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Potential problems in the Bath and North East Somerset Council and surrounding area with respect to hydrocarbon and other exploration and production

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BRITISH GEOLOGICAL SURVEY

COMMISSIONED REPORT

Potential problems within the Bath and North East Somerset Council and surrounding area with respect to hydrocarbon and other exploration and production

N J P Smith & W G Darling

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Foreword

This report is the commissioned product of a study by the British Geological Survey (BGS) in Keyworth and Wallingford.

The remit of the study was to provide:

1. A short review of methods of shale gas and coalbed methane working, and the potential problems that have been attributed to hydraulic fracturing that could give rise to detrimental effects in the B&NES area. These should include changes to the groundwater regime that might affect local water supplies and/or the hot springs; methane leakage at surface into water supplies (potable and the hot springs); and induced seismic events. Comment should be made on the potential risks associated with horizontal drilling if any.

2. A summary of the geological succession and structure with particular respect to possible shale gas and coalbed methane targets in the area and the hydrogeology of the hot springs. Reference could be made here to geothermal projects which may also use hydraulic fracturing.

3. An assessment of the possible risks from hydraulic fracturing that B&NES, adjacent councils and other regulatory bodies would need to consider.

4. Conclusions and recommendations - Having identified the possible risks, what reassurances would B&NES and/or neighbouring councils require from developers to ensure that any proposed works would not have a detrimental effect on persons, facilities or infrastructure in their areas of governance, with particular reference to the hot springs.

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Summary

This report describes the potential for problems for the B&NES area caused by hydrocarbon, geothermal and other exploration in the vicinity.

The greatest threat is posed by near-field exploration within Bath, by drilling wells which divert the flow of the Bath hot springs or other works which might allow coldwater dilution. The timescale of these effects would be relatively rapid. These events have happened in the past.

Geothermal exploration would pose the most direct risk to the springs from the far-field area, as it would be targeting areas of hot water within the Carboniferous Limestone in the Radstock-Coalpit Heath Syncline. Any such wells might escape licensing control (DECC licenses for hydrocarbon exploration but there is no equivalent system for geothermal exploration unlike other countries, although this might be about to change with the Energy Bill or in the future) and requirements for notification to the British Geological Survey, but would still need planning

permission. The timescale of the effects from such exploration are unknown but expected to be in thousands of years.

Exploration activity for coalbed methane (CBM) and shale gas, with seismic reflection profiles and vertical cored wells is not considered likely to have any measurable effect on the springs and minor effects to the population and infrastructure. In fact this would lead to greater knowledge of the subsurface and more data relevant to the Carboniferous near Bath.

Field development of CBM should not pose a significant risk as the stratigraphic level of interest (Westphalian coals) has not been traversed by the hot spring water. Migration of these waters is in strata underlying the Westphalian. However, any hydraulic fracturing needs to be confined to the target coals. Coalbed methane exploration and production is more low-key than shale gas operations and economically successful fields have not been established in the UK yet. The effects on the population, traffic flows and air emissions are therefore difficult to predict.

Field development of shale gas, however, would be a potential risk if the hydraulic fracturing, high gas flow, high density wells (HVHF) model is applied. Both the Courceyan Lower Limestone Shale Group and early Namurian targets are close enough to the probable formations in which the waters are migrating to pose an undefinable risk to the springs. If a slower, low gas flow, cottage-industry type development was allowed and the gas flowed freely from fractures this is considered no risk to the springs.

Providing best practices are followed with regard to the position of legacy shafts and boreholes, well completions, abandonment and monitoring, recently defined in several publications for the European Commission, Environment Agency and DECC, earthquakes and pollution of aquifers are not considered to present a risk any higher than in the rest of the UK. There are no regionally important aquifers like the Sherwood Sandstone or Chalk groups in the area.

Introduction

Current interest in unconventional hydrocarbon resources in the form of shale gas and coalbed methane led to successful applications for PEDL exploration licences in and adjacent to the B&NES area, in 2008. The companies involved have indicated that their primary interests are coalbed methane in the Bristol-Somerset Coalfield and possible shale gas in Carboniferous mudstones. The granting of PEDL production licences in or adjacent to the B&NES area could lead to applications to carry out hydraulic fracturing (also known as fracking, hydrofracking or hydrofracturing) as this is the new commercially proven method of obtaining significant quantities of gas from these unconventional sources. Hydraulic fracturing is used to increase the bulk permeability of rock masses in order to increase the rate of extraction of fluid or gas reserves, principally hydrocarbons and water (cold potable or hot geothermal).

The purpose of this report is to assess the potential for:

(i) possible contamination of potable water supplies by methane and/or chemicals,

(ii) possible changes in the hydraulic regime at depth that might have an effect on water supplies and/or on the hot springs at Bath,

(iii) possible induced seismicity.

The two principal potential hydrocarbon resources in the UK that are potentially amenable to hydraulic fracturing are:

(i) organic-rich mudstones (total organic carbon (TOC) > 2%) that have been sufficiently thermally altered to generate gas (shale gas) and

(ii) coals that contain methane hosted in fractures and/or adsorbed on organic compounds (coalbed methane).

In the Bath-Bristol-Mendips area possible targets are confined to the Carboniferous succession. The underlying Devonian and overlying Triassic rocks are not sufficiently organic rich, and the organic-rich latest Triassic (Westbury Mudstone) and early Jurassic (Lias) have not been sufficiently deeply buried to reach the required thermal maturity. However these might constitute a shale oil or biogenic shale gas target at some future stage if sufficiently organic-rich.

1 Review of exploration

Limited shale gas exploration has taken place in the UK. Four wells have been drilled on the Cuadrilla licence. One well has been hydraulically fractured. Most of the problems in exploration and production derive from the US as this is the only country where production has been established. Coalbed methane exploration has been carried out in the UK since the early 1990s, including with hydraulic fracturing. Pilot projects, extracting gas and generating electricity, have been established at Airth, in Scotland and Doe Green, in Lancashire. Simple vertical CBM wells do not produce unlike, in comparable strata, in the US.

1.1 REVIEW OF SHALE GAS, COALBED METHANE (CBM) AND GEOTHERMAL EXPLORATION METHODS

Two companies holding current licences from DECC for hydrocarbon exploration, relevant to the Bath Spa system, are Eden Energy (Australian) and UK Methane (operator, based in Bridgend, Wales). These companies were initially pursuing a joint venture for coalbed methane in PEDLs 226, 227 and 228, having been awarded these in the 13th Round of licensing held in 2008 (Fig. 1). Neither of the companies, holding current licences, has experience of shale gas drilling. They have experience of coalbed methane (CBM) drilling in South Wales but not, apparently, in Australia. This joint venture now has expressed interest in shale gas exploration and has 3 possible sites in the Mendips (The Royal Society 2012, p18). We understand from B&NES and DECC that UK Methane company has made an application to drill at Keynsham but we have no further information.

Another company, Reservoir Resources Ltd has a 2008-awarded licence to the south, over the southern Mendips. This company has a base in Dublin. It is not known what the original hydrocarbon target of this company was, but the licence is mostly on the southern side of the Mendips (Fig. 1), where the circulation from recharge is probably southwards, away from Bath. The company has a drill or drop (the licence) commitment to DECC which expires on the 1st July 2014.

There is a new, 14th Round of licensing, imminent, but not yet announced. The Strategic Environmental Assessment (SEA) of the onshore has been completed for this round and it does not exclude any of the area of Fig. 1. The full process of the SEA was not complete according to DECC (Rikki Kiff pers. comm.16-4-12), but has been subsequently completed according to the DECC website:

http://og.decc.gov.uk/en/olgs/cms/licences/lic_rounds/timing_of_the_/timing_of_the_.aspx

1.1.1 Shale Gas exploration and production

Since about 2010 a lot of attention has been directed towards shale gas in the petroleum industry. Some early movers like Cuadrilla Resources had already seen this coming and obtained licences in 2008. All the other licences obtained at this time were for conventional hydrocarbons or coalbed methane. By 2011 the media and general public’s attention was also focused on shale gas exploration. Cuadrilla’s first UK shale gas well spudded in August 2010 and began hydraulic fracturing in 2011. This was suspended when felt earthquakes were linked to this testing. No horizontal wells or laterals have been drilled so far, but these would be needed for production of gas.

The Bath-Mendips area is not one of the main conventional hydrocarbon areas of England (DECC 2004, Fig. 5), although seismic reflection data has been acquired to the south and east of Bath for hydrocarbon exploration. It lies to the north of the Wessex Basin, therefore without sufficiently mature Jurassic strata and with unproven Carboniferous source rocks. Consequently this area (Bath-Mendips) has been assumed to be a riskier venture. No drilling took place for conventional hydrocarbons except at distant locations, Devizes and Norton Ferris, which were dry (Fig. 2). However as 13th Round licences have been awarded (for CBM exploration) it is likely that some exploration will be attempted. It is important to draw a distinction between exploration and exploitation. The first only requires a PEDL from DECC, giving exclusivity to the licence area, and various permissions to drill from other regulatory bodies are needed. To convert to production licences requires a new round of permissions from the regulatory bodies.

The targets of shale gas exploration in the Bath-Mendips area are likely to be the Namurian basal shales (unnamed formation of the Quartzitic Sandstone Group) and the Courceyan Lower Limestone Shale Group (basal Carboniferous, Table 1, Figs 1 & 2). The former is the age equivalent of the target in the Cuadrilla licence (Upper Bowland Shale), whereas the latter is an age equivalent of Texas' Barnett Shale.

A partly cored and geophysically-logged vertical borehole is so common nowadays it would be difficult to justify preventing it being drilled, but would be useful for a company's exploration and may serve to rule out the area for exploration. Total organic carbon exceeding 2% is one of the key elements to successful conventional and shale gas exploration in the US and was applied to the UK data set (DECC 2010b, Smith et al. 2011). At present very little data on total organic carbon is available for UK strata outside the main hydrocarbon areas. Gas window maturity of the shales is also required. Very sparse data on Coal Measures suggests this might apply in the Mendips-Bath area, but actual data would be needed for exploration. The thickness of the shales and the gas content are not known without drilling and the companies would need these data in order to make a decision about abandoning the project or proceeding. Discovery of poor or marginal total organic carbon in the two formations and/or immaturity would render the project written off as 'dry'.

Vertical drilling without hydraulic fracturing may also help us get a better understanding of the deep thermal regime. There are very few properly logged boreholes in this area (no sonic logs, which hampers both hydrocarbon and hot spring research) and none which reach the base of the Carboniferous, having started in Mesozoic strata.

Exploration would seek thick, organic-rich shales within the gas window. Exploration wells are needed to confirm fragmentary evidence based on outcrops and testing of cores would be necessary to prove potential.

The current stage in exploration in the UK, where small companies possess potentially attractive acreage, inevitably leads to the prospects being built up in the hope that larger companies farm-in to the acreage or take over the companies. The reason for this is that most of these companies possessed acreage before shale gas exploration potential was known. This has occurred worldwide. Also the large petroleum companies were unaware of the significant developments in shale gas, and its implications for them, until relatively recently.

1.1.2 Coalbed methane (CBM) exploration

UK Methane hold 3 licences, awarded in the 13th Round of Onshore Hydrocarbon Licensing by DECC in 2008 (PEDLs 226, 227 and 228, Fig. 1). These were applied for to explore, originally, for coalbed methane. However since about 2010 all companies have been re-evaluating their acreage by including shale gas prospects, usually found at deeper levels than the Westphalian coals.

Some of the basic data needed to assess coalbed methane prospectivity does not exist for the Bristol-Somerset coalfield (DECC 2010a). Exploration is therefore starting from a very low level of knowledge compared to other coalfields. For example no gas content data on coals was measured by the National Coal Board during its attempts to minimize risks of gas explosions. Few boreholes within the coalfield have been geophysically-logged, so correlation of the sequence between different parts of the coalfield is not satisfactorily completed. Traditionally the late Westphalian coal workings of the Bristol-Somerset Coalfield did not encounter 'fiery' seams but even older workings targeting stratigraphically deeper seams, steeply dipping where involved in Variscan thrusting to the south of the coalfield, did experience gas explosions. Even in other UK coalfields exploration and subsequent coalbed methane field development has been very slow and difficult. The 'easy' model of drilling vertical wells, began in coals of a similar age in the Black Warrior Basin of Alabama, US and establishing economic production does not work in the UK or Europe. The reason is probably the lower permeability of UK coals. IGas have had to drill lateral completions and drill sump completions in order to drain water from the coals in their Doe Green pilot CBM field in Lancashire.

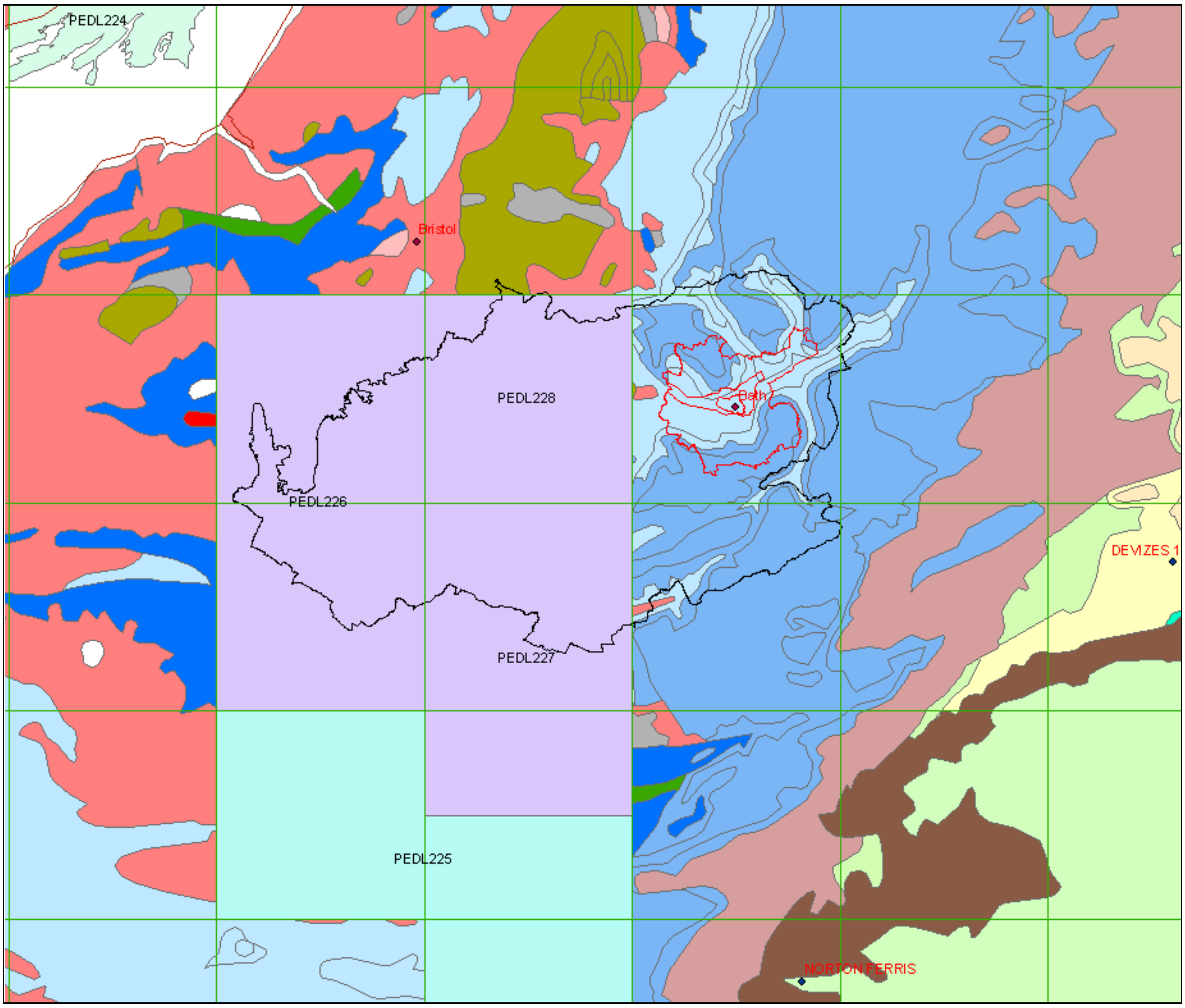

Fig. 1 Onshore hydrocarbon licence areas, PEDLs 226, 227, 228 operated by UK Methane and PEDL 225 operated by Reservoir. The B&NES area is shown in black and the County of Avon Act areas in red, surrounding the City. Fig. 2 shows the complete geological map and key.

It is not known exactly what sort of CBM exploration will be attempted. The following is based on the experience of obtaining production from low permeability coals in the US. These coals are defined as having permeabilities of less than 3 mD. There has been a recent tendency in the UK to explore for CBM without seismic reflection, making concealed highs impossible to locate. No such data, west of Bath, has been acquired either for hydrocarbon or NCB purposes.

The main target will be the Lower Coal Measures, below the main mined seams in the coalfield, hoping for high gas contents. The permeability of these coals is, however, likely to be very low. Those areas without mining of the younger seams might also see drilling to target these seams, because they may have higher permeabilities. Multi-lateral wells will be needed, of which current configurations are trilateral, quadrilateral or pinnate. These are designed to give full coverage of the reservoir, cause the gas to flow faster and therefore recover more of the gas and a greater rate. The laterals are generally unlined. The downdip quadrant is often left undrilled because it is more difficult for gas to lift water in an updip direction. Pinnate wells have been drilled in the US Carboniferous basins, Appalachian, Cahaba and Arkoma, since about 1989. Microholes, of radius 1-2” can be drilled rapidly out from vertical wells e.g. perhaps 3 radials per seam, but the penetration of such radials is so far limited. Most ultimately successful CBM wells require pumping of water for about 18 months by which time gas should be increasing and water production declining. Fracturing of seams is based on several seams per stage or pinpoint, with mostly N_2 foam and or gel fluids. In Australia slickwater fracture treatments are common. Proppant (see section 1.2.2) used is mostly 20-40 mesh sand at a rate of about 5000lb/ft of coal. Surface in seam wells of 4000’ length at an angle of 48 degrees (often 2 in a chevron shape) are drilled to meet vertical production wells in Australia.

IGas, at the Doe Green pilot CBM field in Lancashire, have drilled sumps below their target seams to assist dewatering and completed over 1000’ laterals within the seams in 3 wells. Fracturing needs to be confined to the coal otherwise excessive water production from adjacent non-coal beds may occur and this is more likely in coals with vertical fractures. If this occurs the coals will never be properly dewatered to allow the gas to be produced. These production aims are, coincidently, in keeping with those seeking protection of the Bath hot springs, by restricting fracturing and dewatering within the Coal Measures.

1.1.3 Geothermal exploration

Any future geothermal exploration would seek to find hotter water (possibly nearer to the recharge), probably at maximum depth within the north-south trending Radstock-Coalpit Heath Syncline, west and southwest of Bath. This area is affected by thrust faults and the current seismic reflection coverage is inadequate to define these potential maximum depths. This would be the most serious, direct threat to the Bath hot springs, as it would be focussed on the migrating water, within the Carboniferous Limestone. As far as we know exploration for geothermal does not need a licence, but it would require planning permission from the local authority and any abstraction would come under the Environment Agency control. It is less likely that adjacent local authorities would see such exploration as undesirable as it would bring development to their area.

1.2 WELL COMPLETION TECHNIQUES LIKELY TO BE USED

So far in the UK the Cuadrilla shale gas exploration drilling has been conducted by vertical drilling. Development or appraisal drilling to exploit a field would, however, be conducted by horizontal drilling based on US practice. CBM drilling worldwide now uses horizontal drilling within the coals, because a greater part of the reservoir can then be accessed from individual wells.

The first hydraulic fracturing took place in the Hugoton Gasfield, in 1947 (Pan American Petroleum Corporation) in Grant County, Kansas. This was in a conventional, sandstone reservoir. Hydraulic fracturing has been applied to geothermal reservoirs (both sedimentary and igneous) and is known to generate microearthquakes. These microearthquakes, which are not felt and have minus value magnitudes (M_L), are monitored to assess how far the artificial fractures are developing. During the 1990s hydraulic fracturing was applied to the Barnett Shale in the Fort Worth Basin of Texas, and the subsequent improvement in well productivity sparked off the shale gas exploration which is now worldwide. This technique was combined with horizontal drilling, made possible by the progressive improvement of downhole motors controlling directional drilling from the 1970s. A larger volume of the shale reservoir was now accessible, which could therefore produce larger gas flows.

The report for the European Commission (AEA 2012b) has compiled a lot of detail on the well completion techniques.

1.2.1 Water Used For Fracturing

Hydraulic fracturing applied to shale gas reservoirs was first used in the Barnett Shale of the Fort Worth Basin, Texas. Success here led to the worldwide search for shale gas. Much larger volumes of water are used in unconventional wells compared to conventional wells.

Hydraulic fracturing consists of pumping into the formation very large volumes of fresh water that generally has been treated with a friction reducer, biocides, scale inhibitor, and surfactants, and contains sand as the propping agent. Cuadrilla Resources website lists the chemicals added to the water. Under the Water Resources Act 1991 the environmental regulator has the power to demand disclosure of the chemicals used (The Royal Society 2012, p19). The treatment fluid maximizes the horizontal length of the fracture while minimizing the vertical fracture height. The aim is to avoid fractures reaching other formations above and below the target, which may hold water. The fractures, which are held open by the sand, result in increased surface area, which further results in increases in the desorption of the gas from the shale and increases in the mobility of the gas. The result is more efficient recovery of a larger volume of the gas-in-place.

Temporary storage at the surface in open ponds is not permitted in the UK (The Royal Society 2012), although the report for the Environment Agency (AEA 2012a) referred to ponds and pits in their table 2.1. The impact of spills of fracturing fluid or flowback water at the surface are minimised by installing impermeable site lining, called bunding (The Royal Society 2012) and this is common at many different industrial sites.

The hydraulic fracturing technique now used e.g. in the Marcellus Shale of the Appalachian Basin, US is also known as high volume, hydraulic fracturing (HVHF) because it uses much more fluid than conventional reservoir hydraulic fracturing. In conventional field reservoirs hydraulic fracturing typically used 20,000 to 80,000 gallons of fluid each time, but HVHF uses 2 to 7.8 million gallons of fluids (on average 5.6 million), the exact amount depending on the length of the well bore and the number of fractures created along it.

In 1997, the first slick water fracture (or light sand fracture) was performed in the Barnett and found to be very successful in stimulating gas flow. Slick water uses fewer gelling agents and more friction reducers (greater lubrication) to encourage penetration into the formation. Slick water fracturing of a vertical well completion can use over 1.2 million gallons (28,000 barrels) of water, while the fracturing of a horizontal well completion can use over 3.5 million gallons (over 83,000 barrels) of water. In addition, the wells may be re-fractured multiple times after production decline lasting several years, in order to increase production back to near original rates.

Enhancements to the process have been made, for example a polymer enhanced foam in a patent of 1998 which combined an aqueous solvent, surfactant, fluid loss additive, and foam breaker which is mixed at the surface. Whole conferences in the US are currently devoted to the water issue, the resolution of which may lead to recycling of the water used and technologies to be able to use or re-use saline water are now being applied to onshore operations in the US (The Royal Society 2012).

A typical sequence of operations in the US is described below. The operations are likely to be modified in future years by technological changes and, in the UK, under pressure from environmental regulations. We see the way forward as planning consent being contingent on applying the latest, highest environmental standards. Before operators or service companies perform a hydraulic fracture treatment of a well, they conduct a series of tests to ensure that the well, well-head equipment, and fracturing equipment are in proper working order and will safely withstand the fracture treatment pressures and pump rates. It should be noted that minimum construction requirements are typically mandated by regulatory agencies to make sure that the well construction and fracture treatment design are protective of environmental resources and are safe for operation. After testing surface equipment, the hydraulic fracturing process begins with the pumping of a ‘rock-acid’ (often hydrochloric acid (HCl)) treatment to clean the near-wellbore area which may have become plugged with drilling mud and cement. The next step is a slug of ‘slickwater’ which combines water with a friction-reducing chemical additive allowing the water to be pumped faster into the formation. Slickwater hydraulic fractures treatments work best in low-permeability reservoirs, and have been the primary instrument in opening up unconventional plays like the Barnett Shale, US. In addition to the cost advantage, slickwater hydraulic fractures treatments require less clean-up, provide longer fractures, and carry proppant farther into the fracture network. After the first water slug, the operator begins the fracturing process by pumping a large volume of slickwater with fine sand at a low volume. Subsequent steps include the application of slickwater volumes with coarser sand proppant that keep fractures closer to the well-bore open. The last step is a flush to remove proppant from the equipment and well-bore. After the flush, the next treatment stage is begun on a new portion of the borehole that contains its own specific reservoir parameters including thickness, local stress conditions, compressibility, and rigidity. The staged fracturing treatments are closely monitored by technicians from service and operating companies. By fracturing discrete intervals of the wellbore (either horizontal or vertical), the operator is able to make modifications to accommodate local changes in the shale reservoir including lithology, natural splitting, rigidity, and changes in the stress regime.

Fracturing stages are determined with the help of numerical simulators to predict fracture performance in the shale reservoir. Engineers and geologists can manipulate the simulator and evaluate the effect on fissure height, length, and orientation. Predictions from the simulator can be used to monitor and evaluate the results of the fracture job. Monitoring can also be done in real-time at the well by way of micro-earthquake mapping. This technology can locate the fracture tips in an east-west and north-south direction from the borehole and track their growth as the job proceeds and more steps are completed. Of particular importance is the growth of fractures in the vertical direction. Operators take particular care to ensure that they do not migrate out of the shale reservoir and extend into adjacent water-bearing units. Such fissures can ruin the economics of a shale gas well. During the fracturing treatment, a number of chemicals are added to the water-sand mix. Each chemical compound serves a specifically engineered purpose such as reducing viscosity or bacterial growth or bio-fouling reservoir surfaces. The make-up of fracturing fluid will vary from one basin to another and from one contractor to another. A fracture fluid used in the Fayetteville Shale, US contained 99.5 percent water with less than 0.5 percent other compounds. Any toxicity of the components, such as acid, is greatly reduced by dilution in the pumped fluid and by the reaction of the acid with the rock in the subsurface that converts the acid into salts.

Flow back water is the water which is returned to the surface from the formation after the fracturing. Allowing the well to flow back and recovering more water might be needed to prevent felt earthquakes (see below). Unlike in the US where this is disposed of down wells, in the UK it is likely to be tankered away, for treatment prior to disposal. However, the Royal Society report (2012) does not rule out the option of subsurface disposal in the UK.

1.2.2 Proppant Technology

As a refinement to the hydraulic fracturing process proppants, in the form of different sized sand, about 1-1.9% of the total volume, are pumped down the well into the fractures (King 2012). These hold the fractures open allowing more gas to flow. Patents to improve the likelihood of these proppants remaining in the fractures were obtained in 1959 and 1973 and use has burgeoned subsequently in the US.

1.2.3 Horizontal drilling

Vertical wells are the probable configuration of the first exploration well(s), in order to investigate known targets at different levels and any unknown targets which might be sampled also. Once the targets are more firmly established some form of horizontal drilling is likely to be required for production wells, either by deviation from the surface or laterals at the levels of the target shales or coals. Horizontal wells are shown to be more productive than vertical wells in US shales and UK coals do not produce at all from vertical wells. The reach of wells in the Marcellus Shale of the Appalachian Basin, US is up to 3000m (AEA 2012a).

Before drilling a well DECC reminds operators that, *inter alia*, they should seek access to the land, including that under which deviated wells are to be drilled.

1.3 PROBLEMS ENCOUNTERED IN PREVIOUS EXPLORATION AND PRODUCTION

Problems encountered in previous exploration have been caused by accidents and poor practice in a number of US cases and the earthquakes near Blackpool were the first to have been shown to be caused by hydraulic fracturing during shale gas exploration. Some potential problems, flagged by concerned groups and individuals, have not been shown to be applicable. The various regulatory reports (AEA 2012a, b, The Royal Society 2012) should address most of these issues and make a robust regulatory framework which DECC, the Environment Agency and local planning authorities can apply to exploration and production. B&NES is only in a unique situation (compared to the rest of the UK), with regard to its hot springs. Exploration outside the B&NES area needs to be considered carefully to safeguard the flow to the hot springs.

Compared to the minimal problems associated with exploration problems are likely to magnify if a large footprint production is ever achieved (AEA 2012b). The US Department of Energy identified also community disruption during shale gas production and cumulative adverse impacts namely in water use and quality, land use, air quality, traffic and noise as well as the issue of waste water management. This scale of operation cannot be envisaged as likely to take place in the UK, based on present evidence.

1.3.1 Subsidence

Subsidence risk has been raised as a possible problem in the Blackpool area resulting from fluid (gas) withdrawal. Subsidence has been noted in a relatively small number of the world’s conventional hydrocarbon fields but typically more common in some basins (e.g. in California, in the Po Valley of Italy, the central North Sea and Groningen gasfield in the Netherlands, Doornhof et al. 2006). The reservoirs in these fields all have very high porosity, in mostly Tertiary age sandstones and Upper Cretaceous Chalk. The Groningen field has a Permian reservoir. The subsiding area is restricted to the hydrocarbon field. Shale gas formation porosities, in contrast, are very low. Subsidence has not been shown to affect shale gas fields in US which have been in production for more than ten years. It is not expected that subsidence would occur over such relatively low porosity and permeability shale gas fields.

1.3.2 Induced earthquakes

Hydraulic fracturing caused two felt and other minor earthquakes in the Blackpool area. This resulted in assessments and advice for the company (de Pater & Baisch 2011), subsequently for DECC (Green et al. 2012) and a more general investigation by the Royal Society (2012). The recommendations of these studies now form a basis by which regulating agencies can control exploration in the UK and encourage best practices. If companies follow the guidelines of Green et al (2012) hydraulic fracturing would cease when a 0.5 M_L earthquake is generated. This derives from experience in the UK coalfields. Earthquakes of this magnitude will not be felt at the surface.

The Cuadrilla well Preese Hall was hydraulically fractured in March 2011 and produced 2 felt earthquakes and many smaller ones for a period after each fracturing phase (De Pater & Baisch 2011). BGS attributed the cause of the earthquakes to the fracturing having monitored similar felt and unfelt earthquakes in the geothermal project at Rosemanowes, Cornwall in the 1980s. Other worldwide geothermal projects have induced a large number of earthquakes (e.g. at Basle). De Pater & Baisch (2011) confirmed that the earthquakes in Lancashire were produced by the hydraulic fracturing phases but suggested ways in which the earthquake magnitudes could be reduced. This included using lower injected volumes of water for hydraulic fracturing, allowing increased flow back of the water and using an earthquake traffic light system to stop fracturing if earthquakes of (magnitude) M_L = 1.7 occurred. A review of this work was completed for DECC (Green et al 2012) and suggested an even lower earthquake magnitude (M_L = 0.5) to trigger abandonment of fracturing (using this traffic light system). These findings will be applied when fracturing recommences in Lancashire and, depending on how well it works, are likely to be applied to any future wells. In fact microseismicity (very much lower than any felt earthquakes) is used to map the development of the fractures and would be an essential monitoring tool if any hydraulic fracturing is permitted (see The Royal Society 2012, p31-32).

Prior to this all the US induced seismicity had been blamed on the process of shale water disposal, normally carried out near to exploration wells, but with injection into deeper reservoirs. This is also a known cause of induced earthquakes. This process is unlikely to be allowed by the Environment Agency in England. Hydraulic fracturing caused seismicity but, at present, it is unclear whether felt earthquakes will continue to occur in Lancashire in the Cuadrilla licence (now that a revised guideline requiring operations to be halted, if the defined earthquake magnitude of 0.5 is recorded, Green et al. 2012) and whether other areas would be similarly affected.

Large natural earthquakes, even those occurring on the other side of the world, can affect the productivity of water wells and are known to cause changes in hydrocarbon migration. The Lisbon Earthquake of 1755 caused a reddening of the Hotwells water at Bristol (Hawkins & Kellaway 1991). Also an earthquake in 1892 preceded, and perhaps caused, the appearance of oil in a water well at Ashwick in the Mendips.

Enhanced geothermal systems e.g. Basle in Switzerland, use hydraulic fracturing to increase permeability of rocks containing hot water, but the project there had to abandon operations after earthquakes up to 3.5 M_L were created (The Royal Society 2012). Basle is within an active rift, with historic earthquakes.

Other industries, which give rise to ground motion, measure vibration levels at the vulnerable site (The Royal Society 2012) which might be more applicable to the Bath area, with its possibly vulnerable hot spring pipes and other buildings. This might have been employed when the Spa project seismic reflection survey, using vibrator trucks on the roads, was acquired in the city.

Damage to well integrity also needs to be considered because the casing, near the base of the well in the already perforated section, was deformed in Preese Hall after hydraulic fracturing (de Pater & Baisch 2011).

1.3.3 Water contamination by methane

Subsurface waters frequently contain naturally produced methane and other gases (Darling & Gooddy 2006). The Bath Spa water has a methane concentration of 53µg/L (Edmunds et al. 2002), which is low. The source of this was considered to be biogenic. It is important to know the background levels prior to any exploration.

Hydraulic fractures have been shown to propagate 588m vertically from horizontal wells in the US (Davies et al. 2012) and it would seem prudent to expect a similar horizontal spread from any vertical well.

Leaks to the surface replicate natural surface gas seeps and may use natural (fault) or manmade conduits, for example channels in cement used to seal the well, formed by gas migration (King 2012). This might also happen because the well casing was not set properly, the cement failed in the exploration well or the cemented casing did not extend far enough below the aquifer and other problems related to well integrity (The Royal Society 2012, p24). It could also occur if exploration impinges too closely on pre-existing deep wells which themselves had not been securely completed. This scenario may occur in any old water wells and especially in old coal exploration. The B&NES and surrounding area has very few water supply boreholes but extensive (and old) coalfield drilling and shafts. It is vital to locate these prior to any drilling.

This is a potential risk at the drilling site but a properly cased and monitored well should be expected from professional drillers and engineers. A few improperly completed wells in the US leak methane but some of these are conventional hydrocarbon wells. The cement bond logs run to test the seals should be monitored, perhaps by independent experts. This might be stipulated as part of a planning consent. It is unlikely regulatory bodies would have the manpower do this routinely but there is provision for a well examiner to be commissioned and paid for by the operator (The Royal Society 2012: The Offshore Installations and Wells Regulations 1996). This report also recommends strengthening this role, improving its independence and laying down well integrity tests that are needed.

1.3.4 Water contamination by chemicals used in hydraulic fracturing

Surface spills, either when handling the chemicals or those contained within the flowback water, are more likely than leaks through the exploration well itself, based on research in the US. There is a trend towards ‘greener’ alternative chemicals in the US to minimize such problems (King 2012).

1.3.5 Flowback waters containing Naturally Occurring Radioactive Material (NORM)

Some of the most prospective shales have high gamma ray values, indicating higher uranium contents. Circulating water within these shales is perhaps more likely to scavenge NORM than conventional hydrocarbon wells. Conventional hydrocarbon well waste waters are already treated to remove NORM (The Royal Society 2012). These formation waters are also saline and may need treatment even in the absence of NORM. The trend in the US and, particularly, the Horn River in Canada is to both restrict flow back by shutting in the well and also to use a closed loop system, recycling produced water, acknowledging that former freshwater use was too high (King 2012). In the US the water is disposed of in deep wells and this practice has led to induced earthquakes (Frohlich et al. 2010).

1.3.6 Air emissions around exploration sites

Recommendations of the US Secretary of Energy Advisory Board Natural Gas Subcommittee on the reduction of emissions from shale gas operations have been taken up in the UK (The Royal Society 2012). This measurement would allow assessment of the total carbon footprint of shale gas compared to other fuels, rather than just a comparison with coal extraction. Local authorities are responsible under the Environmental Protection Act 1990 for monitoring of odour and noise associated with the venting or flaring of gas (The Royal Society 2012). So-called 'green completion technologies' (or Reduced emissions completion, RECs) should be used to capture and sell gas from testing wells, rather than flaring or venting. This will be mandatory in the US in 2015. A recommendation has been made that the Environment Agency require operators to monitor methane levels before, during and after well drilling and hydraulic fracturing on all wells as fugitive emissions are considered to be higher than for conventional hydrocarbon wells (AEA 2012a). Methane emission from flow back waters is the main source. Drilling with air rather than with mud may lead to higher emissions (research reported by AEA 2012b).

1.4 FACTORS UNIQUE TO B&NES AND SURROUNDING AREA

There is an active natural geothermal circulation system in early Carboniferous rocks which discharges within the city of Bath. In most countries for an artificially developed, or recently developed geothermal resource there is a licensing system for operating companies e.g Indonesia (to Panax), Kenya, Iceland (permits), Turkey, Macedonia, New Zealand, Nicaragua, Romania, Australia (57 companies involved). This licensing system offers exclusivity for operators.

The UK Energy Bill has an amendment (amendment 35, after clause 97, Feb 2011 in the Lords) regarding establishing a geothermal exploration licensing system:

http://www.publications.parliament.uk/pa/ld201011/ldbills/033/amend/ml033-vi.htm

The latest internet entry for this proposal (March 2011) suggests that primary legislation is needed for such a proposal, so the amendment may have been withdrawn.

2 Geological Setting

Along the northern margin of the Variscan orogen a number of European locations have thermal water springs. Mallow warm spring (Eire) is situated on the eastern margin of an E-W foreland basin north of the Variscan Front, in a very similar structural setting to Bath. Silesian strata occupy a syncline to the west of Mallow which has a pronounced N-S orientation northwards to the Shannon Estuary, structurally very similar to the Bath springs relative to the Radstock-Coalpit Heath Syncline. The cooler Taffs Well spring in Wales lies on the south limb of the South Wales Coalfield syncline, also part of the Variscan foreland basin. The springs of Spa (Belgium) and Aachen (Germany) are variants in that they emerge within the Variscan foldbelt and from rocks older than Lower Carboniferous limestones. Other warm springs in the UK also exploit the karstic Lower Carboniferous limestones in Derbyshire combining surface recharge, karstic subsurface flow and suitable faults to ascend to discharge. The hot springs of Bath and the warm springs of Bristol are on opposite sides of the Radstock-Coalpit Heath Syncline, which overlies the earlier formed Bath-Bristol Basin.

2.1 BATH-BRISTOL BASIN

The Bath-Bristol Basin (BBB, Fig.1) may have been initiated in early Devonian times, because on surrounding highs early Devonian strata are absent. Isopachs of Upper Devonian (including Lower Limestone Shale Group) and other Lower Carboniferous formations (Kellaway & Welch 1993, fig. 12) show that the basin thickens to the south. Westphalian Coal Measures also thicken southwards, an aspect typical of foreland basins. The relatively narrow E-W limit of the basin is atypical for foreland basins, even of Variscan age. The reason for this is the boundary to the east formed by the early Variscan uplift of the Worcester Graben (Smith & Rushton 1993), which along its westernmost limit is a prominent line of Lower Carboniferous inliers (e.g. Wick, Wickwar) and known previously as the Bath Axis.

2.2 VARISCAN OROGENY

The Variscan orogeny is traditionally dated as a late Westphalian thrusting and folding event which uplifted mountains in SW England and foothills in the Mendip-Bath area, limiting a Coal Measures foreland basin to the north of the main thrusting. Earlier events occurred on the eastern margin (Worcester Graben) and these probably determined the strong N-S orientation of structures (e.g. Bath Axis) which were modified by the final E-W trending Variscan thrusting and folding (e.g. Mendips).

The effect of these contrasting trends is seen in the structure of the Radstock-Coalpit Heath Syncline. This structure controls the locations of the Somerset and Bristol coalfields, separated by the E-W trending Kingswood Anticline. The N-S trending syncline is cut by several E-W trending thrusts, some of which crop out (e.g Northern and Speedwell thrusts, fig. 23 Kellaway & Welch 1993, Southern Overthrust), others largely concealed (Farmborough Thrust, Fig. 3) or occur in some boreholes. These thrusts serve to complicate the northward pathway of any migrating water. These thrusts extend at least as far north as the E-W trending Kingswood Anticline, which is affected by northward thrusting and separates the Pensford sub-basin from the Coalpit Heath sub-basin to the north (Kellaway & Welch 1993).

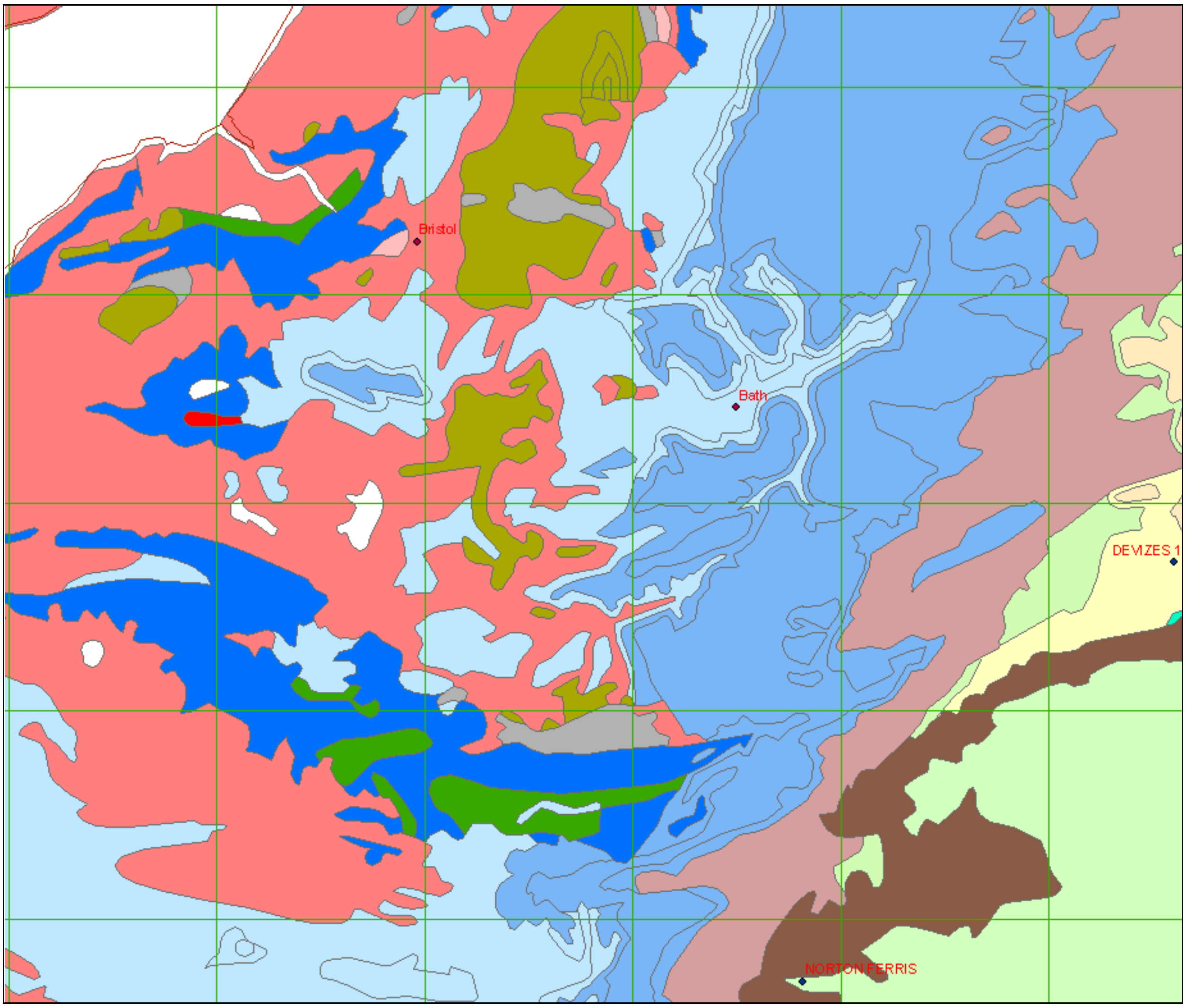

Fig. 2 1:625,000 Geological map of the area surrounding Bath, with simplified legend.

Legend

• major_placenames

UK_625k_BedRock_Batharea

BGSNAME

- Chalk
- Upper Greensand and Gault
- Lower Greensand
- Portland Beds
- Kimmeridge Clay
- Corallian
- Oxford Clay and Kellaways Beds
- Cornbrash
- Great Oolite
- Great and Inferior Oolite
- Inferior Oolite
- Upper Lias
- Middle Lias
- Lower Lias
- Mercia Mudstone
- Warwickshire Group
- Upper Westphalian (including Pennant Measures)
- Lower Westphalian (mainly Productive Coal Measures)
- Namurian (Millstone Grit Series)
- Basalt and spilite
- Carboniferous Limestone)
- Upper Devonian

Shales occur at the base of the Carboniferous Limestone, above its junction with Devonian and crop out in the Mendip Hills and other inliers. Namurian shales are poorly exposed, west of Bristol, and elsewhere are faulted out or unconformably overlain by Late Triassic strata. Palaeozoic strata strike E-W in the south, whereas Mesozoic strata strike NNE-SSW. Bath lies on Lower Jurassic and younger Mesozoic strata form the area to the SE.

Stage	Group	Formation- Bristol	Central Mendips
Marsdenian-?Kinderscoutian	Quartzitic Sandstone	Brandon Hill Grit	absent
?Alportian-Pendleian		**Unnamed shales**	thin
Brigantian	Hotwells	Upper Cromhall Sandstone	
Asbian	Hotwells	Hotwells Limestone	
Holkerian	Clifton Down	Middle Cromhall Sandstone	Clifton Down Limestone
		Clifton Down Limestone	Cheddar Oolite
		Lower Cromhall Sandstone	Cheddar Limestone
Arundian	Clifton Down	**Clifton Down Mudstone (upper**)	
		Goblin Coombe Oolite	
Chadian	Clifton Down	**Clifton Down Mudstone (lower)**	Burrington Oolite
		Gully Oolite	Vallis Limestone
		Sub-Oolite Bed	
Courceyan	Black Rock Group	Black Rock Dolomite & Limestone	Black Rock Limestone
	Lower Limestone Shale	**Lower Limestone Shale**	Lower Limestone Shales
		Shirehampton Beds	

Table 1 Stratigraphic column of Namurian and older Carboniferous groups and formations, with the potential target formations for shale gas emboldened. Groups from Hotwells to Lower Limestone Shale comprise the Carboniferous Limestone Supergroup.

2.3 TOP CARBONIFEROUS LIMESTONE

This is the key reflector to pick and depth convert from two-way travel time displayed on the seismic sections acquired specifically for the Bath Spa project (see Mann et al 1999, their brown coloured reflector). It corresponds to the top Brigantian of Table 1, or base Pendleian. Some Carless-acquired seismic profiles, SW of Bath, image thrust structures, also known from surface mapping and coal-mining (Kellaway & Welch 1993). These thrusts have the effect of uplifting the level of the top Carboniferous Limestone. Cursory interpretation reveals that nowhere in Bath Spa survey area is the top of the Carboniferous Limestone deeper than about 1200m. Unfortunately there are no coalfield or other boreholes which penetrate the Westphalian (and Namurian) sequence and the velocity of these rocks is also unknown (as there are no sonic geophysical logs), both hampering a robust interpretation. However, this information indicates that the migrating waters must continue to descend, north of these profiles, in order to reach the circa 3000m needed to heat the water sufficiently (Edmunds et al 2002). The level at which the waters are migrating within the Carboniferous Limestone is unknown, but this supergroup may be about 1000m thick. Ideally the base of the Carboniferous Limestone needs to be located from seismic reflection surveys because water may be migrating at lower stratigraphic levels within the supergroup. Kellaway (in McCann et al. 2001, fig. 3.21) compiled a section from Kingsmead borehole based on the Spa seismic showing a depth of the base at 2200m, at about 4 km to the SW, giving a thickness of just less than 1000m for the supergroup.

On Spa seismic line 9, south of Twerton, the top of the Carboniferous Limestone descends smoothly southwards to about 1120m depth. In the south faulting affects the level and it may be much higher based on interpretation of Carless profiles which tie to it (Fig. 3). To the east and north, and on all other Spa profiles, it is much shallower. A slightly deeper value of 1350m was calculated previously, using a higher velocity in the overlying Carboniferous (McCann et al 2001). There is no definitive depth until the velocity of the rocks is known.

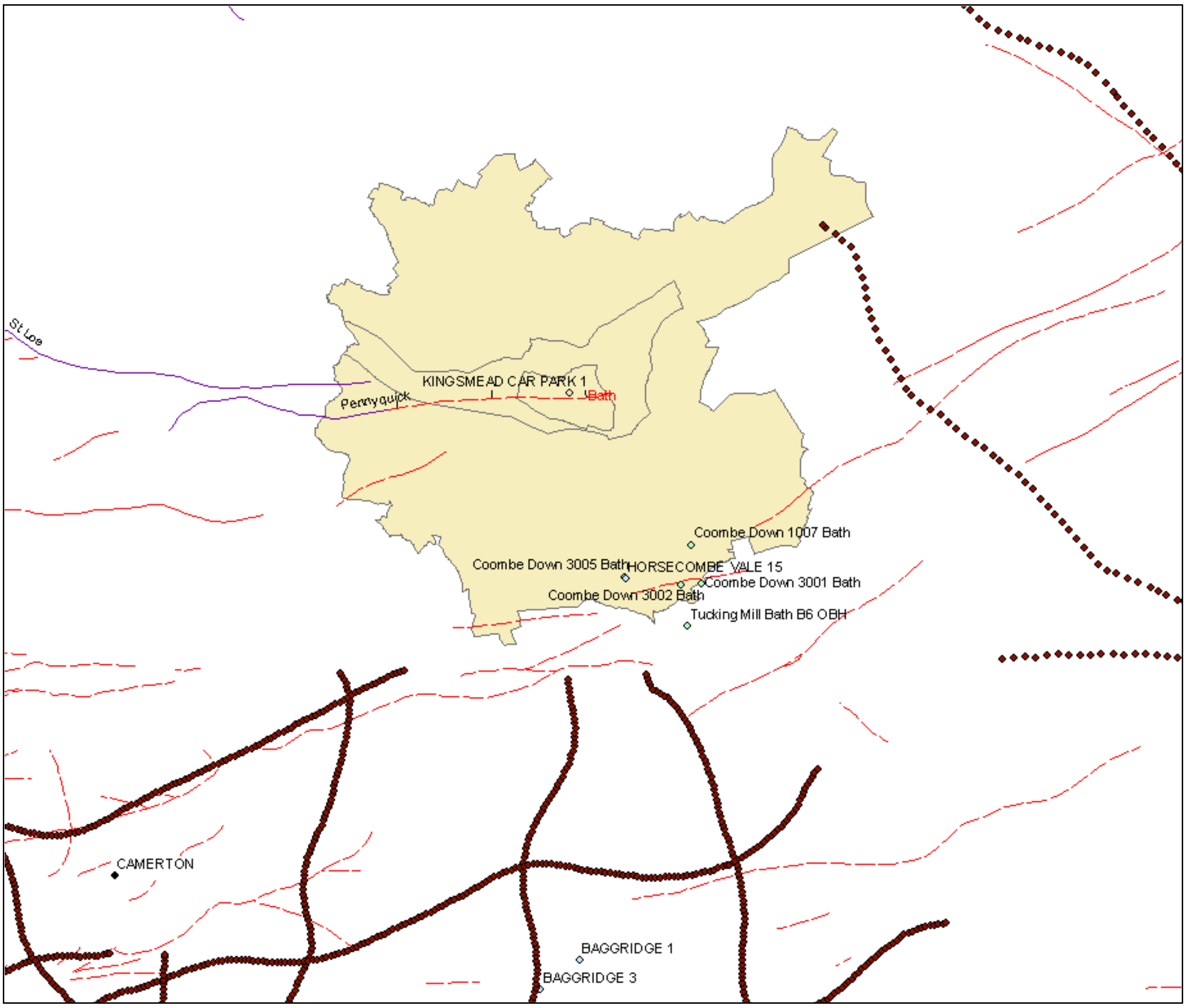

Fig. 3 Relationships of thrusts in the north of Camerton Colliery (Kellaway & Welch 1993, fig. 40), Bath control area and Tucking Mill borehole. Faults (red), Carless seismic profiles (brown), Bath control area (yellow), other seismic (brown spots).

Farmborough Thrust belt (red), north of Camerton Colliery probably crosses the first North-South Carless seismic profile (brown), south of where it joins the Bath Spa seismic (profile 09, not shown). Tucking Mill borehole may lie to the south, in an uplifted position, above this south-dipping thrust.

2.4 HYDROGEOLOGY OF THE BATH-BRISTOL BASIN

Parts of the Bath-Bristol Basin (BBB) have been identified as potential shale gas and coalbed methane exploration targets. Much of the BBB falls within the boundaries of the Bath & North East Somerset Council (B&NES) area (Fig. 4). In addition to the usual concern that groundwater bodies could be affected by the drilling and hydraulic fracturing necessary to exploit the shale gas or coalbed methane, the existence of thermal waters in the basin adds an additional layer of complexity because of the importance to the area of the Roman Baths and Spa as a tourist attraction.

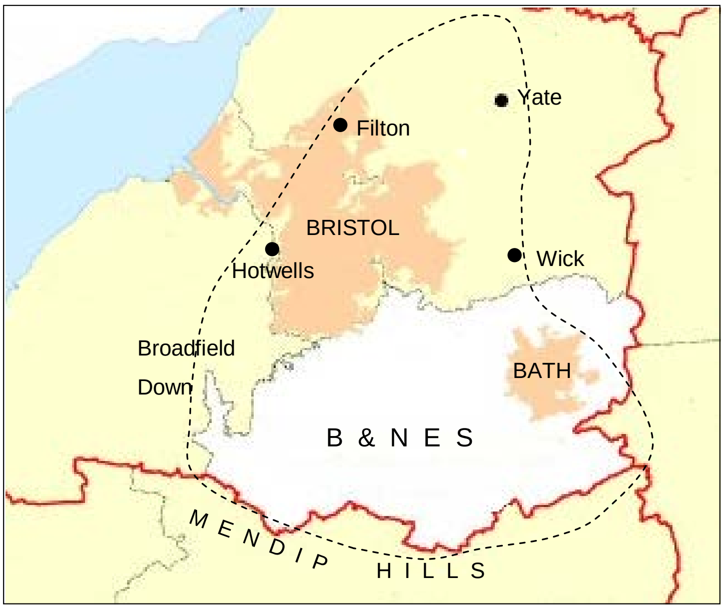

Figure 4 Map of the Bath–Bristol area, with the approximate outline of the Carboniferous Bath–Bristol Basin shown by the dashed line.

The hydrogeology of the BBB has not been extensively investigated to date probably because groundwater is only a minor component in the water supply of the area. For example, about half the water consumed in the Bristol conurbation comes from surface water reservoirs north and west of the Mendip Hills, while the remainder is derived from the River Severn via an intake upstream of the tidal zone. Groundwater within the basin is likely to be exploited via relatively low-yielding boreholes, predominantly for agricultural activities. Considerations of the effect (if any) of fracturing on potable water quality would therefore be a local rather than regional concern. However, the implications for Bath require greater consideration because of the uncertainty over the precise catchment area of the thermal waters.

The most comprehensive review of thermal water hydrogeology and hydrogeochemistry in the BBB was that published by Burgess et al (1980) as part of a more general review of the geothermal potential of the UK. The primary focus of their work was to develop a concept of how the Bath thermal spring system operates, while a subsidiary aim was to explain the existence of thermal water in the Hotwells area of Bristol.

Since the publication of the Burgess et al. report in 1980, the results of more recent studies or reviews have been published but these tend to be more restricted in scope. The following account is based on the findings of Burgess et al. report amended as necessary in the light of subsequent investigations.

2.4.1 Physical Hydrogeology

The Burgess at al. (1980) report focuses primarily on hydrogeochemistry. However, it did review piezometric levels in a number of boreholes across the BBB: six in the Mercia Mudstone succession (Triassic), three in the Pennant and Coal Measures series (Upper Carboniferous), five in the Carboniferous Limestone and Lower Limestone Shales (Lower Carboniferous), and one in the Old Red Sandstone (Devonian). Their findings were that only in the Mendips and the Broadfield Down areas (Fig. 4) which form an arc from the south to the west of Bath were piezometric levels high enough to give rise to the ~40 m OD artesian head calculated for the King's Spring. This was subsequently amended by Atkinson and Davison (2002) to a lower head of 27–28 m OD, which theoretically widens the possible direct recharge area for the Carboniferous Limestone to the whole rim of the basin (Gallois, 2007), although the Mendips and Broadfield Down have by far the greatest outcrop area. With one or two exceptions, piezometric heads in younger formations as measured by Burgess et al. (1980) were too low to allow recharge via leakage to the Carboniferous Limestone. The main exceptions were in the Upper Carboniferous, but on geochemical grounds Burgess et al. (1980) decided this route could be contributing a maximum of only a few percent of any recharge reaching Bath.

Even before the publication of the BBB report (Burgess et al., 1980), it seemed likely that most of the flow to the Bath springs results from recharge on the high ground of the Mendip Hills, and that it must be travelling through the deepest part of the basin beneath the Radstock sub-basin in which coal was formerly mined from the Upper Carboniferous, in order to acquire its elevated temperature. A possible difficulty with this hypothesis is the existence of Variscan tectonic modification of the strata, with tight folding and the formation of southerly-dipping thrust slices and overturning of strata in places to form klippen (Williams and Chapman 1986). However, the modelling of Atkinson and Davison (2002) suggests that tectonisation does not affect hydraulic continuity to any significant extent.

Atkinson and Davison (2002) modelled groundwater flow to Bath and Hotwells as separate systems, with the eastern Mendips as the main recharge area for Bath, and the western Mendips plus parts of Broadfield Down for Hotwells (Fig 5). Whether or not this is correct is impossible to prove without a great deal more piezometric data from the Carboniferous Limestone, mainly from the deep confined zone beneath the Coal Measures and therefore not obtainable for the foreseeable future. At this point it may be worth pointing out that according to Atkinson (1977), the combined outflows from Bath Spa and Hotwells are only 1.5% of the total recharge to the Carboniferous Limestone of the Mendips, so unless there are major unidentified outflows of thermal water along the Avon corridor, only a very small fraction of the recharge is flowing through the deepest part of the basin.

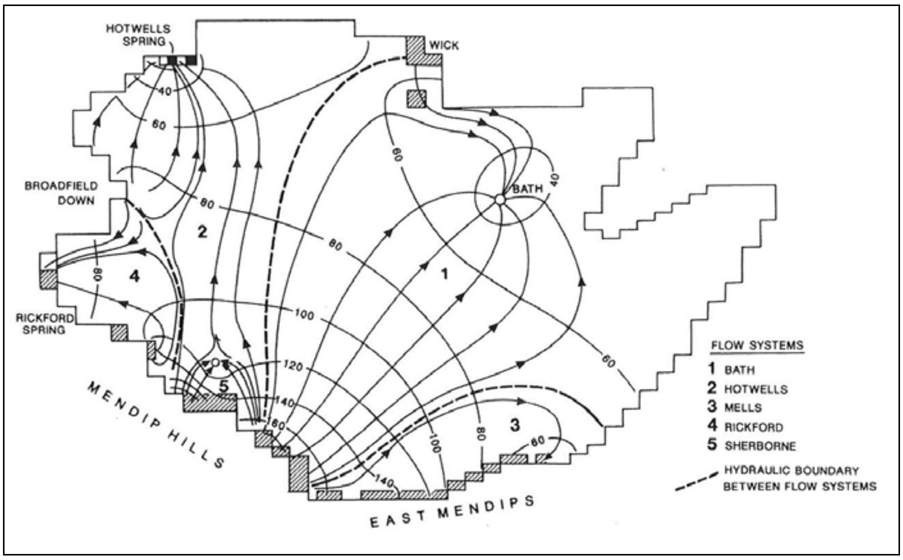

Figure 5 The base-case simulation of Atkinson and Davison (2002) showing calculated contours of groundwater head in the Carboniferous Limestone, flow lines and major groundwater systems. It should be noted that the intra-basin hydraulic boundaries and flowlines depicted are assumed rather than proven.

Consideration of the regional geothermal gradient of ~20°C/km depth requires water to descend to depths in excess of 2500 m to acquire a sufficiently high temperature. According to Gallois (2007) about 100 km^2 of the Carboniferous Limestone lies below this depth beneath the Radstock sub-basin, providing a wide variety of potential flowpaths for the thermal water to travel towards Bath. However, a reflection seismic survey was carried out to explore the deep geology of the Bath area by McCann et al. (2002). They interpreted the data as indicating that in most directions from the city, the surface of the Carboniferous Limestone was at a depth not exceeding 300 m below OD, and therefore too shallow to be contributing a significant proportion of the heat load. Only to the south-west did they find a steep dip (30°), leading to the surface of the Carboniferous Limestone lying at 1350 m below OD at less than 4 km from the springs. It may not continue to deepen SW beyond this point because of the presence of the Farmborough Thrust at Camerton Colliery (see Kellaway & Welch 1993, fig. 40). No seismic profiles exist to the west and northwest of Bath, where it is also likely that the Carboniferous Limestone reaches similar depths. To the SE the Tucking Mill borehole shows that the top (eroded) Carboniferous Limestone is shallow at 185m BOD, but this might be in an uplifted position to the south of (the NE extension of) the Farmborough Thrust belt (Fig. 3).

2.4.2 Hydrogeochemistry

The main emphasis of the Burgess et al. (1980) report on the BBB was on the geochemistry of waters in the basin. An extremely comprehensive range of parameters was measured on the thermal waters, while representative cold sources were sampled across the basin to establish a groundwater quality baseline. Subsequent geochemical studies have centred exclusively on the Bath area, partly because this is by far the most important thermal manifestation, but also because sampling the Hotwells Spring, situated as it is in the mud of the tidal portion of the River Avon, is a major logistical undertaking. In this report, consideration of the geochemistry of the BBB groundwaters is divided into regional groundwater and thermal waters.

2.4.2.1 Regional Groundwater

The cold sources sampled were from the Lias (Lower Jurassic), Mercia Mudstone (Triassic), Pennant and Coal Measures sandstones (Upper Carboniferous), Carboniferous Limestone including Lower Limestone Shales (Lower Carboniferous), and Old Red Sandstone (Devonian). The major ion data are given in Table 2. Four specimen data plots are shown in Fig 6.

Location	Formation	Ca	Mg	Na	K	HCO_3	SO_4	Cl	NO_3-N	TDS
Monkswood Spr	Lias	127	4.3	7.6	1.4	322	56	19	4.9	542
Tucking Mill	Lias	134	4.9	17	2	279	100	32	5.8	575
Norton Malreward	Lias	155	13.6	22	5.1	392	159	18	3.3	768
Ston Easton	Lias	141	3.4	7.6	3.4	349	42	17	10.5	574
Kembery, Bath	Lias	131	5.1	8.8	1.4	313	82	17	3.9	562
Fry's Keynsham No 2	Mercia Mudstone	156	27	32	5.5	369	198	36	7.0	831
Edford	Upper Carb sst	87	21.9	19.4	10.2	334	50	19	0.4	542
Hanham	Upper Carb sst	103	17.3	35	27	248	132	54	6.1	622
Rickford Rising	Carb Limestone	102	6.2	6.6	14.5	295	22	17	5.3	469
Filton	Carb Limestone	143	34	90	9	340	349	40	0.2	1005
Winford	Carb Limestone	133	7.3	9.2	2.7	351	32	20	9.5	565
Shepton Mallet	Carb Limestone	96	19.4	8.4	2.5	368	20	14	3.4	532
Gurney Slade	Carb Limestone	114	8.7	10.6	2.1	338	36	13	3.7	526
Priddy	Carb Limestone	76	4.8	6.6	1.6	219	17	9.5	2.6	337
Upper Charterhouse	Carb Limestone	27	6.8	7.6	2.2	94	12	11	2.9	163
Burrington Combe	Old Red Sandstone	21	6.9	5.8	1.6	85	10	9.1	0.2	140
Waldegrave	Old Red Sandstone	53	5.8	8.6	1.9	153	25	15	1.3	264
Three Ashes	Old Red Sandstone	29	5.4	5.8	1.5	110	4	7.5	1.6	165

Table 2. Major ion data for groundwaters in the Bath–Bristol basin, from Burgess et al. (1980). All concentrations in mg/L.

Virtually all the cold sources are Ca–HCO_3 waters, their chemistry being dominated by interactions between soil CO_2 and carbonate minerals, whether these form the rock matrix, as for the Carboniferous Limestone, or are present as cements in sandstones. In general, the TDS (total dissolved solids) content of waters increases with residence, simply because it takes time to acquire solutes from the rock. In the end this is controlled by the degree of saturation for particular minerals. Burgess et al. (1980) showed that nearly all the waters in Table 2 were slightly undersaturated with respect to the important carbonate minerals calcite and dolomite, and therefore have the potential to dissolve more of both minerals.

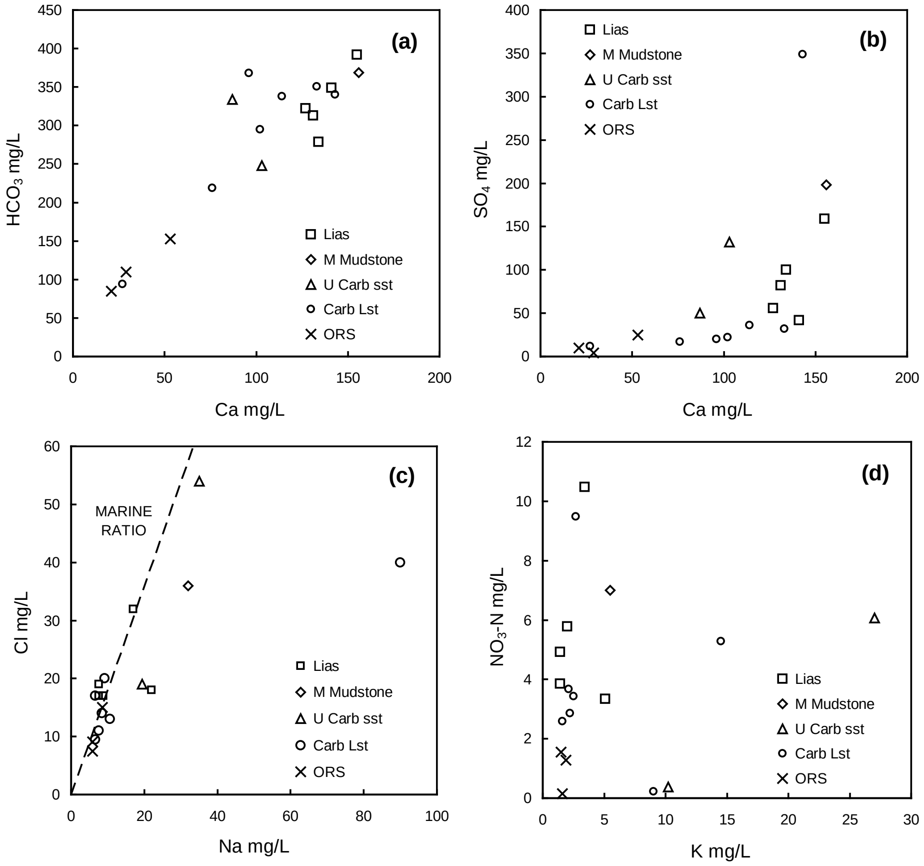

Figure 6 Co-plots of various major ions illustrating the main processes giving rise to ground-water compositions found in the Bath–Bristol basin (see text). Data from Burgess et al. (1980).

Figure 6a shows a largely linear relationship between Ca and HCO_3, consistent with the concept of simple water–rock interaction, albeit most likely with different rates of acquisition depending on the rock-type concerned.

Figure 6b shows a curving relationship between Ca and SO_4. This indicates that most of the Ca enters solution relatively rapidly, most likely from the dissolution of carbonate minerals, but that a small proportion is added more slowly from the dissolution of sulphate minerals, which are less soluble than carbonates. The sample from the Carboniferous Limestone borehole at Filton, the most northerly site sampled by Burgess et al., has the highest SO_4 value. The existence of sulphate minerals in the Triassic in the vicinity is well-documented, and indeed celestite (strontium sulphate) was mined until recently in the area at Yate. It is likely therefore that the sulphate in the Filton groundwater has been acquired by leakage from the overlying Mercia Mudstone. The saturation indices for Ca and Sr sulphates indicate that the all the BBB groundwaters are well below saturation level, but that Filton approaches most closely (Burgess et al., 1980).

Figure 6c suggests that the Na and Cl content of most waters is simply governed by the concentration through evapotranspiration of recharging rainfall, which carries Na and Cl derived from marine aerosols and gives rise to Na and Cl concentrations below ~20 mg/L . There are a few instances of waters acquiring traces of halite from the aquifer rock, but this does not exceed 55 mg/L, for the Coal Measures sandstone sample collected from a drainage adit at Hanham and therefore likely to be an ‘evolved’ (i.e. long-residence) groundwater. The relationship between K and NO_3 (Fig. 6d) is fairly linear for most groundwaters, suggesting that fertiliser inputs are controlling the water quality. Excesses of K are probably derived from water–rock interaction, from feldspar for the Upper Carboniferous sandstones, and by leakage from the Triassic for Filton.

In general the inorganic water quality across the basin appears to be good but, as mentioned above, it is exploited predominantly for local usage in the forms of light industry, agriculture and water supply for isolated dwellings.

2.4.2.2 Thermal waters

In the intervening three decades since the Burgess et al (1980) report was published, other investigations into the geochemistry of the Bath Spa waters have taken place. In contrast, little or no further work seems to have been carried out on Hotwells. This manifestation will be discussed first.

It was the opinion of Burgess et al. (1980) that the Hotwells thermal water represented a 1:2.3 mixture between a Bath-type hot water and locally-recharged cold water. In fact this really only applies for the cations, for which the ratios actually range between 1:2.1 to 1:2.9, with Cl and SO_4 being nearer 1:5 and HCO_3 being lower than unity, though this latter is basically controlled by carbonate equilibria which show the water is at saturation with respect to the likely controlling minerals calcite and dolomite. Figure 7 shows a plot of the major-element chemistry of Bath, Hotwells, the Carboniferous Limestone baseline and the water from the Carboniferous Limestone borehole at Filton. While a case could certainly be made for the Hotwells water being a mixture of a Bath-type thermal water with cold water, it is also very similar in composition to the Filton cold water. Therefore if Filton-type water could travel deep enough to acquire the observed temperature of ~24°C (i.e. to some 1000 m depth) it would appear almost identical to the Hotwells water. However, this seems unlikely because Hotwells is situated along the strike of the Carboniferous Limestone outcrop from Filton and water therefore would be unlikely to reach sufficient depth for heating to occur. It is also undoubtedly the case that the Hotwells water contains a high proportion of modern recharge on the basis of its tritium content (Burgess et al. (1980), so circulation to depth would be taking place far more rapidly (in decades) than is the case for Bath (thousands of years according to Edmunds et al., 2002). This leaves the mixing concept as the more likely explanation for Hotwells.

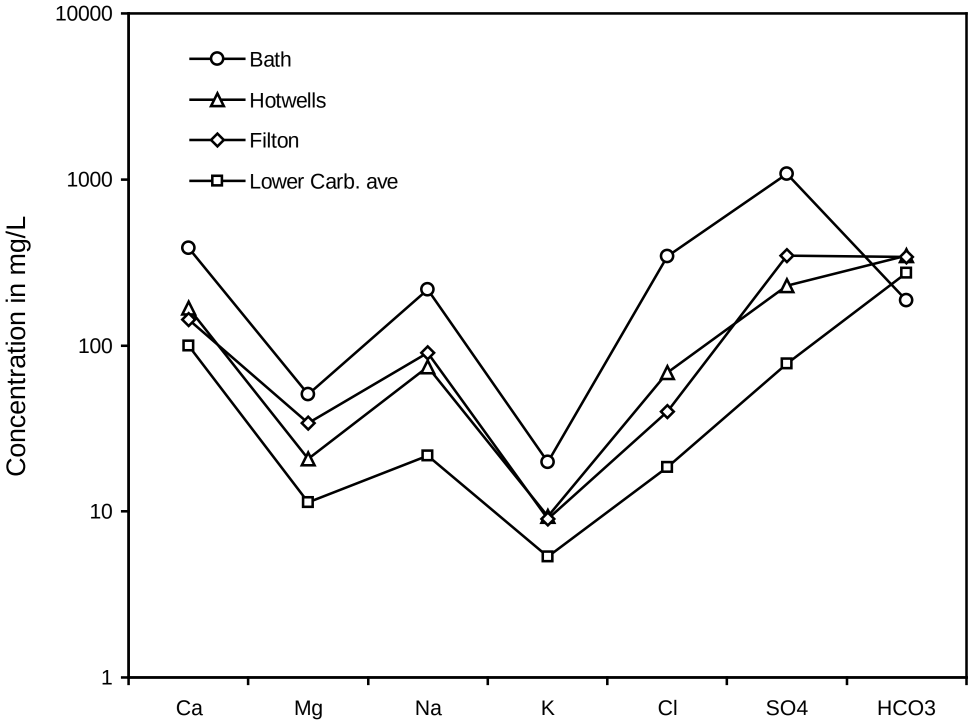

Figure 7 Major ion concentrations (log scale) in the Bath and Hotwells thermal waters compared with the average for Lower Carboniferous sources south of Bristol and water abstracted at Filton, north Bristol. Data from Burgess et al. (1980).

The most comprehensive recent investigation at Bath was the sampling of the Stall Street (King's Spring) borehole in August 2000 for a wide range of geochemical indicators and age tracers (Edmunds et al., 2002). Up to that time, ascribing a recharge age to the Bath thermal water had been problematic, estimates ranging from a few hundred years on simple hydraulic grounds to >20,000 years by radiocarbon dating, depending on how much modern water was entering the spring: small amounts of tritium had persistently been detected during monitoring, so some modern high-activity radiocarbon would presumably be entering the system. The main aim of the sampling was to give a more definite 'bulk' age for the Spa water, and also a more quantitative figure for the amount of modern cold water entering the system presumably fairly close to the discharge in Bath.

In addition to more conventional hydrochemical and stable isotopic techniques, the August 2000 study used a variety of age tracers. Inputs of modern water were investigated by measurement of CFCs (chlorofluorocarbons) and the noble gas isotope ^{85}Kr. These are anthropogenic gases deriving from a variety of industrial activities, in the case of ^{85}Kr from fuel rod reprocessing. Their build-up in the atmosphere is well characterised so, depending on a few assumptions about recharge temperature, they make ideal age indicators for water up to ~60 years old. The bulk age of the water was investigated using the noble gas isotope ^{39}Ar. This has a half-life of 269 years, meaning that it is a good age indicator back to approximately 1000 years.

The findings, reported by Edmunds et al. (2002) were as follows. The use of ^{85}Kr and CFCs indicated that the discharge contains a proportion of up to 5% modern water less than two decades old, and probably derived from Mesozoic strata some 10–20 metres below the point of emergence, entrained in the permeable funnel of the spring chamber (Kellaway, 1991). This modern water contains traces of oxygen and is responsible for the precipitation of iron, colouring the waters on emergence. The modern water was intercepted formerly by the spring under natural discharge conditions, but apparently slightly more of this water has been intercepted since the drilling of the Stall Street borehole. Confirmation of mixing with modern water provides an improved explanation of the residence time and the source of the deeper, thermal component of the spring. The age of this water must be in excess of 1000 years, as indicated by the lack of detectable atmospherically-derived ^{39}Ar signifying the elapse of at least four half-lives. However it must be less than 10,000 years old on the basis of its dissolved noble gas and stable isotope contents, which indicate Holocene recharge temperatures. Qualitative evidence (for example enriched ^{13}C and a likely negligible, residual ^{14}C) suggests the water to be nearer the upper age limit, and therefore an age in the range of 6–10,000 years was proposed.

As part of their investigations, Edmunds et al. (2002) measured the methane content of the thermal water from the Stall Street borehole which they found to be present at a concentration of 53 µg/L. This is not an elevated concentration by comparison with other waters in the UK (Darling and Gooddy, 2006). Ethane was present at a molar concentration some two thousand times lower, which suggests that the methane has been biogenically produced by acetate fermentation. No other groundwaters in the BBB have been measured for methane as far as is known.

3 Risk assessment of different exploration and completion

3.1 REGIONAL GROUNDWATER

If the sites sampled by Burgess et al. (1980) are typical of groundwaters in the BBB, then the consequences of any mixing of waters from different formations brought about the fracturing process itself, or drilling operations in general, would be minor since they share similar hydrochemical properties (Table 2). However, the most likely source of poor-quality water, the Coal Measures sandstones, have not been extensively investigated, the sample from the adit at Hanham being the only site measured by Burgess et al. (1980). While it is the case that mining ceased in the Radstock sub-basin in 1973, thus allowing four decades for natural dilution and dispersion to attenuate poor water quality brought about by mining operations (e.g. the exposure of pyrite to atmospheric oxygen and the consequent acidification of groundwater), there may still be pockets of poor-quality water contained within the strata. Against this, groundwater usage in the BBB is local in nature so the effects of any hydraulic fracturing-related contamination would not have a widespread impact on public water supply. In any case, the following of good engineering practice should minimise such a risk.

In the southern part of the BBB, in the Mendip Hills, karstic features within the Carboniferous Limestone are a major tourist resource. Some of the caves contain flowing water. While any detailed plans for proposed hydraulic fracturing in the Mendip area are not known, it seems unlikely that they would have an impact on cave system hydrology because this is essentially a surficial process.

Contamination of water resources by introduced fluids during hydraulic fracturing operations cannot be ruled out. This could involve anything from the leakage of surface storage tanks to the contamination of water at depth by chemicals contained in gels and foams. Various recent reports have provided guidelines, which, provided they are followed by companies, should minimize the risk (AEA 2012a, b, The Royal Society 2012).

3.2 THERMAL WATERS

In the context of the Bath Spa water dating study conducted by Edmunds et al (2002), the simulation of groundwater flow in the Carboniferous Limestone developed by Atkinson and

Davison (2002) and reproduced in Figure 5 is a plausible representation of what may could be occurring in the BBB. If the age estimate of 6–10,000 years is correct, then on any reasonable figure for Carboniferous Limestone porosity, much of the volume of the BBB must be involved in storage of the deep thermal water (Edmunds et al., 2002). The flowlines in Figure 2 suggest that while the recharge to the Bath thermal water does indeed take place over something like the arc of a 30° segment centred on Bath proposed by Andrews (1991), the flowlines to Bath actually extend well beyond the boundaries of the hypothetical segment, implying a much greater capacity for storage. Thus the bulk age of the Bath thermal water may well be disguising an exponential distribution of travel times about a mean.

In contrast to the Bath situation, Figure 5 shows the flowlines to Hotwells commencing in the western Mendips and on average shorter than those to Bath, with much less storage. This would indicate that Hotwells does not share the same thermal reservoir as Bath, which would perhaps explain some minor discrepancies observed between the two thermal waters, such as the difference in stable isotope values (Burgess et al., 1980). However, there is uncertainty over the position and even existence of the intra-basin hydraulic boundaries and flowlines depicted in Figure 5.

Possible impacts on Bath are now considered using the base case simulation of Atkinson and Davison (2002) reproduced in Figure 5 as a representation of the likely derivation of the thermal water. While this remains speculative, it appears to be the only published representation of groundwater flow in the BBB. Impacts can be divided into three categories: those in the recharge area, at depth in the basin, and in the discharge area.

3.2.1 Recharge area

Dewatering of Carboniferous Limestone quarries in the eastern Mendips has locally lowered water tables to close to OD over the last three decades. Atkinson and Davison (2002) modelled the possible effects on Bath, but these were very speculative because of the uncertainties involved, e.g. such dewatering was likely to be very transient, especially in the context of a thermal water residence time of thousands of years. While it is true that pressure effects can be transmitted through water bodies at a faster rate than the groundwater itself is transported, it remains unlikely that the hot springs would be subject to any noticeable effects within the foreseeable future from any consequences of hydraulic fracturing in the recharge area.

Not everyone is agreed about the recharge areas: William Smith and Kellaway held differing views to those now preferred, including derivation from recharge in the north of the BBB. However there is no subsurface evidence for Kellaway’s proposal for an Avon-Solent Fracture zone in seismic reflection data BGS has interpreted to the SE of Bath.

3.2.2 Basin or synclinal depocentre

The main threat to the thermal water system that could be envisaged deep in the basin is the introduction of waters from the overlying Coal Measures. This would have two likely effects: lowering of temperature, and deterioration of water quality. The temperature effect would probably be relatively small since the Coal Measures themselves would be at a significant depth and therefore at a similar temperature in the Radstock and Pensford sub-basins. Deterioration of water quality is harder to predict, given the lack of information from the coal mines, although there were reports of saline waters at depth in the mines (McMurtrie, 1886). Given the apparent amount of storage in the Carboniferous Limestone aquifer, this would act as a very large buffer against the local introduction of poorer-quality water. There is also the likelihood that piezometric levels in the Carboniferous Limestone are generally higher than in the overlying strata, which would act against the introduction of water from above. It therefore seems unlikely that hydraulic fracturing activities in the centre of the basin would have a significant effect on the thermal water in terms of temperature, quality or flow rate.

3.2.3 Discharge area

As mentioned earlier, the results of the study by Edmunds et al. (2002) leave no doubt that a small proportion (a few percent) of the water pumped from the Stall Street borehole consists of modern cold water mixing with the thermal water presumably in the relatively shallow subsurface. Atkinson and Davison (2002) observed that this was about the percentage of flow calculated to be derived from recharge on the Wick inlier rather than the Mendips, but it is not possible say whether the cold inflow is exclusively derived from this area, or indeed any particular area. In this context, any disturbance to deeper strata, or extraction/addition of deep fluids at or near Bath could have the potential to cause admission of more cold water to the flow system, which would reduce the thermal water temperature proportionally and could affect the water quality in unpredictable ways, not so much in terms of inorganic hydrochemistry as in the addition of contaminants.

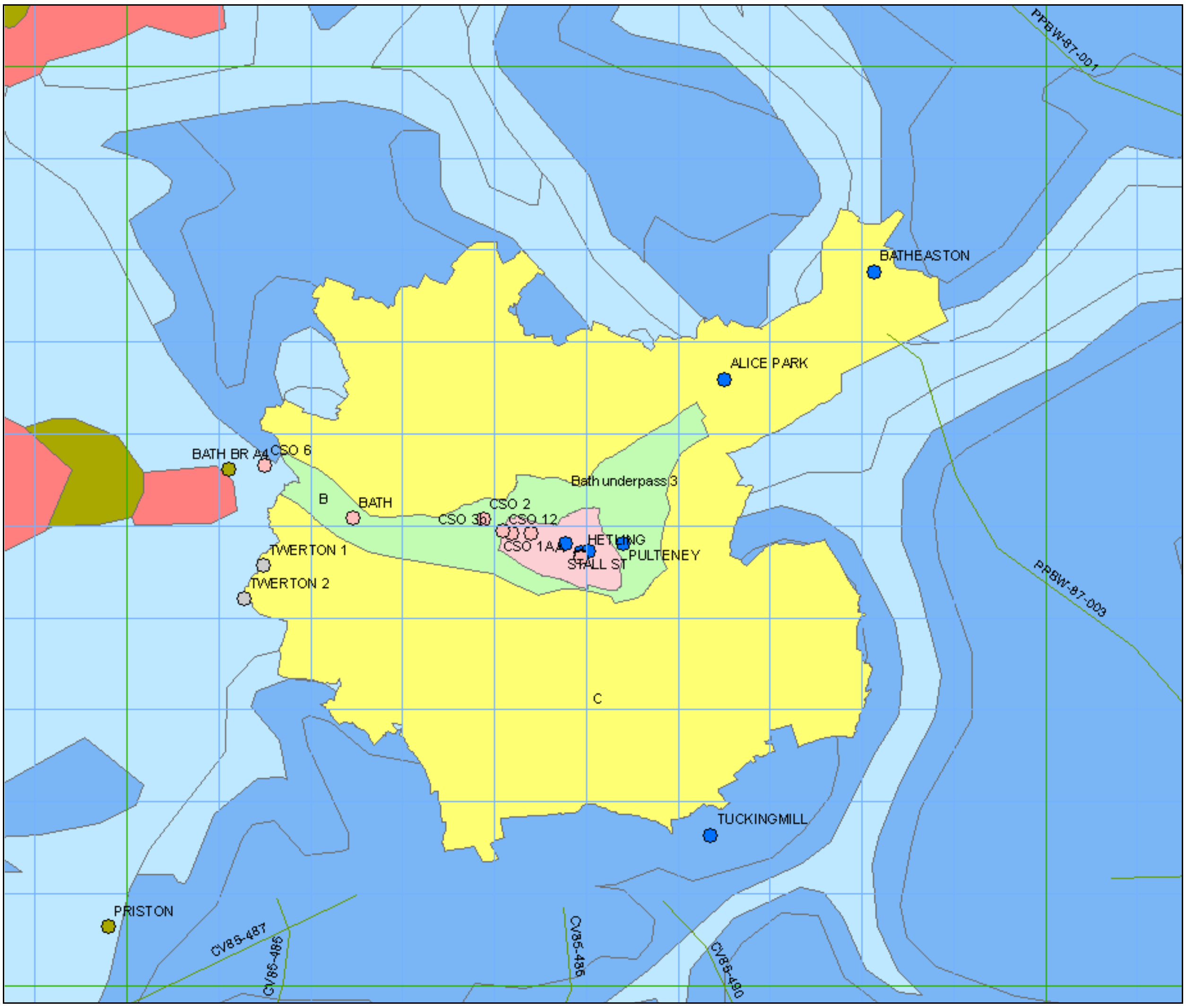

Fig. 8 Geology of Bath area with Avon Act zones A (pink), B (green) and C (yellow) superimposed. Seismic lines in green, wells shown as circles (with colours of Carboniferous strata of Fig. 2 key).

How far the at-risk zone extends beyond the Bath urban area is impossible to say with the present state of knowledge. There is as yet no evidence that three decades' worth of quarrying-related dewatering in excess of 20 m in the Wick area has reduced flow at Bath though monitoring may not have been sensitive enough to pick up the calculated ~3% reduction in flow (Atkinson and Davison, 2002). An 'exclusion zone' around Bath already exists (Fig. 8) but does not provide any control in the recharge and deepest hot water area (Figs 1 & 2).

At least three instances of local disruption have occurred to the hot springs during the 19th Century. The first, in 1810, was reported by Phillips in his 1844 memoirs of William Smith (Torrens 2003). In this case the flow had been diverted into a new channel, according to Smith and he was able to rectify the problem. What caused this is unknown now and probably also in 1810, although earlier problems of blockage with detritus are known (Kellaway 1991). We do not know how this was solved either. Although blamed for the first partial failure of the springs the concurrent sinking of a coal shaft at Batheaston was not responsible. However pumping at Batheaston shaft (Zone C, Fig. 8) did affect the time taken to fill the Cross Bath, and William Smith became aware of this problem having acted as consultant in both enterprises (Kellaway 1991). This appears to show that the reservoir is in connection both to the NE (Batheaston) and west (Pinch's well) of the hot springs.

The third disruption occurred in 1835 when a well at Pinch's brewery (250m W of the hot springs, Zone A, Fig. 8) was deepened from 79' to 170'. This well encountered water of temperature 99°F (37°C) and flowed at about 164,000 gallons/day (746,000 litres). Both the Hetling and Cross Bath springs were affected by the deepening of Pinch's brewery well. This led initially to a court case. A large engineering project to plug the premature escape of hot water to the surface at this site eventually succeeded in about June 1838 when, after sealing the Pinch well, the hot water gradually re-established its flow to the baths (Armstrong 1838).

Stanton (1991, fig. 8.1) showed a map of the accidental proving of waters with elevated temperature and depths at which it was encountered, in the Bath area. The wells range from 19th century water for a brewery to very shallow drilling associated with site investigation work for Bath's redevelopment. This map showed two boreholes near Bath Spa station, one south of the river and a high temperature one at Bathwick Brewery to NE, the latter two for which BGS has no record. Batheaston coal shaft, to the NE of the city (sunk 1804-1813) tapped warm water which still continued to flow from a 60' deep adit in 1888 (Etheridge 1888) and when pumped in the early 19th Century affected the flow at Cross Bath. However, this latter fact was forgotten when Councillor Mr Handel Cosham, M. P. suggested the old shaft as a source of drinking water for Bath (Kellaway 1991). Etheridge did not even have a proper log of the shaft. We can only learn from history if we keep proper records.

A few minor variations, carefully monitored, are also listed (for February 2012) on the Bath Spa website:

- Decreases in flow at Great Drain, Stall Street Borehole and Cross Bath on 8, 9 and 10th are due to drilling works.
- Gradual decrease in flow from 1st to 6th at Great Drain, Hetling Spring and Cross Bath due to flow testing of the Hot Bath Street Borehole.
- Change in pressure at Cross Bath inclined borehole, Kingsmead borehole, Stall Street Borehole and Hetling borehole on 8, 9 and 10th due to drilling work.

All the examples in this section are within the areas regulated by the Avon Act (Fig. 8).

4 Conclusions

It is believed the main threat to the hot springs is provided by the near-field area of Bath City (see above also), where engineering boreholes and deeper wells drilled for various purposes have already encountered warm or hot water accidently. This is mainly from inadvertently diverting the flow, as happened twice in the 19th Century and allowing colder surface waters to invade. The cold, recent water amounts to about 5% of the total (Edmunds et al. 1991), with a maximum residence time of 18 years (Edmunds et al. 2002).

Problems in the near-field area are shorter term, within our lifetimes and easier (but expensive) to resolve. Any problems in the far-field would not probably appear for thousands of years, but it is unlikely we could resolve them, at least not with current technology.

Coalbed methane exploration should not affect the migrating waters because there is no evidence the hot waters have come into contact with Westphalian strata (Edmunds et al 2002). Properly conducted CBM exploration should not pose any problems to the hot springs. Because the structure in the southern part of this syncline is so complicated by thrust faulting (Fig. 7, area where existing Carless CV prefixed seismic profiles are located, Fig. 9) and even more structurally complicated south of the B&NES planning control area no exploration drilling activity is likely here. Exploration is more likely to take place, further north within the area of Bath & NE Somerset Council planning control (Fig. 7), still within the Radstock-Coalpit Heath Syncline. B&NES needs to ensure that the operator takes all steps to avoid making contact with old boreholes or shafts. Seismic reflection surveys are needed to map faults, particularly any thrust faults, which may modify the assumed structure in undrilled areas. Hydraulic fracturing of coal seams is not considered such an invasive process as with shale gas. Monitoring of methane levels before, during and after drilling and fracturing is required (AEA 2012a).

There is a very low risk level from vertical shale gas exploration wells in the Mendips or deeper parts of the Radstock-Coalpit Heath Syncline, but if located at closer locations to Bath these might pose a risk if hydraulically fractured. Locations close to Bath are less likely to be chosen because the attractive locations are where the formations are thickening southwards away from the city. Vertical wells drilled through the Carboniferous Limestone need to be very carefully sited, planned and properly completed. We consider acquisition of seismic reflection data, properly tied to boreholes to be an essential element of a thorough exploration programme.

If shale gas production from horizontal wells were to be attempted on a large scale, between Bath and the recharge areas, this would target formations possibly both above and below where the hot water is migrating from its recharge area. Whereas companies would not wish to extend their fractures into the strata in which the hot waters are migrating their stratigraphic levels of interest would make it difficult to guarantee that this would not occur. The Namurian shale may directly overlie the topmost Carboniferous Limestone, where migration of water may be occurring. The Lower Limestone Shales underlie the limestones in which some of the water may be migrating. It would be preferable to see a cottage industry type development of shale gas here rather than the HVHF slickwater-type methods.

The Reservoir company licence is mainly located over the southern Mendips and south of the Mendips (Fig. 1), but the intended targets are less obvious here and the subsurface flow in most of this licence is likely to be southwards.

Until wells are drilled there is no way of knowing whether there is a potential for field development but both the coalbed methane and shale gas targets are not in areas with conventional gas production or significant shows (DECC 2010a,b). This would make them exploration ventures with a high risk of failure by comparison both with the US and other UK areas with conventional hydrocarbon production. Companies would probably plan initial exploration, in the form of a vertical well, which would target both CBM and shale gas. By choosing a location within the Radstock-Coalpit Heath Syncline coal cores can be cut within the Westphalian sequence and cores would also be taken in early Namurian and Lower Limestone Shale Group (Table 1), in addition to any other shales found to be promising but not prognosed prior to drilling.

Geothermal exploration is the most serious threat to migrating hot water. If licensing provisions in amendments to the Energy Bill are enacted companies are likely to be interested in nearby areas. Any such exploration along the preferred migration route shown in Figure 5 could jeopardise the preservation of the hot springs. There is no assurance that exploring companies could give about the protection of the springs.

The risks to the population, infrastructure and habitats and land-take are covered extensively (AEA 2012b). Their table 5 shows that in the exploration phase groundwater and surface water contamination is considered high risk and that the other risk factors increase only with multiple sites. This report has presumed only a HVHF model for production.

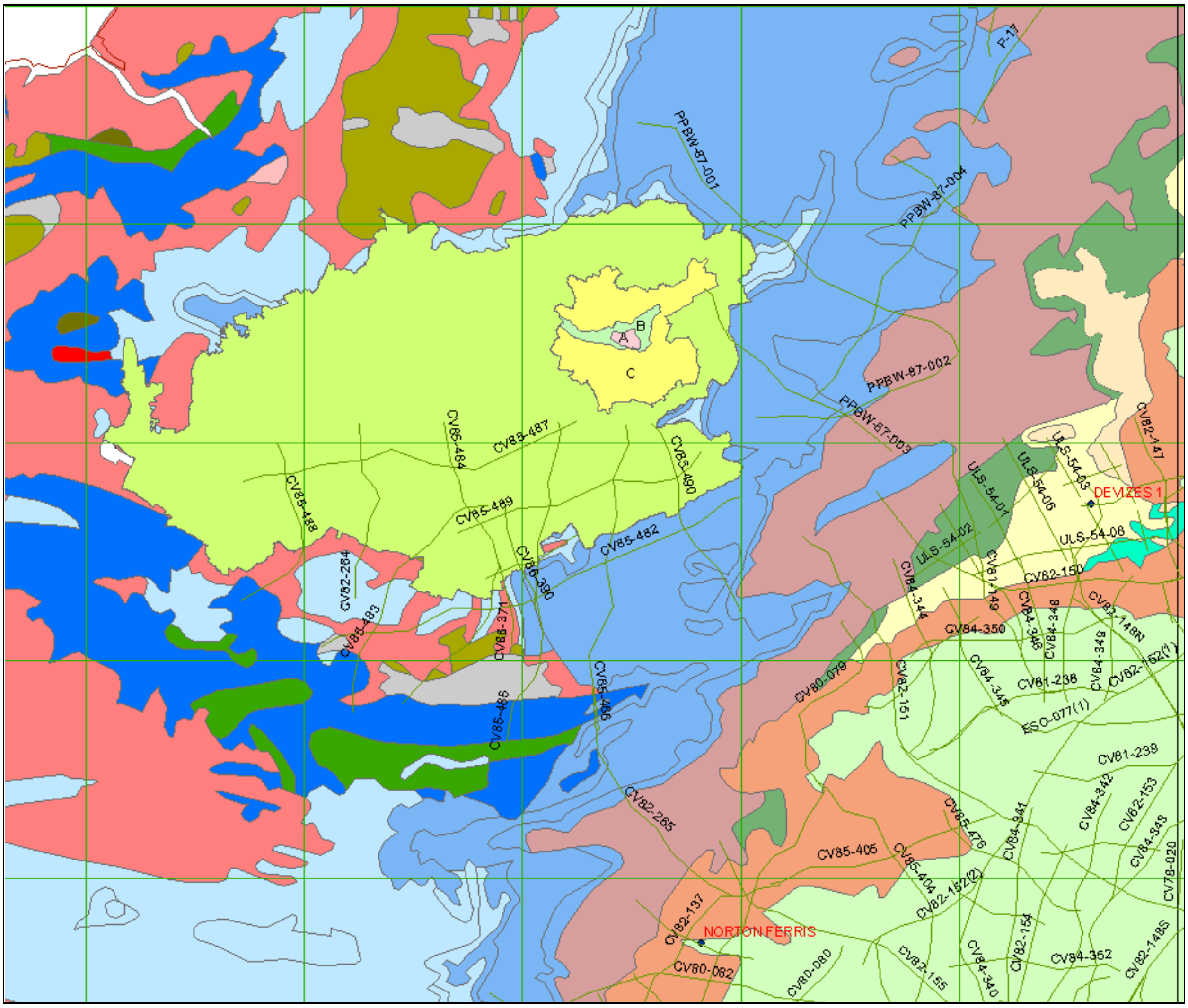

Fig. 9 Bath hot springs (pink Zone A), zones of Avon Act and Bath & NE Somerset Council planning control area

4.1 Recommendations

This report has used previous research to define the most likely area where recharge, migration, storage and ascent to the surface are occurring, but we have to stress that the geological data needed to make a definite interpretation of the pathways does not exist. All production could be prevented in this area, if DECC were to be persuaded, but the area identified is currently a very vague area. There is no way of being able to better define this area, with current knowledge.

DECC could be requested to ensure that companies liaise with B&NES if and when exploration takes place within this area. This could be part of the agreed work programme of any future licences if DECC are asked to include it. Companies undertake work programmes which they agree to in advance of drilling with DECC, when obtaining licences and it would seem appropriate to try to include such instructions, at this stage, for these wider areas. For example the most common is a drill or drop provision, whereby the licence has to be relinquished if no drilling takes place before the expiry of the licence. The 13th Round licences expire in 2014, if there is no drilling. These concerns would need to be addressed by the company at the planning application stage anyway. If this strategy fails it is suggested that establishing close cooperation with exploring companies would be beneficial.

In addition, with DECC's agreement acknowledging the commercial importance of the hot springs and the embarrassment of causing problems to a World Heritage site, it could be suggested that permitted exploration and production should be limited to the cottage industry style used in the US until the 1980s. This would eliminate hydraulic fracturing of shales, but other completion techniques were used, and successful wells based on this former exploration system were more sustainable, with lower flows, but over long periods of time. Of course, it may be that UK shales will not flow under these conditions.

There has been a recent tendency in the UK to explore for CBM without seismic reflection, making concealed highs and faults impossible to locate prior to drilling. No such data, west of Bath, has been acquired either for hydrocarbon or NCB purposes. At the planning stage it could be suggested that these data are acquired.

If the Energy Bill becomes law with the amendments from the Lords (the provisions are for licensing to begin 18 months later) or in some later act of Parliament B&NES could apply for the geothermal licence between the Mendips and Bath or, preferably, the total exemption of this area from geothermal licensing. B&NES would probably need to get in the position of a consultee, when this is being set up (see below).

4.1.1 Precedents for engaging with DECC prior to licences being offered

It would be to everyone's benefit, at the earliest stage possible, to deter fruitless exploration costs for companies. A precedent exists in the offshore hydrocarbon licence areas, where the Ministry of Defence has obtained exclusions before licence areas are awarded.

The Ministry of Defence is a consultee on the licensing of marine developments and the extraction of hydrocarbon resources in the UK continental shelf area, to ensure offshore developments and activities do not affect strategic defence interests or inhibit the use of designated Danger and Exercise areas supporting military training and weapon trials. This results in many areas being excluded for hydrocarbon exploration, prior to offering in licensing rounds. DECC could not recall any such precedents onshore but similar arrangements are expected, for example, around nuclear power stations. However, this approach could discourage exploration in the far field areas and we understand that local MPs have suggested this course of action. It is unlikely, though, that this can alter the status of current licence holders. There is a low probability that shale gas production will be achieved in this area. CBM production is unproven here, but likely to be a similar struggle to obtain commercial flows as is the case elsewhere in the UK.

4.1.2 Local planning authorities and Environment Agency

The existing licences are unlikely to be withdrawn by DECC because they seem to consider that the planning stage can prevent certain types of drilling. This does not necessarily apply to the B&NES position because drilling outside their boundaries might be possible, yet still cause problems for the hot springs. The companies may eventually relinquish their licences, after collecting some data and drilling, but small companies tend to hold acreage when new plays (like shale gas) are being developed in the hope that they attract larger companies to buy their companies or farm-in to the operation. It is unlikely that it would be in their interest to cause a lot of bad publicity, because this would put off potential farm-ins or sales of the licences. Close cooperation is needed with adjacent planning authorities so that conditions can be imposed on drilling. It is not reasonable to ban seismic reflection acquisition and all drilling, and we believe these types of exploration will contribute to knowledge about the subsurface which will improve knowledge of the springs. However, it should be possible to preclude certain developments, particularly hydraulic fracturing and extensive horizontal drilling in formations adjacent to the Carboniferous Limestone.

The Environment Agency (EA) issue permits where there is a specific risk and have powers to control and prohibit dangerous activities. They work closely with DECC, the local authorities and HSE to ensure professional industry practice and there are now several published guidelines on which to base informed decisions (AEA 2012a, The Royal Society 2012, AEA 2012b). It would be sensible to have discussions with the EA, especially as their staff are knowledgeable about subsurface water.

4.1.3 County of Avon Act 1982

Bath was charged with responsibility for the Hot Springs in a Royal Charter of 1591 granted by Queen Elizabeth I and this duty passed to Bath & North East Somerset Council (B&NES). The springs are further protected by the 1982 County of Avon Act.

Section 33 of this Act requires the consent of the council for any works which extend to more than 5 m below the natural ground surface within area A, 15 m within area B and 50m within area C (Fig. 7). However boreholes drilled on behalf of the railways and utilities appear to enjoy an exception clause. The greatest risk to the springs, in our lifetime, concerns activities within the Bath area, while those under the coalfield are a more long term risk and those in the vicinity of the recharge an even longer risk amounting to thousands of years.

This Act confers on B&NES a similar arrangement with respect to exploration (mostly site investigation type exploration envisaged in area A) as that in which the Coal Authority is required to be notified if coal seams are expected to be encountered in wells.

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