A survey of the induced seismic responses to fluid injection in geothermal and CO₂ reservoirs in Europe

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A B S T R A C T

The paper documents 41 European case histories that describe the seismogenic response of crystalline and sedimentary rocks to fluid injection. It is part of an on-going study to identify factors that have a bearing on the seismic hazard associated with fluid injection. The data generally support the view that injection in sedimentary rocks tends to be less seismogenic than in crystalline rocks. In both cases, the presence of faults near the wells that allow pressures to penetrate significant distances vertically and laterally can be expected to increase the risk of producing felt events. All cases of injection into crystalline rocks produce seismic events, albeit usually of non-damaging magnitudes, and all crystalline rock masses were found to be critically stressed, regardless of the strength of their seismogenic responses to injection. Thus, these data suggest that criticality of stress, whilst a necessary condition for producing earthquakes that would disturb (or be felt by) the local population, is not a sufficient condition. The data considered here are not fully consistent with the concept that injection into deeper crystalline formations tends to produce larger magnitude events. The data are too few to evaluate the combined effect of depth and injected fluid volume on the size of the largest events. Injection at sites with low natural seismicity, defined by the expectation that the local peak ground acceleration has less than a 10% chance of exceeding 0.07 g in 50 years, has not produced felt events. Although the database is limited, this suggests that low natural seismicity, corresponding to hazard levels at or below 0.07 g, may be a useful indicator of a low propensity for fluid injection to produce felt or damaging events. However, higher values do not necessarily imply a high propensity.

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1. Introduction

Induced seismicity is recognised as a possible hazard in practically all engineering endeavours where stress or pore pressure in the subsurface is altered. This can be taken as a reflection of the realization that has dawned in the past 20 years that the Earth's crust generally supports high shear stress levels and is often close to failure. Historically, the most damaging events, which have sometimes caused fatalities, are associated with the impoundment of reservoirs (Gupta, 1992). However, earthquakes of a size sufficient to cause damage have also been associated with mining activity (Gibowicz, 1990), long-term fluid withdrawal (Segall, 1989) and fluid injection (Nicholson and Wesson, 1990).

Given that massive fluid injections to stimulate crystalline rocks have routinely been performed during Engineer/Enhanced Geothermal System (EGS) projects – formerly called Hot Dry Rock (HDR) projects – since the early 1970s, it is perhaps surprising that the issue of seismic hazard associated with these operations has only recently come to the fore. This is because the pioneering EGS developments at Fenton Hill (USA), Rosemanowes (UK), Hijiori (Japan) and Soultz (France) (3.5 km reservoir) did not produce events large enough to disturb the local population, whereas more recent attempts to develop systems at 4.5–5.0 km depth at Soultz, Cooper Basin (Australia) and Basel (Switzerland) produced events approaching or exceeding magnitude 3. There are also one or two instances where small but felt events have been associated with the operation of deep (∼3 km) hydrothermal systems.

The recent increase of interest in developing deep geothermal systems and of sequestering large quantities of CO₂ underground makes it desirable to identify factors that influence the different seismogenic responses to fluid injection at various sites. This paper documents the first stage of an on-going study that seeks to determine such factors through examination of incidences where fluid injection has taken place without generating seismic events that were felt by the local population, as well as cases where it has. We make no distinction between induced and triggered seismicity.

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The scope of this study is limited to reporting European case histories of injection-related seismicity, including the project to develop an EGS beneath the city of Basel in 2006. Most, if not all incidences of injection into crystalline rocks are included, regardless of whether events were felt. However, at this stage our coverage of injection into sedimentary rocks is not complete, especially for non-geothermal injections that did not produce felt earthquakes. Two sites where CO2 is injected into sedimentary rock are included. We exclude from consideration other types of induced seismicity associated with such activities as fluid withdrawal, excavation or reservoir impoundment since these may involve somewhat different mechanisms.

The case histories of injections into igneous and sedimentary target rocks are presented in separate sections and are ordered alphabetically according to country. This structuring has the disadvantage that case histories from the same geological province but different countries are not reported contiguous, although the incidences are few. The locations of the sites are shown in Fig. 1, and a summary listing of parameters for the sites is given in Table 1. A rock mass will be referred to as ‘critically stressed’ if the shear stress level it supports would produce failure of an optimally oriented fracture whose strength is described by Coulomb friction criterion with a coefficient 0.65. The maximum and minimum principal horizontal stresses will be denoted by $S_{\text{Hmax}}$ and $S_{\text{Hmin}}$, respectively, and the vertical stress by $S_V$.

For the purpose of comparing the natural seismic activity at a site, we used an index of estimated local seismic hazard which is based on an assessment for all of Europe that conforms to a single standard. This hazard is quantified in Table 1 and Fig. 1 by the peak ground acceleration (PGA) in units of ‘g’, the acceleration of gravity taken from the compilation of Giardini et al. (1999). The value of PGA for a site denotes the acceleration level on stiff soil that has a 10% probability of being exceeded in 50 years (equivalent to a recurrence period of 475 years). Regions of low hazard are characterised by values below 0.08 g, high hazard areas have PGAs above 0.24 g, and moderate hazard regions present intermediate values. It should be emphasised that this value is not necessarily a measure of the seismogenic response of the ground to injection, but rather, is a conveniently available index of natural seismic hazard at a site that is based on the peak earthquake-induced shaking that is likely to occur at the site. Consequently, PGA values will be high for localities with no natural seismicity if it neighbours a region where large events occur. Such situations are noted in the text.

Throughout this report, seismic magnitudes are given as either local magnitude, $M_L$, duration magnitude, $M_D$ or moment-magnitude, $M_W$. Whenever possible, macroseismic intensities are given in terms of the EMS-98 scale (Grünthal et al., 1998) and denoted ‘Io(EMS)’. Most macroseismic intensities given in this paper were derived before EMS-98 was defined. These values are denoted as ‘Io’ and should be broadly consistent with the EMS-98 classification. The most likely difference is that indistinct values such as Io = IV–V or Io = VI–VII would most probably be assessed as Io(EMS) = IV and Io(EMS) = VI respectively in the EMS-98 classification.

2. Geothermal injection case histories: igneous rocks

2.1. France

2.1.1. Le Mayet de Montagne, France

The site is located 25 km south-east of Vichy, France, at the northern fringe of the Massif Central where the granite outcrops. It was established in 1985 as an EGS test site with two boreholes drilled to 800 m depth. The local stress state is characterised as
Table 1
Summary of site and injection parameters and the associated maximum earthquake magnitudes for the cases discussed in the text. The injection parameters refer to the operation (i.e., stimulation or circulation) associated with the largest magnitude event detected.

<table>
<thead>
<tr>
<th>Location/Country</th>
<th>Setting</th>
<th>Depth (km)</th>
<th>Rock</th>
<th>Stress regime</th>
<th>Critical stress?</th>
<th>PGA (%)</th>
<th>Date</th>
<th>Inject. type</th>
<th>Qmax (l/s)</th>
<th>Pw-max (MPa)</th>
<th>Vinjh (m³)</th>
<th>Max M°</th>
<th>Well sep. (km)</th>
<th>Comments</th>
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<td></td>
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<td></td>
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<tr>
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<td>1987</td>
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<td>73</td>
<td>25</td>
<td>200</td>
<td>N-Felt</td>
<td>1.9</td>
<td>Attempted hydrofracture</td>
<td></td>
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<tr>
<td>Soultz/FR</td>
<td>3.5</td>
<td>Granite</td>
<td>SS/NF</td>
<td>Yes</td>
<td>8</td>
<td>1993</td>
<td>Stimulation</td>
<td>38</td>
<td>10</td>
<td>20 × 10³</td>
<td>Initial inj. rate drops from 50 to 10 l/s in hrs.</td>
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<td>Gneiss</td>
<td>SS/NF</td>
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<td>9</td>
<td>2002</td>
<td>Stimulation</td>
<td>50–4</td>
<td>34</td>
<td>5.6 × 10³</td>
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<td></td>
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<tr>
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<td>Gneiss</td>
<td>SS</td>
<td>Yes</td>
<td>6</td>
<td>1994</td>
<td>Inject. test</td>
<td>9</td>
<td>55</td>
<td>200</td>
<td></td>
<td></td>
<td></td>
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<tr>
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<td>Gr/SS/Carb.</td>
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<td>2007</td>
<td>Circulation</td>
<td>70</td>
<td>6.0</td>
<td>Balanced</td>
<td>2.7</td>
<td>1.3</td>
<td>Wells intersect faults. Event after 1.9 yrs.</td>
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<td>45</td>
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<td>14</td>
<td>1997–1999</td>
<td>Circulation</td>
<td>6–21</td>
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<td>Balanced</td>
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<td>Basalt</td>
<td>49</td>
<td>2003</td>
<td>Drill&amp;Stim.</td>
<td>50</td>
<td>1.7</td>
<td>Balanced</td>
<td></td>
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<td>Monte Amani/IT</td>
<td>3.0</td>
<td>Metam.</td>
<td>SS/NF</td>
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<td>19</td>
<td>1969</td>
<td>Circulation</td>
<td>8</td>
<td>200</td>
<td>5.6</td>
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<td>Granite</td>
<td>TF</td>
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<td>3</td>
<td>1989</td>
<td>Stimulation</td>
<td>21</td>
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<td>2006</td>
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<td>30</td>
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<td>Simbach-Brunau/AT</td>
<td>1.9</td>
<td>Carb.</td>
<td>SS/TF</td>
<td>5</td>
<td>2001</td>
<td>Circulation</td>
<td>74</td>
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<td>N-Rep</td>
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<td>Both wells intersect faults</td>
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<td>Altheim/AT</td>
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<td>Carb.</td>
<td>SS/TF</td>
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<td>Circulation</td>
<td>81</td>
<td>&lt;1.7</td>
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<td>N-Rep</td>
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<td>SS/TF</td>
<td>6</td>
<td>1998</td>
<td>Circulation</td>
<td>21</td>
<td>&lt;0.2</td>
<td>Balanced</td>
<td>N-Rep</td>
<td>1.6</td>
<td>Injection well near a fault</td>
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<td>Carb.</td>
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<td>1999</td>
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<td>Thisted/DK</td>
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<td>SS</td>
<td>4</td>
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<td>56</td>
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<td>2</td>
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<td>65</td>
<td>7.0</td>
<td>Balanced</td>
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<td>1.3</td>
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<td>Paris/FR</td>
<td>1.16–1.98</td>
<td>Carb.</td>
<td>4</td>
<td>1971–</td>
<td>Circulation</td>
<td>83</td>
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<td>N-Rep</td>
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<td>2.4</td>
<td>SS</td>
<td>2</td>
<td>1995</td>
<td>Circulation</td>
<td>31</td>
<td>0.8</td>
<td>Balanced</td>
<td>N-Rep</td>
<td>1.5</td>
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<td>Waren/DE</td>
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<td>SS</td>
<td>2</td>
<td>1984</td>
<td>Circulation</td>
<td>14</td>
<td>6.0</td>
<td>Balanced</td>
<td>N-Rep</td>
<td>1.3</td>
<td>P-inject. reduced to 1.6 MPa in 1986</td>
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<td>SS</td>
<td>2</td>
<td>1989</td>
<td>Circulation</td>
<td>28</td>
<td>1.1</td>
<td>Balanced</td>
<td>N-Rep</td>
<td>1.2</td>
<td>Data from stimulation of 2nd well</td>
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<td>SS/Volc.</td>
<td>NF</td>
<td>Yes</td>
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<td>2007</td>
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<td>59</td>
<td>13 × 10³</td>
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<td>SS</td>
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<td>2003</td>
<td>Circulation</td>
<td>50</td>
<td>32</td>
<td>&lt;20 × 10³</td>
<td>Balanced</td>
<td></td>
<td>Injection well intersects minor fault</td>
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<td>Carb.</td>
<td>SS/TF</td>
<td>5</td>
<td>1999</td>
<td>Circulation</td>
<td>45</td>
<td>1.5</td>
<td>90% injected</td>
<td>N-Rep</td>
<td>1.7</td>
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<td>3.4/3.4</td>
<td>Carb.</td>
<td>SS/TF</td>
<td>5</td>
<td>2005</td>
<td>Circulation</td>
<td>32</td>
<td>4.0</td>
<td>Balanced</td>
<td>N-Rep</td>
<td>1.8</td>
<td>Neither well intersects fault</td>
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<td>Carb.</td>
<td>SS/TF</td>
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<td>2004</td>
<td>Circulation</td>
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<td>Carb.</td>
<td>SS/TF</td>
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<td>Circulation</td>
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<td>Balanced</td>
<td>N-Rep</td>
<td>2.4</td>
<td>Both wells intersects faults</td>
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<td>Carb.</td>
<td>SS/TF</td>
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<td>2003</td>
<td>Circulation</td>
<td>100</td>
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<td>SS</td>
<td>7</td>
<td>2008</td>
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<td>24</td>
<td>0.5</td>
<td>Balanced</td>
<td>N-Rep</td>
<td>1.4</td>
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<td>Capacity</td>
<td>Carbonat</td>
<td>Sandstone/Gneiss</td>
<td>Yes/No</td>
<td>Year</td>
<td>Circulation Type</td>
<td>Peak Event</td>
<td>Operational Field</td>
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</tbody>
</table>
| Larderello-Travale/IT | 2.0      | Yes      | SS/NF            | Yes    | 1977 | Injection        | 3.0        | Event near active injection well.
| Latera/IT         | 1.0      | Yes      | SS/NF            | Yes    | 1984 | Injection        | 2.9        | Max. event larger than background.
| Torre Alfina/IT   | 2.0      | Yes      | SS/NF            | Yes    | 1977 | Injection        | 2.0        | Injection into well RC-1.
| Cesano/IT         | 2.0      | Yes      | SS/NF            | Yes    | 1978 | Injection        | 2.0        | In operation since 1992.
| Bialy-Dunajec/PO  | 2.4      | Yes      | SS               | Yes    | 2001 | Circulation     | 3.8k       | System extended in 2004.
| Uniejów/PO        | 2.0      | Yes      | SS               | Yes    | 1977 | Circulation     | 2.0        | Balanced N-Rep 1.2-1.7.
| Riehen/CH         | 1.25/1.55| Yes      | SS               | Yes    | 1989 | Circulation     | 1.2        | Balanced N-Rep ~1.

**CO₂ sequestration: sedimentary rocks**

<table>
<thead>
<tr>
<th>Location</th>
<th>Capacity</th>
<th>Type</th>
<th>Yes/No</th>
<th>Year</th>
<th>Circulation Type</th>
<th>Peak Event</th>
<th>Operational Field</th>
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<td>Ketzin/DE</td>
<td>0.65</td>
<td>SS</td>
<td>Yes</td>
<td>2008</td>
<td>Injection</td>
<td>1.7k</td>
<td>Balanced N-Rep.</td>
</tr>
<tr>
<td>Sleipner/NO-Offshore</td>
<td>0.8–1.1</td>
<td>SS</td>
<td>Yes</td>
<td>1996</td>
<td>Injection</td>
<td>&lt;3.4k</td>
<td>Balanced N-Rep.</td>
</tr>
</tbody>
</table>

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| a | AT: Austria; CH: Switzerland; DE: Germany; DK: Denmark; FR: France; IS: Iceland; IT: Italy; PO: Poland; UK: United Kingdom.  
| b | Where two values are given: the first denotes the depth of the injection well.  
| c | Carb.: carbonate; GR: granite; Meta: metamorphics; SS: sandstones; Volc.: volcanics.  
| d | TF: thrust faulting (i.e. S₁ is vertical); SS: strike-slip (i.e. S₂ is vertical); NF: normal faulting (i.e. S₃ is vertical).  
| e | Peak ground acceleration (% of the acceleration due to gravity (9.81 mm/s²)) with a 10% probability of being exceeded in 50 years as estimated on the basis of natural seismicity. Values of 7 or less denote low hazard: 8–23 moderate hazard: 24–48 denote high hazard: and 49 and greater very high hazard.  
| f | Stimulation: relatively short high-pressure injection to enhance rock mass permeability; Drill: injection during drilling due to fluid losses; Circulation: simultaneous injection and production from doublets or triplets whose flow volumes may or may not be equal. ‘CO₂’: injection of liquid carbon dioxide.  
| g | The injection or circulation parameters reflect peak operational values.  
| h | The fluid volume injected is difficult to estimate for circulations lasting more than a few months. Balanced: injection and production rates are equal.  
| i | N-Rep: No events reported either by local population or a regional/local network. N-Felt: events of uncertain magnitude recorded by a local network but none were felt by the local population.  
| j | Separation at reservoir depth between injection and production wells for circulation operations. No separation is given for single-well injection tests.  
| k | Value indicates estimated downhole injection pressure above the natural formation pressure.  
| l | Flow rates and volumes are specified in terms of mass because the fluid is a gas under formation pressure and temperature conditions.
2.1.2. Soultz-sous-Forêts, France

The Soultz-sous-Forêts site is located in the Upper Rhine Graben (URG), some 40 km NNE of Strasbourg, France (other sites in the URG described in this paper are Bruchsal, Landau, Basel and Riehen). At the Soultz site, the granitic basement lies below 1.4 km of sediments. Graben–parallel faults produce a horst-and-graben structure within the basement. Fracture zones within the basement are high-angle and strike approximately normal to the E–W average minimum stress direction. The magnitude of $S_{\text{min}}$ is about 0.55, which is typical of a graben setting. Thus, the rock mass, and many of the large-scale structures within it, is critically stressed at all reservoir depths (Evans, 2005; Valley, 2007). The region has low-to-moderate seismic hazard (Table 1). In 1954 a series of events with magnitudes up to $M_L$ 4.8 and intensities up to Intensity Io/EMS VI on the European Macroseismic Scale (EMS-98) occurred 10–20 km to the southeast of Soultz towards Seltz/Wissenbourg (Helm, 1996). The hypocentre depth is uncertain although the macroseismic observations suggest several kilometres.

The development of the project site began in 1987 with the drilling of a 2 km deep well to explore the granitic basement below 1.4 km. Subsequently, a doublet system was developed and circulated at 3.0–3.5 km depth in 1992–1997, and a triplet at 4.5–5.0 km depth developed and tested between 1998 and 2009. Long-term circulation of the deep system with power production commenced in 2010 (Genter et al., 2010).

All wells were subjected to massive hydraulic injections of typically 20,000–40,000 m$^3$ at flow rates of 40–80 l/s and pressures that reached the maximum stress value at the reservoir (Cornet et al., 2007). Seismic activity was monitored with downhole and surface networks. Tens of thousands of events associated with each stimulation were recorded by the downhole array. For the reservoir at 3.0–3.5 km depth, the largest event that occurred during the first massive injection into the rock mass in 1993 was assigned a magnitude of $M_L$ 1.7 from the surface array (Helm, 1996) and occurred during the highest-rate injection of 36 l/s. However, a $M_L$ 1.9 occurred some 9 days after shut-in. Neither of these events were felt by site personnel. At Soultz, magnitudes greater than $M_L$ 2.0 can be felt by the nearby population under ideal conditions (N. Cuenot, pers. comm., May 2010). Fluid circulation of the 3.5 km deep system for 4 months in 1997 was balanced (i.e., injection = production), and hence did not involve a component of net injection. No seismicity was detected during this test (Baria et al., 1997).

Stimulation of the wells of the deeper reservoir involved comparable injection volumes to those used in the upper reservoir, and again pressures appear to have been limited near the minimum principal stress level by natural processes (Valley and Evans, 2007). Stimulation of the first well that penetrated the 5 km reservoir, GP2, began in June 2000 with the injection of 22,000 m$^3$ of water at rates of up to 50 l/s. Wellhead pressure rose to 14.5 MPa at shut-in. Some 700 events with magnitudes between $M_L$ 1.0 and 2.5 occurred during injection, but a magnitude $M_L$ 2.6 occurred some 10 days after shut-in (Dorbat et al., 2009). Stimulation of the second deep well, GP3, took place in May 2003 and involved the injection of 34,000 m$^3$ of brine and water into GP3, for the most part at 50 l/s with occasional increases for a few hours of up to 90 l/s which produced the maximum wellhead pressure of 17.9 MPa. Midway through the stimulation, some 3400 m$^3$ of water was simultaneously injected into GP2 for ~40 h at a rate of 20 l/s (Baria et al., 2004). GP2 wellhead pressure rose to 7.9 MPa. Some 200 events with magnitudes between $M_L$ 1.0 and 2.5 occurred during this injection (Charlété et al., 2007). A magnitude $M_L$ 2.9 event occurred 2 days after shut-in, despite an attempt to avoid this by a stepwise injection rate reduction (Baria et al., 2004).

The stimulation of the third deep well, GP4, began in September 2004. Injection rate was maintained at 30 l/s with a few short increases of 2 h duration to 44 l/s. Peak wellhead pressure was 17.5 MPa. The injection was terminated after injecting 9000 m$^3$ due to a pump failure. The stimulation program resumed in February 2005 when a further 12,500 m$^3$ of water was injected at up to 45 l/s and peak wellhead pressures of 18.5 MPa (Dorbat et al., 2009). Some 128 events with magnitudes between $M_L$ 1.0 and 2.7 were recorded during injection, but none larger than $M_L$ 2.0 occurred during shut-in.

Of the three deep Soultz wells, GP3 appeared to be the most prone to produce large events in response to injection. Dorbat et al. (2009) found the $b$-values for the GP2 and GP3 seismicity to be 1.23 and 0.94, respectively (although only over the respective limited magnitude ranges of $M_L$ 1.0–1.9 and 1.0–2.3), and suggested that the difference reflected the activation of a major fracture zone intersecting GP3. In 2005, the 3-well system was subjected to a 6-month close-loop circulation test at 15 l/s using only buoyancy drive to produce from GP2 and GP4. The fluid was injected into GP3 at a wellhead pressure that progressively increased from 4 to 7 MPa. Seismicity began soon after injection commenced, and a total of 32 events exceeding $M_L$ 1.2 were recorded during the entire period, the largest being $M_L$ 2.3.

A 2-month closed-loop circulation test of wells GP2–GP3 was performed in 2008 at 25 l/s using a production pump in GP2. No seismicity was observed for 5 weeks during which time the GP3 injection pressure rose steadily to 6 MPa. Seismicity began once that pressure was exceeded, and included four events having magnitudes in the range $M_L$ 1.3–1.4 (Cuenot et al., 2010).

2.2. Germany

2.2.1. Bad Urach, Germany

The site is located near the centre of a geothermal anomaly in the foothills of the Swabian Alb mountains. The orientation of $S_{\text{max}}$ of N82°E is well defined by breakouts that are observed below 1900 m depth in the wells at the site (Heinemann et al., 1992). The magnitudes of the horizontal principal stresses are not known with confidence, although the frequency of breakouts and their consistent orientation suggests they are significantly different. A ‘hydrofracture’ stress test on a 1 m naturally fractured interval at 3350 m in Urach-3 yielded an instantaneous shut-in pressure (ISIP) of 41–50 MPa (Rummel et al., 1991), implying $S_{\text{min}}$ is about 50–55% of the vertical stress. However, this value is not obviously consistent with the 33 MPa overpressure sustained in the 168 m open-hole.
interval during the hydrotesting phase. The area has moderate natural seismicity. Several events of intensity 10 IV–VI have occurred within 15 km of the site in the past 200 years. However, it lies only 40 km from a region where events of up to M 5.5 have occurred, and hence the PGA takes a relatively high value. In 2002, a seismic network of five 3-component sensors was installed in 250 m deep boreholes to monitor the stimulation of the deepened hole (Schanz et al., 2003).

The HDR project was initiated in 1977 with the drilling of a 3334 m deep borehole, Urach-3, through 1.6 km of sediments into the basement of metamorphic gneisses (Dietrich, 1982). Bottom-hole temperature was 143 °C. Seven inch casing was cemented to 3320 m, leaving 14 m of 8–1/2 in. open hole. Further access to the formation was provided by three 5 m long perforated intervals located 25, 47 and 58 m above the casing shoe. Each interval was subject to series of small-volume (<100 m³) stimulation injections, which included gel and proppant for the perforated intervals, at rates up to 201/s to establish a hydraulic linkage between them. Very high wellhead pressures of up to 66 MPa were required (Schädell and Dietrich, 1982). Post-stimulation interval transmissivities were of the order of 10⁻⁶ m²/s (Stober, 1986) implying an equivalent porous medium (EPM) permeability of 8 × 10⁻¹⁸ m². A circulation loop was established by running a packer on production tubing into the well and setting it below the lowest perforation interval. Most circulation tests involved injection into the rock mass through the three perforated intervals in the annulus and production from the open hole section through the tubing. Fluid losses were low but system impedance was high and increased during the test sequence (e.g. 35 MPa wellhead pressure required to inject at 0.5 l/s in test 22) (Schädell and Dietrich, 1982). No seismic events were felt on-site during the injections (Stober, 2011).

In 1983, the hole was deepened to 3488 m, leaving 168 m of open hole. Initial hydraulic testing of the combined open hole and perforated intervals combined showed that the transmissivity of all intervals had been significantly reduced during the deepening, suggesting mud invasion of the fractures had reduced their permeability (Stober, 1986; Stober and Bucher, 2000). Transmissivity was also pressure-dependent, and markedly increased at wellhead injection pressures above 17 MPa, indicating the onset of fracture dilation. No limiting injection pressure, as might be expected for hydrofracture growth, was reached up to 33 MPa (Stober, 1986).

In 1992, the well was further deepened with a 5–7 1/8 in. bit to 4395 m TVD (true vertical depth) as the first well of an intended doublet. Bottom-hole temperature was 170 °C. Following logging, a drill string was lost in the well (Tenzer et al., 2000). The top lies within the casing at 3234 m and obstructs access to the open hole, although it remains hydraulically open. Injection tests showed similar behaviour to that seen before the latest deepening, with evidence of fracture dilation above 17 MPa and no limiting pressure being reached up to a maximum wellhead pressure attained in the tests of 25 MPa (Stober, 2005). The low-pressure transmissivity was of the order 5 × 10⁻⁷ m²/s, implying an EPM permeability of 9 × 10⁻¹⁸ m².

In September 2002, the 1125 m long open hole together with the perforated intervals was subjected to a large-volume stimulation injection of 5600 m³ of brine and water. The stimulation began with two ~1 h, high-rate injections of heavy brine prepared from high-grade salt. In the second of these, ~150 m³ was injected at 35–40 l/s and a wellhead pressure of 34 MPa, the maximum imposed by casing limitations (Tenzer et al., 2004). The main water stimulation began immediately afterwards at a rate of 50 l/s and a wellhead pressure of 34 MPa, but injection rate had to be progressively reduced to 10 l/s over several hours due to rapidly increasing reservoir impedance. The first seismicity was detected 9 h after the start of operations (Schanz et al., 2003), and was coincident with the injection impedance increase, suggesting that the initial high-rate phase had served to inflate the reservoir created in previous phases of the project. After 5 days, a further slug of brine was injected to achieve higher downhole pressure. Injectivity declined further, necessitating a further reduction in injection rate to 5 l/s and eventually 4 l/s to prevent wellhead pressure exceeding the 34 MPa casing limit (Tenzer et al., 2004). This may have been due to clogging of the flow paths by sediment from the salt used to prepare the brine (U. Schanz, personal comm., April 2011). Injection was paused after 7.4 days and the well vented in two ~4 h relatively high-rate production periods during which fluid volumes of ~210 and ~140 m³ were recovered at rates which declined to 12 and 10 l/s. Each period was followed by a ~4 h period of shut-in (note that the venting rate of 90 l/s reported by Stober (2011) for this phase is in error (1. Stober, personal comm., March 2011)). Wellhead pressure rose within ~2 h to stable levels of 14.7 and 12.3 MPa during the first and second periods respectively. Given the fluid volumes recovered and the low porosity nature of the rock, these observations qualitatively indicate that reservoir overpressures in excess of 10 MPa extended significant distances from the wellbore and were not limited to the near-field. A total of 420 events were detected during the injection. These had moment-magnitudes of ~0.6 to 1.8, and extended more than 500 m from the well (Tenzer et al., 2004).

A step-rate injection test was conducted 2 weeks after the stimulation. A total of ~1200 m³ of water was injected at rates of 2.4 and 1.8 l/s and wellhead pressures of up to 17.0 MPa. Following shut-in, wellhead pressure dropped quickly within a few hours to 13 MPa but then declined more slowly to reach 7.5 MPa after 6 days (Baisch et al., 2004; Schanz et al., 2003). Transmissivity estimates lie in the range 0.5–1.5 × 10⁻⁶ m²/s, only marginally higher than before the stimulation (Stober, 2011). A further set of injections was performed in summer 2003, the largest of which involved the injection over 10 days of ~1950 m³ of water at a rate of 2.1 l/s and wellhead pressure of up to 18.3 MPa. A total of 218 events were detected (Tenzer et al., 2004). The seismic energy release rate continued to increase with pressure once 15 MPa was exceeded (Baisch et al., 2004).

In 2006, drilling of a second borehole, Urach-4, commenced with the intention of forming a doublet. The drilling was stopped at a depth of 2793 m due to budgetary considerations (Stober, 2011). The condition of the wells was evaluated in 2008 with a view to developing a duplet between the 100 m separated wells at ~2500 m depth. Urach-4 could not be logged below 1600 m because of gelled drilling fluid. The costs of cleaning the well were considered prohibitive and so the proposal was abandoned (Cammerer et al., 2009). The lost drill string remains in Urach-3.

2.2.2. KTB borehole, Germany

The 9.1 km deep German Continental Deep Borehole (i.e. the KTB borehole) that penetrates gneisses and amphibolites was completed in 1994 in SE Germany. Natural seismicity at the site is very low. However, it lies just south of a region of moderate natural seismic activity characterised by swarms of events whose intensity rarely exceeds Io V within 30 km of the site. The rocks are in a critical stress state, at least between 3 and 7.5 km depth (Brudy et al., 1997). Shortly after completion, about 200 m³ of brine was injected at up to 91 l/s and 55 MPa wellhead pressure into the 70 m open-hole section at well bottom. Microseismicity was monitored using a temporary surface network of 73 short-period stations augmented by an instrument located at 3.8 km depth in the KTB pilot borehole. A group of 400 events of magnitude less than M 0 extended several hundred metres above the injection interval, and a cluster that included the largest event of M 1.2 occurred at 8.6 km depth (Zoback and Harjes, 1997). A few events were observed as much as 1.5 km above the injection interval.
In 2000, a larger injection of 4000 m³ of water was performed at flow rates of up to 1.2 l/s and wellhead pressures of 30 MPa over 60 days. The injection was monitored by a surface network of 40 3-component stations augmented with a downhole instrument at 3.8 km in the pilot borehole. A total of ~2800 seismic events were located. The vast majority were found to be clustered at 3.3, 5.4, 6.6 km, as well as near the hole bottom at 9.0 km. These depths are believed to reflect points where fluid flow into the rock mass occurred, through casing leaks or open hole. The maximum event magnitude was Ml 0.5 (Raisch and Harjes, 2003). More recently, a 10-month injection test was conducted into the 4.0 km deep pilot hole at a constant rate of ~3 l/s and a wellhead pressure of 9–12 MPa. Some 3000 events were recorded (Shapiro et al., 2006), but they were of lower magnitude than those in the earlier experiments (Kümpel et al., 2006).

2.2.3. Landau, Germany

This dual use (electricity/district heating) project is located in the Upper Rhine Graben some 35 km NE of Soultz (Fig. 1). The injection occurs into both basement and the lowermost units of the sedimentary section, and so this site could equally well be included in Section 3 on sedimentary rock (Schindler et al., 2010). The locality is cut by high-angle faults that strike N–S (Illies and Greiner, 1978), sub-parallel to the NNE–SSW strike of the graben. There is no published stress information for the site. However, given the graben setting, the focal mechanism solutions of local earthquakes and the measured stress state at the Soultz EGS site, it is likely that 3min is oriented E–W to SW–NE, and is substantially less than 5h. The region has low-to-moderate natural seismic activity with historical events that produced maximum intensities of up to Io VII–VIII on the European Macroseismic Scale (EMS–98). An event with an estimated maximum intensity of Io VII occurred some 10 km to the south of Landau, near Kandel in 1903 (Ahorner et al., 1970b). For the Upper Rhine Graben region, a maximum intensity Io (EMS) VII for shallow events corresponds to a magnitude Ml of 4.0–4.5. Macroseismic observations suggest a depth of a few kilometres (Ahorner et al., 1970b). The site borders an oilfield that has produced oil from a formation at 1.1 km depth since 1955 (Doebi, 1968) and continues to do so today. Long-term fluid extraction can be a source of seismicity (Van Eck et al., 2006).

During 2005 and 2006, two boreholes were drilled deviated in opposite E–W directions so as to penetrate faults that cut relatively permeable carbonates and sandstones at the base of the sedimentary section and the uppermost level of the basement at ~3 km depth (Schindler et al., 2010). Well separation at reservoir depth is 1.3 km. The faults are believed to intersect some distance north of the site, and so flow within the reservoir is complex and probably fault-controlled (Baumgärtner et al., 2010b). The injection well, Gt-La2, was subjected to a hydraulic stimulation at rates of up to 190 l/s and wellhead pressures of 13.5 MPa (Hetttamp et al., 2007). There was no felt seismicity associated with this operation (Baumgärtner et al., 2010a). The production well, Gt-La1, did not require hydraulic stimulation because it intersected a highly transmissive fault.

The doublet was tested during 2007, and power production from a 3.8 MW electric ORC plant was demonstrated in November of that year. A balanced circulation rate of ~65 l/s was maintained from February to November 2008, during which time the injection pressure declined from 6.0 to 3.0 MPa (Baumgärtner et al., 2010a). Following the installation of a downhole pump in Gt-La1, circulation at 70 l/s resumed in February and continued until mid-September 2009. Injection pressure during this time steadily increased from 4.0 MPa to almost 5.5 MPa (Baumgärtner et al., 2010a). In February 2008, two small earthquakes with magnitudes of Ml 1.7 and 1.8 were recorded in the area by the Seismological Services of Baden-Württemberg and Rheinland-Pfalz. Another event of Ml 1.7 occurred in the area in October 2008, and three further events of magnitudes Ml 1.6–1.9 were detected in the area on 9 May 2009. Although these events occurred in the area of Landau, their depths were not well constrained. On 15 August 2009, an Ml 2.7 event that was felt by the population of Landau occurred shortly after operation of the system had been halted for maintenance operations. The hypocentre was located by an expert group as lying 1.5–2.0 km north of the plant at a depth of 2.3–3.3 km (Bönnemann et al., 2010). Thus the failure area could lie either in the sediments or the basement or both. A further seven events were recorded on the same day. The plant resumed operation in November 2009 with the maximum injection pressure lowered to 4.5 MPa.

A similar dual use project is being developed about 5 km south of Landau near Insheim. Drilling and initial testing of the second well of the doublet was completed in 2009 (Baumgärtner et al., 2010a). In September 2009 the Seismological Services of Baden-Württemberg and Rheinland-Pfalz recorded five events of magnitude approximately Ml 2.0 within a few kilometres of the site (LED-LGRB, 2010). The relationship of these events to operations at the site is unclear.

2.3. Iceland

Geothermal well injection in Iceland is used both for reservoir stimulation and pressure maintenance or recharge. In most cases, injection takes place at pressures less than several MPa or is gravity-driven since the basalt reservoirs tend to have relatively high natural transmissibility. The reservoirs and hence the injection horizons also tend to be comparatively shallow, the deepest injection well being 2.8 km. Many geothermal areas experience intermittent phases of natural seismic activity that are clearly unrelated to fluid injection or other human activities. Here we describe four sites where the seismic response to injection has been documented.

2.3.1. Krafla

Geothermal power has been generated at Krafla since 1977. A 60 MW power station is located in the Krafla caldera, which was the source of a series of eruptions and intrusions associated with crustal accretion that took place between 1975 and 1984 (Gudmundsson, 2001). The magmatic events were accompanied by considerable seismicity which subsequently declined to low levels. Analysis of focal mechanisms of earthquakes up to magnitude Ml 2.1 occurring 1 year after the termination of the eruptions indicated that a heterogeneous stress field prevailed at that time (Foulger et al., 1989). Some of the events were believed to result from heat-mining operations. In 2004 a passive seismic experiment was performed around the main injection well KG–26 of the high-temperature Krafla-Leir hinduk field, which is located within the caldera, 1 km north of the power station. This well supplies fluid to the lower reservoir at a depth of 2.0–2.1 km (Tang et al., 2005a), and had been used as an injector more-or-less continuously since 2002 at rates of up to 70 l/s and wellhead pressures of 0.3 MPa. In 2004, the rate and wellhead pressure were 45 l/s and 0.1 MPa (A. Gudmundsson, pers. comm., July 2010). The seismic activity and velocity structure (including anisotropy) near the well were monitored for 2 months with two 20-station 3-component arrays (Onacha et al., 2005). During this period, injection into K–26 was halted for 11 days to study the effect on seismicity and velocity structure. An average of four locatable seismic events per day of magnitudes less than Ml 2.0 were detected (Tang et al., 2008). The hypocentres lay between 1 and 3 km depth, and defined a predominantly E–W trend near the well (Kahn, 2008; Tang et al., 2008). Consequently, it is likely the majority of events were associated with injection, although no obvious change in event frequency accompanied the halt in injection (Tang et al., 2005b). However,
shear velocities along local raypaths around the well increased during the halt in injection, implying the closure of fractures that were open during injection (Tang et al., 2005a). This is consistent with the observation of shear-wave velocity anisotropy.

2.3.2. Laugaland

This is a low-temperature field in central N-Iceland where production had resulted in a pressure drop of 3.5 MPa (Axelsson et al., 2000). To recharge the reservoir, 15–20 °C water from the district heating system was injected at rates of 6–21 kg/s and wellhead pressures of up to 2.8 MPa into two deep wells (1.6 and 2.8 km) over a 2-year period. Microseismic activity was monitored throughout the operations by a network with a detection threshold of $M_L \sim 1$, but no events that could be ascribed to the injection were recorded (Axelsson et al., 2000).

2.3.3. Svartsengi

Exploitation of this high-temperature field since 1976 had resulted in a 2 MPa drop in reservoir pressure (Brandsdóttir et al., 2002). In 1984, intermittent injection of 70–80 °C water waste into a 2.0 km deep well commenced with year-averaged rates as high as 55 l/s. A single seismometer installed on site in 1984 failed to detect any events within the field through 2001. The single instrument was supplemented by a 16-instrument array for a 5-month period in 1993 when 217,000 m$^3$ of water was injected at rates up to 301 l/s under gravity, but again no events were recorded (Brandsdóttir et al., 2002).

2.3.4. Hengill

This extensive geothermal area is located at a triple-junction in a volcanically active region. Two geothermal fields lie immediately north and south of the Hengill volcano. The area is characterised by episodes of natural seismic swarm activity, and two $M_l$ 5.0 events occurred in 1998 (Agustsson and Halldorsson, 2005). Consequently, numerous studies have been conducted in the area to assess the seismic hazard (Agustsson and Halldorsson, 2005) and for geothermal exploration purposes (Arnason et al., 2010; Tang et al., 2006). The field to the north, called Nesjavellir, is one of the highest temperature geothermal systems under exploitation in Iceland and has been producing power since 1987 (Arnason et al., 2010). The field to the south, called Helisheidi, is also high-temperature and was explored somewhat later. It began producing power in 2006.

Significant injection-induced microseismicity appears to have occurred during the drilling and stimulation of a 2.8 km deep well HE-8 in the Helisheidi field in 2003 (Bjornsson, 2004). The area within a few kilometres of the well had been microseismically active between 1995 and 1999, possibly associated with activity at Mt. Hengill, but had been largely quiet since then. During drilling, water was lost into the formation at rates of 20–50 l/s, essentially constituting injection (Bjornsson, 2004). Drilling was paused at 2500 m and the hot well stimulated by intermittently injecting cold water at up to 60 l/s for several days. This coincided with the detection by the national seismic network of a series of earthquakes below the well at depths provisionally given in the catalogue as 4–6 km. Shortly after drilling recommenced, another series of events occurred near the well, the largest of which had a magnitude $M_L$ 2.4 and a provisional depth of 7 km. After several months of shut-in, cold water was injected for 15 days at 50 l/s with downhole pressures of 1.7 MPa (Fig. 4 of Bjornsson (2004)). This was accompanied by events with magnitudes in the $M_L$ –0.2–1.2 range at depths between 4 and 6 km.

Similar behaviour was observed during injections into the 2.0 km deep well HE-21 in the same field in February 2006. Following completion, the well had a low injectivity, and was stimulated over a 3 days period by first circulating and then injecting cold water at progressively higher rates and downhole pressures up to 1.8 MPa above the formation pressure (Axelsson et al., 2006). By the end of the operation, some 31 l/s of the fluid entered the formation at a downhole pressure of 1.4 MPa above the formation pressure (Mortensen et al., 2006). During this time, several small events of magnitude up to $M_L$ 2.0 were detected close to the well by the national network of the Icelandic Meteorological Office (Axelsson et al., 2006; Vogfjörd and Hjaltadóttir, 2007). Consequently, two 3-component seismic stations were temporarily installed to improve event detectability and location accuracy (K. Vogfjörd, pers. comm., July 2010). Thermal stimulation operations resumed after 1 week of shut-in with injection for 2 days at 65 l/s and a downhole over-pressure of 3.4 MPa (Mortensen et al., 2006). Most fluid entered the formation through a fracture zone at 1850 m. No events were detected during injection although a few that were too small to locate occurred 1–2 days later (Vogfjörd and Hjaltadóttir, 2007). A few days later, a 2.5 day injection was conducted. The details of this injection are not currently available, although it appears that flow rates were not significantly higher than the earlier injection due to limitation of the water source, which was two nearby groundwater wells. Seismicity began after 24 h of injection and included a $M_L$ 2.7 event. A total of 50 events could be located, the vast majority of which lay between 1.0 and 2.5 km depth and defined a structure that extended from the well towards the northeast (Vogfjörd and Hjaltadóttir, 2007).

The four Icelandic examples above emphasise the importance of stress criticality in injection-induced microseismicity. The Laugaland and Svartsengi reservoirs had suffered pressure depletion, and thus injection would serve to restore the stress-state to pre-exploitation conditions, whereas the Helisheidi and Krafla reservoirs are located in zones which are undergoing, or have recently undergone, tectonic activity, and hence the stress state is more likely to be critical.

2.4. Italy

2.4.1. Monte Amiata area

This area is located at the southern boundary of Tuscany, and contains the Piancastagnaio and Bagnore fields (Billi et al., 1986). Both fields have two reservoirs: a shallow one in evaporites/carbonates at 0.6–1.0 km depth, and a deeper, water-dominated reservoir in the metamorphic basement at 2.5–3.5 km with temperatures of 300–350 °C (Barelli et al., 2010; Bertini et al., 2005). The level of background seismicity at the site is substantial (Batini et al., 1980b, 1990), and tends to mask potential induced events. Studies of historical seismicity since year 1000 AD indicate that a relatively large event occurred in the area that produced intensity IX MCS shaking (Batini et al., 1990). An 8 MWe power plant supplied with fluid from the deeper reservoir was installed at Piancastagnaio in 1969 and was expanded to 88 MWe in the middle-to-late 1990s through the addition of 20 MW plants.

A seismic network of 10 stations was installed at the site in 1982 and operated until 1992 when the network geometry was changed (Moia, 2008). Seismicity is generally shallower than 8 km, and tends to occur in swarms with many small events (Moia, 2008). A magnitude $M_l$ 3.5 event occurred within the reservoir region in 1983 (Moia et al., 1993). However, it could have been a natural event that would have occurred in the absence of injection activity (Batini et al., 1990; Moia et al., 1993). Examination of the INGV (Istituto Nazionale di Geofisica e Vulcanologia) catalogue shows that a further $M_l$ 3.5 (duration magnitude) event occurred within 10 km of Piancastagnaio at a reported depth of 5 km in 2000 (INGV Earthquake Catalogue).

The 88 MWe power plant is still in operation, although expansion is being slowed by environmental concerns unrelated to seismicity (Cappetti et al., 2010).
2.5. Sweden

2.5.1. Fjällbacka, Sweden

This was a shallow (~500 m) facility established on the west coast of Sweden in 1984 to evaluate the Bohus granite as a potential HDR reservoir (Wallroth, 1992; Wallroth et al., 1995). Natural seismicity is low, although the historical record indicates that several events of magnitude approaching Mw 4.0 and intensities up to 10 were obtained within 25 km of the site. The stress regime at reservoir depth is 'thrust', and near-critical in as much as an overpressure of a few MPa above hydrostatic is sufficient to produce shearing of a fracture set (Jupe et al., 1992).

Borehole FjB1 was drilled to about 500 m depth and stimulated with numerous injections culminating with 200 m$^3$ of gel at 21 l/s and 13 MPa wellhead pressure. A 16-station microseismic network was installed that recorded 74 events during the stimulation with magnitudes ranging between M$_L$ ~1.3 and ~0.2 (Elisson et al., 1988).

Subsequently, well FjB3 was drilled through the microseismic cloud about 100 m from FjB1 and stimulated by injecting 36 m$^3$ of gel with proppant at 161 l/s and wellhead pressures of up to 19 MPa. A further 50 events were recorded. The system was circulated for 40 days during 1989 by injecting water at 1.8 l/s into FjB3 and producing FjB1 against a 0.3 MPa back-pressure. Injection pressure at FjB3 rose quickly to 3 MPa within a few hours and then progressively more slowly to reach 5.2 MPa by the end of the test (Elisson et al., 1990). Only 50% of the injected fluid was recovered, the remainder being lost to the formation. Several hundred microseismic events were recorded at distances up to 400 m from the injection point. One was felt on site by the project employees but no complaints were received from the local residents, some of whom lived within 500 m of the site. The event magnitude was not determined because records were clipped (T. Wallroth, pers. comm., May, 2010).

2.6. Switzerland

2.6.1. Basel, Switzerland

The Basel EGS site is located at the southern end of the Upper Rhine Graben, where it meets the fold and thrust belt formed by the Jura mountains. The granitic basement lies under 2.4 km of sediments. The average orientation of S$_{min}$ within the granite section is N144°E ± 14° (Valley and Evans, 2009), and is consistent with that obtained from inversion of focal mechanisms from natural seismicity (Kastrup et al., 2004). A lower bound on the magnitude of S$_{min}$ in the open-hole interval (4629–5000 m) given by 0.69S$_{o}$ is set by the maximum downhole injection pressure of 74 MPa developed during the stimulation injection of well BS-1 (Haering et al., 2008). The magnitude of S$_{max}$ is currently not well constrained. The region is characterised by moderate seismicity, although the city of Basel was severely damaged by a nearby earthquake that occurred in 1356 (Meghraoui et al., 2001). For this reason, the PGA value listed in Table 1 is relatively high.

Borehole BS-1 was drilled to 5 km depth within the city of Basel in 2006 as the first well of an intended doublet. In December 2006, the lowermost 370 m was stimulated by injecting approximately 11,500 m$^3$ of water at rates that were progressively increased from ~1 to 55 l/s over 5 days. Wellhead pressures were restricted to 30 MPa by casing limitations (Haering et al., 2008). Seismic activity accompanying the injection was monitored on a six-sensor network of borehole stations installed at depths of 317–2740 m, as well as surface stations of various networks.

Seismicity began at injection pressures of a few MPa indicating that the rock mass is critically stressed. More than 10,500 events were recorded on the borehole array during the injection phase, with event rate and magnitude increasing with flow rate and pressure. On the fifth day of injection (8 December 2006), a magnitude M$_L$ 2.6 event occurred within the reservoir. Since this exceeded the safety threshold for continued stimulation, the rate was reduced to 30 l/s for 5 h before shutting-in. Two events of magnitude M$_L$ 2.7 and 3.4 occurred during shut-in. Hence, venting was initiated after 5 h of shut-in to reduce the pressure as quickly as possible. In the following days about one-third of the injected water volume was allowed to flow back from the well (Haering et al., 2008). Seismic activity declined rapidly thereafter, although three events with magnitudes exceeding M$_L$ 3.0 occurred 1–2 months after blowoff (Deichmann and Giardini, 2009; Mukuhira et al., 2008). Minor, sporadic microseismic activity is still occurring more than 4 years later.

The hypocentre locations of 195 induced events that occurred since the start of injection, and that were strong enough to be recorded by the surface network of the Swiss Seismological Service, are shown in Fig. 2. The overall hypocentre distribution defines a near-vertical lens-shaped cloud of 1.2 km diameter that strikes NNW–SSE and lies between 4 and 5 km depth. During injection, seismicity migrated away from the borehole, as would be expected for a diffusion-regulated process (see Fig. 6 of (Deichmann and Giardini, 2009)), and step-increases in flow rate/pressure tended to increase event rate (Haering et al., 2008). After shut-in and bleed-off, seismic activity took place mainly at the periphery of the stimulated volume (Deichmann and Giardini, 2009). Fault plane solutions determined for the 28 strongest events are mostly pure strike-slip mechanisms with two pure normal faulting, and one a mixture of the two (Deichmann and Ernst, 2009). These focal mechanisms are largely in accord with the mechanisms of the naturally occurring regional seismicity. However, the strike of the nodal planes of most of the events is oblique to the overall orientation of the seismic cloud. In fact, the focal mechanism of the M$_L$ 3.4 event and its neighbours, together with the alignment of these events, suggest that failure occurred on a NNW–ESE striking, near-vertical plane (Deichmann and Ernst, 2009; Kahn, 2008). This suggests that the internal structure of the stimulated rock volume is composed of a complex network of individual fault segments oriented obliquely to the general trend of the microseismic cloud.

2.7. United Kingdom

2.7.1. Rosemanowes, Cornwall, UK

The Rosemanowes HDR project was active between 1978 and 1991, and culminated in the development and operation of a circulation system at a depth of ~2 km within the Carnmenellis granite, which extends to the ground surface. Seismic activity was monitored throughout operations with a surface network of 3-component accelerometers and occasionally a string of hydrophones at reservoir depth (Batchelor et al., 1983). The stress state is strike-slip and critical, the coefficient of the Coulomb friction strength law required to prevent failure at 2.0 km under ambient conditions being 0.85 (Evans et al., 1992). The area has low natural seismic hazard. The nearest events of note, which include a M$_{L}$ 3.5 event that occurred in 1981, are clustered near the town of Constantine, some 6 km south of the site (Turibitt et al., 1987).

Initially, two wells were drilled to 2050 m and stimulated with a variety of methods, including gel and water injections. For the main water stimulation, the wellhead pressure was 14 MPa and flow rate was 90 l/s. Many tens of thousands of events of magnitude less than M$_L$ 0.16 were detected (derived from a moment of 1.8 × 10$^{19}$ Nm given by Baria et al. (1985)). None were felt by the local population or the on-site project staff (CSM-Report, 1989; Turibitt et al., 1987). The seismic activity preferentially grew downward, which is ascribed to the pore pressure increase required for shear failure decreasing with depth (Pine and Batchelor, 1984).

In 1985, a third well was drilled through the microseismic cloud to 2.65 km depth and stimulated with the injection of 5700 m$^3$
of intermediate-viscosity gel (0.05 Pa s) at rates up to 260 l/s and downhole pressures up to 35 MPa, which is 12.8 MPa above formation pressure (Pine et al., 1987; Parker, 1989). A program of circulation tests that featured a variety of configurations and flow rates commenced in August 1985 and ran until the end of 1989. Fluid losses averaged about 20%, and thus circulation constituted long-term net injection. Losses and seismic activity increased significantly at injection pressures above 10 MPa (about 241 l/s), when downhole pressures approached $S_{\text{min}}$, indicating reservoir growth (Baria and Green, 1990). The largest seismic event that can reasonably be associated with project operations was a magnitude $M_L 2.0$ that occurred in July 1987 and was mildly felt by the local population within a few kilometres of the site (Turkitt et al., 1987). At the time, the injection rate was 33 l/s at 11.1 MPa wellhead pressure, which is somewhat less than the peak rate of 38 l/s at 12 MPa that had been maintained for 2 weeks in April 1986. The event occurred at 3.1 km depth, and reactivated a seismic structure that had been active early in the testing (CSM-Report, 1989). Subsequently, injection rate was lowered to 21 l/s for a long-term, constant-rate test. Another event of $M_L 1.7$ occurred in January 1988, several hundred metres below the earlier event but was not reported as felt (Walker, 1989).

3. Injection case histories: sedimentary rocks

3.1. Austria

3.1.1. Upper Austria (South-German Molasse basin):

The region of Upper Austria within 25 km of the German border is host to a cluster of five doublets that utilise heat from the Malm carbonate aquifer. These are Simbach-Braunau, Altheim, Geinberg, Oberndorf, and St. Martin (Goldbrunner et al., 2007). Here we describe the first three of these sites. The only available stress information in the area comes from a short (11 m) drilling-induced tension fracture imaged in a well at the Simbach-Braunau site which indicates an $S_{\text{max}}$ orientation that is consistent with the N–S regional stress trend (Reinecker et al., 2010). Stress magnitudes are uncertain. The area has low natural seismicity, although three events of $M_L 2.0$ and 3.0 and intensity Io V have occurred within 30 km of the sites.

3.1.1.1. Simbach-Braunau. This dual use doublet is constructed on the border between Germany and Austria and provides district heating to communities in both countries. Although the plant itself is in Germany, it is included here under Austria because it shares a similar geologic setting as the neighboring plants in Upper Austria. The injection well, Simbach-Braunau Thermal 1, was drilled vertical to 1848 m in 1999 and completed with 113 m of 8–1/2 in. open hole in heavily fractured and karstified Malm which contains a fault (Goldbrunner, 2005b; Unger and Risch, 2001). The Malm at this site is separated from basement by 100 m of the Dogger formation. Formation pressure is artesian with a shut-in wellhead pressure of 0.23 MPa. The well is highly productive and yields 801 l/s on artesian flow with the choke fully open. The down-hole pressure change on artesian flow was only 0.06 MPa implying a transmissivity of 0.04 m²/s (Goldbrunner, 2007). The production well, Simbach-Braunau Thermal 2, was drilled from the same pad and deviated to reach the Malm some 2100 m from the first well at a vertical depth of 1942 m (3203 m MD). The well targeted a small-offset fault in the Malm (Goldbrunner, 2005c) and was completed as 6–1/2 in. open hole (Goldbrunner, 2007). The system was commissioned in 2001 and operated with a submersible pump in Thermal 2 that produced 741 l/s at 80 °C. The water was injected into Thermal 1 at 55 °C. Given the high transmissivity, it is unlikely that the pressure increase in the reservoir during the injection exceeded 0.1 MPa. A 200 kW ORC unit was added in 2009 that produced 150 kW net (Goldbrunner, 2010).

3.1.1.2. Altheim. The site lies 15 km east of Simbach-Braunau. Development began in 1989 when the first well, Altheim Thermal 1, was drilled vertical to 2472 m and reached basement near a fault (Pernerker, 1996). The fractured Malm extended between 2147 and 2429 m, and was found to directly overlie the basement. The reservoir pressure was artesian and the well flowed at 11 l/s with fully open choke. Owing to clogging and ensuing technical difficulties, it was necessary to drill a side-track, Thermal 1a, from 1772 to 2300 m TVD. This was 20 m closer to a fault where the rock was
more fractured, which resulted in a higher artesian-flow of 181 l/s. This increased to 46 l/s after acid stimulation (Goldbrunner, 2005b). The well was operated under artesian drive and supplied a district heating system from 1991 to 1998 (Goldbrunner, 2005c). Thereafter it was decided to counter declining reservoir pressure by injecting the spent fluid. In 1997 the injection well was drilled deviated to a vertical depth of 2165 m (3078 m MD). Very high permeabilities were encountered on entering the Malm, possibly indicating that a fault had been intersected (Perneckar and Uhlig, 2002). Well separation at the top of the Malm is 1600 m (Goldbrunner, 2005b). In 2000, the production flow rate was increased to the operating level of 81 l/s using a submersible electric pump in Altheim Thermal 1a, and a 500 kW ORC unit was installed. The fluid is produced at 105 °C and reinjected into Thermal 2 at 70 °C and 1.7 MPa wellhead pressure (Goldbrunner, 2005b). The system supplies 10 MWt during the winter months and generates electricity during the summer.

3.1.1.3. Geinberg (Austria): This dual use project is located 5 km ENE of Altheim and has a developmental history similar to its neighbour. The first well was a vertical hydrocarbon exploration hole drilled in 1976 that entered Malm at 2127 m, near a fault (Goldbrunner, 1999b), but was terminated at 2166 m due to excessive mud losses. The well was reopened and successfully deepened to 2180 m in 1978 and became Geinberg Thermal 1 (Goldbrunner, 2005b). The well produced 22 l/s of fluid at more than 100 °C under artesian drive and thereafter supplied a small district heating system. The system was extended to a doublet in 1998 by drilling Geinberg Thermal 2, partly to counter declining reservoir pressure. This was deviated to reach Malm at a vertical depth of 2225 m and a distance of 1600 m from the first well (Goldbrunner, 1999). The well was completed with 276 m of open hole, mostly in Malm, and after an acid stimulation the productivity index was 1.0 l/s/MPa (Goldbrunner, 1999). An injectivity test of Geinberg Thermal 1 using hot water produced from Thermal 2 showed that 30 l/s could be injected at 0.2 MPa (Goldbrunner, 1999). The doublet system has been in operation since late 1998, with 25 l/s produced from Thermal 2 at 105 °C under buoyancy drive (Karytsas et al., 2009), and 21 l/s injected into Thermal 1 at 30 °C under gravity drive (Goldbrunner, 2005b).

3.1.2. Bad Blumau (Styrian basin of south-east Austria): This multiple use doublet is located some 50 km east of Graz and exploits heat from Paleozoic dolomites at a depth of ~2.5 km. There are no published stress measurements within 45 km of the site. Whilst seismic hazard is low, two events of intensity I-VI are reported to have occurred within 40 km in the past 159 years (Grüenthal et al., 2009).

The injection well, Blumau 1a, was drilled as a steeply inclined side-track from a hydrocarbon exploration well in 1995. It runs approximately parallel to and within 180 m of a WSW–ENE trending growth fault with more than 1 km of throw (Goldbrunner, 2005a) and is completed in heavily fractured dolomites that are encountered at 2583 m TVD. These lie above phyllites that overlie basement rocks (Goldbrunner, 1999). The production well, Blumau 2, was drilled vertical to 2843 m and completed with 475 m open hole in the fractured dolomites. The open-hole section lies between two faults that cut the wellbore. Well separation at reservoir depth is ~1800 m (Goldbrunner, 2005a). Pumping tests in one well produce perturbations in the other and imply a far-field transmissivity of 5 × 10⁻⁵ m²/s (Goldbrunner, 1999). Near-well transmissivities are much higher, thanks in part to an acid stimulation, and production flow rates of up to ~80 l/s were obtained during tests (Goldbrunner, 1999). The water is rich in CO₂, which aids ‘artesian’ production through the gas-lift effect.

The system began operation for heating usage in 1999 at a flow rate of 30 l/s. Water is produced from Blumau 2 under artesian flow at a temperature of 110 °C. Almost all of the produced water is injected into Blumau 1 at 50 °C or slightly greater temperature yielding 7.6 MWt (Goldbrunner, 2005a). Injection pressure at the wellhead is less than 0.7 MPa (Goldbrunner, 2005b). Electricity generation began in 2001 using a 250 kW ORC unit (Legmann, 2003) to produce 180 kWhe net (Goldbrunner, 2005a). The heating power then dropped to 5.1 MWt.

3.2. Denmark

3.2.1. Thisted: This district heating project is located in NW Jutland in the Danish basin. It exploits heat from the Upper Triassic Gassum sandstone aquifer at 1.25 km depth that has a transmissibility of 10⁻³ m³ (Mahler, 1995). A large salt diapir structure exists immediately to the NNW of the site (Mahler and Magtengaard, 2005), and so it is possible that the sedimentary section is hydraulically decoupled from the basement. Unpublished analyses of borehole breakouts in the injection well for the interval 804–1014 m reported in the World Stress Map database (Heidbach et al., 2010) indicate a mean Ŝₘ∥ orientation of N77°E. Natural seismicity at the site is low. Only two documented historical events of estimated intensities to VI are recognised within 50 km, the nearest being 13 km away (Grüenthal et al., 2009).

The project began in 1984 with the drilling of a 3287 m deep vertical exploration well, Thisted-2, which was plugged back to 1273 m and a ~37 m screen installed for production. The injection well of the doublet, Thisted-3, was drilled vertical to 1242 m and the lowermost 50 m screened (Mahler, 1995). Well separation is 1.5 km (Mahler and Magtengaard, 2005). The system was initially circulated at 101 l/s (Mahler and Magtengaard, 2010). In 1988, following an improvement in the surface plant, the circulation rate was increased to 41 l/s, yielding a total power of 4 MWt. The system was further upgraded to 7 MWt in 2001 by increasing the circulation rate to 56 l/s. The water is produced at 44 °C and cooled to 11 °C before injection at a pressure of 1.7 MPa (Mahler and Magtengaard, 2005).

3.2.2. Margrethelholm (Copenhagen): The project supplies a district heating system from a doublet completed in the Bunter formation at 2.5 km depth. No salt deposits are present between the Bunter and the Precambrian basement (Dong E&P, 2004). The natural seismicity in the area is low. Only three events with intensity I-VI are recognised as occurring within 50 km of the site since the 17th century (Grüenthal et al., 2009).

The first exploration well of this project, Margrethelholm-1, was drilled vertically to basement at 2677 m in 2002. Testing showed the Bunter formation at 2.5–2.6 km had a productivity of 22 l/s/MPa and was suitable for reservoir development (Mahler and Magtengaard, 2005). A second well, Margrethelholm-2, was deviation drilled to 2745 m TVD in 2003 from the same pad so that well separation at reservoir depth was 1.3 km. Testing showed a productivity of 17 l/s/MPa and communication with the first well (Mahler and Magtengaard, 2010). The system began operation in late 2004. Water is pumped to surface at 65 l/s and 1.0–1.5 MPa by a downhole pump (700 kW) at 650 m depth. It is cooled to 17 °C before being injected at pressures up to 7.0 MPa (Mahler and Magtengaard, 2010).

3.3. France

3.3.1. Paris basin (Paris): Exploitation of heat from carbonate units beneath Paris for space heating began in the early 1970s and the system now is second only to Reykjavik (Iceland) in terms of size. The primary reservoir
is the mid-Jurassic Dogger aquifer composed of oolitic limestone. This is exploited over a large part of the eastern Paris region, at depths and temperatures ranging from 1450 to 2000 m and 56 to 80 °C respectively (Ungemach and Antics, 2006; Ungemach et al., 2005). Fifty-five doublets or triplets have been drilled of which 34 are currently active (Lopez et al., 2010). The sedimentary section in the area is cut by N–S oriented normal faults (Cornet and Burlet, 1992). There are no reported stress measurements in the area. The regional stress state is characterised by normal-to-strike-slip faulting with mean $S_{\text{max}}$ oriented approximately N145°-150° E (Cornet and Burlet, 1992; Vidal-Gilbert et al., 2009). Natural seismicity in the region is very low with no earthquakes reported within 50 km of the centre of Paris.

Most well trajectories are deviated from a single drilling pad and have reservoir separations of about 1200 m (Ungemach and Antics, 2006). The average flow rates are 38–97 l/s, although operation of most sites follows a seasonal cycle with peak flow rates in the winter (Lopez et al., 2010). Corresponding injection pressures usually range between 2.0 and 3.0 MPa with a maximum of 4.0 MPa at two sites (P. Ungemach, pers. comm., Oct 2010).

3.4. Germany

3.4.1. North-German Basin

There are several projects in this basin that mostly exploit medium-enthalpy geothermal resources hosted in clastic formations.

3.4.1.1. Neustadt-Gleve/Waren/Neubrandenburg: These plants are located in the northeast of Germany and extract heat from the high-porosity Rhätkeuper (Triassic) and Hettang (Jurassic) sandstone aquifers at depths of 1.0–2.5 km. They were developed in the 1980s and were the first geothermal doublets in Germany (Seibt and Kellner, 2003). Throughout the area, the sandstone aquifers are underlain by evaporites that include the extensive, thick salt deposits of the Zechstein (Permian) (Seibt et al., 2005). The salt may hydraulically isolate and mechanically decouple the units of the overlying section from the basement. Regional stress data from formations below the salt indicate an approximately north–south orientation for $S_{\text{max}}$ and high deviatoric stress (Röckel and Lempp, 2003). The stress state in the overlying strata shows greater heterogeneity (Röckel and Lempp, 2003). The natural seismicity in the region is low with no recognized events located within 40 km of any of the sites (Leydecker, 2009).

Neustadt-Gleve is the deepest and most westerly of the projects. It utilises the 40–60 m thick Contorta sandstone aquifer that has a porosity of 0.20–0.23 and a permeability of 0.5–1.0 × 10⁻¹² m² (Seibt et al., 2005). The fluid is produced at 99 °C from the 2455 m deep well NG-1 and injected at 60 °C into the 2335 m deep well NG-2, which is separated by 1500 m from NG-1. The static fluid levels in the wells are about 125 m below ground level (Poppei et al., 2000). Acid and hydraulic stimulations were conducted on NG-2 in 1993, but details of the treatments could not be located (Heederick, 1997). The system began supplying up to 6 MWt to the district heating system in 1995 and a 210 kW elec ORC generator was installed in 2003. The initial flow rate of 31 l/s could be injected with a downhole overpressure of 0.5 MPa (Seibt and Wolfgramm, 2008). However, occasional decreases in injectivity due to mineral precipitation and particle clogging led to temporary increases to 0.8 MPa. These increases could be remedied with soft acidization treatments, implying the increased impedance was localised near the well. Thus it is probable that the formation pressures in the aquifer beyond the immediate vicinity of the well were unaffected.

Waren began supplying a district heating system in 1984, and was the first operational geothermal plant in Germany. The initial configuration produced water from Contorta sandstone at 1560 m depth (reservoir temperature of 62 °C). The water was injected into the Aalen sandstone at 1160 m depth through a well only 50 m distant (Kabus and Jäntsch, 1995). The system was circulated at 14 l/s using a submersible pump. The wellhead pressure at the injection well reached 5 MPa (U. Reimer, pers. comm., Sept. 2010). In 1986 a second injection well was drilled to 1580 m at a distance of 1.3 km from the production well, and was screened in the Hettangian sandstone, which lies just above the Contorta. Thereafter, the flow rate could be increased to 17 l/s (Kabus and Jäntsch, 1995). Production temperature is 62 °C and injection temperature is no less than 45 °C (U. Reimer, pers. comm., Sept. 2010). Injection takes place under gravity drive. As the static water level in the injection well is 110 m below ground level, the downhole pressure change under injection is less than 1.1 MPa (U. Reimer, pers. comm., Sept. 2010).

Neubrandenburg is the most easterly and shallowest of the projects. In 1985 four boreholes were drilled to make two doublets accessing the Hettang and Postera sandstones, which are sandstone units above and below the Contorta respectively. The Postera pair were N1 (production at 1250 m) and N3 (injection at 1250 m) wells, and the Hettang pair were N2 (production) and N4 (injection at 1120 m) wells. The two injection wells were 5 m apart and had a static water level of ~62 m (U. Richlak, pers. comm., Sept 2010). The Hettang production well N2 had technical problems. Thus, between 1989 and 2001 the system was circulated at 19 l/s with production from well N1 (Postera) and injection to the 1.2 km distant well pair N3 (Postera) and N4 (Hettang) at 0.5 MPa wellhead pressures (U. Richlak, pers. comm., Sept. 2010), implying a downhole overpressure of 1.1 MPa. Production temperature was 54 °C.

In 2001, the system was reconfigured to allow waste-heat from gas-turbine electricity production in summer to be stored in the Postera reservoir and reused in the winter. Borehole N4 (Hettang-injection) was deepened to reach the Postera, and the existing Postera injection well N3, was back-filled leaving a doublet (N1–N4) accessing the Postera. Operation of the thermal storage system began in April 2004. In summer, water is produced from N4 at 28 l/s and 54 °C, heated to 80 °C with waste-heat from a gas-turbine generator, and the water injected into N1. In winter the flow is reversed with production from N1 at 28 l/s and 70–80 °C, and injection into N4 at ~45 °C (Seibt et al., 2010). Wellhead injection pressures are always less than 0.5 MPa implying a 1.1 MPa downhole overpressure (U. Richlak, pers. comm., Sept. 2010).

3.4.1.2. Gross Schönebeck: This pilot project located north of Berlin is designed to evaluate the possibility of using the EGS concept to extract heat from low-permeability sedimentary rocks. The reservoir rocks are the sandstones and conglomerates of the Rotliegend formation and the volcanic rocks of the uppermost Carboniferous, all of which lie below the Zechstein salt layer. Hydraulic tests indicate a $S_{\text{min}}/S_{\text{v}}$ ratio of 0.52 in the sandstones at 4150 m depth (Huenges et al., 2006), indicating that the stress state is critical (Moeck et al., 2008). $S_{\text{max}}$ is oriented N18° E (Zimmermann et al., 2008). Natural seismicity in the area is low, the closest event being a M 2.7 event at a distance of 50 km that occurred in 1736 (Leydecker, 2009).

The largest volume injection tests were performed in 2003, after the first well (E GrSk3/90) was deepened to 4309 m. Some 10,000 m³ of water was injected at rates up to 80 l/s and downhole pressures that exceeded $S_{\text{min}}$ by up to ~5 MPa. Most fluid entered the volcanics below the sandstones. A surface seismic network consisting of six 3-component stations in shallow boreholes was operational at the site during the injections, but detected no events attributable to fluid injection (M. Weber, pers. comm., Oct. 2010). Subsequently, a second well (Gt GrSk4/05) was drilled and stimulation injections performed in the same formations, the largest involving the injection of 13,000 m³ of water and propellant into the volcanic unit at rates of up to 150 l/s and wellhead pressures of
59 MPa (Zimmermann et al., 2008). Such volumes and flow rates are comparable to those used in the hydraulic stimulation of crystalline reservoirs. Seismic activity was monitored by the surface network augmented by a downhole 3-component sensor placed at 3800 m depth in the first borehole. Only 70 events with magnitudes in the range Ml = 1.3 to 1.5 were detected, and then only by the downhole sensor (Kwiatkiewicz et al., 2008). This low level of activity despite the injection of large volumes at high pressure is consistent with the growth of hydrofractures within the reservoir.

3.4.1.3. Ketzin, Germany (CO2 injection): This CO2 injection test site is located 40 km west of Berlin and is designed to monitor the behaviour of CO2 injected into the Triassic Stuttgart formation. Natural seismicity is very low, the nearest historical events of intensity Io IV or greater being more than 100 km distant. The reservoir is an 80 m thick fluvial sandstone saline aquifer that has its top at 630 m depth. It is highly heterogeneous, with porosities in the range 0.05–0.35 (Norden et al., 2010), and permeabilities of 0.05–1.0 × 10⁻¹² m² (Würdemann et al., 2010). The static formation pressure is 6.3 MPa at 642 m, and the temperature is 35 °C (Wiese et al., 2010). Thus, the CO2 is a gas under formation PT conditions. The caprock consists of fine-grained, clay-rich clastic sediments of the Weser Formation. Further containment is provided by the Rupelian mudstone which served as the caprock to a gas storage reservoir at depths of 250–400 m that was seasonally operated from 1960s until 2000 (Juhlin et al., 2007). There are no faults within the CO2 reservoir (Juhlin et al., 2007).

The reservoir is penetrated by three vertical wells drilled in 2007: one 750 m deep injection well (Ktz-201); and two 800 m deep monitoring wells (Ktz-200 and Ktz-202) located 50 and 100 m from the injector in orthogonal directions (Prevedel et al., 2008). All three wells are instrumented with fibre-optic cables for distributed temperature sensing and supporting pointwise temperature and pressure measurements, and a 15 electrode vertical resistivity array (Prevedel et al., 2008). The CO2 is injected through screens at a depth of 650 m. CO2 injection commenced in June 2008 at a rate of about 2 ton/h which was gradually increased to 3 ton/h over 9 months. Pressure at the formation depth increased steadily to 8.1 MPa after 1 year, which is 1.7 MPa above the formation pressure (Würdemann et al., 2010). A seismic network has been operational at the site since September 2009. No seismic events have been felt at the site (S. Lüth, pers. comm., March 2011).

3.4.1.4. Horstberg. This is a geothermal pilot facility designed to evaluate the possibility of using single wells to extract heat from sediments in the North-German Basin (Wessling et al., 2009). The site is located north of Hannover, and the target production formations are low-permeability sandstone beds within the Buntsandstein unit that lies above the Zechstein salt beds at about 4000 m depth (Orzol et al., 2005). Natural seismicity in the region is low, although a very rare event of magnitude Ml 4.0 occurred near Soltau, some 26 km from the site in 1997 (Leydecker, 2009).

Massive water stimulations were performed through perforations into several sandstone beds in 2003–2004. These injections involved volumes of up to 20,000 m³ and rates of 501/s. Wellhead injection pressures of up to 32 MPa were higher than expected on the basis of other injection operations in the area, possibly reflecting stress heterogeneity in the formations above the salt beds due to doming (Jung et al., 2005). Fluid from post-stimulation production tests was injected into the Kalkarenit formation at 1200 m depth, which is a karstic carbonate aquifer. The operations were monitored by an 8-station seismic array of 3-component sensors with a detection threshold of magnitude Ml 0. Only seven events were detected, and all were too small to be located.

3.4.2. South German–Austrian Molasse basin

This basin is host to numerous medium-enthalpy (100–140 °C) geothermal projects. Most are centred on the Munich area (Schubert et al., 2007; Schulz et al., 2007), the remainder being distributed over a wide area that extends into Austria (see Section 3.1.1) (Goldbrunner et al., 2007). The majority of projects target the high-transmissibility zones within the Malm carbonate aquifer, which may be either karstic or fault-related, and many are doublets that involve injection. Productivities are high, and injection and production pressures are typically less than a few MPa (Schulz et al., 2007). Stimulation operations tend to use acid rather than high-rate hydraulic injections. For doublets, the production and injection points within the Malm are two or more kilometres apart, and thus the flow field between the wells within the reservoir can be complex, and may involve faults.

3.4.2.1. Straubling:. This site lies on the Danube some 10 km south of the Danube fault and 100 km northeast of Munich. It was one of the first doublets to become operational in the basin. The nearest stress measurement in the World Stress Map (WSM) database lies 60 km to the south and indicates a NS-orientation for Șimax (Reinecker et al., 2008). The area has low natural seismicity, nearest documented earthquake is located at a distance of 33 km and had an intensity Io V (Leydecker, 2009). The production well, Thermo I, was drilled vertical to 824 m depth in 1990 and entered fractured and karstic Malm at 708 m. The well was artesian with a static wellhead pressure of 0.41 MPa (Goldbrunner, 2007) and produced 29 l/s of water at 37 °C on unchoked flow. The second borehole, Thermo II, was drilled vertical to 885 m depth at a distance of 1680 m NNW of Thermo I and penetrated Malm at 715 m, Dogger-age sandstone and clay (Opalinus) at 842 m and crystalline basement at 863 m. Most of the discharge during drilling came from the Dogger sandstone. Static wellhead pressure was 0.5 MPa. A production test with a downhole pump yielded 39 l/s with the water level at 203 m (productivity of ~15 l/s/MPa), but only 5 l/s could be injected at 2.0 MPa wellhead pressure (injection of 3.3 l/s/MPa) (Goldbrunner, 2007). To improve injectivity, the 9–5/8 in. well was plugged at 600 m, and an 8–1/2 in. diameter side-track was drilled towards a fracture zone that lay to the East. The casing shoe was set when the Malm was reached at 721.8 m TVD, and the hole continued as a 6 in. with a sail angle of 77° to produce 339 m of open hole in the Malm (Goldbrunner, 2007). The initially poor injectivity was significantly improved by an acidization treatment with injection at 22 l/s at up to 5.0 MPa. Venting produced significant quantities of clastic material, presumably from the natural fractures that intersected the well. Following the treatment, 45 l/s could be injected at a wellhead pressure of 1.9 MPa (injection of 321 l/s/MPa). The system was commissioned in 1999 and operated with 21 l/s of water produced from Thermo I at 36 °C and 19 l/s injected into Thermo II at 12 °C yielding 1.9 MWt for district heating. Later, the production flow rate was increased to 45 l/s of which 40 l/s was injected at 14 °C at a wellhead pressure of 1.8 MPa. There are no reports of felt seismicity associated with this site during its 12 years of operation.

3.4.2.2. Munich area:. In the Munich area, the top of the Malm top deepens from 1.6 km in the north to 3.5 km in the south, and the unit directly overlies the crystalline basement. The stress state in the Malm is strike-slip/thrust with Șimax oriented approximately N–S (Reinecker et al., 2010). No natural seismicity has been recorded within 40 km of Munich since records began to be kept in the 19th century. Formation pressure in the Malm is sub-hydrostatic, the equilibrium water levels in the wells declining from 85 m below ground surface in the north to 250 m in the south. Since transmissibilities tend to be relatively high, the pressure increase above formation pressure in the injection wells at reservoir depth is in
all cases less than 5.0 MPa under operational conditions (T. Fritzer, personal comm. December 2009).

The construction of doublets in the Munich area began in 2003 with the commissioning of the system at Unterschleissheim which was soon followed by doublet systems at Riem (2004), Pullach (2005) and Unterhaching (2007) (Schubert et al., 2007; Wolfgramm et al., 2007). The operational parameters of these systems are listed in Table 1. The number of doublet and triplet systems built or planned has accelerated since then, including the deepest hydrothermal system in Europe at Sauerlach to the south of Munich, which will produce 140 °C water from 4.2 km depth for district heating and electricity production in 2012 (Plet et al., 2010). Systems commissioned after 2007 are not included in Table 1 to avoid introducing a local bias. Of the many projects in operation at 2012, the one at Unterhaching is located near an area with recent, weakly felt seismicity. Thus this project is described in detail.

At Unterhaching, the production (GT1a) and injection (GT2) wells have vertical depths of 3.35 and 3.59 km respectively and intersect the Malm at a vertical depth of 3.0 km (Wolfgramm et al., 2007). The wells are 4 km apart at the Malm depth, and intersect different faults (E. Knapek, pers. comm., June 2010). The wells have high injectivity/productivity, and pressure perturbations are seen to propagate between the wells in 24 h, presumably through the fault system (Wolfgramm et al., 2007). Under operational conditions, the system to date has been circulated at 120 l/s, the downhole pressure excess above formation pressure in the injection well at this rate being 2.5 MPa. The system began operation for district heating in October 2007 and electricity production was added in February 2009. In February 2008, 5 months after operations began, an earthquake of magnitude \( M_s = 2.3 \) was detected in this formerly aseismic region by the German Regional Seismological Network. The event was located within several kilometres of Unterhaching and was scarcely felt by the local population living within 5 km of the injection well GT2 (J. Wassermann, pers. comm., June 2010). A further three events of magnitude \( M_s = 2.1–2.4 \) occurred over a 3-week period in July 2008, the largest of which was felt by the local population. In July 2008 a 3-station local network was established in the area to improve the location accuracy. On 2nd February 2009, shortly after electricity production commenced, a series of seven earthquakes of magnitudes between \( M_l = 0.7 \) and 2.1 was detected by the local network (Kraft et al., 2009) but none were felt by the local population (Bayerische-Landtag, 2009). No change in circulation parameters occurred at this time (E. Knapek, pers. comm., June 2010). Analysis of the data using a local velocity model indicates that all hypocentres are located at a depth of 3.6 ± 1.5 km and some 0.5 ± 0.3 km west of the GT-2a injection interval, which lies at a vertical depth of 3.1–3.6 km (Kraft et al., 2009). The larger events were also recorded by the national network and found to have waveforms that were very similar to those of the earlier events, suggesting that all events occurred within 1 km of the open-hole section of the injection well (Kraft et al., 2009). The injection interval includes a fault with a vertical throw of 238 m (Wolfgramm et al., 2007).

3.4.3. Upper Rhine Graben

The graben hosts several projects at various stages of development that seek to develop hydrothermal reservoirs in faulted Triassic sandstone (Bundsandstein) and carbonate (Muschelkalk) units or the immediately underlying weathered basement (Baumgärtner et al., 2006). The project at Landau exploits both sediments and basement and is described in Section 2, whereas that at Riehen can be found in this section under Switzerland.

3.4.3.1. Bruchsal, Germany. This dual use geothermal project is located some 20 km northeast of Karlsruhe, on the eastern flank of the graben. It is one of the first geothermal projects in the graben, the first borehole being drilled in 1983. Unpublished borehole breakout analyses for the geothermal site reported in the World Stress Map database (Heidbach et al., 2010) indicate \( S_{\text{Hmax}} \) is oriented N130°–140°. E. Stress magnitudes are uncertain. The site has a low seismic hazard level of 0.07 g, although 10 small events of magnitude \( M_s \) up to 3.3 with intensities up to Io 5 have occurred within 25 km of the site since 1970 (Leydecker, 2009). The largest historical event within 30 km of the site is the 1948 Forchheim earthquake that is 26 km distant and has been assigned a peak intensity of Io VII (Abornier et al., 1970a).

An exploration borehole, GB1 was drilled vertical to 1932 m in 1983 and discovered an exploitable reservoir in the lower Triassic Bunter and underlying Permian Rotliegend sandstones which are cut by elements of the main boundary fault of the graben (Herzberger et al., 2010; Köbl et al., 2010). In 1985, a second vertical well was drilled to 2450 m depth some 1400 m southwest of the first well to target the same formations (Köbl et al., 2010). The system was circulated for 6 weeks at up to 151 l/s in 1987, but technical difficulties and economic considerations led to the suspension of the project in 1990. It was reactivated in 2002 using the deeper, hotter well, GB2, as the production well. No hydraulic stimulations were conducted. Static water levels in the wells were 60 m below the ground surface. A 550 kW e Kalina plant was installed in 2008 and has been in operation since mid-2009. A pump in GB2 produces water at a rate of approximately 24 l/s and a temperature of 118 °C. The cooled water is injected into GB1 under gravity producing an increase in downhole pressure of approximately 0.5 MPa above the static pressure (Köbl, 2010). There are no reports of felt microseismic events that can be ascribed to the operation of the system. A 4-station seismic monitoring network has recently been installed to detect and locate any induced microseismic events that are too small to be felt (Köbl et al., 2010).

For Landau see Section 2.2.3, and for Riehen see Section 3.9.1.

3.5. Italy

3.5.1. Tuscan-Latium geothermal areas, Italy

The region lies in western Italy between Rome and Pisa, and includes several geothermal sites that have been explored and in some cases developed since 1970. The area is characterised by high geothermal gradients, sometimes exceeding 100 °C/km, that reflect the presence of shallow magmatic bodies. The tectonic setting is transient/transitional with predominant strike-slip faulting (Brogi and Fabbrini, 2009). The fields that have been explored include Larderello-Travale and Monte Amiata in Tuscany, and Latera, Torre Alfina and Cesano in Latium. All fields except Cesano are associated with significant natural seismicity ( Battini et al., 1980b), suggesting that the reservoirs are likely to be critically stressed. In the 1970s, local seismic networks were installed at the sites in order to systematically assess the seismic response of the various reservoirs to fluid injection. In most cases the networks were installed prior to injection so that induced events could be distinguished from the background. The networks were operated throughout the exploration phase (1977–1992) and remain active in those fields that are still in production (Larderello-Travale and Monte Amiata).

3.5.1.1. Larderello-Travale. (Shown as “Larderello” in Fig. 1). This geothermal area has long produced steam from folded anhydrites and carbonates that overlie metamorphic basement at a depth of 2 km. In the early 1970s, injection of cold condensate from the power plants was initiated in order to recharge the upper reservoir, and a seismic monitoring network was installed, in part to monitor the impact of the injection.

The analyses of seismic data from 1978 to 1982 are presented by Batini et al. (1980a, 1985). The area has a long history of seismicity, and therefore many, if not most of the events are likely to
be natural. The 5 years of data show large spatial-temporal variations in event rate and b-value. The events are shallower than 8 km, with 75% located between depths of 3.0 and 5.5 km. The maximum event size approached $M_L 3.2$. A clear correlation between volume of water injected and event count is seen, although most of the induced events appear to be of small magnitude. No change to the frequency of events of magnitude $M_L \geq 2.0$ was evident (Batini et al., 1985).

3.5.1.2. Monte Amiata area. Listed in Section 2.4.1 on igneous rocks.

3.5.1.3. Latera. The reservoir is hosted by fractured, carbonate rocks at 0.6–2.0 km depth and has a temperature of 200–230 °C. A 10-station seismic network began operation late in 1978, about a year before the first injection (Batini et al., 1980b). Several natural events having magnitudes in the range $M_L 0.6–1.7$ were detected each month at distances of 20–35 km from the reservoir (Batini et al., 1980b). We describe experiments at this site in some detail as they have not been published in the international geothermal literature.

One of several injection episodes took place during March–April 1980. A total of 30,000 m$^3$ of water was injected into the 1.4 km deep well L2 during two periods lasting 8 and 10 days, implying average flow rates of 35–45 l/s (Moia, 2008). Wellhead pressure is uncertain. Some 24 events with magnitudes $M_L 1.5–2.0$ occurred in two localised clusters during the 2-month period (Batini et al., 1980b). One cluster was located only 200 m south of the injection point at a similar depth, suggesting that the microearthquakes were induced. It is of note that a magnitude $M_L 2.9$ event occurred near the L2 well on December 9, 1984 when it was being used to inject fluid produced from the 2 km distant well L3D. Unfortunately, the circulation parameters are unknown (Moia, 2008). This is the largest event that is thought to have been induced by geothermal operations at Latera.

A more complete investigation of the seismic response of the reservoir to injection was conducted in the 2.8 km deep well L1 between June 1981 and May 1982. The records for the test sequence are shown in Fig. 3a. The details of the well completion are uncertain although it is known to have been open to the formation in a fracture zone at a depth of 1.7 km (Carabelli et al., 1984). Three separate injections of durations 17–102 h were performed months apart at progressively increasing flow rates of 15, 25 and 831 l/s. The corresponding mean wellhead pressures were 5.5, 5.0 and 9.0 MPa (Moia, 2008). Wellhead pressure reached 7.0 MPa at the start of the first test but then declined to 5.0 MPa over the 61 h of the test. Microseismicity near the well began after a few hours and stopped after 35 h (Fig. 3b). A total of 223 events were recorded with magnitudes less than $M_L 0.5$ (Carabelli et al., 1984; Moia, 2008). The second injection was conducted at a higher rate but comparable wellhead pressure in May 1982 and lasted 102 h. Microseismic activity began only after 55 h of injection, by which time 1.5 times the net volume of the first test had been injected. Sporadic seismic activity persisted until shut-in, resulting in 148 events with a maximum magnitude of $M_L 0.4$. The third and highest-rate injection was conducted in May 1982 and lasted 17 h. Microseismicity at a high-rate began almost immediately but subsided after 6 h. A total of 370 events were detected, the maximum magnitude being $M_L 0.5$ (Carabelli et al., 1984; Moia, 2008). The hypocentres from all three injections are located between 150 and 1500 m from the well, and at depths between 1.5 and 2.0 km, which is close to the depth of a fault that intersects the well. However, the formal location error is large (see caption to Fig. 3). It is clear that the seismicity was induced and possibly reactivated the fault. The well was treated with acid shortly after the third injection, which

Fig. 3. (a) Injection parameters and recorded seismicity (in events/hour), for the injection tests in well L1 at Latera during 1981–1982 (After Carabelli et al., 1984). (b) Hypocentres of earthquakes associated with the injections. The x- and y-axes point east and north respectively. The locations differ slightly from those given by Carabelli et al. (1984) as station elevation corrections were included in the inversion conducted with the Hyperellipse program, although the velocity model was unchanged. The events cluster closely about the well. However, it should be noted that the formal location errors from the program are mostly larger than 1 km for the vertical, and occasionally also for the horizontal. This is because clear P- and S-wave arrivals were rarely recorded on all stations.
improved the injectivity. A subsequent injection at 111 l/s and 6.0 MPa wellhead pressure produced no detected events (Fig. 3a).

Further studies of the effect of injection on local seismicity at Latera were conducted in well L6 in December 1981. The test records and the corresponding induced seismicity are shown in Fig. 4. The first test was performed into volcanic rocks at 1.4 km depth with the injection of formation fluid at a rate of 66 l/s and a wellhead pressure of 7.5 MPa. About 20 events were observed, all of negative (i.e. very small) magnitude. The second suite of injections was conducted on 18–19 December at a depth of 1.7 km into carbonate rocks. The sequence began with three short ~2 h injections at a rate of 81 l/s and wellhead pressure of 13–14 MPa that culminated in an acid treatment and a step-increase in rate to 28 l/s and wellhead pressure of 14.5 MPa for 1 h (Moia, 2008). Microseismicity began as soon as the flow rate was increased and stopped with shut-in. A 24 h injection at 28 l/s was then performed. Microseismic activity began after 10 h, even though wellhead pressures were below 13 MPa, and terminated with shut-in. The final injection of 20 h duration was conducted some 2 days later at a rate of 40 l/s and mean wellhead pressure of 14.5 MPa (Carabelli et al., 1984). Microseismicity began after 11 h, reached a peak just before shut-in and continued for several hours afterwards. Some 196 events were detected, 28 after shut-in. Most had negative magnitude, the largest being Ml 0.8. The hypocentre locations lay to the SE of the well at distances of 200–1500 m (Fig. 4b), although the inferred locations could be significantly influenced by poor network geometry (see caption to Fig. 4).

The field was subsequently developed and had up to 14 wells operational from 1999 to 2003 (Bertani, 2005). The wells were plugged in 2008 because of problems related to gas emissions, and not to microseismicity.

### 3.5.1.4. Torre Alfina

This field lies 10 km north of Latera. The reservoir is a fractured limestone at 0.5–1.7 km depth and 140–150 °C temperature (Billi et al., 1986). Borehole RA1 was drilled to ~2710 m and a sequence of injection tests performed with fresh water in January and February 1977 with injection rates in the range 20–40 l/s and wellhead pressures of up to 1.2 MPa. A 4-station temporary microseismic network that included three 3-component instruments recorded 177 events close to the well (i.e. at 1.4–3.3 km depth and 0.2–2.0 km distance). The largest event had a magnitude Ml 3.0 and was felt by the local population (Batini et al., 1980b; Moia, 2008). The events occurred only at flow rates greater than 25 l/s when injection pressures exceeded 0.7 MPa, and ceased soon after injection was stopped. Batini et al. (1980b) report that the injection of fluid produced from well A14 into well A4 under gravity drive did not result in a detectable change in seismicity.

#### 3.5.1.5. Cesano

This 250 °C brine reservoir, located north of Rome, is hosted by fractured carbonates at a depth of 1.5–3.0 km (Billi et al., 1986). A 5-station temporary seismic network was installed in May 1978 and was upgraded to a permanent network in 1979 (Batini et al., 1980b). Dispersed, low-level natural seismicity occurs at depths of 6–12 km.

A 2 km deep well RC-1 was drilled in 1978 and short injection tests conducted once the temporary network had been installed. The first test involved a 1-day injection of water at 28 l/s. Wellhead pressure rose steadily from 3.5 to 7 MPa. A few events of maximum magnitude Ml 1.6 occurred near the well at the start of the test, but none thereafter (Batini et al., 1980b). The second injection was conducted using a flow rate of 151 l/s sustained for 1.5 days. Wellhead pressure again steadily rose from 4 to 7.5 MPa. Seismicity began after 1 day when wellhead pressure reached 7 MPa and continued until shut-in. Batini et al. (1980b) indicate that the events reached magnitude Ml 2.0 and were mostly located within 400 m of the injection well. However, they were recorded on relatively few stations and it is likely that the location uncertainty is large. Nevertheless, the events were clearly triggered by injection.

A further set of experiments was conducted in September 1981 and April 1982 when a very dense seismic network was operational. Circulation tests with production from well RC-1 (sometimes referred to as C-1) and injection into well C-5 at rates of up to 900 l/s demonstrated systematic changes of the seismicity pattern and frictional heating was observed.
42 l/s under gravity drive produced no seismic events that could be identified as triggered by injection (Cameli et al., 1983). To summarise the results for the Tuscan-Latium geothermal areas, the impact of injection on seismicity at the various sites is as follows: the effect at Monte Amiata is difficult to assess because of high background seismicity (see Section 2); at Larderello-Travale, injection enhances the number of small-magnitude events but does not detectably affect the large-magnitude events; at Torre Alfina, Latera and Cesano, dedicated injection experiments yielded clear examples where injection has induced seismicity up to and including magnitude Ms 3.0. However, the injection experiments also yielded examples where injection produced negligible seismic response.

3.6. Lithuania

3.6.1. Klaipeda:

This district heating project is located on the Baltic Sea coast. The objective was to produce 167 l/s of water at 40 °C from a Lower Devonian Viesvile formation at depths between 990 and 1118 m. The unit consists of sandstone of porosity 0.2–0.3 interspersed with clay-rich packets, and has a permeability of 0.2–6.2 × 10⁻¹² m² (Zinivicius et al., 2003). The basement lies at about 2200 m. There are no published stress measurements within 50 km of the site. The area has low natural seismic hazard. The nearest event in the catalogue of Grünsthal et al. (2009) is a Mw 4.2 event at a distance of 100 km.

Construction on the system began in 1996. Initially two neighbouring vertical production wells KGDP-2P and KGDP-3P were drilled to 1128 and 1225 m respectively, and one injection well, KGDP-11 was drilled to 1228 m at a distance of 800–1000 m from the production wells (Zinivicius et al., 2003). However, it was found that the injectivity of the well was insufficient to dispose of fluid at the desired rate of 167 l/s at the maximum injection pressure of 4.0 MPa. Therefore, a second injection well, KGDP-14, was drilled to 1128 m depth even further from the production wells (Zinivicius et al., 2003). All wells are completed with 9–5/8 in. casing and screened between 1028 and 1128 m. The fluid has 95 g/l dissolved solids and low gas content. The system began operation in 2001 but capacity declined because of decreasing injectivity, primarily because of mineral precipitation in the surface lines, well and formation (Seibt and Wolfframm, 2008). Periodic remedial operations produced only temporary improvement (Seibt and Wolfframm, 2008). System operation was suspended in 2007 to perform a major overhaul because flow rate had dropped from 97 to 39 l/s (Zinivicius and Sliupa, 2010). Operation resumed in November 2008 with injection rate into KGDP-14 increasing from 30 to 50 l/s (Zinivicius and Sliupa, 2010). Injection pressures during operation could not be determined but presumably approach the design limit of 4 MPa. Information is unavailable as to whether a seismic network was operational and whether any earthquakes were felt.

3.7. Norway

3.7.1. Sleipner, North Sea, Norway (CO₂ injection):

This is a pioneering project of Statoil to remove CO₂ from natural gas produced from the Sleipner-Vest gas field underlaying the Sleipner-A platform in the North Sea and inject it into the extensive, high-permeability, 200 m thick Utsira saline aquifer that lies at a depth of 800–1100 m (Torp and Gale, 2004). The Sleipner-A platform is located near the eastern margins of the southern part of the Viking Graben, which is characterised by moderate seismicity. Several events of magnitude Mₛ 2–3 have occurred within 50 km of the platform over the past 20 years (ISC, 2010). The Utsira formation is a hydrostatically-pressured, unconsolidated sandstone that has an estimated porosity of 35–40% and a permeability of 1–8 × 10⁻¹² m⁻¹ (Baklid and Korbøl, 1996; Torp and Brown, 2005). The well entered the Utira formation at 872 m true vertical depth (TVD), and was deviated so that the injection point is approximately 3 km away from the platform complex. The lowermost 1365 m is completed sub-horizontal with 7 in. liner to 1086 m TVD, and is perforated over a 138 m interval centred at 1015 m TVD (Hanssen et al., 2005). At the P–T conditions of the Utira, the CO₂ is expected to be in the supercritical phase, which is supported by seismic and gravity measurements (Zumberge et al., 2006). Injection began in 1996 at a rate of 1 Mton/year, or an average of 32 kg/s. The CO₂ is injected at a wellhead temperature of 25 °C and a pressure 6.2–6.4 MPa, and is thus close to the liquid/gas phase boundary (Hanssen et al., 2005; Eiken et al., 2011). Consequently, downhole injection pressure above hydrostatic is uncertain (O. Eiken, pers. comm., April 2011). The tables produced by Baklid and Korbøl (1996) suggest a value of 3.5 MPa above hydrostatic pressure. This is probably an upper bound: other evidence suggests pressure may be only marginally above hydrostatic (Eiken et al., 2011). Possible local seismic activity is not monitored at the site. However, there is no evidence from the regional networks of seismicity associated with the CO₂ injection operations (T. Torp, pers. comm., March 2011).

3.8. Poland

3.8.1. Bialy-Dunajec/Banska (Podhale basin):

The geothermal plant in the basin is located near Banska where a doublet began operation in 1992. This was expanded to a 4-well system in 2001, primarily for heating. The reservoir is a heavily fractured, karstified, overthrust Triassic carbonate overlay post-tectonic, Eocene nummulitic-limestone at depths of 2–3 km (Kępińska, 2000). The boreholes lie close to the major lineament of the Bialy-Dunajec fault, which contributes to the high degree of fracturing (Kępińska, 2000; Wieczorek, 1999). The area has moderate seismic activity. Events of intensities up to Lo V–VI are common within 50 km of the site, with occasional but rare events with intensities up to Lo VII. Intensity distributions show that at least some events occur above the basement at depths of a few kilometres (Gutcher et al., 2005). An earthquake of magnitude MB 4.5 that produced intensities up to Lo 7.0 occurred only several kilometres from the site in 2004 (Wiejacz and Debski, 2009). The focal mechanism of the event indicates normal faulting with Smin oriented approximately NW to NW (Wiejacz and Debski, 2009). The proximity of the event to the site suggests the stress state in the area is critical. The relationship of the earthquake to geothermal operations is unclear as there was no local seismic network.

The production well of the initial doublet, Banska IG-1, was an exploration borehole drilled to 5261 m in 1981. The well was completed in the Triassic/Eocene carbonates by perforating over the interval 2588–2683 m. Static wellhead pressure was 2.7 MPa, and unchoked arsian-outflows of 171 l/s were obtained (Kępińska, 2003). The injection well of the doublet, Bialy Dunajec PAN-1, was drilled 1220 m distant from the producer in 1989, and was completed in the same unit between 2117 and 2394 m (Kępińska, 2003a). Static wellhead pressure was 2.4 MPa. The doublet was operated between 1992 and 2001 at flow rates up to 171 l/s and injection wellhead pressures up to 2.5 MPa (B. Kępińska, pers. comm., Oct. 2010). Production temperature was up to 80 °C and injection temperatures were no less than 50 °C (Bujakowski, 2000).

In 2001 the capacity of the system was increased by adding an additional production and an injection well. These were drilled into the same formations at locations near the existing wells giving a pair of injection and a pair of production wells 1.2–1.7 km apart. The second production well, Banska PGP-1, was highly productive and discharged 1521 l/s of fluid at 87 °C under arsian drive. The second injection well, Bialy Dunajec PGP-2, required 8.4 MPa
wellhead pressure to inject 45 °C water at 561 l/s (Kępińska, 2003c), but this was reduced to 5.0 MPa by acid stimulation (Nagy, 2007). The 4-well system began operation at a peak flow rate of 1861 l/s in 2001. The maximum wellhead pressure at both injection wells was 6.0 MPa (Kępińska, 2003c). Given a static wellhead pressure of 2.4 MPa, negligible friction losses in the 9–5/8 in. casing, and an increase in column weight due to cooling of about 0.2 MPa (Dlugosz and Nagy, 1995), the corresponding maximum downhole pressure excess above formation pressure during injection is approximately 3.8 MPa.

3.8.2. Uniejów (Polish Lowlands):

The town lies in the Polish Lowland Province, some 50 km WNW of Lodz. It is located on the southern margin of the Mid-Polish Trough, which is a major continental suture (Dadlez, 2003; Dadlez et al., 1995). The reservoir is a Lower Cretaceous sandstone at a depth of 1.9–2.0 km (Kępińska, 2010). The basement lies at depths of 5–6 km and is overlain by Zechstein salt deposits (Dadlez et al., 1995). The nearest stress estimate registered in the WSM database is from a site some 150 km away. Regional data are reasonably consistent in indicating a pattern of NS compression. The area has low natural seismic hazard. The nearest events are located some 110 km to the east and have magnitudes in the range Mw 4.2–4.6.

The injection (AGH-1) and production (AGH-2) wells of the initial doublet were drilled 1 km apart in 1990–1991 (Sapinska-Sliwa, 2003). The reservoir temperature was 70 °C (Kępińska et al., 2000), and the static wellhead pressure was 0.4 MPa (Kępińska, 2003b). Production flow rate from AGH-2 under artesian drive was 18.8 l/s at 68 °C but could be increased to 33.4 l/s with the aid of a submersible pump (Kępińska, 2010). Total dissolved solids were 5–8 g/l. The doublet was commissioned for district heating in 2001. The operational flow rate in 2004 was 18.8 l/s at 68 °C, with injection at 42 °C giving 2.1 MWt (Kępińska, 2005). Injection pressure was 0.7 MPa (Sapinska-Sliwa, 2003). The system was expanded in 2005 with the addition of a second injection well, IGH-1, and the installation of a submersible pump in the production well (Sapinska-Sliwa and Goten, 2010). The peak flow rate in winter was 28 l/s at a temperature of 69 °C with injection temperature of at most 45 °C yielding 2.75 MWt (Sapinska-Sliwa and Goten, 2010). The injection pressures of the 3-well system were approximately 0.6–0.7 MPa (Sapinska-Sliwa et al., 2010).

3.9. Switzerland

3.9.1. Riehen, Switzerland

This hydrothermal doublet is located at the southern end of the graben, some 5 km east of the Basel EG site. The locality is characterised by moderate levels of natural seismicity (see Section 2.6.1 on Basel EG). The system consists of two boreholes drilled to intersect the Muschelkalk carbonate at a depth of 1.25–1.55 km where they are 1 km apart (Mégel and Rybach, 2000). This geologic unit is separated from the basement by thick anhydrite beds and possibly salt that might serve to hydraulically isolate the pore pressure disturbance in the reservoir from the basement (Hauber, 1991). The system has been in balanced operation at a flow rate of 18 l/s and injection wellhead pressure of less than 1.5 MPa since 1989. There are no reports of felt seismicity associated with the operation of this dual use (electricity/district heating) plant.

4. Discussion

The primary objective of this study is to document case histories of fluid injection with a view to identifying any systematic dependence of the seismic response on reservoir injection depth or the various parameters that constitute ‘geological setting’. It must be recognised from the outset that the available data are not ideal in this regard. Injections that involve a net fluid volume increase within the reservoir such as in hydraulic stimulation operations would, in principle, produce a greater disturbance of pressure in the reservoir and its surroundings than comparable injections that are balanced by production from the same reservoir, as is the case with most operating geothermal plants. These cases are distinguished in Table 1. Even allowing for this, the data are too heterogeneous and too few in number to allow firm conclusions to be drawn on the basis of single-parameter correlation with seismic response. Multi-parameter correlations such as examining simultaneously the dependence of seismic response on depth and volume injected are probably more appropriate but require more data than the 41 sites included here. A further limitation arises from the absence of local seismic networks at most sedimentary injection sites. In these cases, all that is known about the seismic response is whether or not a felt event was generated. In contrast, most igneous injection sites included in the study are EGS sites where seismic networks were operational, and thus exact measures of the maximum magnitude of the induced earthquakes are available.

The index of natural seismic activity adopted in this paper is the local peak ground acceleration value that has a 10% chance of being locally exceeded in 50 years, and is denoted as PGA in Table 1 (Giardini et al., 1999). The map of PGA values for Western Europe is shown with site locations in Fig. 1. A comparison of the maximum magnitudes triggered by fluid injection and the local PGA value is shown in Fig. 5 for igneous and sedimentary sites. The boundary between low and moderate hazard is taken by Giardini et al. (1999) as 0.08 g. Although this is somewhat arbitrary, it will be seen to have some utility. The threshold magnitude for an earthquake to be felt is taken as Ml 2.0, which is the magnitude found for events in the 5 km reservoir at Soultz to be felt by the local population (N. Cuenet, pers. comm., May 2010). This corresponds to the boundary between ‘microearthquake’ and ‘earthquake’ proposed by Bohnhoff et al. (2010), although this is also somewhat arbitrary. Thus, the maximum possible magnitude of induced events at sites without a local seismic network, and where seismicity was not felt or recorded on regional networks, was set at 2.0. These sites are indicated in Fig. 1 by the ‘error bar’ extending down from Ml 2.0 to indicate the range of possible values. The multiplicative factor indicates the number of sites that are superposed. Sites where an exact value is available for the maximum magnitude of induced events are shown by filled circles.

It is evident that there is no simple correlation between the PGA index of natural seismicity at a site and the maximum Ml induced in response to injection, either for igneous or sedimentary rocks. For igneous rocks, where the trends are clearer owing to the availability of exact measures of max-Ml, all felt events occurred at sites where the PGA value was 0.08 g or greater. Most igneous cases denote stimulation injections. Two Icelandic sites at Laugarland and Svartsengi have relatively high PGA values, but showed very low seismic response to injection. This is probably because both involved injection into reservoirs whose pressure had declined by a few MPa owing to earlier production (Brandsdóttir et al., 2002). For injection into sedimentary rocks, only four out of 25 cases produced felt events, and three of these have PGA values substantially greater than 0.07 g. There are three sites where local PGA values exceed 0.07 g but no felt events were initiated by the injections, although one of these, Cesano, is marginal in as much as an event of Ml 2.0 was recorded. The other two cases are Riehen in Switzerland, where there are evaporites below the reservoir that might inhibit pressure diffusion into the basement, and Bialy-Dunajek in Poland.

The only exception to the rule, based on the current admittedly limited data, that sites with felt events have PGA values higher than 0.07 g is the Unterhaching site where an event of Ml 2.4 occurred during operation despite the area having an expected PGA of 0.05 g. At Unterhaching, injection takes place into a high-angle fault in
Fig. 5. Maximum local magnitude of induced earthquakes as a function of the PGA value at each of the injection sites. The PGA value is the estimated seismic hazard and is used as a measure of natural seismic activity. The largest magnitude events may occur during either stimulation or circulation operations, as listed in Table 1. The vertical bars denote the range of uncertainty of maximum magnitude at sites where no local seismic network was operational and no event was felt (N-Rep in Table 1). Bars marked ‘>4’ indicate that four datapoints are superposed. We assume that events of ML greater than 2.0 are felt and reported. a) Results for injections into igneous rocks. All except Laugaland, Svartsengi, Krafla and Monte Amiata are ‘stimulation’ injections involving a net fluid volume increase in the reservoir. b) Results for injections into sedimentary rocks. All except Gross Schönebeck and Horstberg involve essentially balanced circulation.

limestone just above the basement, and the production well is 4.5 km distant from the injector, both factors that might reasonably be expected to increase the risk of inducing seismic events. The event was small, but nevertheless serves to emphasise the point that felt events cannot, a priori, be ruled out in regions with no historic record of felt seismicity.

The present limited data tentatively suggest that low natural seismicity levels given by PGA values below 0.08 g may be a useful indicator of a low propensity for fluid injection operations to produce damaging events. However, higher values do not necessarily imply a high propensity. Other factors can be decisive. This conclusion is essentially in accord with the findings of three EGS-induced seismicity workshops which recommended that the record of historical seismicity, the data underpinning the local PGA estimates, be included in assessments of the potential of planned EGS projects to induce felt events (Majer et al., 2007, 2008). It is possible that other indices of local natural seismicity may be better than PGA for anticipating the seismic response to injection, such as local seismic moment release or b-values. An evaluation of these indices is beyond the scope of this study, although we note that neither would have predicted the event at Unterhaching.

The data are too limited to address the question of whether injection into sedimentary rock tends to be less seismogenic than comparable injection into crystalline rocks in the same seismo-tectonic and geologic setting. As noted earlier, most data from igneous rocks are from stimulation injections that involve a fluid volume increase in the reservoir (Fig. 5a), whereas the vast majority of data from sedimentary rocks are from balanced circulation at operating geothermal plants (Fig. 5b). Exceptions are the stimulations of sedimentary reservoirs at Gross Schönebeck and Horstberg, and the long-term CO₂ injections at Slepner and Ketzin, none of which have produced felt seismicity. The issue of induced seismicity due to long-term injection (rather than circulation) is particularly important for CO₂ sequestration. Hydraulic fracturing operations of oil and gas reservoirs are commonplace but are not usually associated with felt seismicity. The volumes injected are small in comparison to those used for EGS stimulations, although the net volumes injected per well for gas shale stimulations are comparable (Cipolla, 2009). Recent gas shale fracturing operations near Blackpool, UK may have been associated with ML 2.3 and 1.5 events that reportedly occurred close to the injection well in April and May 2011 respectively (BGS, 2011). There is no doubt that felt earthquakes can occur in sediments. In the present study, Unterhaching and possibly Landau if the failure occurred in sediments rather than basement, represent examples. Waterflood operations for secondary oil recovery have long been associated with felt induced seismicity, the classic example being Rangely (Raleigh et al., 1976). However, there have also been several natural earthquakes of sizeable magnitude in recent years, such as the 1996 ML 5.3 Annecy (France) event and the Fribourg (Switzerland) earthquake sequences with a maximum magnitude ML 4.3, where the failure occurred entirely in sediments at 2–3 km depth (Kastrup et al., 2007; Thouvenot et al., 1998). Noteworthy examples of even shallower seismicity are the earthquake sequences in the Tricastin area of southern France that occurred at depths of only a few hundred metres (Thouvenot et al., 2009), and the well-documented cases of rain-induced seismicity in Germany and Switzerland (Husen et al., 2007; Kraft et al., 2006).

The risk of inducing seismic events is likely to increase when injection takes place near to or within fault zones (Davis and Frohlich, 1993), as is often the case in geothermal projects. This is not only because earthquakes represent the local failure of faults, but also because faults are often highly transmissive and serve to channel flow. As such, they promote deeper penetration of pressure perturbations, both laterally and vertically, thereby increasing the likelihood of the perturbation reaching a region where conditions are close to those required for extensive failure. Large separation between injection and production wells will also tend to increase the spatial extent of pore pressure perturbation within the rock mass. However, it is clear from the data that injection into fault zones does not necessarily produce felt earthquakes. At least 8 of the 24 sedimentary sites inject into or close to faults, but only one of these (Unterhaching) is associated with felt seismicity. The injection at Landau, which is also associated with induced seismicity, also takes place into or near faults in both the basement and overlying sedimentary units. The largest events in the Soultz reservoir also appear to be associated with a fault that intersected the injection well (Dorbath et al., 2009). Interestingly, all wells at Soultz were intersected by numerous fracture zones that for the most part were critically stressed (Evans, 2005). These were seismically active during the injections, but for the most part the magnitudes of the events were too small to be felt. The faults are distinguished in Soultz as larger structures that have accommodated greater offset. Whether the faults become activated depends upon whether they are critically stressed, although the maximum magnitude earthquake that will result depends upon other factors, such as the scale of the fault, and stress and strength heterogeneity.

Simple physical considerations might be taken to suggest that high injection pressures will increase the risk of producing felt events. However, felt events will arise only if other factors, such as
the prevailing stress state and presence of suitably oriented fracture zones or faults, are favourable (Davis and Frohlich, 1993). This dependence on other factors is evident in Fig. 6, which shows the maximum magnitude of earthquakes induced at the sites as a function of the injection pressure values listed in Table 1. Fig. 6a presents the data for injection into igneous rocks. All injections at pressures higher than 8 MPa, except Rosemanowes, correspond to high-rate stimulation injections which involve a fluid volume increase in the reservoir. Those below 8 MPa, except for Hellisheiði, are long-term balanced circulations. The data points for Landau and Rosemanowes correspond to circulation parameters at or immediately before the largest magnitude earthquakes occurred, and that stimulation injections at substantially higher pressures were performed at both sites without generating felt events. Results for injections into sedimentary rocks. All data are for balanced circulations, except for Horstberg and Gross Schönebeck which were both large-volume stimulation injections. Collectively the results show that there is no simple relation between injection pressure and the maximum magnitude of the induced events.

All data in Fig. 6b are for balanced circulations, except for Horstberg and Gross Schönebeck which both involved large-volume stimulation injections.

Significant seismicity, albeit usually at non-damaging magnitudes, invariably accompanies injection into crystalline rocks. All of the igneous rock masses (and at least some of the sedimentary reservoirs such as Gross Schönebeck) are found to be critically stressed in the sense that optimally oriented fractures and faults whose strength is governed by a Coulomb friction criterion with a coefficient of 0.65 would be at or close to failure. The existence of large faults that are critically stressed near a prospective reservoir has been used as an indicator of the potential of fluid injection to produce damaging earthquakes (Hunt and Morelli, 2006). Whilst this approach may be practical for assessing the potential for inducing large events on major faults that have a mapped surface expression, it is difficult to apply it to seismic events of smaller size, say in the $M_L$ 2.5–4.5 range (circular source diameters of 250–2700 m for 1 MPa stress drop), since these may occur on structures that are wholly buried or too small to have been mapped. For example, the Sulzt reservoirs contain critically stressed fracture zones or faults that are seismically activated by fluid injection, but the scale of the larger structures, and hence the maximum event size that can be generated, is unknown.

It should also be noted that the stress levels supported by geo-logic structures in many of the geothermal reservoirs examined here imply equivalent frictional strengths that are significantly higher than the threshold of 0.65 used to define criticality in this paper (e.g. ~0.95 at Sulzt (Evans, 2005)). Thus, criticality in the sense used here is a necessary but not a sufficient condition for failure. The uncertainty in fault strength, and often also the prevailing stresses which are invariably difficult to measure and, like strength, are subject to heterogeneity, greatly limits the degree to which it is possible to estimate the ‘proximity to extensive failure’ from measurable geomechanical parameters.

Seven of the sedimentary reservoirs described here are underlain, albeit usually not directly, by extensive evaporite deposits. The presence of these units can mechanically decouple and hydraulically isolate the overlying strata from the basement. The carbonate reservoir at Riehen, which is only 5 km from the Basel EGS site, is underlain by anhydrite and possibly salt deposits that might serve to hydraulically isolate it from basement. This may be a contributing factor to the different seismogenic responses, although the different nature of the injections (i.e. stimulation as opposed to balanced circulation) is possibly the primary reason.

The data presented here are not entirely consistent with the view that deeper injection in crystalline rocks tends to produce larger magnitude events. Events approaching or exceeding $M_L$ 3.0 were generated through injection at 5.0 km in two EGS crystalline reservoirs (Basel and Sulzt ~ 5 km), but only minor seismicity resulted from injection at 3.3–4.4 km depth in Bad Urach and at 6 and 9 km depth in the German KTB site, despite high injection pressures. Neither of these cases involve the injection of large volumes, and it is uncertain whether larger events would have been registered had injection continued for longer periods. There are too few data to draw any firm conclusions in this regard.

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