facility in an emergency and for the safe discharge of small volumes of gas associated with routine maintenance and operations. Equipment such as well chokes and manifolds would be installed to control gas flow pressures and a network of gathering pipelines would be installed to convey the product to a gas compressor station (Plates 1.9 and 1.10). A proportion of the pipeline network would probably be located within the corridors established for the wellpad access roads.

Treated gas would be exported from the production block at the requisite pressure and flow rate via a pipeline. This would supply gas to the 1 000 MW CCGT power station, which would be established probably less than 100 km from the production block.

[41] The assumption here is that there is synchronization and cooperation between the E&P Applicant/s and state interests. An E&P Applicant's likely desire to exploit resources as quickly and financially favourably as possible would need to be balanced against state economic interests for production to sustain the downstream development presented for this scenario (also for the next scenario that is described).

[42] An average EUR/well of 2.2 bscf (billion standard cubic feet) is reported for the USA Barnett Shales (Oil and Gas Journal, 2014; http://www.ogj.com/articles/print/volume-112/issue-11/drilling-production/new-well-productivity-data-provide-us-shale-potential-insights.html). Production from the Marcellus Shales, in Pennsylvania USA, is averaging approximately 6.5 bscf per well (Tom Murphy, Pennsylvania State University, USA). For this assessment, a conservative EUR/well value of 4.0 bscf is assumed; i.e. mid-way between the reported Barnett and Marcellus shale production values.

Plate 1.9: Example of a shale gas compressor station situated at a wellhead complex. Tanks used to store produced water and condensate, separated from ‘wet gas’, are shown located towards the top left of the plate (Source: Tom Murphy, Pennsylvania State University, USA)

Plate 1.10: Example of a centralised gas compressor station. Compressed gas would be exported from this facility, via pipeline, to a downstream facility such as a CCGT power station (Source: Tom Murphy, Pennsylvania State University, USA)

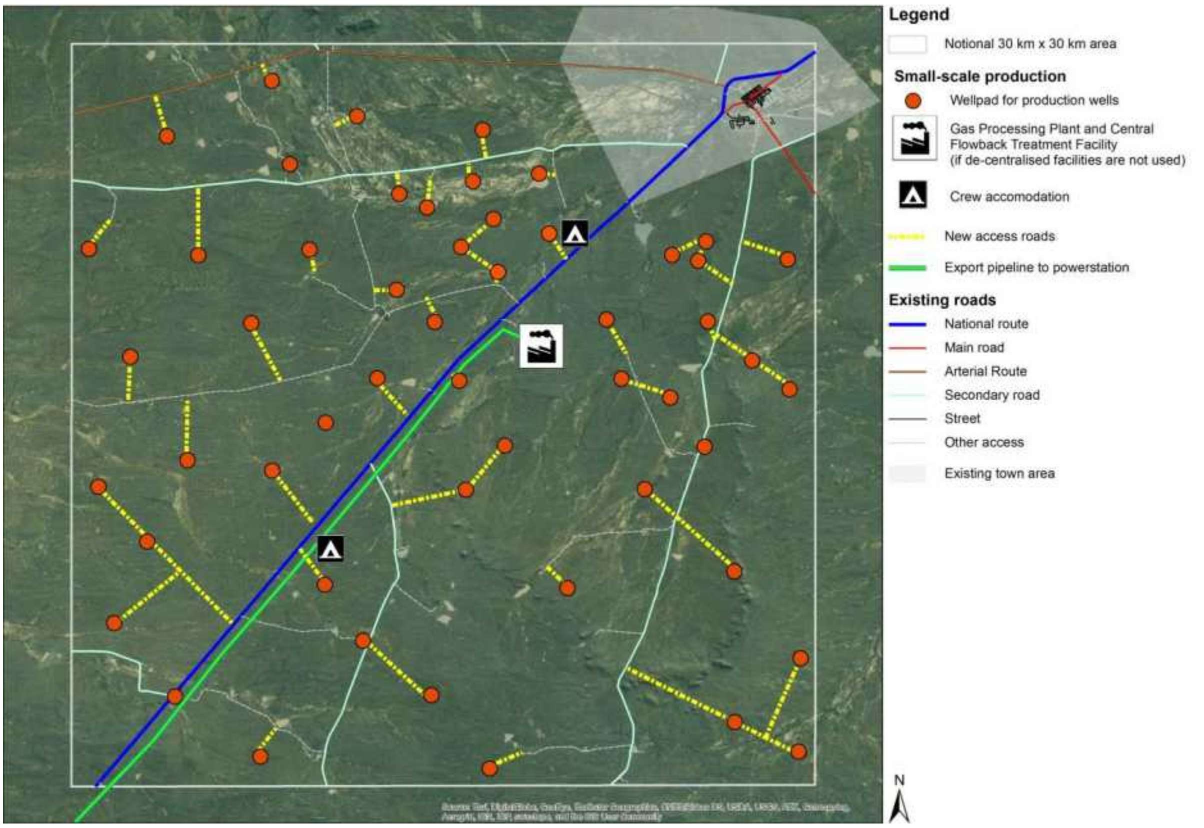


Figure 1.30: Schematic illustration of wellpads, access roads pipeline grids and other infrastructure established in an area (30 x 30 km) notionally targeted for small-scale development and production. In practice, there would likely be greater orderliness, than indicated here, to the distribution pattern of wellpads and wells, for example, to accommodate regional tectonic stresses. For the scheme presented here, the gathering pipeline system conveying gas to the processing plant would be located within the road corridors that are indicated

Planning, site preparation, drilling, hydraulic fracturing and production would proceed as described in Section 4.3.2.2.1. Although many activities would be associated with each of these project elements, those to which the status can be assigned of being key impact drivers include the following:

- Clearing of wellpad areas and the crew accommodation sites
- Construction of new access roads to wellpads
- Rail plus road transport to site of drilling fluid compounds (mostly containerised)
- Rail plus road transport to site of well casing
- Road transport to site of the components for several drilling rigs (power units, derricks and other equipment)
- Road transport to site of the components for several drilling rigs (power units, derricks and other equipment).
- Road transport to site of ancillary equipment supporting drilling operations at the wellpads (e.g. pumps, generators).
- Road transport to site of temporary infrastructure and equipment used to refurbish the crew accommodation (e.g. to upgrade the camp previously used for exploration operations).

- Transport to site of a truck-mounted drilling unit for creating shallow aquifer water monitoring wells (probably mobilised to site during the phase of establishing environmental baseline conditions).
- Road transport during operations.
- Sourcing and supply of potable water for domestic use.
- Sourcing and supply of process water to prepare drilling mud and for hydraulic fracture fluid.
- Process water treatment and disposal of waste (including brine and sludge recovered from flowback).
- Drill cuttings disposal.
- Noise and light emissions.
- Construction of gathering gas pipeline networks.
- Construction of gas processing facilities, including a compressor station.
- Servitude arrangement and construction of a gas export pipeline and its connection to the CCGT power station.
- Domestic and solid waste management.
- Hazardous waste management.
- Flaring of gas during drilling and well-flow testing.
- Employment, personnel logistics, labour negotiations.
- Management of safety, security and medical/health.

Quantification of the main activities/impact drivers is presented in Table 1.4.

Table 1.4: Small Gas development and production scenario: Quantification of key activities/impact drivers associated with drilling, gas-processing and -pipeline infrastructure within the study area.

Impact driver	Unit	Factor	Total	Comments
Drilling rigs commissioned	3 rigs		3 rigs	
Employment: Drilling campaign	100 personnel per rig [43]	3 rigs; 5-10 years duration of operations	300 personnel	Expat specialists 20%;[44] National professionals 10%; National skilled 10%; Local unskilled 60%

[43] As experienced drilling crews are established, this total number of personnel could reduce; i.e. this is an estimate of the maximum crew size (also, the crew size that would likely be employed in the first number of years).

[44] Over time, the proportion of expatriate personnel would diminish relative to the involvement of national professionals. Local competency and capacity would develop through training, experience gained and entrepreneurial drive – probably also in response to licensing conditions.

Impact driver	Unit	Factor	Total	Comments
Drill rig height	40 m			
Number of wellpads established (10 wells per wellpad)	55 wellpads		55 wellpads	
Access roads constructed to wellpads	0.5 km per wellpad	55 wellpads	27.5 km	
Wellpad footprint	2 ha per wellpad	55 wellpads	Up to 110 ha	Larger multi-well wellpads, compared to exploration
Crew accommodation camp footprint	1 ha	1 camp	1 ha	Same camp used for exploration, but refurbished
Transport of drilling rig, casing and ancillary equipment to and from wellpads	Truck visits per well First 100 wells: 500 Next 100 wells: 400 Next 100 wells: 300 >300 wells : 200 (split between 10 t and 20 t trucks)	550	160 000 truck visits	Extrapolated from and adjusted based on Shell EMPr: (http://southafrica.shell.com/aboutshell/shell-businesses/e-and-p/karoo.html). Golder Associates (2011)
Hydraulic fracturing: truck visits per well	Truck visits per well First 100 wells: 500 Next 100 wells: 400 Next 100 wells: 300 >300 wells: 200	550 wells	160 000 truck visits	Extrapolated from and adjusted based on Shell EMPr: (http://southafrica.shell.com/aboutshell/shell-businesses/e-and-p/karoo.html). Golder Associates (2011)
General utility vehicles in operation throughout	Numerous		Numerous	Tbc through transport planning study.
Drilling fluid water: vertical wells sections Assumed 3000 m depth (no re-use of water)[45]	825 m^3	275 wells[46]	226 875 m^3	
Drilling fluid water: horizontal wells Assumed 1500 m horizontal (no re-use of water)	450 m^3	550 wells	247 500 m^3	

[45] "no" and "% re-use" statistics are given here (and elsewhere in the table) to indicate the range of possibilities regarding the demand for process water and the use of drilling and hydraulic fracturing compounds. Total demand/use will be lower in the event that there is recovery and re-use at the levels (%) indicated.

[46] It is assumed that a pair of horizontal wells would be directionally drilled for hydraulic fracturing from each vertical well.

Impact driver	Unit	Factor	Total	Comments
Drilling fluid water: vertical well sections (50 % re-use of water)	412 m^3	275 wells	113 300 m^3	
Drilling fluid water: horizontal wells (50% re-use of water)	225 m^3	550 wells	123 750 m^3	
Drilling fluid compounds: vertical well sections (no re-use)	300 t per well	275 wells	82 500 t	
Drilling fluid compounds: horizontal wells (no re-use)	150 t per well	550 wells	82 500 t	
Drilling fluid compounds: vertical well sections (50% re-use)	150 t per well	275 wells	42 250 t	
Drilling fluid compounds: horizontal wells (50% re-use)	75 t per well	550 wells	41 250 t	
Drill cuttings: vertical well sections	550 m^3 per well	275 wells	151 250 m^3	
Drill cuttings: horizontal wells	300 m^3 per well	550 wells	165 000 m^3	
Drilling rig fuel use	1. Diesel: 1 850 gal/day; 7 t /day [47] 2. Natural gas: 257 MMBtu/day; 6.5 t/day oil equivalent [48]	30 days drilling per well 550 wells	1. Diesel: 115 000 t 2 Gas: 107 000 t	Over time, with experience gained by drilling crews, the assumed drilling duration of approximately 30 days per well could reduce to around 20 days.
Hydraulic fracturing water: (no-reuse)	15 000 m^3 per well	550 wells	8 250 000 m^3	
Hydraulic fracturing water: (30 % re-use)	10 000 m^3 per well	550 wells	5 500 000 m^3	

[47] Diesel consumption of a drilling rig powered by a Caterpillar C32 or C3512 engine
[48] Natural gas consumption of a drilling rig powered by a General Electric JC 320 Jenbacher engine

Impact driver	Unit	Factor	Total	Comments
Flowback sludge	Injected volume of fluid per well: approx 15 000 m^3; Flowback: 30% of injected volume (5 000 m^3); Sludge: 3% of flowback (i.e. 150 m^3 per well)	550 wells	82 500 m^3	
Flowback brine	Injected volume of fluid per well: approx 15 000 m^3; Flowback: 30% of injected volume (5000 m^3); Brine: 50% of flowback (i.e. 2 500 m^3 per well);	550 wells	1 375 000 m^3	
Produced water	2 m^3 per well per day; 10 year well lifetime	550 wells	4 015 000 m^3 produced water	Some fraction of this volume may be classed hazardous
Light emissions				24 hr operational and security lighting of wellpads with development operations underway; crew accommodation areas.
Drilling rig emissions	Diesel-fuelled rig CO: 10.38 kg/day NOx: 160.13 kg/day PM: 1.675 kg/day HC: 2.345 kg/day Gas-fuelled rig CO: 9.94 kg/day NOx: 34.27 kg/day Particulates: 0.08 kg/day Hydrocarbons: 0.5 kg/day	550 wells 30 days drilling per well	Diesel-fuelled rig CO:171 270 kg NOx: 2 642 145 kg PM: 27 637 kg HC: 38 692 kg Gas-fuelled rig CO: 164 010 kg NOx: 565 455 kg PM: 1 320 kg HC: 8 250 kg	Approximately 30 days drilling per well; drilling duration could decrease to around 20 days as drilling crews gain experience. Emissions calculations based on 30 days drilling duration per well (compare diesel vs gas)
Hazardous waste (e.g. grease, used engine oil)	1 t per well	550 wells	550 t	
Domestic water use (drinking, sanitation)	0.15 m^3 per person per day			See crew sizes per operation
Drilling rig noise emissions	90 dB			24 hrs
Domestic waste	0.46 kg per worker per day			See crew sizes per operation
Sanitary waste	0.1425 m^3 per worker per day			See crew sizes per operation

In the event that an economically viable shale gas discovery within the study area does not exceed 5 tcf, the scenario of small-scale development and production would be limited to what has just been described. However, if the gas discovery is considerably larger, development and production could proceed via an initial small-scale development (e.g. as above) to the scenario that is described next.

1.4.5 Scenario 3: Big Gas

1.4.5.1 <u>Scenario statement</u>

The scenario that could result from SGD proceeding to a large-scale production development is expressed as follows:

> In 2050, directed by the country's Gas Utilisation Master Plan, there are two CCGT power stations established in the central Karoo. Each of the power stations is of 2 000 MW generating capacity. One of the power stations is an upgrade to and expansion of the 1 000 MW CCGT facility built almost 20 years ago as the first downstream SGD project was initiated in partial response to constraints on electricity generation capacity experienced in South Africa at the time. The second power station is recently constructed. The modular design of both facilities allowed for their construction much more efficiently than, for example, coal-fired equivalents. The power stations contribute significantly to the country's energy supply mix, which is also defined by major contributions from an LNG-fuelled power station established north of Cape Town and from the Karoo's renewable energy sector. Directed by the country's Integrated Energy Plan, there is also a new Gas to Liquid (GTL) plant established at the coast. It is supplied with shale gas via a pipeline from the central Karoo.[49] Designed and built using best available technology, its operations are in compliance with strict global environmental standards.[50]
>
> Shale gas exploration was initiated in 2018. By 2025, exploration operations revealed an economically viable shale gas reserves in the central Karoo totalling approximately 20 tcf, sufficient to sustain production demand for several decades. An environmental audit of all SGD activities in the study area, undertaken in 2048, showed that rehabilitation of areas at abandoned exploration, appraisal and decommissioned production wellpads and the network of decommissioned access roads to these sites has fully achieved the targets specified in the project Environmental Impact Assessments and accompanying Environmental Management Programmes. Environmental monitoring will continue for a number of decades.

The suite of SGD activities comprising this scenario correspond largely with those just described for Small Gas scenario (Section 4.4) but scaled up considerably. The up-scaling process and

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[49] The facility could be located elsewhere (e.g. at Sasolburg).

[50] Although production via a GTL plant is more expensive than, for example, refining of crude oil, economic justification for the plant could be based on balance of payment savings (i.e. through reduced importation of purchased crude oil or LNG). The country's Integrated Energy Plan provides for the establishment of one new GTL plant in South Africa of relatively small refining capacity (similar to what is proposed in this scenario).

infrastructure development are discussed below, including a quantification of key SGD activities/impact drivers that would define this production scenario.

1.4.5.2 Key impact drivers of large-scale gas development

The scenario considered here, of large-scale production, would materialise in stages, with the development described in Section 4.4 being an early stage initiative. Commencement of development and production of subsequent stages would likely occur approximately 10 years after initiation of SGD activities within the study area and would continue over a period of decades (Figure 1.19).

It is assumed that the main activities through which the large-scale development and production scenario would materialise would occur within 4 production blocks, each measuring 30 x 30 km i.e. three blocks in addition to the single block developed for the already-described small-scale development and production scenario. A schematic indication of how the suite of wellpads and associated access roads and other infrastructure might be distributed per production block, in their fully developed state, is presented in Figure 1.31.

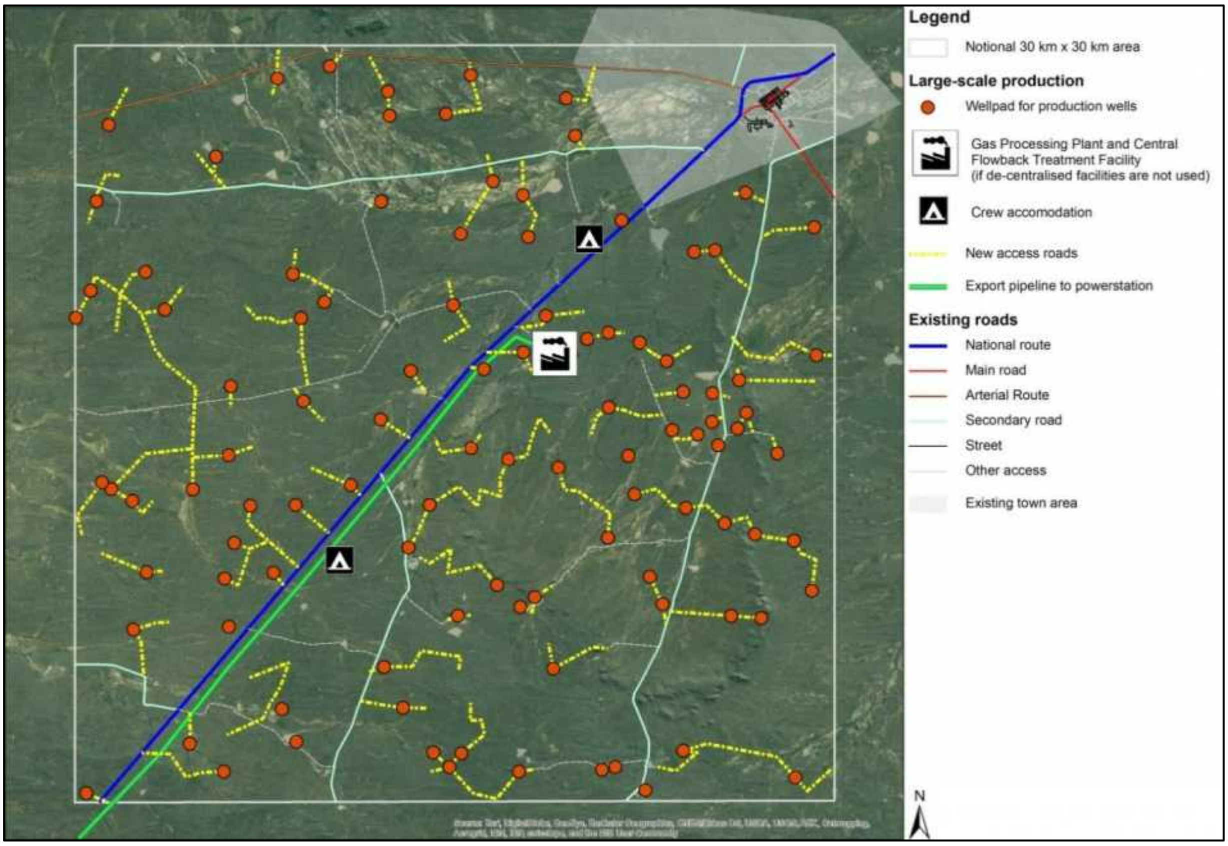

Figure 1.31: Notional schematic representation of gas production infrastructure within one fully developed block (30 x 30 km). See caption of Figure 1.25 regarding the greater degree orderliness expected for the wellpad locations in practice. Note that an additional three similar production blocks would be developed to deliver the volumes of gas required for the Big Gas production scenario (i.e. a total of four production blocks with similar development layouts). For the Big Gas production scenario the size of the production blocks may increase in extent to account for technical and environmental buffer areas between wellpad locations. These buffer areas are not indicated in the notional schematic.

Development would follow a similar pattern as for the scenario of small-scale SGD. On a block-by-block basis, an initial suite of wells and infrastructure would be developed to supply the downstream gas demand, with ongoing development compensating for diminishing gas flow from older wells.[51] Development and production would have a dual focus: First, gas production would ramp up to approximately 688 MMscf per day to supply two 2 000 MW CCGT power stations. This would include the 172 MMscf flow of gas per day sourced from 550 wells already in production supplying the established 1 000 MW power station, which would be upgraded (Section 4.4). Second, production would provide a sustained flow of gas of approximately 600 MMscf per day to supply a GTL plant with a refining capacity of 65 000 bbl per day.[52] Feedstock supplying both the power stations and the

[51] Each production block (30 x 30 km) would be divided into a series of smaller sub-blocks (e.g. 9 x 6 km), which would be individually developed as discrete units.

[52] The rate of 600 MMscf per day is derived from supply statistics for PetroSA's Mossel Bay GTL facility.

GTL plant (approximately 1 100 MMscf per day) would be sourced from approximately 4 100 production wells (410 wellpads; 10 wells per wellpad).[53]

Planning, site preparation, drilling, hydraulic fracturing and production would proceed as described in Sections 4.3.2.2.1 and 4.4.2. Although many activities would be associated with each of these project elements, those to which the status of key impact drivers can be assigned include the following:

- Clearing of wellpad areas and crew accommodation sites.
- Construction of new access roads to wellpads.
- Rail plus road transport to site of drilling fluid compounds (mostly containerised).
- Rail plus road transport to site of well casing.
- Road transport to site of the components for a number of drilling rigs (power units, derricks and other equipment).
- Road transport to site of ancillary equipment supporting drilling operations at the wellpads (e.g. pumps, generators).
- Road transport to site of temporary infrastructure and equipment used to refurbish and establish new crew accommodation facilities.
- Transport to site of a truck-mounted drilling unit for creating shallow aquifer water monitoring wells (probably mobilised to site during the phase of establishing environmental baseline conditions).
- Road transport for operations.

<u>CCGT power station gas consumption</u>

As stated for Scenario 2, the fuel consumption of an SGT5 8000H gas turbine with an electricity generation capacity of 1 150 MW is 40 kg/s. For a 35-year operating lifetime, total fuel consumption (expressed in scf) for a set of turbines with four times this generating capacity (i.e. in the order of 4 000 MW) would be approximately 8 829 bscf. Assuming an EUR/well of 4.0 bscf (see earlier footnote), the minimum number of wells required to provide for this consumption would be 2 200. This is the number of production wells assumed for Scenario 3 relating to the CCGT facilities.

<u>GTL gas supply</u>

For a flow-rate of 600 MMscf per day (0.6 bscf per day) supplying a GTL facility over a 35-year operating lifetime, total consumption of gas would be approximately 7 665 bscf. Assuming an EUR/well of 4.0 bscf, the minimum number of wells required to provide for this consumption would be approximately 1 900.

<u>Gas demand of CCGT and GTL facilities</u>

For Scenario 3 the assumed total number of production wells that would be developed is approximately 4 100. Note this is less than the number of wells that could theoretically exhaust a shale gas reserve of 20 tcf, which is approximately 5 000. For this assessment, the conservative total of 4 100 wells is assumed.

[53] An average EUR/well of 2.2 bscf (billion standard cubic feet) is reported for the USA Barnett Shales (Oil and Gas Journal, 2014; http://www.ogj.com/articles/print/volume-112/issue-11/drilling-production/new-well-productivity-data-provide-us-shale-potential-insights.html). Production from the Marcellus Shales, in Pennsylvania USA, is averaging approximately 6.5 bscf per well (Tom Murphy, Pennsylvania State University, USA). For this assessment, an EUR/well value of 4.0 bscf is assumed; i.e. mid-way between the reported Barnett and Marcellus shale production values.

- Sourcing and supply of water for domestic use.
- Sourcing and supply of process water to prepare drilling mud and for hydraulic fracture fluid.
- Process water treatment and disposal of waste (e.g. brine and sludge recovered from flowback).
- Drill cuttings disposal.
- Noise and light emissions.
- Construction of gathering gas pipeline networks.
- Construction of gas processing facilities, including an upgraded compressor station.
- Servitude arrangements; construction of gas export pipelines to the power stations and the GTL plant.
- Domestic and solid waste management.
- Hazardous waste management.
- Flaring of gas during drilling and well-flow testing.
- Employment, personnel logistics, labour negotiations.
- Management of safety, security and medical/health.

Quantification of the main activities/impact drivers comprising the production drilling and gas processing and pipeline infrastructure is presented in Table 1.5.

Table 1.5: Big Gas development and production scenario: Quantification of key activities/impact drivers associated with drilling and gas-processing and -pipeline infrastructure within the study area.

Impact driver	Unit	Factor	Total	Comments
Drilling rigs commissioned	Up to 20 rigs		Up to 20 rigs	
Employment: Drilling campaign	100 personnel per well rig [54]	20 rigs (assumed)	2 000 personnel employed	Expat specialists 20%;[55] National professionals 10%; National skilled 10%; Local unskilled 60%.
Drill rig height	40 m			
Number of wellpads established (10 wells per wellpad)	410 wellpads		410 wellpads	
Access roads constructed to wellpads	0.5 km per wellpad	410 wellpads	205 km access roads	
Wellpad footprint	2 ha per wellpad	410 wellpads	Up to 820 ha	
Crew accommodation camp footprint	1 ha per camp	2 camps per production block; 4 blocks; 8 camps	Up to 8 ha	
Transport of drilling rig, casing and ancillary equipment to and from wellpads	Truck visits per well First 100 wells: 500 Next 100 wells: 400 Next 100 wells: 300 >300 wells : 200 (split between 10 t and 20 t trucks)	4 100 wells	1 066 000 truck visits	Extrapolated from and adjusted based on Shell EMPr: (http://southafrica.shell.com/aboutshell/shell-businesses/e-and-p/karoo.html). Golder Associates (2011)
Hydraulic fracturing: truck visits per well	Truck visits per well First 100 wells: 500 Next 100 wells: 400 Next 100 wells: 300 >300 wells : 200	4 100 wells	1 066 000 truck visits	Extrapolated from and adjusted based on Shell EMPr: (http://southafrica.shell.com/aboutshell/shell-businesses/e-and-p/karoo.html).
General utility vehicles in operation throughout	Numerous		Numerous	Tbc through transport planning study.
Drilling fluid water: vertical well sections 3000 m depth (no re-use of water)	825 m^3 per well	2 050 wells [56]	1 691 250 m^3	

[54] As drilling crews gain experience, this total number of personnel could reduce; i.e. this is an estimate of the maximum crew size. It is assumed that this is the crew size that would be employed in the first number of years of production.

[55] Over time, the proportion of expatriate personnel would diminish relative to national professionals; i.e. local competency and capacity would develop.

Impact driver	Unit	Factor	Total	Comments
Drilling fluid water: horizontal wells 1500 m horizontal (no re-use of water)	450 m^3 per well	4 100 wells	1 845 000 m^3	
Drilling fluid water: vertical well sections (50% re-use of water)	412.5 m^3 per well	2 050 wells	845 625 m^3	
Drilling fluid water: horizontal wells (50% re-use of water)	225 m^3 per well	4 100 wells	922 500 m^3	
Drilling fluid compounds: vertical well sections (no re-use)	300 t per well	2 050 wells	615 000 t	
Drilling fluid compounds: horizontal wells (no re-use)	150 t per well	4 100 wells	615 000 t	
Drilling fluid compounds: vertical well sections (50% re-use)	150 t per well	2 050 wells	307 500 t	
Drilling fluid compounds: horizontal wells (50% re-use)	75 t per well	4 100 wells	307 500 t	
Drill cuttings: vertical well sections	550 m^3 per well	2 050 wells	1 127 500 m^3	
Drill cuttings: horizontal wells	300 m^3 per well	4 100 wells	1 230 000 m^3	
Drilling rig fuel use	1. Diesel: 1 850 gal/day; 7 t /day [57] 2. Natural gas: 257 MMBtu/day; 6.5 t/day oil equivalent [58]	Approximatel y 30 days drilling per well; 4 100 wells	1. Diesel: 861 000 t 3. Gas 799 500 t	Over time, the drilling duration of approximately 30 days per well could reduce to around 20 days.
Hydraulic fracturing water: (no-reuse)	15 000 m^3 per well	4 100 wells	61 500 000 m^3	
Hydraulic fracturing water: (30% re-use)	10 000 m^3 per well	4 100 wells	41 000 000 m^3	

[56] It is assumed that a pair of horizontal wells would be directionally drilled for hydraulic fracturing from each vertical well.

[57] Diesel consumption assumed for a drilling rig powered by a Caterpillar C32 or C3512 engine

[58] Natural gas consumption assumed for a drilling rig powered by a General Electric JC 320 Jenbacher engine

Impact driver	Unit	Factor	Total	Comments
Flowback sludge	Injected volume of fluid per well: approx 15 000 m^3; Flowback: 30% of injected volume (5000 m^3); Sludge: 3% of flowback (i.e. 150 m^3 per well)	4 100 wells	615 000 m^3	
Flowback brine	Injected volume of fluid per well: approx 15 000 m^3; Flowback: 30% of injected volume (5000 m^3); Brine: 50% of flowback (i.e. 2 500 m^3 per well);	4 100 wells	10 250 000 m^3	
Produced water	2 m^3 per well per day; 10 year well lifetime	4 100 wells	29 930 000 m^3	Some fraction of this volume may be classed as hazardous
Light emissions				24 hr operational and security lighting for wellpads with development operations underway; crew accommodation areas.
Drilling rig emissions	Diesel-fuelled rig CO: 10.38 kg/day NOx: 160.13 kg/day Particulates: 1.675 kg/day Hydrocarbons: 2.345 kg/day Gas-fuelled rig CO: 9.94 kg/day NOx: 34.27 kg/day Particulates: 0.08 kg/day Hydrocarbons: 0.5 kg/day	4 100 wells 30 days drilling per well	Diesel-fuelled rig CO: 1 276 740 kg NOx: 19 695 990 kg PM: 2 016 025 kg HC: 288 435 kg Gas-fuelled rig CO: 1 222 620 kg NOx: 4 215 210 kg PM: 9 840 kg HC: 61 500 kg	Approximately 30 days drilling per well; drilling duration could decrease to around 20 days as drilling crews gain experience. Emissions calculations based on 30 days drilling duration per well (compare diesel vs gas)
Hazardous waste (e.g. grease, used engine oil)	1 t per well	4 100 wells	4 100 t	
Domestic water use (drinking, sanitation)	0.15 m^3 per person per day			See crew sizes per operation
Drilling rig noise emissions	90 dB within 10 m			24 hrs operations
Domestic waste	0.46 kg per worker per day			See crew sizes per operation
Sanitary waste	0.1425 m^3 per worker per day			See crew sizes per operation

Box 1.2: Key features of a Combined Cycle Gas Turbine power station

Produced shale gas would provide the feedstock for the two CCGT power stations assumed for this assessment. After compression, the gas would be transported to the power stations by pipeline. The duration of construction of the facilities would be approximately 24 and 30 months for a 1 000 and 2 000 MW facility respectively. About 150 permanent operation jobs would be created for skilled staff and support labour per facility. The combined spatial footprint of the two power stations would be in the order of 30 ha (an additional 10 ha during construction). Gas turbine air emissions would be in the order of:

- NO_x: < 25 parts per million by volume dry mass (ppmvd) during base load
- CO: < 10 ppmvd during base load
- CO_2: 650 kg/MW (IPCC, 2014)
- Exhaust flow: 850 kg/s

In the water-scarce environment of the study area, air cooling technology would be employed. The total water consumption (not for cooling) would be about 10 m^3 per day. Generated power would feed into the national electricity grid via either an existing or a new dedicated sub-station. The appropriate kv transmission line capacities would be provided for the power stations.

Box 1.3: Key features of a Gas-to-Liquid plant

For the scenario considered here, produced shale gas would be compressed and piped to a Gas-to-Liquid (GTL) plant located either at the coast (e.g. Coega Industrial Development Zone, the existing PetroSA GTL refinery at Mossel Bay) or in Gauteng (e.g. Sasolburg). A new GTL plant would take about 5 years to construct. The basic GTL process converts natural gas into longer-chain hydrocarbons such as gasoline, diesel and other valuable petrochemical products using modern Low-Temperature Fischer–Tropsch technologies. Piped shale gas would feed the GTL plant at a rate of 600 MMscf per day. About 65 000 bbls per day of refined product would be produced. The facility would have a physical footprint of approximately 160 ha. A GTL plant at the coast would use sea water as a cooling medium. In the case of an inland facility, fresh water would be used, with the quantity determined on the basis of the quality of available fresh water and average water and ambient air temperatures. Approximately 750 – 900 permanent jobs would be created during operations. GTL air emissions would be in the region of:

- Flue gas: 1800 t/hr; CO_2 = 24 % - 27 %.
- Nitrogen: 2000 t/hr
- Cooling water evaporation losses: 1200 t/h

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1.6 Addendum A1

Table A.1: Substances commonly used in drilling and fracking fluids, and an indication of their toxicity levels.

Compiled from US EPA 2015a and US EPA 2015b.

Additive type	Function	Types of chemical used	Toxicity
Thickeners	increase viscosity of the fracking fluid, making high-pressure pumping more efficient; suspension of proppants	carboxymethylcellulose, xanthan gum, guar gum, glycol	ethylene glycol (radiator fluid) extremely toxic
Deflocculants	thinning agents used to reduce viscosity or prevent flocculation (sometimes incorrectly called "dispersants")	acrylates, polyphosphates, lignosulphonates	acrylates may be toxic; acrylamide is a known neurotoxin
Friction reducers, lubricants	additives used to produce "slick water", which reduces friction in the wellbore, increasing fluid-flow velocity	petroleum distillate, used as a carrier fluid for poly-acrylamides or polyacrylics	petroleum distillates contain hazardous chemicals; polyacrylamide not toxic but breaks down to toxic acrylamides
Weighting agents	increase weight of muds, prevent ingress of water into the well being drilled; prevents blow-outs	barium sulphate (barite)	extremely insoluble so not classified by USEPA as hazardous
Fluid-loss additives	reduce loss of drilling fluids into permeable rock formations	diesel, particulates, sand	diesel contains hazardous chemicals
Clay control	Prevent swelling and migration of formation clays, which can cause reduced permeability and productivity by clogging pore spaces in the formation	KCl; quaternary amines (= quaternary ammonium compounds: QACs)	QACs toxic to aquatic organisms at environmentally relevant concentrations (Tezel 2009)
Gelling agents	Increase fluid viscosity; increase the ability of the fluid to carry proppant and help to minimize fluid loss.	Hydroxy-ethyl cellulose (HEC) HEC and carboxy-methyl-hydroxy-ethyl cellulose (CMHEC); guar gum; foams/ poly-emulsions using N_2, CO_2 or a hydrocarbon (e.g. propane), diesel or condensate; ethylene glycol	Diesel and condensate (ultra-light fuel oil) contain hazardous chemicals; ethylene glycol (radiator fluid) extremely toxic
Cross-linkers	Increase molecular weight of polymers by cross-linking, thereby increasing viscosity, elasticity and ability of the fluid to transport proppant	guar and CMHEC based gels; Boric acid and B salts of Ca and Mg; metals including Titanium, Zirconium, Iron, Chromium & Aluminum; organic borate complexes; ethylene glycol; methanol	Some metals toxic at low concentrations; borates used in insecticides and antibiotics, and "toxic for reproduction" (EU regulations); ethylene glycol (radiator fluid) extremely toxic; methanol highly toxic
Buffers	Adjust pH to allow for dispersion, hydration and crosslinking of the fracking-fluid polymers	Combinations of sodium bicarbonate; formic acid; sodium carbonate; fumaric acid; sodium hydroxide; hydrochloric acid; monosodium phosphate; magnesium oxide	formic and fumaric acids mildly toxic; hydrochloric acid corrosive, causes severe burns when concentrated
Surfactants	Reduce the surface tension of the fracturing fluid to improve fluid recovery; prevent formation of emulsions; can be used as emulsifiers, foaming agents, defoaming agents, and dispersants.	EGMBE (ethylene glycol monobutyl ether) and BGMBE (butylene glycol monobutyl ether)	toxicity of both EGMBE and BGMBE low but "potentially toxic inert, with high priority for testing" (USEPA)
Viscosity stabilizers	Stabilize the fluid at high temperatures	methanol (used at 5 to 10% of the fluid volume) and sodium thiosulfate	methanol highly toxic

Additive type	Function	Types of chemical used	Toxicity
Scale inhibitors	Prevent scale deposits in pipes	sodium polycarboxylates including co-polymers of acrylamide and sodium acrylate; phosphonic acid salts	acrylates may be toxic; acrylamide is a known neurotoxin
Acids	Restore permeability lost as a result of the drilling process or initiate fracturing, achieve greater fracture penetration, and reduce clogging of the pore spaces and fractures by dissolving minerals and clays.	hydrochloric acid (concentrations up to 15%) and hydrofluoric acid	both acids corrosive, cause severe burns when concentrated
Biocides	Minimize decomposition of gelling polymers by aerobic bacteria; prevent anaerobic sulphate- reducing bacteria, which can “sour” a well and produce corrosive hydrogen sulphide gas	quaternary amines, amides and aldehydes (= quaternary ammonium compounds: QACs); glutaraldehyde; chloro-phenates [= chlorophenols?]; isothiazolinone; ozone; chlorine as hypochlorous acid, chlorine dioxide; UV light	Biocides are by their nature toxic: QACs (Tezel 2009) and isothiazolinone toxic to aquatic organisms at environmentally relevant concentrations; glutaraldehyde (similar to formaldehyde) and chlorophenols highly toxic
(Gel) breakers	Reduce viscosity and facilitate blowback of fluid after fracking	oxidizers: ammonium persulfate, sodium persulfate; calcium and magnesium peroxides; acids: acetic or hydrochloric acid; enzymes: hemicellulase, cellulase, amylase and pectinase	Persulphates irritants and toxic; peroxides unstable and sometimes explosive; hydrochloric acid corrosive, cause severe burns when concentrated
Corrosion inhibitors	Protect iron and steel equipment and well-bore components from corrosive acids	e.g. N,n-dimethyl formamide	N,n-dimethyl formamide a hazardous chemical; thought to cause birth defects
Radioactive tracers	Show the injection profile and locations of fractures	Antimony-124, argon-41, cobalt-60, iodine-131, iridium-192, lanthanum-140, manganese-56, scandium-46, sodium-24, silver-110m, technetium-99m, xenon-133	Radioactive tracers pose negligible risk to the public when handled, transported, stored and used according to appropriate guidelines.
Scale inhibitors, iron control	Increase the solubility of metals, particularly iron, so controlling rust, sludges, and mineral scales	citric and acetic acids; ethylene glycol	ethylene glycol (radiator fluid) extremely toxic
Oxygen scavengers	Control rust by removing oxygen from the fluid	ammonium bisulphite	ammonium bisulphite “hazardous to health”
		volatile organic compounds (VOCs) such as benzene, toluene, ethylbenzene and xylene - (BTEX compounds)	effects on CNS; human carcinogens

Table A.2: Chemicals that may not be added to fracking fluids in South Africa (DMR 2015).

NOTE that the heading of the list refers to "chemicals regulated under Safe Drinking Water Act ...", but this seems to be an Australian Act (there is no such Act in South Africa, where drinking water is regulated under SANAS 421).

1- Methylnaphthalene
2- Butanone
2- Hexanone
2- Methylnaphthalene
2- Methylphenol
2- Pyrrolidone
3- Methylphenol
4- Methylphenol
4- Methylphenol
Acetaldehyde
Acetone
Acetonitrile
Acetophenone
Acrylamide
Aniline
Benzene
Benzidine
Benzyl chloride
Bromomethane
Chloroethane
Copper
Cumene (isopropylbenzene)
Di (2- [Incomplete name - might be able to identify the substance by searching for CAS no. 117-82-7 at https://www.cas.org/content/chemical-substances]*
Diesel
Diethanolamine (2,2-iminodiethanol)
Dimethyl formamide
Ethylbenzene
Ethylene glycol
Ethylene oxide
Formaldehyde
Hydrogen chloride [hydrochloric acid]
Hydrogen fluoride (hydrofluoric acid)

Isophorone
Lead
Methanol
Naphthalene
Nitrilotriacetic acid
p- Xylene
Phenol
Phenol
Phthalic anhydride
Propylene oxide
Pyrrole
Sulphuric acid
Thiophene
Thoreau [Thoreau is a chemical company - might be able to identify the substance by searching for CAS no. 62-56-6 at https://www.cas.org/content/chemical-substances]*
Toluene
Vinyl chloride