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Development of deep geothermal energy resources in the UK

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Deep geothermal exploration in the UK in the 1980s resulted in only one operative borehole (in Southampton). In 2004, a 995 m deep borehole was drilled into the Weardale granite in County Durham. This project differed markedly from the earlier 'hot dry rock' investigations in the granites of Cornwall, in that it deliberately targeted possible high natural permeability derived from large fault zones. The new approach met with success, discovering what is believed to be the highest natural permeability ever found in granite anywhere in the world. Drilling of a second borehole at Eastgate in 2010 confirmed that high permeability is preferentially associated with major west–east geological faults. Further deep drilling is now targeting similar faults cutting nearby sedimentary sequences. Meanwhile, renewed interest is being shown in Cornish prospects, as well as in previously unexplored resources in Scotland and Northern Ireland. There is also significant interest in the possible geothermal exploitation of hot brines, which are co-produced with hydrocarbons in existing oilfields. Technological advances in directional drilling, reservoir stimulation and power generation using binary-cycle turbine plants are finally making deep geothermal energy a realistic target for full-scale development in the UK.

1. Geothermal energy in a changing climate

Geothermal energy has been defined by the International Energy Agency (IEA, 2010) as follows:

> Geothermal energy is energy available as heat contained in or discharged from the earth's crust that can be used for generating electricity and providing direct heat for numerous applications such as: space and district heating; water heating; aquaculture; horticulture; and industrial processes. In addition, the use of energy extracted from the constant temperatures of the earth at shallow depth by means of ground source heat pumps (GSHP) is also generally referred to as geothermal energy . . .

Use of GSHP technology has been expanding rapidly in the UK in recent years, and it is extensively discussed elsewhere (Banks, 2008; Younger, 2008). Whereas GSHP harvests thermal energy (ultimately derived from solar radiation), which is stored in soils, rocks and groundwater at a few tens of metres' depth (Banks, 2008), the exploitation of heat 'discharged from the earth's crust' depends on accessing natural heat sources at far greater depths. 'Deep geothermal energy', which is the focus of this paper, is here defined as natural heat encountered at depths in excess of 300 m. As the definition offered by the International Energy Agency (IEA, 2010) makes clear, deep geothermal heat can either be used directly, or used to generate electricity. While natural steam or very hot waters (>180°C) can be used to drive steam turbines directly (DiPippo, 2008), for the more modest maximum temperatures likely to be encountered in non-volcanic regions of the world, power generation can only be achieved using a binary-cycle power plant (Figure 1). In most circumstances, a temperature around 120°C would be deemed desirable for commercial binary plant applications (albeit binary plants have been made to work at temperatures as low as 73°C (IEA, 2010), although at such temperatures they remain subeconomic at current energy prices).

Although deep geothermal energy has been successfully exploited for more than a century (DiPippo, 2008), until the turn of the second millennium, expansion of uptake was largely confined to countries with active volcanoes. In recent years, mounting concern over anthropogenic climate change has greatly increased the impetus for the development of low-carbon energy sources. As deep geothermal energy has one of the lowest carbon emission rates of any energy technology, and as it does not suffer from the intermittency that dogs other renewable energy sources such as wind and solar, uptake of geothermal energy is burgeoning to an unprecedented extent: with annual growth in use since 2005 amounting to 4·5%

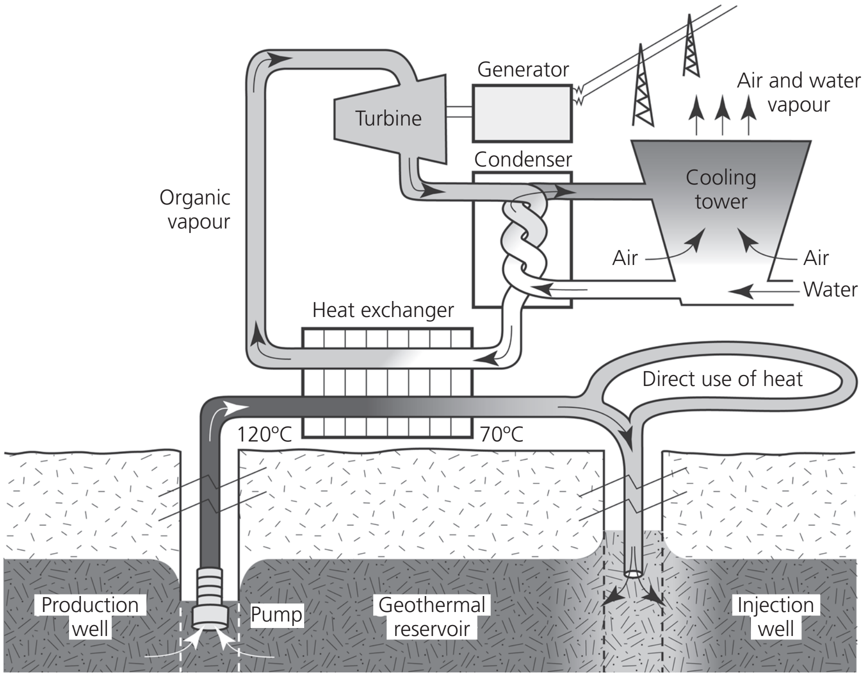

Figure 1. Simplified process flow diagram for a typical binary power plant of the type proposed to harness deep geothermal resources in the UK for power generation. Binary plants are principally useful for waters with temperatures below 150°C, which do not yield enough steam to achieve pressures sufficiently high to drive a turbine directly. Following power generation, the remaining heat in the partly cooled geothermal brine will in most cases be captured for a range of direct uses, such as in spas, in space heating, and a wide variety of industrialised processes. A power plant such as that shown is referred to as 'binary' as it involves two separate closed circuits of fluid circulation: (i) geothermal brine pumped from one borehole and reinjected into another (typically sited several hundred metres apart to minimise breakthrough of cooled water to the pumping borehole); (ii) a 'working fluid' (in this case marked 'organic vapour', although other fluids are occasionally used (DiPippo, 2008)), which has a boiling temperature far lower than that of water. When heated by passing through the heat exchanger (which receives its heat from the geothermal brine), the working fluid vaporises, forming a high-pressure gas phase that can then be used to drive a turbine

for power generation and 15% for direct use (IEA, 2010). As the industry has expanded sufficiently to realise some economies of scale, and as governments around the world have begun to incentivise low-carbon energy, the costs of geothermal energy have begun to be more competitive, at least in comparison with other renewables. Thus in the most recent global assessment, capital costs were estimated to range between £1200 and £3600 per kW_e (i.e. kilowatt of installed electrical capacity), with electricity generation costs for binary plants of between £0·04 and £0·12 per kW h, and production costs for direct heat use of between £0·04 and £0·10 per kW h_t (i.e. kilowatt-hours thermal) (IEA, 2010). With the recent announcement of a tariff of £0·03 per kW h_t for geothermal energy in the UK, it is easy to see why geothermal energy is finally stimulating substantial interest in the UK, which hitherto was lagging behind many other non-volcanic countries in uptake of the technology. This paper explores recent and current developments in deep geothermal energy in the UK.

2. A brief history of deep geothermal energy development in the UK

In the 1970s and 1980s the UK was at the forefront of international developments in deep geothermal energy (Armstead and Tester, 1987). Through a combination of desk studies and the drilling and testing of seven deep boreholes, investigations were made of two main types of geothermal resources (Armstead and Tester, 1987; Barker *et al.*, 2000; Brown and Garnish, 2004; Downing and Gray, 1986a, 1986b)

- deeply buried sedimentary aquifers (in Hampshire, Lincolnshire and Antrim)
- radiothermal granite in Cornwall ('radiothermal' means that heat is produced by the natural radioactive decay of isotopes of uranium, thorium and potassium present in the granite).

The locations of the seven boreholes drilled in the 1980s are indicated on Figure 2, and basic information on them is summarised in Table 1. They comprised three boreholes in the Carnmenellis granite at Rosemanowes, Cornwall, and individual boreholes piercing Mesozoic sedimentary strata at

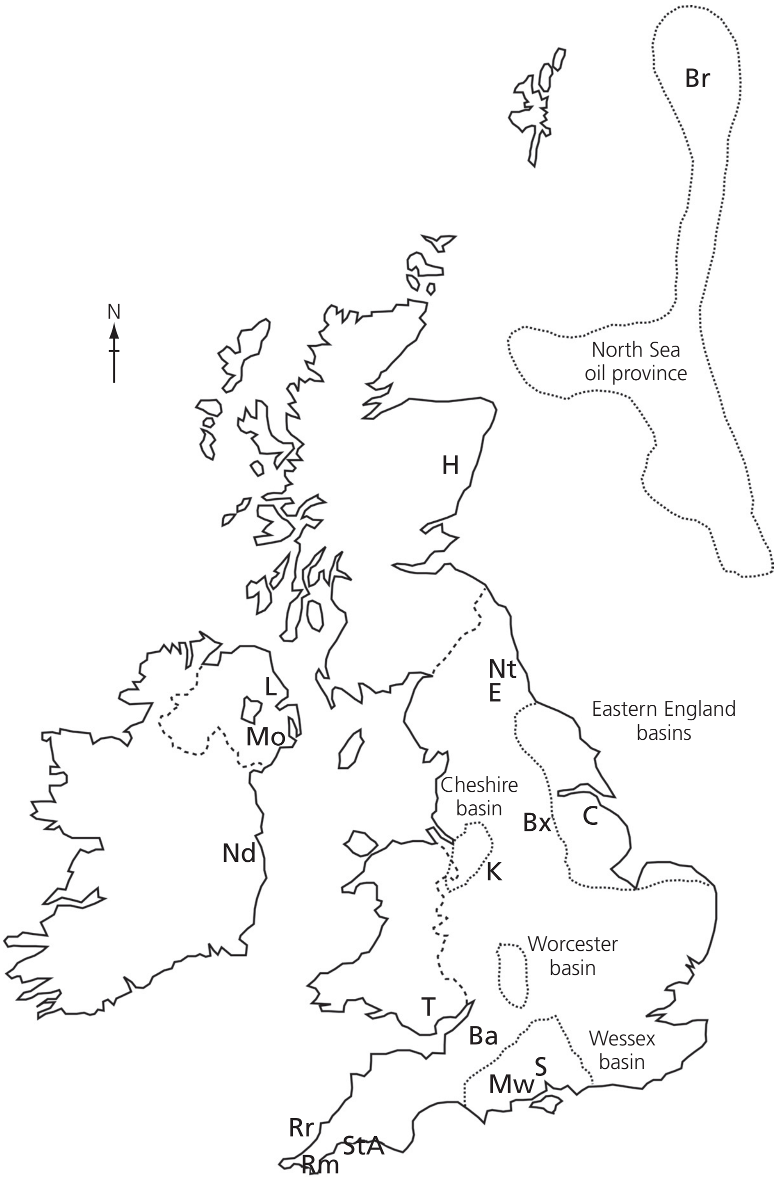

Figure 2. Sketch map of Britain and Ireland showing the sedimentary basins and principal localities mentioned in the text. Ba = Bath hot spring; Br = Brent offshore oil province; Bx = Buxton (warm spring); C = Cleethorpes borehole; E = Eastgate boreholes, County Durham; H = East Highlands granites (for more detail see Figure 3); K = Keele university; L = Larne borehole; Mo = Mourne granite; Mw = Marchwood borehole; Nd = Newcastle, County Dublin; Nt = Newcastle upon Tyne (site of Science Central Borehole in footwall of Ninety Fathom–Stublick fault zone); Rm = Rosemanowes quarry; Rr = Redruth; S = Southampton borehole; StA = St Austell; T = Taff 's well (warm spring)

Marchwood, Southampton, Cleethorpes and Larne (Barker *et al*., 2000). Of these, only the Southampton borehole was eventually brought into production (in 1987), providing a maximum of 1·7 MW_t to a range of public and private properties in central Southampton (Barker *et al*., 2000). This 1800 m deep borehole yields water at 76°C, which is derived principally from the Sherwood sandstones aquifer (Triassic), which is present in the depth interval 1725–1749 m. This hot water contributes to a substantial combined heat and power plant, mainly supplied using heat engines, which serves more than 20 city-centre buildings. As the spent brine at Southampton is disposed of to the sea rather than reinjected into the geothermal aquifer, water levels in the aquifer have been declining over time (Barker *et al*., 2000), and further drop in yield can be expected owing to gradual deterioration of screens, casings and pumps over the decades. In fact since 2001 the borehole had been out of regular use until, in December 2010, the UK government's Department of Energy and Climate Change (DECC) announced the award of some £200 000 to the operators to refurbish the borehole and bring it back into production.

Despite the success of the Southampton geothermal borehole exploitation, it is not nearly as widely recalled as the 'hot dry rock' (HDR) experiments, which were undertaken between 1977 and 1991 at Rosemanowes quarry, near Penryn in Cornwall (Armstead and Tester 1987; Downing and Gray, 1986b; Richards *et al*. 1994). These experiments were never intended to lead to the establishment of a power plant; rather, the intention always was to apply the lessons learnt in Cornwall to a subsequent pilot project on a more promising site. Indeed, a key design criterion was to keep the temperature below 100°C. These experiments were predicated on the artificial stimulation of fracture permeability in otherwise low-permeability (but impressively heat-producing) radiothermal granite. Much of value was indeed learned at Rosemanowes, and it paved the way for subsequent developments elsewhere, most notably in the Soultz-sous-Forêts project on the Franco-German border (Huenges, 2010; Phillips, 2000), in which the HDR approach was effectively renamed EGS, standing for enhanced (or engineered) geothermal systems (EGS) (Huenges, 2010). EGS is now the most widely-used name for this technology (MIT, 2006). Nevertheless, in Cornwall itself there was no further development of HDR/EGS in the two decades following completion of the last borehole at Rosemanowes in 1983.

3. The renaissance of deep geothermal energy development in the UK: Eastgate, County Durham

In 2004, deep geothermal drilling into radiothermal granite recommenced in the UK; however, this was not in Cornwall, but 500 km away at Eastgate, County Durham, in the North Pennines of England (Figure 2). The drilling of the 995 m deep Eastgate no. 1 borehole was undertaken under a paradigm rather different from that of the former HDR experiments, in that it deliberately targeted potential high natural permeability derived from large natural fractures in the granite (Manning *et al*., 2007).

The geothermal resource now proven at Eastgate is associated with a major west–east structural feature known as the Slitt Vein, which can be traced at outcrop for more than 12 km. Perhaps best described as a regional wrench fault, the upper few hundred metres of this structure host major lead–zinc–fluorspar mineralisation, in the form of veins formed by precipitation from hot, metalliferous waters that were clearly circulating in the Slitt Vein during the period of ore deposition some 280 million years ago (Dunham, 1990). These hydrothermal minerals were mined until the late twentieth century, just outside the

Location (for positions see Figure 1)	Completion	Well depth: m	Bottom hole temperature: °C	Main aquifer depth: m	Temperature of aquifer: °C
Rosemanowes RH11	December 1981	2175	90	2100	55–70
Rosemanowes RH12	October 1981	2143	90		
Rosemanowes RH15	January 1985	2652	100		
Marchwood	February 1980	2609	88	1672–1686	74
Larne	July 1981	2873	91	960–1247	40
Southampton	November 1981	1823	77	1725–1749	76
Cleethorpes	June 1984	2092	69	1093–1490	44–55
Eastgate no. 1	December 2004	995	46	411	27
Eastgate no. 2	July 2010	420	–	–	–

Table 1. Summary of deep boreholes drilled for geothermal exploration in the UK up to 2010 (expanded from a table originally published by Brown and Garnish (2004)). Data for Eastgate no. 1 from Manning *et al.* (2007); data for Rosemanowes from Armstead and Tester (1987)

area tested by Eastgate no. 1 borehole. The chemistry of certain waters found in the last working mines (Manning and Strutt, 1990) suggested that warm water might still be circulating at depth in the Slitt Vein structure. At a nearby mine on the next major vein striking parallel to the Slitt Vein, repeated water temperature measurements of discrete groundwater inflows to mine tunnels over a depth interval of 150 m revealed a geothermal gradient of 5·3°C per 100 m (Younger, 2000) – one of the highest geothermal gradients ever directly measured in the UK. Both of these observations were ascribed to the presence of the radiothermal Weardale granite of Devonian age (Kimball *et al*., 2010), which lies beneath a thick sedimentary cover of Carboniferous age. The Weardale granite is nowhere exposed at the surface, and before the drilling at Eastgate began it had only been penetrated by one borehole (drilled at Rookhope in the 1960s (Dunham, 1990)). The Eastgate no. 1 borehole entered the Weardale granite at a depth of some 273 m, beneath a largely sedimentary sequence (mainly mudstones, with thin, interbedded limestones and subordinate sandstones, but also including a penecontemporaneous dolerite intrusion (the Whin Sill) of Carboniferous age) (Manning *et al*., 2007). At 138 m into the Weardale granite (at a total depth from surface of 411 m) a major fracture zone was intersected by the borehole. Subsequent packer-testing over a 24 h period (Younger and Manning, 2010) revealed this fracture zone to have a permeability of around 170 darcies ($=1{\cdot}68\times10^{-10}\,\text{m}^2$), which is the highest permeability yet found in any granite in the UK, and quite possibly anywhere in the world. This vindicated the proposition of deliberately targeting high natural permeability in granite. The borehole was continued through granite to a total depth of 995 m, where the bottom-hole temperature was recorded as 46·2°C, yielding a geothermal gradient estimate of around 3·8°C per 100 m. The heat flow from the Weardale granite at Eastgate was calculated to be 115 mW/m^2 (Manning *et al*., 2007), which is 25% higher than previous estimates for this granite (Downing and Gray, 1986b), and comparable to the rates found in Cornwall.

The geothermal resource at Eastgate appears to be of enormous proportions. The Eastgate no. 1 borehole proved capable of yielding 140 m^3/h per of warm water per metre of drawdown; this is a phenomenal specific capacity for a borehole in granite, and is in fact comparable to that of highly permeable zones in the Chalk, which is the UK's most prolific freshwater aquifer. Even without any further development the Eastgate no. 1 borehole could support 5 MW_{th} of heat use for only 8·5 m of drawdown. Furthermore, geothermometric modelling of the evolution of the brines found in the Eastgate no. 1 borehole (Manning *et al*., 2007) suggests that it originated at temperatures as high as 191°C, which is far greater than the threshold for cost-effective power generation using a binary power plant (Figure 1). Notwithstanding the uncertainties surrounding geothermometric calculations for highly saline waters, this is encouraging. It raises the question of whether drilling to greater depth in the Slitt Vein structure might yield abundant waters hot enough to support electricity generation. The likelihood of this would be greatest if the fracture permeability found at 411 m in Eastgate no. 1 were shown to be associated with the Slitt Vein itself, rather than corresponding to some sub-horizontal feature, such as a deep weathering zone.

In 2010, this issue was addressed by drilling of a second borehole (Eastgate no. 2) to a depth of 420 m, at a location some 700 m east of the original borehole and approximately 300 m north of the Slitt Vein. No sub-horizontal zone of fracturing was found in Eastgate no. 2 at the depth corresponding to the 411 m fracture zone in Eastgate no. 1; furthermore, the granite penetrated by Eastgate no. 2 was of uniformly low permeability, thus supporting the inference that the very high permeability found in Eastgate no. 1 was indeed associated with the Slitt Vein. Further investigations are now underway, with a view to deepening one or other of the two Eastgate boreholes to intercept the Slitt Vein at depths of 3 km or more, at which temperatures sufficient to support operation of a binary power plant (Figure 1) would be anticipated, to judge from the geothermal gradient of 3·8°C/100 m estimated in Eastgate no. 1 (Manning *et al*., 2007), which according to modelling results presented by Downing and Gray (1986b, pp. 30–32) can be expected to persist on a linear trend to such depths.

4. A new dawn for deep geothermal prospecting in the UK?

In the wake of the news from Eastgate, renewed interest in deep geothermal energy has arisen in several areas of the UK. The current state of prospecting is summarised below. Locations of sites mentioned in the text are shown on Figure 2. The description that follows proceeds roughly from south to north through the UK.

4.1 Cornwall

Two companies have recently been established with the aim of developing full-scale exploitation operations for deep geothermal energy associated with the granites of Cornwall (British Geological Survey, 1990). Both companies build on experiences in the former Cornish HDR experiments as well as in the more recent developments of allied technology at Soultz-sous-Forêts.

EGS Energy Ltd has obtained planning permission (and partial funding from DECC) to enable drilling of a 4–5 km exploratory borehole, to be followed by further boreholes if the geology proves propitious. The proposed depth of the boreholes is predicated on encountering temperatures as high as 190°C, which would be hot enough to raise high-pressure steam directly to drive a turbine, as opposed to using a binary plant. Should the natural permeability prove insufficient to support sustained heat production, EGS Energy Ltd will deploy their in-house expertise in the stimulation of previously existing joints and fractures by inducing shear slippage. In the first phase of development, EGS Energy Ltd intends to develop some 4 MW_e, which is sufficient to power the celebrated Eden Project site near St Austell. The direct use of heat would be sufficient to supply 5000 homes (EGS Energy, 2010). Later phases of work will expand to include other favourable sites in western Cornwall, with the eventual ambition of developing several hundred MW of geothermal energy.

A second Cornwall-based company, Geothermal Engineering Ltd, has also received planning permission to commence development of a geothermal power plant rated at 10 MW_e and 55 MW_{th}, based on boreholes to be drilled to depths of 4·5 km in the vicinity of Redruth (Geothermal Engineering Ltd, 2010). This company also has plans progressively to develop further power plants in the southwest peninsula of England, with an aim of achieving a total installed capacity of 300 MW_e and 1 GW_{th} by 2030. To place the latter aim in perspective, this would represent implementation of district heating on a scale for which the UK can as yet offer no precedents, although examples on the scale can be cited from, for instance, Esbjerg in Denmark, where district heating has achieved market penetration of more than 70%.

4.2 Deep sedimentary basins of England

The UK does not have many natural warm springs, but the few that are recorded (most notably at Bath (48·8°C), Bristol (24·4°C), Taff's Well (18·6°C) and Buxton (27·5°C) (Barker *et al.*, 2000); see Figure 2) are all associated with deep circulation of groundwater in sedimentary basins. Geological faults cutting limestones of Carboniferous age are believed to be responsible for the rise of these waters to the surface sufficiently rapidly to avoid complete cooling (Barker *et al.*, 1990; Brassington, 2007). Indeed a single major fault, the Avon–Solent fracture zone, appears to account for both the Bath and Bristol springs, and also passes through the strata exploited by the Southampton borehole, while a parallel fault appears to account for Taff's Well (Barker *et al.*, 2000).

At the Southampton site, hot water is produced from a deep Triassic aquifer, the same stratigraphic interval that hosts the giant Wytch Farm oilfield in the Wessex basin of Dorset and the English Channel. The Wessex basin is one of several deep sedimentary basins in England, which (together with the Midland Valley of Scotland reported below) have been explored for oil and gas, which means that temperature data are available from deep wells. Permo-Triassic basins include those of Cheshire, Worcestershire, Wessex and Cleveland/East Yorkshire/Lincolnshire. Some of these are underlain by Carboniferous basins while additional Carboniferous basins occur in the East Midlands (Nottinghamshire and Lincolnshire) as well as in northern England. Of these only the East Midlands and Wessex basins have abundant well databases because of the many oil and gas fields located there. Nonetheless there are sufficient data from the other basins for the gross geothermal gradient to be calculated as well as to estimate the permeability and hence transmissivity of the buried strata.

The Cheshire basin contains up to 5 km of Permian and younger sediments, which in turn are underlain by hundreds of metres of Carboniferous strata (Plant *et al.*, 1999). The thermal gradient is not well constrained, although over much of the basin it is quite low at 20–22°C/km. However, in North Staffordshire the gradient is much higher within the Carboniferous section, at around 37°C/km (Verma, 1981), and this has inspired plans by Keele University to drill a 1200 m borehole into this section with the aim of supplying low-carbon heating for a new sustainable campus development. This geothermal prospect is to be developed in harmony with existing coal bed methane activities on the site. Measurements taken from core and wireline logs in the nearby Permo-Triassic Staffordshire basin indicate the Triassic Sherwood sandstone typically has greater than 20% porosity, while that for the Permian Collyhurst sandstone is more likely to be 10–15% (Plant *et al.*, 1999). The corresponding permeabilities range from a few darcies to a few tens of millidarcies.

Similarly deep basins with thick sequences of Carboniferous strata occur east of the Pennines. The Gainsborough and Widmerepool Troughs have sedimentary infills of 5 km and 4 km, respectively. Successful oil production from these areas (Fraser and Gawthorpe, 1990) has demonstrated the ability of Westphalian and Namurian sandstones to transmit significant quantities of fluids. The Cleveland basin is the onshore extension of the southern North Sea gas province. It contains up to 2·5 km of Permian and younger sediment. It is also a gas province, which indicates that the coal source rocks must once have been buried to 150°C, although inversion of the basin may have induced a temperature reduction. Each of these basins, together with several other smaller ones, remains largely unevaluated from a geothermal perspective, although preliminary work in the 1980s by the British Geological Survey (Hurter and Haenel, 2000; Rollin *et al.*, 1995) suggested that the geothermal resource that they contain could be as much as 300 EJ. To put this in perspective, if fully exploited this could decarbonise the entire UK heating requirement for the next 100 years (the UK uses around 3 EJ per annum, amounting to 38% of total energy requirements).

4.3 Major faults in northern England

Elements of the granite resources at Eastgate and Cornwall are combined with some of the attributes of the deep sedimentary basins of southern and central England in a third category of resource, which is currently being actively explored by deep drilling: major fault planes that delimit the Carboniferous 'block and basin' geology of northern England. A number of powerful lines of evidence suggest that heat generated by the Weardale granite (and other northern English granites such as those of Cumbria and Wensleydale) is transmitted laterally into the surrounding sedimentary strata by groundwater convection, which is particularly focused along the axes of major inactive fault zones. That such convection has occurred for many millions of years is attested, for instance, by the marked zonation of thermal maturity ('rank') of coals in County Durham, with the highest rank coals occurring closest to the buried granite (Johnson, 1995). It is also clear that thermal convection is particularly focused along fault planes: this is manifest in the form of the numerous hydrothermal veins associated with the North Pennine orefield (Dunham, 1990; Kimball *et al.*, 2010), and in the presence of unusual barite cements in sedimentary rocks adjoining the fault planes. For instance, on the coast at Cullercoats Bay (UK grid reference NZ 367 712), east of Newcastle, the Ninety Fathom–Stublick fault zone (NFSFZ) is in contact with Permian Yellow Sands (De Paola *et al.*, 2005). While these are essentially uncemented throughout the rest of their outcrop in north east England, where they adjoin the NFSFZ at Cullercoats they are thoroughly cemented by barite ($BaSO_4$).

It appears that the hydrothermal circulation that gave rise to these barite cements is continuing: warm, barium-rich brines were found in close proximity to the NFSFZ and one of its footwall splays (the Rising Sun fault) in the former North Tyneside collieries of Eccles (near Backworth) and Rising Sun (Wallsend), and their chemistry (Edmunds, 1975) indicates equilibration at high temperatures (150–200°C). The recorded flow rates of the waters were significant and remained steady over many years; the Rising Sun pit registering 1·4 million litres/day and Eccles 0·82 million litres/day (Gray and Judd, 2003). In the case of the Eccles colliery, they were so abundant and persistent that they were processed at industrial scale for their barium content for 43 years until the mine closed in 1978 (Banks *et al.*, 1996).

Taken together, these lines of evidence strongly support the inference that these unusual brines are indicators of the presence of a substantial geothermal resource associated with the NFSFZ, ultimately deriving its heat from the Weardale granite, but transmitted through overlying and adjacent sedimentary strata through permeable sandstones and major faults and splays. This is the basis for the announcement in December 2010 that the deep geothermal challenge fund of DECC has awarded £400 000 to the Newcastle science city consortium, who are providing a further £500 000 to support the drilling of a 2000 m deep borehole in central Newcastle to probe the geothermal potential of NFSFZ footwall strata. Subsequently, the British Geological Survey provided a further £150 000. Drilling of this, still only the tenth deep geothermal borehole ever in the UK, but the third since 2004, commenced in February 2011 and is expected to yield valuable insights into the stratigraphy, structure and geothermal gradient in the area by the end of the summer of 2011. If this exploration borehole is successful, the geothermal resource will be harnessed as part of a site-wide combined heat and power system on the 20 acre Science Central redevelopment site in Newcastle, and possibly also for the adjoining Eldon Square shopping complex, which is the largest city-centre indoor mall in the UK. Furthermore, as the NFSFZ is a major regional structure extending all of the way between Newcastle and Carlisle, success here could well encourage the development of similar systems elsewhere. Furthermore, other major faults with the same west–east orientation as the NFSFZ show similar promise, such as the Butterknowle Lunedale fault which extends between Hartlepool and Appleby, and the Craven faults in the Airedale/Ribblesdale area of Yorkshire and Lancashire.

A key consideration in developing fault-associated geothermal resources is the orientation of both faults and boreholes relative to the prevailing present-day subsurface stress field. While there are abundant data on the principal axes of compressive stress in the North Sea oilfields, such data are scarce for the deep subsurface onshore. Hence one of the tasks in the Science Central borehole project is the use of geophysical logging techniques to infer the principal stress azimuths from patterns of preferential borehole wall expansion (known as 'borehole breakouts'). Armed with this information, it will be possible to design future oriented boreholes to maximise both their own stability and their chances of intersecting open, flowing fractures (Zoback, 2010).

In view of the much-publicised problems associated with deep drilling and reservoir stimulation in a fault zone at Basel in Switzerland on 8 December 2006, which induced an earthquake measuring 3·4 on the Richter scale (Serianex, 2009), it is important to emphasise that these major faults in northern England are inactive, so that their development for deep geothermal energy does not run similar risks. The Basel area is in fact highly prone to earthquakes associated with the ongoing movement of the Alpine frontal thrust zone; as such, there was always a high risk of inducing earthquakes there (Serianex, 2009).

4.4 Scotland and Northern Ireland

Scotland hosts the majority of the UK's radiothermal granite plutons, but has hitherto been considered to have little potential for hot rock geothermal energy (Wheildon *et al.*, 1984). However, a re-evaluation of the evidence presented below suggests that some excellent deep geothermal prospects may indeed exist in the eastern Highlands and Aberdeenshire.

The UK-wide exploration programme for hot rock resources during the 1980s used heat production values determined from whole rock concentrations of uranium, thorium and potassium in granites to identify regions of geothermal potential. Combining these data with geophysical models led to the recognition of the granites in Cornwall, northern England and the eastern Highlands of Scotland as the geological features with greatest potential (Downing and Gray, 1986a). These regions were further investigated for heat flow, although this was generally only possible using relatively shallow ($\leqslant$300 m) boreholes (Wheildon and Rollin, 1986). These investigations led to the conclusion that the Cornish granites represented the best prospect in the UK, with the northern England batholiths also showing considerable promise (which has since been verified by the work at Eastgate; Manning *et al*., 2007; Younger and Manning, 2010).

The disappointing heat flow estimates for the eastern Highlands batholith led to its elimination from further investigations in the 1980s (Barker *et al*., 2000; Downing and Gray, 1986a, 1986b). However, the paradox of relatively low heat flow (*c*. 60–70 mW/m^2) in a high-heat-producing batholith (4–8 μW/m^3) remained unexplained. It was tentatively ascribed to depletion in radiothermal elements with depth and/or reduced heat flow from crustal basement rocks or the mantle. However, detailed scrutiny of these possibilities reveals that they are insufficient to account for such a large discrepancy in heat flow (Stephens, 2011). A more likely explanation is the residual depression of geothermal gradients in the uppermost few hundred metres of the crust due to cooling during periods of glaciations in the Quaternary period (Majorowicz *et al*., 2008). Models of geothermal gradients in deep (>2 km) boreholes in other parts of the northern hemisphere that experienced glaciation suggest that near-surface heat flow estimates may still be depressed by 20 mW/m^2 or more (Majorowicz and Wybraniec, 2010). If heat flow were calculated from much deeper boreholes than those used in the 1980s, it is entirely possible that high heat flows more commensurate with the elevated heat production rates will be found in the granites of the eastern Highlands.

Bearing this in mind, the heat production capacity of the granites of Scotland has been reassessed, using a much larger geochemical database than that used in the studies in the 1980s. The heat production rates of all of the Scottish granites are summarised in Figure 3. This confirms the earlier conclusion that the best prospects are to be found in the geochemically distinct suite of granite plutons of the 'Cairngorm suite' (Stephens and Halliday, 1984) in the eastern Highlands. The Cairngorm suite granites have heat production rates of $6{\cdot}0 \pm 2.2$ μW/m^3 (1σ), which significantly exceed the heat production rates of the granites of Cornwall and northern England (which have means of 4·6 and 4·1 μW/m^3 respectively). In addition, some other plutons, such as some of those in the southern Scotland and the Cromarty suites (Figure 3) including the uranium-rich Helmsdale pluton, also display values in excess of 5 μW/m^3. All other suites appear to have low potential, at least on the basis of heat production.

Re-inclusion of the granites of the eastern Highlands (as well as some in the Cromarty and southern Scotland suites) in the register of deep geothermal prospects represents a substantial increase in the total UK resource base. However, until deep drilling is carried out to confirm greater heat flow at depth, and to assess permeabilities, fracture patterns and other features of importance in geothermal development, they cannot yet be regarded as immediate prospects. A deep borehole to about 2 km in one of the eastern Grampian plutons would provide such information as well as testing the extent to which heat flow in the glaciated regions of the UK has been underestimated owing to transient geothermal gradients.

An intriguing possibility is that some radiothermal plutons may be present in the basement underlying sedimentary basins such as the Midland Valley. This is supported by the discovery of Caledonian-age granitic basement xenoliths in volcanic vents in East Lothian (Badenszki *et al*., 2009). As in the case of Eastgate described above, and indeed the case of the world's largest current engineered geothermal system (in the Cooper basin of south Australia; Wyborn (2010)), this suggests there may be value in a prospecting model in the Midland Valley based on heat derived from highly radiothermal granites buried beneath a thick insulating sedimentary cover.

In Northern Ireland heat production maps indicate that the greatest hot rock potential is associated with the Tertiary-age Mourne Mountains granite complex (Figure 2), which has values ranging between 2 and 5 μW/m^3, significantly greater that the background of less than 2 for the remainder of the province (Pasquali *et al*., 2010).

Scotland has some excellent aquifers either outcropping at the surface or accessed at shallow depths by agricultural boreholes, the best of which are primarily sandstones in various Devonian, Carboniferous, Permian and Triassic formations in the Midland Valley, Borders and the Moray Firth (Robins, 1990). None of these aquifers has yet been demonstrated to have geothermal potential but Upper Devonian sandstones of the Midland Valley probably reach depths in excess of 4 km, and if the near-surface aquifer properties are maintained at depth – as they clearly are in the equivalent strata in the Central Graben of the North Sea (Gluyas *et al*., 2005) – there may well be exploitable hot sedimentary aquifer potential in the region of the Forth Valley. Even better hot aquifer prospects probably exist in the basins of Northern Ireland, in which up to 3000 m of Permo-Triassic sediments have accumulated. Drilling associated with oil and gas exploration provides useful stratigraphic, geothermal and reservoir property constraints, and reservoir modelling has led to the identification of potential geothermal

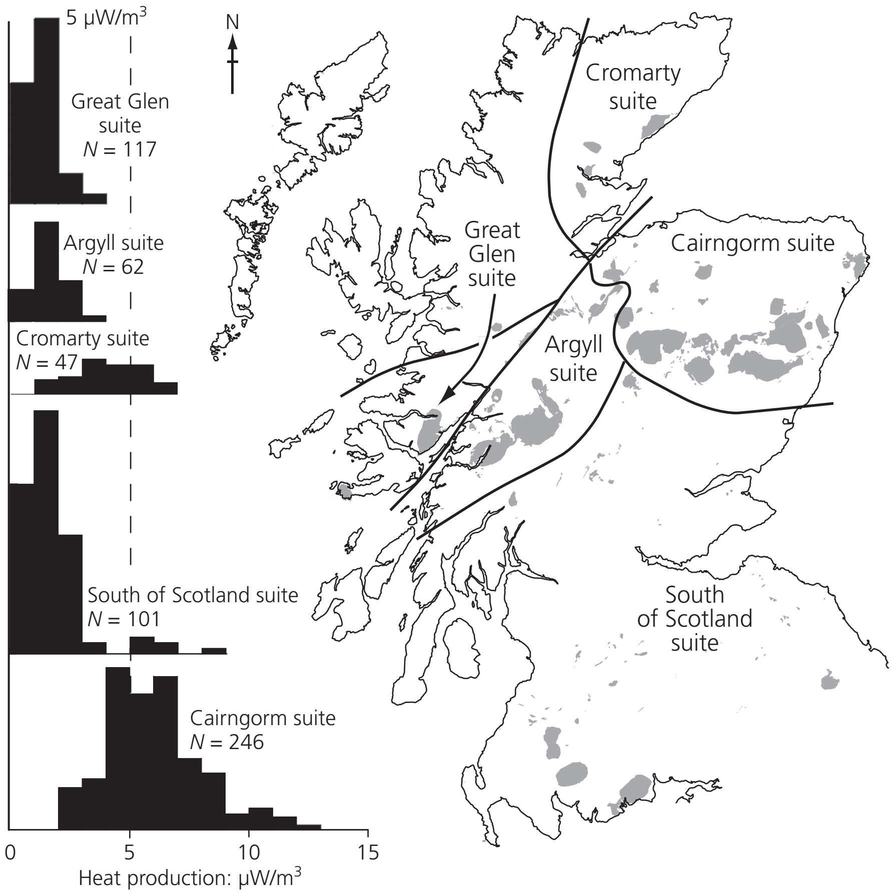

Figure 3. Heat production rates in granite suites of the Caledonian newer granites of Scotland. Suites adapted from Stephens and Halliday (1984). Heat production rates were calculated from whole rock analyses of potassium, uranium and thorium. The dashed line is an arbitrary threshold of 5 μW/m^3, indicating high-heat-producing granites, which are revealed to be particularly common in the Cairngorm suite

targets in Lower Permian sandstones of the Larne, Lough Neagh and Rathlin basins (Pasquali *et al*., 2010). Indeed, a 2880 m deep borehole was drilled at Larne in the 1980s, which demonstrated that these sandstones have better aquifer properties than the local Triassic Sherwood sandstones (lateral equivalents of the strata successfully exploited at Southampton), with temperatures in excess of 85°C recorded at a depth of 2500 m. Preliminary resource assessments (Downing and Gray, 1986b) suggest that exploitable energy in these Lower Permian sandstone reservoirs could range from 380 to as much as 2270 MW_h. Other deep sedimentary strata have recently been targeted by deep drilling by the company G T Energy (2011) near Newcastle, County Dublin (Figure 2). Two boreholes were drilled to 300 m, then a further two to 1400 m, and the company now plans further work on that site to develop a 4 MW_e power plant. G T Energy is also pursuing a possible geothermal development at Ballymeana, not far from the Larne borehole.

4.5 North Sea oilfield brines

The reservoirs from which petroleum is produced in the North Sea typically lie between 2·5 km and 5 km deep (Gluyas and Hichens, 2003). The basins that constitute the North Sea oil province typically have geothermal gradients of about 30°C/km. Thus the temperature of the reservoirs commonly lies between 70°C and 150°C. At these temperatures, produced fluids (oil and brine) have the potential to be used for geothermal power generation and, unlike most other parts of the UK, abundant data exist relating to geothermal gradients, fluid flow rates and sustainability of fluid flow. The first gas field came on stream in 1965 in the southern North Sea; the first oil arrived 10 years later (Abbots, 1991). Most of the large fields are now over 30 years old and well past their prime in terms of oil and/or gas production. Typically the gas fields are produced by primary depletion drive, and water (brine) ingress is avoided as much as possible. Depending upon the specific properties of the field, in terms of the strength of the aquifer and quality of the reservoir, in excess of 90% of the 'in-place' gas can be recovered from the best fields using this method. However, oil fields behave differently and are thus managed differently.

Production of oil from most fields follows two distinct phases. The initial phase is much the same as for gas. Petroleum is produced by simple pressure depletion. This can occur through a variety of natural processes: gas exsolution from the oil, gas cap (expansion) drive, natural aquifer inflow or compaction drive. Typically the pressure is allowed to decline to just above 'bubble point': that is close to, but above, the pressure at which free gas will start to be exsolved in the reservoir itself. If this process is taken too far, breakout of this gas can lead to collapse of the relative permeability to oil, and hence loss of production.

The second phase of production involves the injection of (sea) water at a rate that is commonly similar to the rate at which fluids (oil plus water) are extracted from the field. This so-called 'water flood' does two things: (a) maintains the pressure and (b) sweeps oil from the pore spaces (and hopefully towards the production wells). Essentially the field becomes a large washing machine with the water flood, as it is known, entraining oil and delivering it from injection to production well. As time goes by, the rate of production of water (known as the 'water cut') relative to oil increases. Dependent upon the permeability-architecture of the reservoir relative to the injection and production points, the rate of increase in water cut can be rapid or slow, but inevitably it will increase. After decades of production the quantity of water produced on a daily basis may outstrip oil yield ten or 20-fold. In many instances the residence time of injected water in the oilfield is sufficient that there is no appreciable drop in temperature of the produced water through time. Even at these enormous water cuts the fields can remain economic if the oil price is high enough. However, production costs invariably rise as ever more water needs to be handled, separated from the oil and either reinjected or more commonly treated and discharged to the sea.

The largest cost item in this secondary recovery process is the power required to inject the water at high rates deep on the flanks of the oilfields. The power requirement for a platform, including that needed for water injection, typically totals 10–30 MW (with a large water injection pump alone typically rated at about 4 MW); traditionally this power has been generated by burning some of the gas released from the oil. However, during secondary recovery, these high power demands persist into a period during which the potential for on-board generation is diminishing. With falling oil production, there can come a time when insufficient gas is produced to generate the power required for the platform. At this point the plant will either need to shut down or import gas, diesel or electricity. This may be costly, environmentally undesirable or simply impractical. Such power shortages already affect several areas of the North Sea, none more so than the Brent province (Figure 2) where approximately half of the fields do not now produce sufficient gas to support platform power needs. The Brent province thus currently provides an interesting case study in the possible use of geothermal energy to fill the energy gap.

In energy terms it is possible that the produced hot water could be used partly to power the platform (Adams *et al*., 2010). Moreover, in fields where the produced water is already reinjected, cooler water arising as a by-product of such a process would have increased value for injection, given that cooler waters (a) promote greater thermal fracturing in strata surrounding injection wells and (b) improve the mobility ratio with the oil (as cold water is more viscous than hot water) and hence sweep efficiency. In addition to these direct effects, use of geothermal energy as a replacement for fossil fuels either imported or co-produced will reduce carbon dioxide emissions from the platform.

Based upon current binary cycle power plant technology (DiPippo, 2008; Quolilin and Lemort, 2009) (Figure 1), the present authors calculate that it should be possible to produce 1 MW of electricity from about 50 000 barrels per day, that is 7950 m^3/day of water at 100°C (assuming the cooling water entering the condenser is at about 20°C, and that the plant achieves a lowering of temperature in the oilfield water of 30°C). At lower temperatures the process becomes less efficient, becoming impractical and/or uneconomic as temperatures drop below 70°C (IEA, 2010). It is estimated that a binary plant required to generate 1 MW would occupy about the same volume as a sea-container (i.e. $6 \times 2{\cdot}4 \times 2{\cdot}4$ m), and weigh around 150 t. Given that many of the ageing platforms no longer use or require their drilling rigs, it is quite possible that such new facilities could be readily accommodated on the majority of offshore platforms.

Table 2 shows selected reservoir temperatures and co-produced water pumping rates for selected oilfields in the Brent province. Figure 4 cross plots these data, superimposed on modelled binary plant power outputs, assuming attainment of a 30°C drop in water temperature during passage through the plant. Largest among the fields is Statfjord, which in 2008 produced on average over 680 000 barrels per day (Table 2), and which has a potential geothermal power output in excess of 10 MWe. Similarly, the Ninian field produced over half a million barrels of water per day in 2008, but has a similar geothermal potential

Field	Temperature: °C	Water production: barrels/day	Year
Cormorant N	95	93 945	2008
Cormorant S	107	14 482	2008
Dunbar	128	15 699	2008
Dunlin	99	36 154	2008
Dunlin (peak)	99	146 388	1999
Eider	107	27 971	2008
Eider (peak)	107	86 785	2000
Heather	113	2 628	2008
Heather (peak)	113	21 805	2003
Murchison	110	152 934	2008
Ninian	102	544 054	2008
Statfjord	89	680 977	2008
Tern	93	60 124	2008
Tern (peak)	93	93 705	2005
Thistle	104	58 558	2008
Thistle (peak)	104	92 444	2007

Table 2. Water production rates and temperature data for selected Brent province oilfields (collated from sources given in Abbots (1991) and Gluyas and Hichens (2003))

to Statfjord on account of its higher temperature (Table 2). While water production rates for Statfjord and Ninian are exceptional, most of the power-depleted platforms in the Brent province produce (or at peak rate produced) sufficient hot water to generate between 1 and 3 MWe. In many of these fields, the production of oil (and of course co-produced hot water) is currently declining simply due to paucity of sufficient natural gas to power the 'water flood' injection pumps. Recent experience with the Thistle field (Gluyas and Peters, 2010) has demonstrated that with increased injection of water to support production, oil rates can rise. Thus a restoration of power availability using geothermal energy from produced waste water may help deliver increased oil reserves and field life extension as well as reducing carbon emissions.

5. Conclusions

Until very recently, the UK had been lagging behind other European countries in the practical development of deep geothermal energy, despite the excellent low-carbon credentials and year-round availability of this particular form of renewable energy. Indeed, to date, only one deep borehole has been exploited, at Southampton. However, since 2004 three new, purpose-drilled, deep geothermal boreholes have been drilled

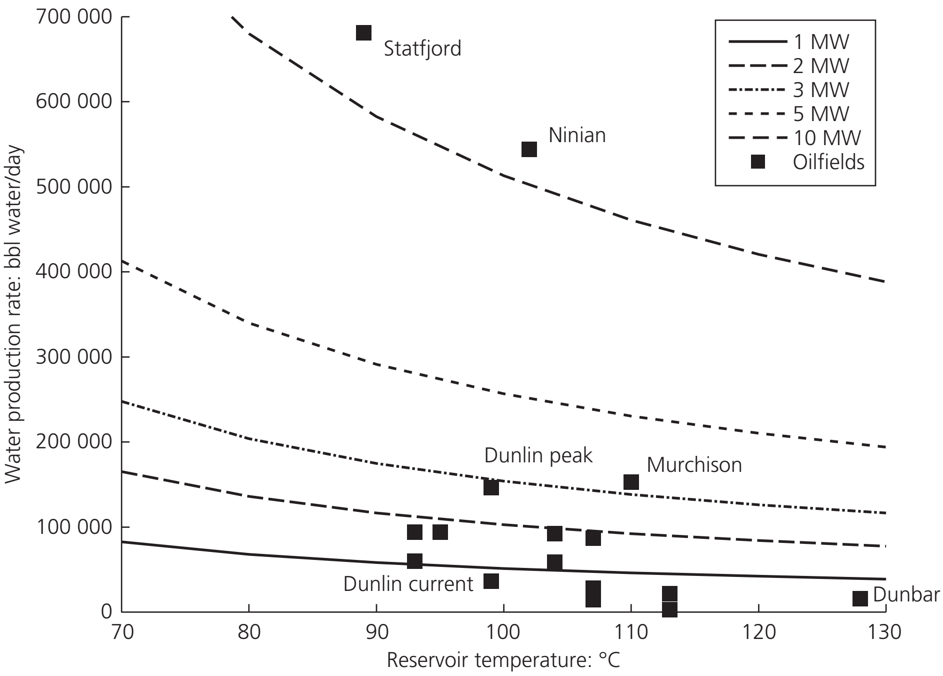

Figure 4. Plots of predicted binary plant power outputs, based on energy extraction equivalent to a 30°C temperature drop for the flow rate and starting temperature indicated, with estimates of potential power production for several Brent province oilfields (production rate data from DECC; temperature data from a range of sources (see Abbots, 1991; Gluyas and Hichens, 2003)). Where two points are joined by a line, this denotes current and peak rates of water production

(all by teams led by the first author): two at Eastgate in County Durham, accessing the Weardale granite, and one in central Newcastle upon Tyne, exploring sedimentary-hosted resources associated with a major inactive geological fault. There are currently plans for deep drilling at three other sites: Keele (in Staffordshire), Redruth and St Austell (both in Cornwall; Figure 2). All four of these recent developments have benefitted from substantial grants from the deep geothermal challenge fund of the UK government's DECC. This public investment has already led to substantial leverage of private investment, with firm plans to develop commercial systems on all sites. Reflecting this growing interest, a parliamentary consensus is now emerging in favour of introducing a deep geothermal licensing system for the UK (Hansard, 2011), similar to that which has long been in force for oil and gas, in which a given licence would cover a geographically delineated area, within which the licensee would have exclusive rights to exploration and production over a specific number of years. The surety such a system would provide would further expedite the raising of private capital to support such investments. Of course technical challenges remain, for instance in relation to

- lowering the costs of deep drilling for geothermal purposes
- identifying new materials and process routes to lower the costs of heat-exchange processes involving highly saline hot groundwaters
- optimal operation of binary power plants
- improving the match between heat demand and supply by, for instance, identifying strategies for retro-fitting district heating solutions in old urban areas.

All of these challenges are being actively addressed at present, not only in the UK but worldwide.

Given all of this, the scene finally seems set for full-scale development of deep geothermal resources in the UK. Deep geothermal energy stands out among many other large-scale renewable energy technologies in that it is independent of the foibles of British weather. Where temperatures sufficient for efficient operation of binary power plants can be obtained (i.e. $\geqslant 120^{\circ}$C), deep geothermal energy offers truly low-carbon baseload power generation. Both in those cases and in the more widespread situations where temperatures of 70°C or more can be accessed, it also offers large loadings of low-carbon heat, which is particularly attractive for industrial applications, and for large buildings that have high heat demands, such as hospitals and shopping centres.

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