Good practices guide for managing seismicity induced by deep geothermal operations

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Good practices guide for managing seismicity induced by deep geothermal operations

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Preface

It has been known for over a century that some anthropogenic activities, such as underground mining or tunneling, can cause earthquakes. This phenomenon, known as induced seismicity, caused by underground industrial operations, was first observed and studied in gold mines in South Africa, and then in European coal mining basins.

With very few exceptions, such earthquakes are of very low amplitude and they are barely perceptible at the surface. Nevertheless, such induced earthquakes, observed throughout the world, have sometimes had economic and human costs.

Deep geothermal operations conducted in tectonically-active zones must account for this risk.

For every deep geothermal project, it is essential to better know the underground geology affected by the geothermal project and understand the natural phenomena, particularly seismic phenomena, that could be activated by the work, in order to minimize their likelihood of occurrence and their intensity. The Law of August 22, 2021, regarding the fight against climate change and increasing resilience against its effects, requires operators conducting such underground work to prepare a technical brief addressing these two objectives. Thus, operators will be better prepared to determine and implement the measures required to protect the local population, environment, property and buildings, by accounting for local geological conditions, well design, and operating conditions, particularly during transitional phases.

Management of seismic hazard involves operators creating a fine-tuned process for monitoring and controlling their drilling operations and the associated stresses generated in the reservoir.

In addition, this guide is being published several months after a substantial change to the French Mining Code that improves consideration of the environmental issues associated with mining activities.

Under their primary responsibility, deep geothermal project operators must control the risks and impacts resulting from their exploration and operating activities, particularly induced seismicity.

Government agencies provide information on the regulatory context for better awareness of the environmental issues and thoroughly examine the applications submitted.

In this new reinforced framework, inspectors from the Regional Directorates for Environment, Development and Housing (DREAL), of the Regional and Interdepartmental Directorate for Environment, Development and Transports (DRIEAT) of the Paris region and of the overseas Directorates for Environment, Development and Housing (DEAL), as well as local agencies, continually carry out their field missions of inspection and supervision of mining activities.

Finally, the proper management of geothermal projects must be based on the collective mobilization of operators, but also public authorities, professional geothermal energy organizations, the public, residents, elected officials, and local associations.

More broadly, the goal of this guide therefore is to provide all stakeholders with a set of information to enable them to best comprehend the issues related to seismicity induced by geothermal energy exploration and operation activities and to control the risks and nuisances.

I wish to thank the authors of this guide for their work, which is an integral part of the shared goals of modernizing the administration's action, enabling greater transparency, effectiveness, and understanding by all stakeholders involved in deep geothermal operations.

Cédric Bourillet
General Director for Risk Prevention
Ministry of Ecological Transition and Social Cohesion of Regions

Contents

Foreword

In the 2021 revision of the Mining Code, Article L. 164-1-2 contains new provisions requiring geothermal project applicants to submit technical briefs in order to demonstrate their knowledge of the underground geology explored and also the measures they have planned in order to prevent natural phenomena, such as seismicity, that could be activated by such work.

In this context, this guide has been prepared at the request of the General Directorate for Risk Prevention (DGPR) of the Ministry of Ecological Transition and Cohesion of Regions and of the General Directorate for Energy and the Climate (DGEC) of the Ministry of Energy Transition.

It was produced jointly by the French Geological Survey (BRGM) and the National Institute for Industrial Environment and Risks (INERIS) as part of their mission to support public authorities.

It has been reviewed by the French Association of Geothermal Professionals (AFPG) and by two academic experts in the field, Mr. Benoît Valley (University of Neuchâtel) and Mr. Jean Schmittbuhl (University of Strasbourg) whom we thank for their comments.

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This guide, intended to reflect the state of the art, is addressed to **deep geothermal energy** professionals. It can also provide information to all stakeholders (associations, residents, authorities including Regional Directorates for Environment, Development and Housing, etc.) on seismic risks and the means of preventing them.

The guide proposes recommendations and good practices in line with the state of the art, and concepts and knowledge as of its publication date; it will be updated following feedback from several application cases, as well as based on technological advances.

The purpose of opinions, recommendations, and suggestions is to advise project operators. As a result, the responsibility of the authors and reviewers of this guide shall not replace that of operators, who are the only parties responsible for their interpretations based on this document.

This guide uses a technical and scientific vocabulary. For the proper understanding of all readers, terms explained in the glossary are indicated in a different color in the text.

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Composition of the Editorial Board:

For BRGM	For INERIS
Julie Maury	Francesca De Santis
Peter-Borie Mariane	Emmanuelle Klein
Dominique Pascal	Isabelle Contrucci

In accordance with the quality procedures of both organizations, this guide has also undergone a technical and scientific verification by Mr. Karim Ben Slimane and Mr. Christophe Didier (for BRGM) and Mr. Hafid Baroudi (for INERIS).

1. Introduction

Deep geothermal operations, involving heat extraction at depths ranging from over 200 meters, up to several kilometers in depth, to produce electricity and/or heat, are a renewable, non-intermittent energy source that can contribute to the transition to an energy mix featuring a smaller carbon footprint and lower greenhouse gas emissions. Only a small fraction of the world's geothermal potential is currently exploited, and many countries, including France, have made accelerated development of this activity one of their goals for the coming decades. As is the case for all underground industrial activities, deep geothermal energy operations may cause induced seismicity. This seismicity is generally of low **magnitude** (M < 2) and only rarely causes damage to surface structures and infrastructure. Nevertheless, it is one of the main causes of nuisances for exposed populations, since geothermal projects are generally located very close to the energy demand, i.e., in immediate proximity to urban areas. Several recent examples in France and Europe show that induced seismicity can rapidly cause projects to be halted or even permanently abandoned, once surface vibrations exceed the threshold of human perception.

This good practices guide, written jointly by INERIS and BRGM as part of their respective missions, is addressed to all stakeholders in the deep geothermal energy sector (industry, representatives, and public authorities). It is meant to provide a framework for assessing seismic hazard depending on the type of geothermal reservoir involved and to reevaluate it iteratively, in order to adapt the exploitation method to the project and to its development. To be more precise, a strategy for reviewing the seismic hazard assessment is proposed for each key project development phase using data and factual criteria. Based on the observed hazard, it would be possible, if needed, to adapt the technical phases of the project as well as the tools used for the prevention and control of seismic hazard.

This guide also sets out recommendations concerning the essential data to be acquired, as well as for consolidating knowledge gained using **models**, in order to optimally anticipate the hydromechanical behavior of the reservoir during operations and to optimize and manage a microseismic monitoring network when it is required based on the hazard level. This guide also gives basic concepts for the definition of operational protocols to conduct and manage operations depending on the technologies used and seismicity recorded. Nevertheless, it must be stated that the purpose of this guide is not to set threshold values for injection and/or production. Such values are necessarily site specific, given the diversity of projects, the operators' objectives, and the complexity of fluid-rock interactions in depth, driven by both local tectonic and **industrial operations**.

There are four main sections preceding all these practical recommendations in the present guide. The first section describes the types of **geothermal reservoirs**, as well as exploitation methods, and presents the current regulatory framework. The second section explains the specific features of induced seismicity, whose main driver is the underground anthropogenic disturbance, compared to natural seismicity. The following sections provide an overview of the situation in France, the second leading producer of geothermal energy in Europe, and discuss feedback from many projects throughout the world representative of reservoir types in metropolitan France and overseas departments. Illustrating the environmental factors as well as the operational parameters controlling the occurrence of seismicity, they are then used to draw the recommendations of the following chapters.

2. Presentation and definition of deep geothermal energy and the associated exploitation methods

The aim of this chapter is to define the key elements involved in the exploitation of deep geothermal energy. The chapter is divided into two parts. The first contains the definition adopted in France, explains the vocabulary used and describes the technologies for the exploitation of deep geothermal. The second part briefly describes the key steps of deep geothermal energy exploitation and states the applicable regulatory obligations in France.

2.1. Deep geothermal energy: definition, typology and associated exploitation methods

2.1.1. General context and definition

Geothermal energy, sometimes called geothermy, comprises all technologies for the use of energy stored underground in the form of heat. Geothermal energy is available everywhere in the world: the Earth is an immense energy reservoir that offers a lasting, non-intermittent resource that is independent of meteorological conditions. Underground heat energy can be used to produce heat, cold or to generate electricity.

Underground temperatures increase with depth. This is called the geothermal gradient. The mean increase in France is 3.3°C (5.9°F) per 100 m over the first several dozen kilometers. **Deep geothermal energy** (see https://www.geothermies.fr, AFPG (2021), and Figure 1), **extracts energy** at depths **of over 200 m and as deep as several kilometers**. At present, the available technologies use the heat to produce electricity and/or heat, directly supplying heating networks or for industrial or agricultural processes. In 2020, 700 MW of heat and 17.2 MW of electricity were produced by deep geothermal energy in France (AFPG, 2021).

This guide deals only with deep geothermal energy whose features, in terms of the type of geothermal systems, the exploitation methods and the applied technologies are described in the next section.

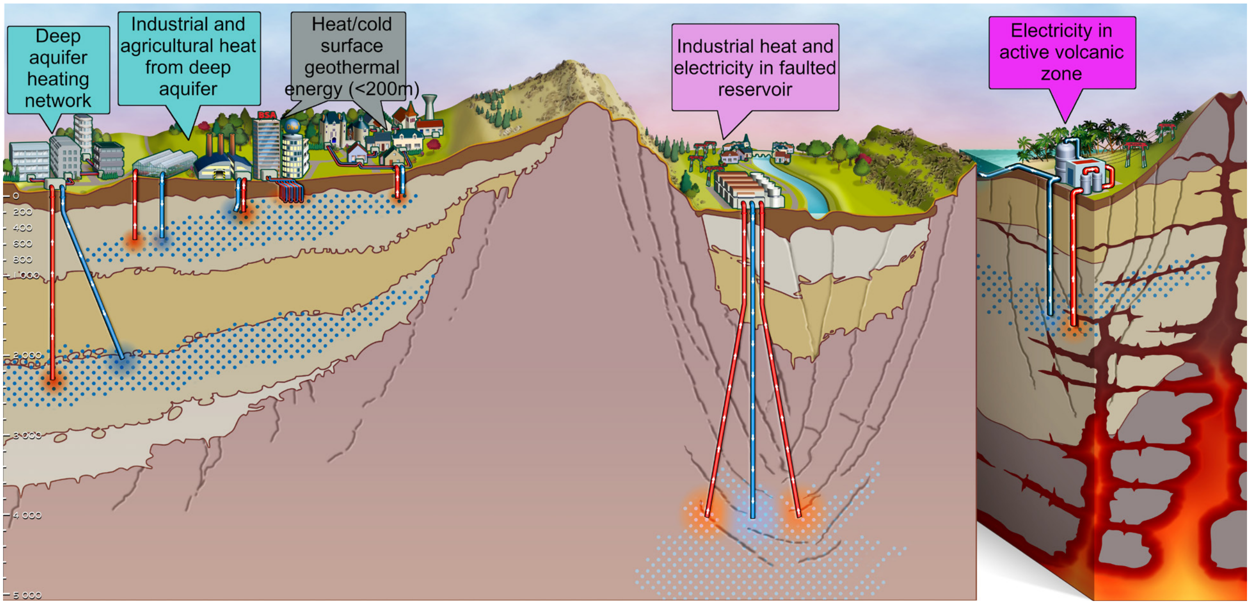


Figure 1: Examples of deep (> 200 m) and shallow (< 200 m) geothermal projects. Various geological contexts are shown: an **intracratonic basin type** *similar to the Paris Basin, a* **tectonic rift** *such as the Rhine Graben and a* **volcanic type** *such as Guadeloupe. See section 2.1.2 for further details on these types of systems (modified from https://www.geothermies.fr/).*

2.1.2. Deep geothermal energy exploitation: geothermal play types, exploitation methods and employed technologies

Deep geothermal operations extract underground energy in a variety of geological, hydrogeological and thermal contexts (as illustrated in Figure 1) which allow to classify the **geothermal play types** (Figure 2, first line and detailed in section 2.1.2.1 below). In each of these contexts, or geothermal systems, and depending on the quantity of energy to be extracted and/or the size of the geothermal reservoir, one or more wells can be used to extract the geothermal fluid (production well(s)) and there may be one or more wells to reinject the fluid once its calories have been extracted (reinjection well(s)). **Different exploitation methods** may thus exist, as shown in section 2.1.2.2 and illustrated in Figure 2, second line. Finally, when necessary, the capacity to produce or reinject the fluid in each well can be enhanced (Figure 2, third line) through the use various **technologies** detailed in section 2.1.2.3. Such technologies are based on adapting well geometry and on stimulation techniques applied to improve hydraulic properties near the wells.

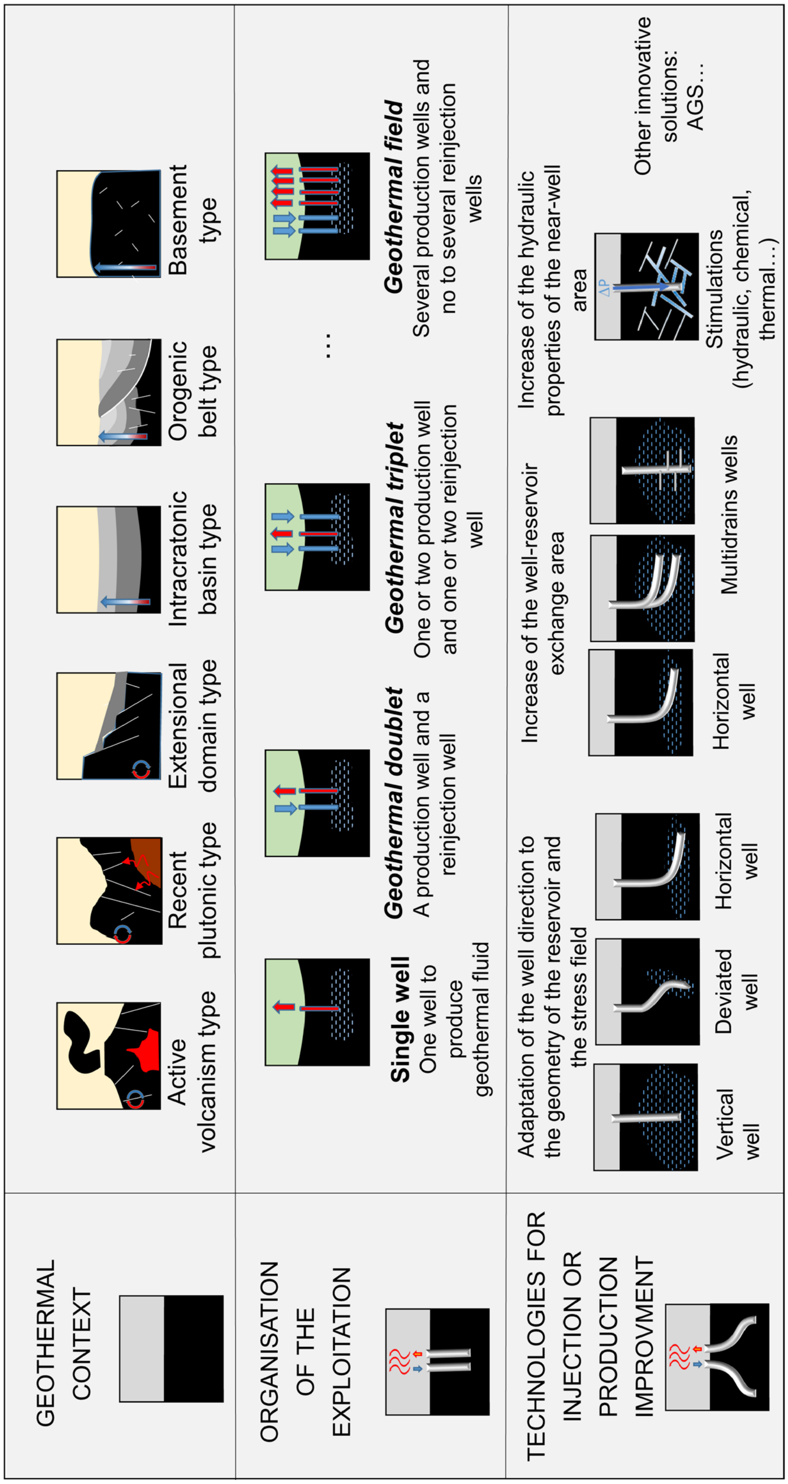


Figure 2: Deep geothermal energy: geothermal play types, exploitation method and examples of technologies that can be used to increase the capacity of a well to fluid production or reinjection. : convective processes; conductive processes.

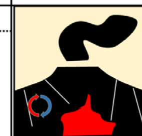
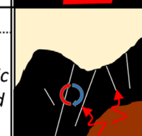
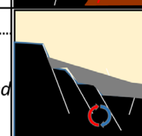
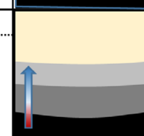
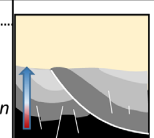
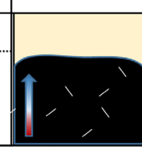
2.1.2.1. Classification of geothermal systems

Several classifications of geothermal systems (systems) have been proposed, especially in terms of temperature and **enthalpy** of the system (e.g., Haenel et al., 1988; Sanyal, 2005), **exergy** (Lee, 2001), or the **petrophysical** characteristics of the reservoir (Moeck, 2014). In this guide, we will use and adapt the classification proposed by Moeck (2014), based on the oil & gas industry's definition of play times, which comprise both geological and hydrogeological aspects and which suggest the exploitation methods to be applied. In the oil & gas industry, the system is determined by the particular stratigraphic or structural geological context, defined by the source rock, the reservoir rock and the hydrocarbons capture mode. Adapted to geothermal energy, **the geothermal system can be defined by its heat source, the geological controls on heat transfer, the capacity to store heat and the fluid, if it exists, and the economic potential for heat extraction.** The geological context in fact controls not only the system, it also constrains the choice of heat recovery technology to be used(Moeck, 2014).

Table 1 summarizes and illustrates the different geothermal play types Moeck (2014) makes a distinction between **two main families of geothermal plays** , based on the heat transfer mode (Figure 3):

- Convection dominated geothermal plays(Figure 3a),where fluids can naturally flow through natural discontinuities (**faults and fractures) over a thickness sufficient for convection cells to develop; these are identified within three geological contexts:**
  - **Active volcanic** (Table 1, first line), where heat is related to the presence of a magma chamber and fluids flow through faults and fractures (and to a lesser extent through the **porosity** of certain rocks);
  - **Recent plutonic** (Table 1, second line) where heat is related to recently cooled or cooling magmas, and fluids flow through a network of faults and fractures;
  - **Extensional domain** (Table 1, third line), associated with an extensive deformation of the earth's crust; extensional domain contexts are characterized by the presence of **normal faults** that delimit **tectonic rifts** or **grabens** and that control a large part of flows in the geothermal system.
- Conduction dominated geothermal plays (Figure 3b), for which geothermal fluids can flow through rock matrix porosity and/or through natural discontinuities (**faults and fractures); we make a distinction between the following plays, from the most permeable to the least permeable ones:**
  - **Intracratonic basin** (Table 1 fourth line), in which **aquifers** develop thanks to the porous and permeable sedimentary layers deposited in the basin;
  - **Orogenic belt** (Table 1, fifth line), characterized by both potentially aquiferous sedimentary deposits (porous and permeable) and by the presence of numerous faults accommodating tectonic deformations and controlling a part of the flows in the geothermal system;
  - **Basement types** (Table 1, sixth line) which develop in ancient rock massifs with very low porosity and permeability, whose fracturing does not allow for significant fluid circulation (clogging, sealing by mineral precipitation, stress state no longer allowing discontinuities reopening), but whose temperature may be elevated, in particular due to radiogenic heat production.

Table 1 – Classification of geothermal play types in function of geological controls on the heat source and heat transfer, illustrated by examples of typical sites (modified from Moeck, 2014).

Heat transfert	Geothermal context	Illustration	Temperature (T) and depth (D) range most commonly exploited	Exemples	Geothermal system type Classification used in this guide
Convection dominant	**Active volcanic type** *Systems developed within active volcanism area*		T : 70-350 °C D : 500 m-3000 m	Bouillante, Guadeloupe, France	Faults/fractures control
	Recent plutonic type *Systems developed around magmatic plutons recently intruded and cooled*		T : 100-350 °C D : 1500 m – 4000 m	Larderello, Italie	
	Extensional domain type *Systems developed as through extensive tectonic dynamics, traduced by the formation of grabens*		T : 150-240 °C D : 2500 m - 5 000 m	Soultz-sous-Forêts, France	
Conduction dominant	**Intracratonic basin type** *Systems associated to aquifer sediment layers, in non-active tectonic zone*		T : < 150 °C D : 500 m – 2 000 m	Paris basin, France	Porosity and permeability matrix control
	Orogenic belt type *Systemss associated to sediment layers more or less aquifer and to faults and fractures resulting from an important tectonic activity*		T : < 160 °C D : 500 m – 3500 m	Bavarian molassic basin, Germany	Mixed control of porosity and permeability by matrix and faults/fractures
	Basement type System developed in a rock mass with low permeability in a craton*		T : 150-320 °C D : 3500 - 5500 m	Forge project, USA	Faults/fractures control

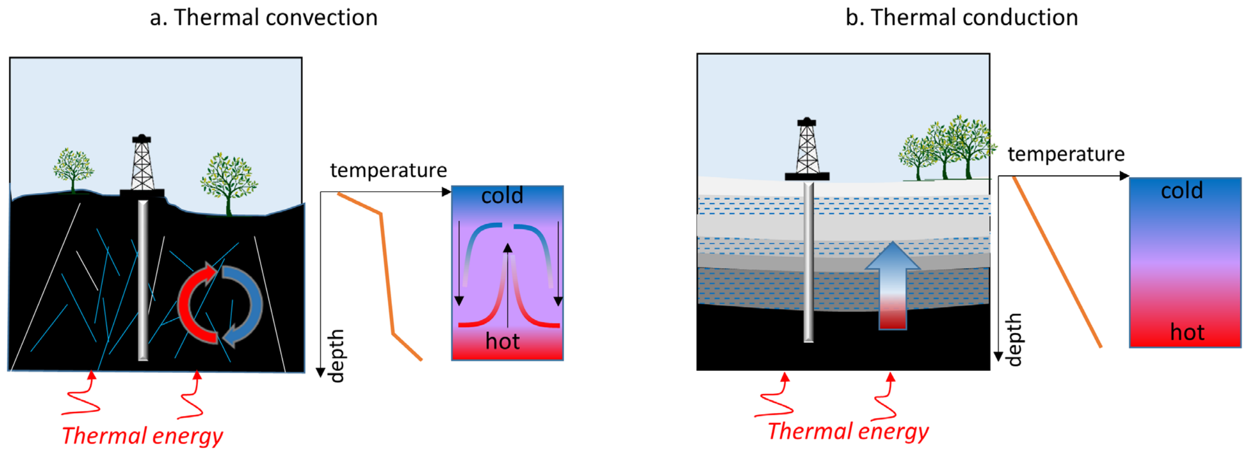


Figure 3: Convective (a) and conductive (b) heat transfer modes in the earth's crust and example of the associated geological context. a. Thermal convection resulting in a uniform temperature over the height of convection cells (near zero ***geothermal gradient*** *in the convection zone). Fluid flow Is indicated by the arrows. b. Thermal conduction resulting in a constant thermal gradient along depth.*

These two major play types and sub-play types, based on the classification proposed by Moeck (2014), can be grouped into **three major families**, which represent the retained classification in the present guide (*see* chapter 5):

- **Geothermal systems controlled by faults and fractures** which include convection-dominated plays (volcanic, plutonic and extensional domain types), as well as basement types;
- **Geothermal systems with a mixed control due to porosity and permeability of the rock matrix, as well as of faults and fractures**: these are **orogenic belt types**;
- **Geothermal systems controlled by matrix porosity and permeability**: these are **intracratonic basin systems** in which aquiferous sedimentary layers are found.

Geothermal energy in these different systems is extracted by drilling deep wells for the circulation of a fluid in the **geothermal reservoir**. The term 'geothermal reservoir' refers here to a hot, porous and/or fractured rock environment. The heat contained in this medium can be collected by heat and mass transfer using the geothermal fluid (e.g. as in the geothermal **doublet**) or by conductive exchange (closed-loop borehole heat exchanger), for producing heat and/or electricity. Depending on the geothermal play type, reservoirs may have different geological characteristics and hydraulic properties (particularly porosity, permeability,presence of natural fractures in the rock ,as well as presence of fluid in liquid, vapor or **supercritical** form). In the case of an open system, technologies to improve insufficient permeability can be used to produce energy economically. Depending on the quantity of energy to be extracted and the system, the number and spatial organization of wells may differ; this aspect is discussed in the following section.

2.1.2.2. Wells set-up in deep geothermal projects

For a given play type , the planned use of the geothermal energy will define the quantity of energy to be extracted, which in turn will affect the design and geometry of the exploitation (Figure 2, second line).

Geothermal energy exploitation, can be done:

- Either in a **geothermal site** with a single production well or few nearby wells (doublets, **triplets** or quadruplets, most often with one well producing the geothermal fluid and one or two wells for its reinjection) (Figure 4 on the left); or
- **In geothermal fields**, such as Larderello in Italy, with several wells producing the fluid (Figure 4 on the right). The geothermal fluid is then totally or partially reinjected by reinjection wells or it is rejected into a dedicated zone (the ocean, into basins that will become lakes over time, or in the air if the fluid is gaseous), depending on the nature of the fluid and the characteristics of the reservoir (if reinjection is possible or not).

In this document, the term **geothermal project** is used to designate a given geothermal site or field, composed of one or more wells in which **operations** are conducted (tests and development before operation, maintenance during operation), in particular those to increase well capacity to produce or reinject a fluid, which are discussed in the next section.

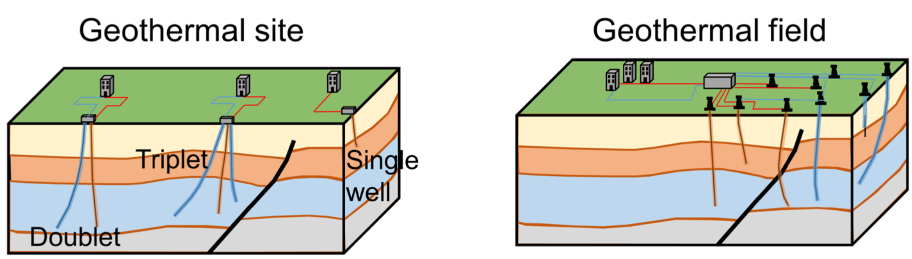


Figure 4: Examples of wells set-up for deep geothermal exploitation: geothermal site (on the left) or geothermal field (on the right).
The diagram represents operations for district heating but can be applied to other uses such as industrial heating and/or electricity production.

2.1.2.3. Different geothermal exploitation technologies

Deep geothermal energy exploitation is most often based on the production of the geothermal fluid, circulating naturally in the reservoir, via a well. Once calories are removed from this fluid, it can be reinjected into the same reservoir and, under certain special conditions requiring authorization in France, into a different reservoir or at the surface. The flow-rate of the operation depends on several factors, but overall it is between 100 and 300 m^3/h for geothermal installations in the Paris Basin (e.g., Hamm et al., 2020) and the Rhine Graben (Reinecker et al., 2019; https://geoenvi.brgm.fr/en/node/2369).

Once drilling is completed or during the life of the installation, if production and/or reinjection flow-rate is lower than project requirements, it may be increased through the use of various methods and technologies (Figure 2, third line). Currently, they are based primarily on adapting the well geometry to the reservoir characteristics or on improving the hydraulic properties of the reservoir around the well (stimulations):

- It is possible to increase the exchange surface between the well and the reservoir, thereby increasing flow-rate of produced fluid from the reservoir, by **adapting well geometry**: deviated wells, horizontal wells multidrains technology (Figure 2, third line) to increase the contact surface between the well and the reservoir (e.g., Fraija et al., 2002; Hamm et al., 2019; Nair et al., 2017). For example, in the Paris Basin, where the reservoirs are in sedimentary layers, advanced well geometries have led to increased **productivity**, as is the case in Cachan (subhorizontal drilling) or in Vélizy-Villacoublay (multi-drain wells; AFPG, 2021);

- Improving hydraulic properties of the reservoir through the use of chemical, thermal or hydraulic processes. Such processes are grouped under the generic term of **stimulations,** even though this term covers various processes and impacts. The processes used aim to:
  - **Improve permeability** in the rock mass by **dissolution**: this is **chemical stimulation**[1] that affects the immediate well volume (the first meters around the well). For example:
    - In systems controlled by matrix porosity and permeability, such as the Paris Basin, (chemical stimulations) are often applied to dissolve drilling residues and waste, such as drilling mud, **to widen the pore openings in reservoir rock** or to locally broaden the borehole radius (Hamm et al., 2019);
    - In systems controlled by faults and fractures, such as the Rhine Graben, in addition to the dissolution of drilling residues and waste, chemical stimulation generally aims at dissolving materials that fill discontinuities (faults or fractures, e.g., Portier et al., 2009). Beyond opening up circulation paths in such discontinuities, their mechanical properties are also modified (reduced cohesion and/or friction coefficient), that may result in their shear. When this process is used in faults/fractures controlled systems, microseismicity may therefore be induced (e.g., Nami et al., 2008).
  - **Increase the permeability of preexisting discontinuities** by hydraulic or thermal stimulation which allow **shearing** of such discontinuities; as a result, these processes may induce seismicity:
    - **Hydraulic stimulation** involves increasing the hydraulic pressure in natural discontinuities; shear occurs by a mechanical effect, when the pressure increase is sufficient with regard to the state of stresses applied to the discontinuity (mechanisms detailed in section 3.3). As a result of the induced displacement , the **fault walls** are not perfectly interlinked. The resulting spaces create a permanent opening in the discontinuity in which the fluid can circulate. This type of stimulation is widely used in faults and fractures controlled systems controlled by faults and fractures, in particular in extensional domain systems and are often called "**EGS**" (Enhanced Geothermal Systems, e.g., Majer et al., 2007);
    - **Thermal stimulation**[2] involves injecting a fluid at a temperature much lower than that of the reservoir, which improves permeability of rocks close to the well. Cooling the **fault walls** causes it to contract, resulting in the modification of its mechanical resistance as well of the **stress state**. This causes shear of the cooled discontinuity, which increases its **hydraulic opening**. This type of stimulation is used primarily in very high temperature reservoirs such as those found in volcanic contexts. For example, at Bouillante in Guadeloupe, well BO4 was improved using thermal stimulation technologies (Sanjuan et al., 2000). Systems improved by this type of stimulation may fall under the term EGS, but the term is not usually used when this method has been widely used for a long time (e.g. in the case of volcanic play-types).
  - **Create new discontinuities** in the rock mass in order to open up new circulation paths. Such new discontinuities can be created:
    - Using mechanisms of hydraulic overpressure called hydraulic fracturing or fracking[3]. This method is rarely used in deep geothermal operations and is limited to special contexts (in particular basement

1 *– This guide does not address the possible environmental impacts resulting from the use of chemicals.*

2 *– During these operations it is impossible to know if thermal stimulation has caused fracturing of the rock or the shear of preexisting discontinuities. Often, a mixed process occurs.*

3 *„;– Hydraulic fracturing also causes the shear of preexisting fractures and faults in a mixed process (e.g., McClure and Horne, 2014). The fluid used can be soft water or the fluid of the formation itself.*

types). It is no longer used in France, since prefectoral decrees authorizing operations generally limit maximum wellhead pressure to values that are much lower than those required for hydraulic fracturing (it requires fluid pressures more than ten times higher than those used for hydraulic stimulations intended to shear preexisting discontinuities);

- Through a thermal shock (thermal stimulation). The abrupt cooling of a rock mass or of fracture filling may result in the occurrence of cracks (Peter-Borie et al., 2018). In the course of a thermal stimulation, there may be simultaneous fracturing and shearing of preexisting discontinuities, depending on the physical and mechanical characteristics of the rock and on the temperature variation.

EGS most often include projects that have undergone hydraulic stimulations to increase the permeability of a rock volume, but several definitions of this term exist (Breede et al., 2013). The term 'EGS' may also include chemical and thermal stimulations, in particular when they are used in new or unconventional contexts. The term 'EGS' (and in particular the formulation Engineered Geothermal Systems) can also be used to designate projects using optimized well geometry (e.g., Gentier, 2013; Peter-Borie et al., 2020a). **In the context of this guide** and for practical purposes to distinguish between the methods in chapters 4 and following, **the term EGS will be used to refer to projects using hydraulic stimulation** and/or thermal and chemical stimulation at fluid pressures significantly higher than the initial pressure of the reservoir in new or unusual contexts.

More recently, the **so-called advanced technologies** (AGS, for Advanced Geothermal Systems), or **improved versions of engineered systems**(EGS or EGS2.0), which are still in the concept phase or under development, are designed to overcome some of the challenges of geological control, in particular, these technologies try to overcome aspects related to the circulation of natural fluids in the rock mass, by proposing special well designs with little or no fluid exchange with the reservoir, where heat transfer is therefore taking place by conduction. The geometries of such systems may be variable, e.g., a U-shaped system with several subparallel horizontal drains as in the Eavor Loop project (Holmes et al., 2021). These technologies are in the concept phase and so will not be detailed in this guide.

Technologies for extracting underground heat are advancing, and periodically, new emerging concepts are studied in order to increase the yield of installations while minimizing risks (risks of project failure, but also environmental and societal risks). This document contains recommendations for good practices related to the state of the art and to concepts presently on the market at the time of its publication and will undoubtedly evolve as future technologies become reality.

2.1.2.4. Parameters the operator can manage

As stated above, the characteristics of a project depend on the type of geothermal system and on the planned operating technologies. Once the location of the project is defined and thus the geothermal system is known, **the parameters that can be modified to obtain the desired energy while limiting seismicity are** ::

- The number of wells, their trajectory and interwell distance (at depth, in the reservoir);
- Outfitting the well(s) (open hole liner, etc.);
- Injection and/or production flow-rate: this is one of the operating parameters that can be adjusted. In operations, a flow-rate is imposed and the pressure is measured. Flow-rate is the parameter to adjust based on the action to be conducted;
- The injection pressure;
- The volume injected: for stimulation operations or for projects where the fluid is not totally reinjected. The volume of fluid extracted from the reservoir is the difference between the volume of fluid produced and the volume of fluid injected;
- The fluid properties: density, viscosity, chemical composition and temperature of the injected or reinjected fluid;
- Injection interval for stimulation operations: duration of fluid injection must be determined, and if injection is step-wise, the duration and flow-rate increment between steps must also be determined.

2.1.3. The situation in France

France is the second-leading producer of deep geothermal heat in the European Union (134.6 ktoe: kilotons of oil equivalent) and produces 17 MWe of geothermal electricity[4]. The three major families of geothermal systems previously defined (section 2.1.2.1) are encountered in France (Figure 5):

- **Systems controlled by faults and fractures** (volcanic types such as Bouillante in Guadeloupe and extensional domain types such as the Rhine Graben);
- **Systems with mixed control by matrix porosity and permeability and by the porosity and permeability of faults and fractures** (including the Southeast Basin);
- **Systems controlled by matrix porosity and permeability** (including the Paris Basin and the Aquitaine Basin, both intracratonic basin types).

Heat extracted from deep geothermal energy in France is used primarily for urban heating systems. In 2020, there were almost 60 such district heating systems, primarily in the Paris region (54 deep geothermal installations covering more than 200,000 housing equivalents with 100% RE, AFPG (2021)), the region with the highest density of such installations in Europe, but some are also located in the Nouvelle-Aquitaine, Grand-Est, Occitanie and Centre-Val de Loire regions. In addition to heating buildings, deep geothermal energy can be used to heat greenhouses or fish farms, balneotherapy installations or industrial processes (there are currently about 15 such installations in France). This heat is captured using so-called conventional technologies based on a system of doublets, or single producer wells, vertical or deviated, except for:

- Rittershoffen (industrial heat) where one of the two wells was stimulated (Vidal et al., 2016);

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4 *– https://www.geothermies.fr/usages-production*

- The Cachan heating system, where optimized well design (horizontal drilling) was implemented in 2018.

Most French installations producing heat use **systems controlled by matrix porosity and permeability** (primarily the Paris Basin and the Aquitaine Basin Figure 5a). There are two installations producing heat from a **system controlled by faults and fractures**, shown in Figure 5a:

- Rittershoffen in Alsace (the only **concession** in France producing heat for industrial use only in 2021), that uses a reservoir formed by a fault or a system of major faults and that required the stimulation of one of the wells to improve its connection to the reservoir (hydraulic and chemical stimulations, Genter and Maurer, 2016);
- Illkirch, also in Alsace, where there is an ongoing development project with an exclusive exploration permit for the production of heat and that also uses a reservoir formed by a fault or a system of major faults.

It should be noted that the project in the small Alsatian town of Vendenheim, currently suspended by prefectoral order, involved a **geothermal system controlled by faults and fractures,** intended to co-generate electricity and heat.

At the present time, the production of electricity is limited to only two **concessions** located in Bouillante, Guadeloupe, and Soultz-sous-Forêts in Alsace, but other projects are under development (a large number of exclusive exploration permits (section 2.2*)* were active in 2021).

The total capacity of Bouillante in Basse-Terre, Guadeloupe, is 15.5 MW of electricity from two production units: Bouillante 1 (operational since 1986, 4.5 MW of electricity) and Bouillante 2 (operational since 2005, 11 MW of electricity). Both units use a fluid at 250-260°C captured from a reservoir at a depth between 500 and 1,000 m. Two prefectoral decrees authorizing several additional wells to be drilled to a depth between 1,000 m and 1,600 m were signed in 2019 with the purpose of furnishing an additional 10 MW of electricity (AFPG, 2021). This site exploits **a geothermal system controlled by faults and fractures** (a system composed of a volcanic type overlying a zone locally in extension; Figure 5b).

Soultz-sous-Forêts in Alsace has been part of a scientific pilot program (1986-2010) intended to demonstrate the concept of extracting very deep underground energy in **systems controlled by faults and fractures**, in an **extensional domain system** (Figure 5a), using EGS technology to produce electricity. Following a phase as operational pilot site between 2010 and 2013 and a transition phase, the power plant was brought on line in 2016, generating 1.5 MWe through the commercial use of a geothermal fluid at a temperature of 165°C and three wells at a depth of 5,000 m.

Finally, obtaining coextracted substances has been considered and tested in France for several years, in order to increase the profitability of deep geothermal drilling. A test recovery of lithium, abundant in the waters of the Rhine Graben, is currently under way at Rittershoffen (AFPG, 2021).

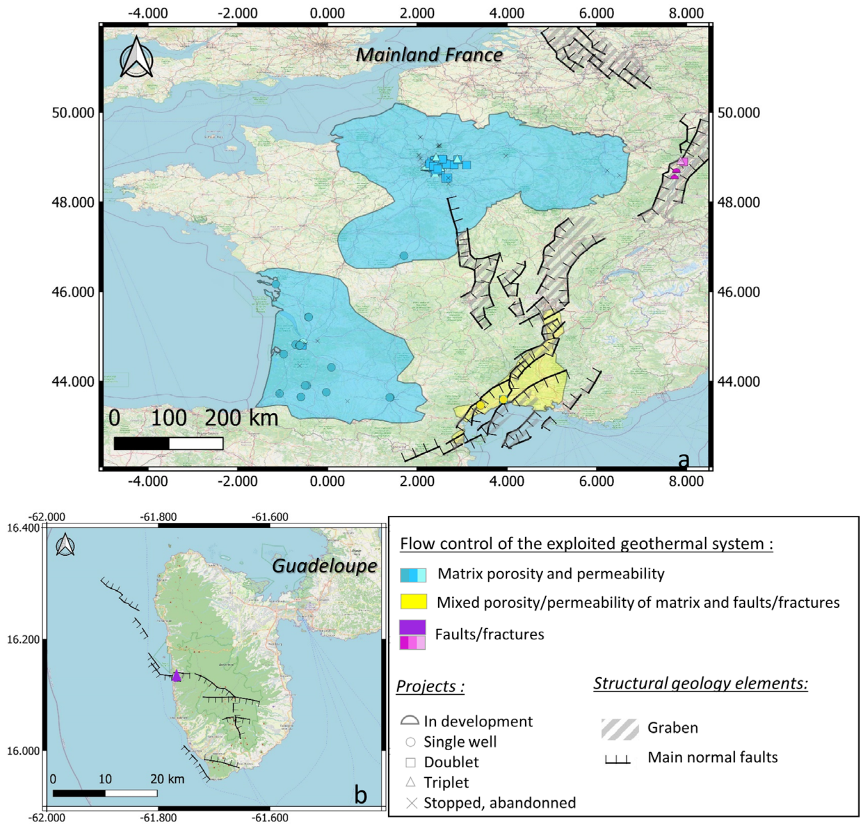


Figure 5: deep geothermal operations in France in their geothermal context a. in continental France; b. in Guadeloupe (Basse Terre).

2.2. Exploitation of geothermal systems: steps and regulations

2.2.1. Key steps for exploiting geothermal energy

From the initial definition of needs to the end use of geothermal energy, the path is marked by different steps governed by the French Mining Code (see section 2.2.2):

- **Exploration before drilling or surveying** with the aims of locating the resource and defining the position of the reservoir and its properties; this leads to a conclusion on the potential use of the reservoir and if positive, to defining the location of the wells. The importance of this step varies, depending on whether the reservoir is known and already used (existence of preexisting geothermal wells using the same reservoir) or not (zone external to preexisting geothermal wells using the same reservoir, or a new reservoir);
- **Exploratory drilling** to reach the reservoir and obtain direct data on the resource (hydraulic and thermal characteristics) and on the reservoir, in particular its geomechanical features to better define the seismic incident hazard;

- **Drilling of production and reinjection wells** to extract heat energy from the reservoir and reinject fluids. The same well can first be used for exploration and then be converted to a production or injection well. This is often the case with geothermal energy, but not in the oil & gas industry. Some wells previously drilled for other underground uses but which did not fulfill their intended purpose can be subsequently used to exploit the reservoir;
- **Development of the well-reservoir connection** to eliminate drilling residues and to improve the **injectivity** and/or productivity of the well when their initial properties did not enable economically-viable exploitation. The steps in **well development** are: filling the well with water, initial assessment of well capacities, improving the productivity/injectivity index (hydraulic, chemical or thermal stimulations; multi-drains), assessment of well capacities with respect to the objective and determination of the improvement resulting from stimulation. The last two steps are repeated until the desired flow-rate is obtained or if there is no further improvement. The initial assessment of well capacities and improvement after stimulation involves **hydraulic tests** including stepwise tests and long-duration tests (see Hamm et al., 2019 for more information on such tests). When conducting injectivity tests, special attention must be paid to the volume injected and the pressure applied during the tests in order to avoid stimulating the reservoir.
- **Operation**, the phase during which geothermal energy is extracted and redistributed according to the defined use. Maintenance operations are conducted regularly during this phase;
- **Permanent shutdown of operating wells** when, in spite of maintenance or improvement operations they no longer produce in an economically-satisfying manner or when operation is stopped for any reason.

From a regulatory point of view, only three major steps are defined: 1. Exploration, which includes the phases of prospecting, drilling and development of the previously-defined reservoir, 2. Operation and 3. Shutdown.

2.2.2. Regulatory context applicable to deep geothermal energy

This section deals with the principal elements of French regulation, updated from the latest changes to the Mining Code[5] (version of November 10, 2021).

It should be noted that we are presenting here regulations applicable to deep geothermal energy resulting from the reform initiated by governmental Order No. 2019-784 of July 24, 2019, modifying the provisions of the Mining Code relative to the granting and the extension of exploration and exploitation permits for geothermal deposits, and its implementation Decree No. 2019-1518 of December 30, 2019, relative to permits of geothermal deposits. This reform is applicable for the request of exploration or exploitation permits to the administrative authority starting from January 1, 2020.

According to Articles L.112-1 and L.112-2 of the Mining Code, geothermal deposits belong to the legal mining framework.

In order to find or develop a geothermal deposit, the following must be obtained from the Government, except for a geothermal operation of minimal importance:

- **a mining exploration permit** or a **mining exploitation permit**;
- **an authorization to begin mining work** to conduct drilling required for exploration or operation.

5 – The provisions of the Mining Code concerning geothermal operations have been modified by: government Order No. 2019-784 of July 24, 2019, modifying the provisions of the Mining Code relative to the granting and extending of permits for the exploitation and use of geothermal deposits; and Act No. 2020-1525 of December 7, 2020 on the acceleration and simplification of public actions.

2.2.2.1. Mining exploration permit or mining exploitation permit

For the exploration phase

As stipulated in article L. 124-1-1 of the Mining Code, subject to 1° and 2° of Article L. 124-1-2, exploration of geothermal deposits may be carried out only by the holder of an **exploration authorization permit (AR) or an exclusive exploration permit (PER)** . The choice of permit is up to the applicant, regardless of the estimated primary power of the geothermal deposit (Table 2).

For the exploitation phase

As stipulated in article L. 134-1-1 of the Mining Code, geothermal deposits can be exploited only with an **exploitation permit or a concession**, issued by the competent administrative authority (Table 2).

The procedure for granting exploration and exploitation permits for geothermal deposits is specified by the provisions of Decree No. 78-498 of March 28, 1978, modified by Decree No. 2019-1518 of December 30, 2019.

Table 2 - Summary of the major elements of the procedure for obtaining the mining permits necessary for the exploration and exploitation of deep geothermal energy.

<table>
<tr><th colspan="3">Mining permits required for EXPLORATION</th></tr>
<tr><td></td><td colspan="2">The applicant chooses:</td></tr>
<tr><td>Mining permit</td><td>Exploration Authorization (AR)</td><td>Exclusive Exploration Permit (PER)</td></tr>
<tr><td>Delivered by</td><td>Prefect</td><td>Ministry in charge of mines</td></tr>
<tr><td>Call for competition</td><td>Yes</td><td>Yes</td></tr>
<tr><td>Public hearing</td><td>Yes</td><td>No, but online consultation</td></tr>
<tr><td>Initial duration</td><td>3 years</td><td>5 years, max[6]</td></tr>
<tr><td>Extension of validity</td><td>No</td><td>Yes (maximum of two 5-year periods)[6]</td></tr>
<tr><th colspan="3">Mining permits required for EXPLOITATION</th></tr>
<tr><td></td><td>Primary power[7] < 20 MW</td><td>Primary power [7] > 20 MW</td></tr>
<tr><td>Mining permit</td><td>Operating Permit (PEX)</td><td>Concession</td></tr>
<tr><td>Delivered by</td><td>Prefect</td><td>Decree by the Council of State (French Supreme Court)[8]</td></tr>
<tr><td>Call for competition</td><td colspan="2">Not if requested by the holder of the PER or the AR during its period of validity.
In other cases, there will be a call for competition.</td></tr>
<tr><td>Public hearing</td><td>Yes, except if the AR is valid and under certain conditions (L. 134-9 of the Mining Code)</td><td>Yes</td></tr>
<tr><td>Initial duration</td><td>30 years, max</td><td>Maximum of 50 years in light of the exploration and operation costs and the economic balance of the project.</td></tr>
<tr><td>Extension of validity</td><td>Yes (maximum of 15 year periods)</td><td>Yes (maximum of 25 year periods)</td></tr>
</table>

6 – As of July 1, 2023, the maximum validity of PERs is 15 years and can be extended only once for a maximum of 3 years to carry out production tests.
7 – Primary power is the maximum thermal power that can be taken from underground over the entire area specified by an operating permit.
8 – Simple decree in effect as of July 1, 2023.

2.2.2.2. Mining work permit to conduct drilling required for exploration or exploitation.

The mining permit alone does not grant its holder the right to conduct exploration or exploitation work. They are subject to a prefectoral authorization or declaration, depending on their extent (Table 3).

The content of the application for requesting a mining work permit (corresponding to drilling permit or operation permit in foreign legislation), as well as the corresponding procedure, which require a public hearing, are specified in Decree No. 2006-649 of June 2, 2006, modified concerning mining work, underground storage work and the police of mines and underground storage facilities. Nevertheless, the application of the Act of August 22, 2021 on the fight against climate change and increasing resilience against its effects, empowers the Government, with required adaptations, to shift the authorization to begin mining work to the environmental authorization regime contained in the Environmental Code and to revise the object, modalities and sanctions of mine Police, in particular to render the administrative sanctions of this Code applicable to mining work subjected to environmental authorization and specifying the obligations of operators. Once the order concerning environmental authorization for mining work is adopted and its implementation decree is published, authorizations to open mining work will depend on the environmental authorization regime.

The aforementioned application is accompanied by a report (L. 164-1-2 of the Mining Code) stating the measures used and those planned to determine the underground geology affected by the work and to understand the natural phenomena, particularly seismic phenomena, that could be activated by the work, in order to minimize their probability, their intensity and the risks of reappearance of such phenomena after their possible occurrence, in order to protect the interests stated in Article L. 161-1 of the Mining Code.

Modifications concerning the work, installations or methods that could lead to a substantial change of the initial authorization data result in a new authorization application, subject to a new public hearing.

In addition, during exploration work, the operator is required to provide the technical documents listed in the following table and submit them to the Prefect.

Table 3: Documents concerning exploration and exploitation works to be submitted to the Prefect.

Phase	Regulatory phase	Document to be submitted to the Prefect	Submission deadline
Exploration	Art. 30-2 of Decree No. 2006-649 Art. 4 of the Order of October 14, 2016[9]	Work program[10]	One month before beginning an operation on a well
	Art. 30-4 of Decree No. 2006-649 Art. 9 of the Order of October 14, 2016	Work completion report	Within a maximum of 6 months after the end of work on wells
	Art. 5 of the Order of October 14, 2016	Program of production tests	Before beginning production tests
	Art. 10 of the Order of October 14, 2016	Report on production tests	30 days after terminating production tests
Exploitation	Art. 6 of the Order of October 14, 2016	Major intervention program	

The recommendations in chapters 6, 7 and 8 of this document are in line with these regulations

9 – Order of October 14, 2016 concerning drilling exploration work and exploitation of mining substances with wells.
10 – The effective start of work depends on approval by the Prefect. If the Prefect does not respond within one month, the operator may begin operations.

3. Definitions, features, and mechanisms of induced seismicity

This chapter summarizes the basic concepts required to understand the conditions of the occurrence of a seismic event in relation with underground industrial activities, particularly deep geothermal operations. These concepts are important for understanding how such operations can, under certain conditions, cause seismic activity. The terms "natural seismicity" and "induced seismicity" are defined, and we describe factors that can be related to the energy released by an earthquake (magnitude) or directly related to vibrations observed at the surface. The chapter concludes with a summary of induced seismicity throughout the world and several key features of seismicity induced by deep geothermal operations that introduce the following chapters of the guide.

3.1. Natural seismicity and induced seismicity

An earthquake is a sudden slip of two rock compartments along a fault plane. It occurs when stresses accumulated in the fault zone reach a critical value that the rock can no longer accommodate (section 3.3). It generates **seismic waves** and ground vibrations that can be felt at the surface.

It has been known for over a century that certain anthropogenic activities can cause earthquakes (Figure 6). The link between underground human activity and the occurrence of earthquakes was shown for the first time in South Africa in 1894, during underground mining operations (Deichmann and Giardini, 2009). Since then, many similar situations have been observed worldwide in other industrial domains, such as oil & gas extraction, reservoir impoundment, as well as deep geothermal operations, etc. (e.g., Aochi et al., 2017; Contrucci and Klein, 2017; Foulger et al., 2018).

In the literature, we distinguish between natural seismicity and anthropogenic seismicity, the latter arising from human activities. The definitions generally used by authors (e.g., Cesca et al., 2013; Dahm et al., 2013, 2010) are:

- **Natural seismicity** is related to tectonic forces generated by plate motion. It represents the most frequent source of seismicity in the world, and usually occurs at the limit between tectonic plates. Natural seismicity is generally located at depths ranging from several tens of kilometers to several hundred kilometers. **It does not result from human activity**;
- **Anthropogenic seismicity** is the result of human activities. Two major families of anthropogenic seismicity are distinguished according to the causal mechanism:
  - **Induced seismicity** is caused by human activity. It results from an anthropogenic modification of the stress field in the rock mass and would never have occurred in the absence of human intervention in the natural environment. It is generally related to the shearing of preexisting discontinuities, faults, or fractures, and is usually of low **magnitude** (microseismicity) and **intensity**. It occurs at shallower depths compared to natural seismicity, and generally ceases rapidly when industrial operations have terminated. Such seismicity is generally localized around the zone interested by the industrial activity.
  - **Triggered seismicity** is caused or accelerated by human intervention in a predisposed environment. The term "predisposed" means the presence of a fault or faults near the site, close to rupture (slip may occur with very low disturbances to the stress state). in other words, a natural seismic event would probably have occurred in the more or less long term even without human intervention. Such seismicity may occur at the industrial site and/or up to several kilometers from the site, and can also occur or even last for several

months to several years after industrial operations have terminated. Its magnitude may be higher than in the case of induced seismicity because it will be controlled primarily by the characteristics of the preexisting fault, particularly its size and the quantity of elastic energy stored in the fault by the action of tectonic forces.

Thus, anthropogenic seismicity includes induced and triggered seismicity.

It is difficult to differentiate the seismicity type directly from seismic recordings, because the seismic signals are very similar regardless of the disturbance source. As a result, the ability to distinguish between natural seismicity, induced seismicity, and triggered seismicity is currently a complex issue that may cause conflicting discussions between scientists, operators, government agencies, elected officials, and residents' associations. In any case, the approach usually used is based on knowledge of the possible presence of faults and the stress state, and on spatio-temporal correlations between seismicity, seismic rate variations, and industrial operations.

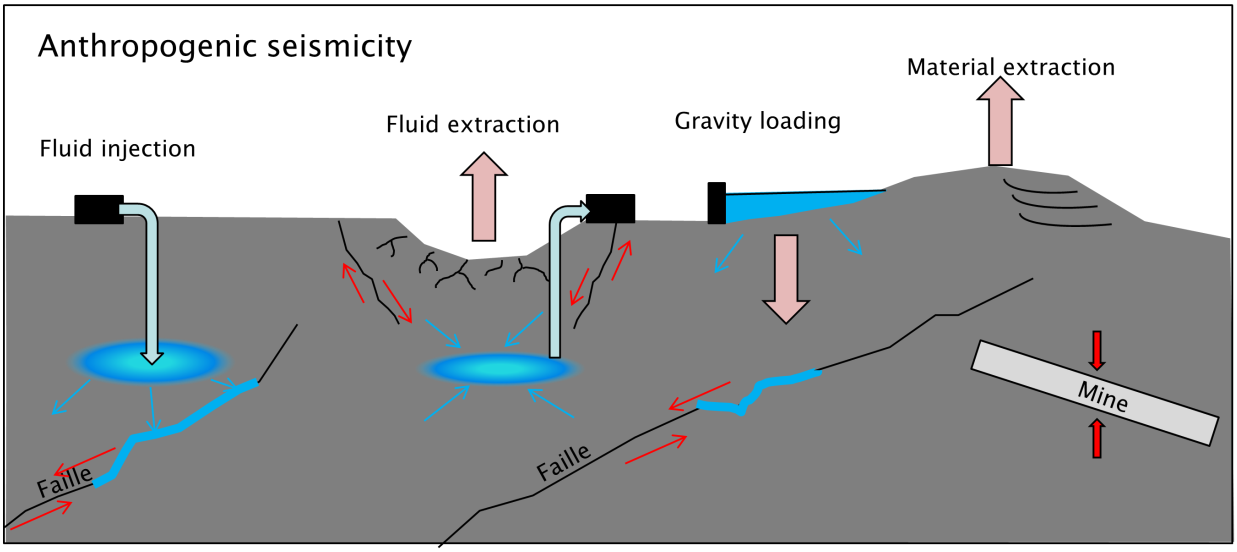


Figure 6: Simplified diagram illustrating certain anthropogenic loading conditions that a rock mass may by subjected to (Contrucci and Klein, 2017 from Ellsworth, 2013 and McGarr et al., 2002). The pink arrows show the effects of underground ***loading*** *or unloading related respectively to the industrial processes of water impoundment (e.g., dams) or fluids extraction (e.g., oil & gas industry) or mass removal (e.g., mining). The red arrows represent possible movements along fault planes and the possible collapse of underground spaces, such as in mining operations. The blue arrows represent the possible migration of fluids in the rock mass, which could reach fault planes and promote their slip (blue lines).*

It should be noted that several authors often use the term induced seismicity to discuss both induced and triggered seismicity (as defined above). **In this guide, the generic term 'induced seismicity' is used to qualify both types of seismicity caused by deep geothermal operations.**

3.2. Definitions and characteristic parameters of seismicity

3.2.1. Hazard, risk, and risk perception

Seismic risk (Figure 7) is evaluated by analyzing the probability of occurrence of an earthquake of a given intensity at a given location (hazard), and also by determining the physical, functional, and social vulnerabilities of the assets exposed to seismic hazard that may be of a human, economic or even heritage character.

Thus, assessing seismic vulnerability of buildings and infrastructures requires their precise examination, including dense urban and/or industrialized areas and historic areas with very old buildings that do not meet current construction standards. The sensitivity level of local populations to seismic vibrations is also a key component of the vulnerability assessment. In the context of induced seismicity, it is important to consider human perception, awareness, and the local context of the project and its consequences on the population (Appendix to the report by Maury and Branchu, 2020). This results in case-by-case decision-making by competent authorities regarding the safety thresholds to adopt and acceptable risk levels.

Such aspects largely exceed the framework of this guide, which is why only a hazard assessment related to "seismicity induced by deep geothermal operations" hazard at the site level **will be proposed (chapter6) ; vulnerability aspects cannot addressed by a general approach.**

Natural seismic hazard in France is reflected by the national seismic zoning map (Decree No. 2010-1255 of October 22, 2010).

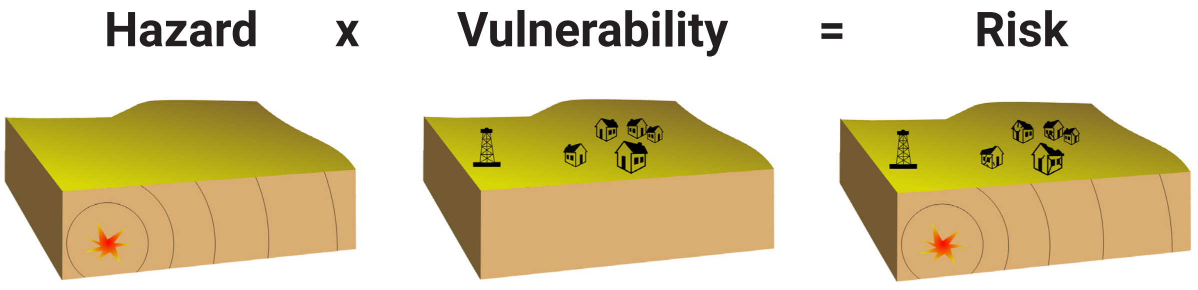


Figure 7: Illustration of the definition of seismic risk, by the product of hazard and vulnerability

3.2.2. Magnitude

Magnitude characterizes the earthquake energy released in the form of waves. It is calculated using the waves recorded by seismometers. There are several types of magnitude scales, which differ in the calculation method used. This is why multiple magnitude values may be assigned to the same earthquake. The **Richter scale** is the oldest and most widely known to the general public, but it is less used by seismologists. For the past several years, moment magnitude has become the international reference, since it is the only scale truly related to the surface and the amplitude of the rupture (Annexe 2). From a practical perspective, local magnitude is used the most, because it is calculated more easily and quickly, particularly in an operational context. In the rest of this guide, the generic term "magnitude" will be used for all magnitude types.

A one-unit increase in magnitude is equivalent to multiplying the energy released by 32: a magnitude 4 earthquake releases 32 times more energy than a magnitude 3 earthquake, and 1,000 times more energy than a magnitude 2 earthquake. Magnitude also makes it possible to estimate the size of the fault activated. .

In general, the term "microseismicity" covers earthquakes whose magnitude does not exceed a value close to 2, corresponding to the rupture of a fault along a distance of about 50 meters, with displacement of a few millimeters on one side of the rupture surface area relative to the other. The magnitude scale has no lower or upper limits. Until now, the strongest earthquake ever recorded was a magnitude 9.5 natural earthquake in Chili in 1960. It is also common to record earthquakes of a negative magnitude, particularly related to anthropogenic activities; the lowest magnitude recorded during stimulation at Soultz-Sous-Forêts in 2003 was -0.5. It should be noted that recording negative magnitude events depends on the performance of the seismic network used[11].

3.2.3. Intensity

Intensity characterizes the earthquake's effects at the surface. It also gives an indication of the public's perception and of eventual damage to buildings or the environment. Intensity is generally highest directly over the hypocenter, called epicentral intensity, and generally decreases with increasing distance from the **epicenter**. This means that, for a given earthquake, the intensities (effects/perceptions) vary depending on where one is located at the ground surface.

The most frequently-used intensity scales in Europe are the MSK 1964 scale (Medvedev-Sponheuer-Karnik) and EMS-98 (*European Macroseismic Scale*, 1998). The more recent EMS-98 scale (Table 4) is well-suited to the various existing construction types. However, methods for assessing the surface impact of natural earthquakes cannot be directly transposed to analyze vibrations caused by induced earthquakes (Bommer et al., 2015). In fact, these latter earthquakes are relatively shallow (depth < 5 km), of low magnitude, and more frequent, therefore it is difficult to directly apply attenuation relationships (or ground vibration models) established based on natural earthquakes, which are generally more distant and deeper. These relationships link the magnitudes and distances to the seismic source with intensity values, but also the peak ground velocity (PGV) or peak ground acceleration (PGA) (section 3.2.4) expected at a given point at the surface. Thus, vibrations caused by such shallow earthquakes may be much more harmful and damaging than deeper tectonic earthquakes of the same magnitude (NRC, 2013 and Figure 8).

Given the relatively low depth of underground disturbances due to deep geothermal operations, **induced seismicity** is **relatively shallow** (generally less than 5 km). This feature results in a substantial increase in surface seismic movements for the same magnitude, compared to natural earthquakes, which are generally deeper. Thus, low magnitude events, even those less than 2, may be felt. For example, microseismic events in Landau (Germany) were felt starting at magnitude 1.3 (Groos et al., 2013). Several microseismic events ranging from magnitude 1.7 to 2.1 were recently felt by the population in the region of Strasbourg, France (French Central Seismological Bureau - National Seismic monitoring network (BCSF-RéNaSS) data).

Figure 8 is a simplified illustration[12] of this principle: a magnitude 1 or 2 earthquake is not (or very little) felt at the surface in the case of a tectonic earthquake at a depth of 10 km, while it can be felt for a superficial earthquake (generally the case for induced seismicity) of the same magnitude, e.g., at a depth of 2 km. A magnitude 3 earthquake can be felt in both cases, but over a larger surface area in the case of a shallow earthquake.

11 *– Negative magnitudes are associated with events of very low amplitude and energy. Recording them requires very sensitive measurement stations located near the event.*
12 *– This does not take into account possible site effects, the **directivity** of the source etc.*

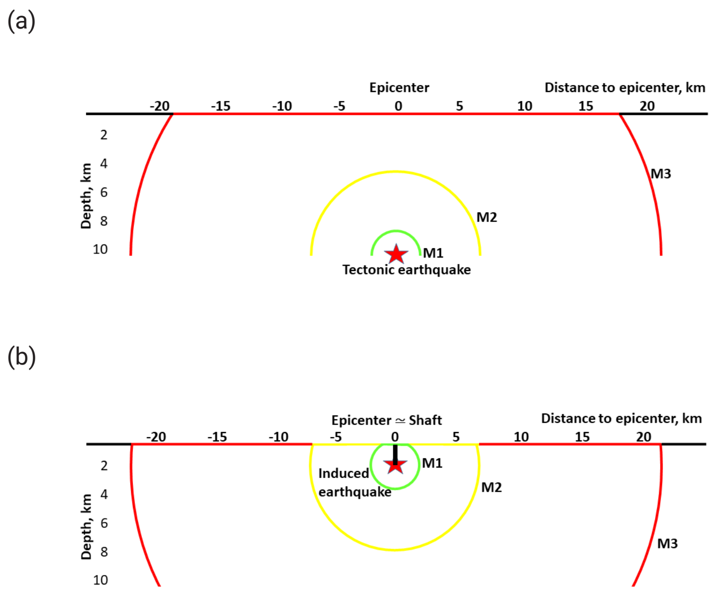


Figure 8: Cross-sections illustrating the maximum distance at which earthquakes will be felt for magnitudes 1 (green line), 2 (yellow line), and 3 (red line) for (a) a tectonic earthquake at a depth of 10 km or (b) an induced earthquake at a depth of 2 km. Diagram from NRC (2013).

3.2.4. Ground movement parameters

The definition of intensity itself may lead to a subjective quantification of seismic surface movement. For example, populations having already experienced an earthquake develop an enhanced perception of the slightest movement resulting from aftershocks.

In contrast, recordings from surface seismic stations provide an objective measurement of seismic movement at the probe, without over- or under-interpretation bias. Such objective surface measurements include all changes in the seismic signal between the **hypocenter** and the observation point. These correspond to displacement, velocity, or ground acceleration. The amplitude, duration, and frequency content of the seismic signal characterize the intensity of a vibration representative of the perception or the potential damage at the surface.

***Peak Ground Velocity* – PGV** or ***Peak Ground Acceleration* – PGA** are the most commonly-used parameters. Experience has shown that velocity is often the most significant parameter for assessing the effects of vibrations on buildings. In France and abroad, velocity is generally used as a criterion in prefectoral regulations setting maximum limits for quarry blasting or even for **TLS** *(Traffic Light System*, see chapter 8) thresholds for certain deep geothermal operations.

Peak ground acceleration is also widely used to determine reference seismic movements in order to design buildings for earthquake resistances (e.g., standard in international seismic building codes, such as Eurocode 8, 2018 International Building Code). However, as mentioned above, these standards were created for deep natural earthquakes, and could require revision for induced earthquakes, generally at depths less than 5 km.

Seismic sensors record the seismic signal directly as velocity (velocimeter) or as acceleration (accelerometer). However, it is easy to switch from one parameter to another by a simple derivation or integration of the seismic signal. Without discussing the various instrumentation types in detail, we can say that the velocimeter is better suited overall for recording a low magnitude earthquake very far away. Conversely, it is more sensitive to installation conditions and temperature differences, particular for installations on the ground surface. The accelerometer is very well suited to recording strong movements in relative proximity with no risk of clipping the seismic signal.

Figure 9 illustrates seismic movement in displacement, velocity, and acceleration as a function of time, with the following respective maximum values: *Peak Ground Displacement **(PGD)**, Peak Ground Velocity (PGV) and Peak Ground Acceleration (PGA)*. .

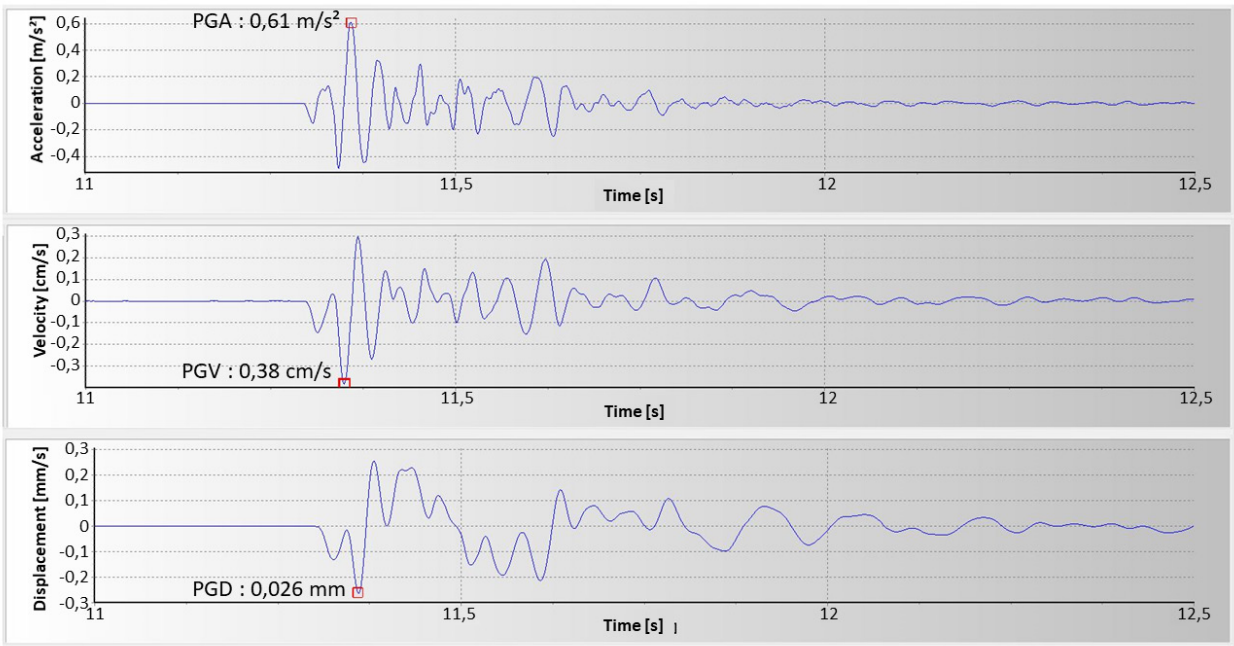


Figure 9: Example of seismic signals in acceleration, velocity, and displacement recorded by a station in the former coal basin of Gardanne in Provence, France. Induced microseismic event of July 27, 2022 – Magnitude 1.3 at a depth of 550m (PGA = 0.61m/s^2; PGV = 0.38cm/s; PGD = 26μm)

For information, Table 4 gives an indication about the correspondence between intensity and ground movement parameters (PGA and PGV).

Like intensity, ground movement parameters express the amplitude of seismic displacement at the surface. The higher the magnitude, and the shallower (or less deep) the earthquake, the greater the seismic displacement will be at the surface, while it will be influenced by **site effects** explained below. This is typically expressed by the ***Ground Motion Prediction Equation*** **(GMPE)**, which **provides ground movement parameters** according to distance, magnitude and other parameters related to the earthquake source or to site conditions. These equations are used to determine the level of vibration, generally PGV, of an earthquake of a certain magnitude at a given distance. There are several published examples of GMPE as a function of the magnitude intervals considered, as well as the attenuation characteristics specific to each site. Douglas (2020) recently published a review of existing GMPEs, which were determined empirically using real seismic data. In this context, we can cite the equations of Convertito et al. (2012) and Douglas et al. (2013) that were formulated explicitly for induced seismicity in geothermal projects.

Table 4: Effects on population and buildings (in gray) and ground motion parameters as a function of intensity (scale from Caprio et al., 2015)

Intensity EMS98	I	II	III	IV	V	VI	VII	VIII	IX	> X
Potential damages vulnerable buildings	none	none	none	none	None	moderate	some partial collapses	many partial collapses	many collapses	Widespread collapses
Potential damages Low vulnerable buildings	none	none	none	none	none	none	very slight	moderate	partial collapses	many collapses
Human perception	none	very weak	Weak	moderate	strong	brutal	very brutal	severe	violent	extreme
PGA (cm/s²)	< 0,2	0,7	2,8	11	46	84	154	281	514	> 940
PGV (mm/s)	< 0,07	0,3	1,3	5	23	55	130	310	730	> 1740

3.2.5. Site effects and related phenomena

Site effects are generally an amplification of seismic waves directly related to the topographic or geologic configuration of the site. Thus, we can make a distinction between:

- **Site effects that depend on the structure and nature of the ground**: the geometry of formations (stacking, filling valley bottoms), and mechanical characteristics (density, rigidity, compressibility) that may accentuate the effects of seismic movement; and
- **Topographic site effects**: hilltops, elongated ridges, and the rims of plateaus and cliffs are the sites of substantial amplification of seismic movement.

Figure 10 is an example of a configuration that could amplify seismic movement.

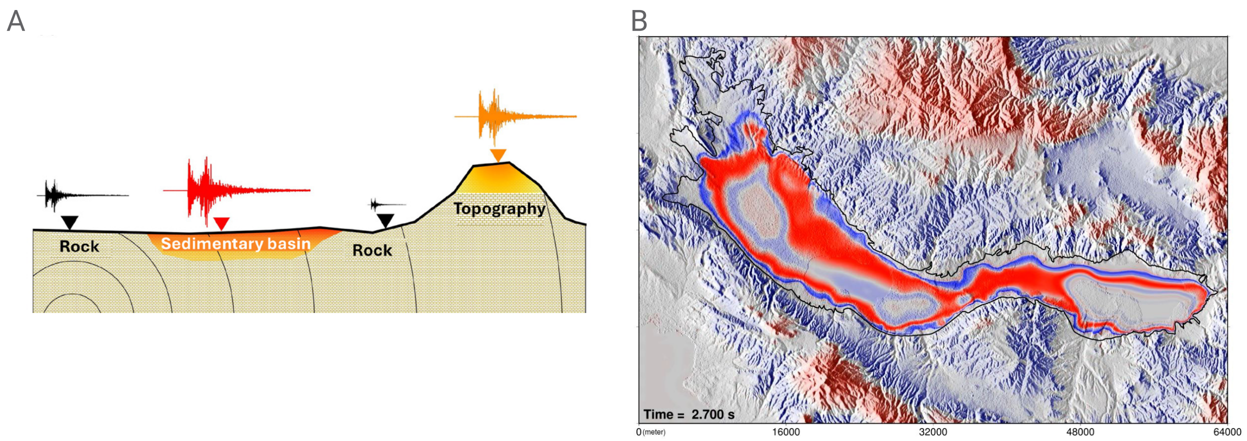


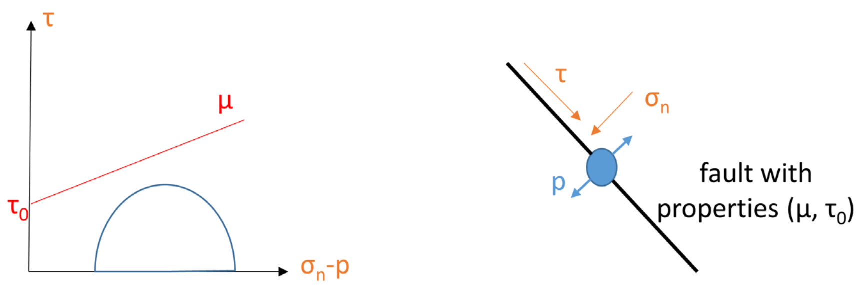
Figure 10: (a) diagram of site effect types (lithological and topographical). Seismic signals (seismograms) show the strongest movements recorded in site effect zones: ridges, 3D structures (in orange), and a zone of sedimentary basins (in red). The seismograms in black are recorded from rock. They are attenuated with increasing epicentral distance. (b) Example of amplification (in red) of seismic movement in a sedimentary basin and on neighboring 3D structures in Greece (De Martin et al., 2021; Sochala et al., 2020).

3.3. Mechanisms of induced seismicity

3.3.1. Mechanisms of fault slip responsible for seismicity related to geothermal operations

As discussed earlier (section 3.1), an earthquake occurs along a fault or a fracture and results in the violent release of stresses accumulated in the rock mass. The natural stress field depends on a number of factors and can be altered by human activities. The circulation of fluid in deep geothermal operations plays a major role in the mechanisms associated with stress changes and transfers. Seismicity can result from direct effects associated with fluid circulation, which acts on pore pressure, and from indirect effects with stress state changes due to poroelastic and/or thermoelastic mechanisms. It can also result from geochemical alteration of the rock matrix caused by fluid circulation.

Theoretically, several mechanical and hydromechanical criteria can explain the conditions of rupture. The Mohr-Coulomb failure criterion is most commonly used to describe slip along a discontinuity (Figure 11); it shows the relationship between shear stress (τ) and normal stress (σ_n) to the rupture plane.



(1)

$$\boldsymbol{\tau < \tau_0 + \mu(\sigma_n - p)}$$

Figure 11: Diagram of parameters acting on a discontinuity (in the center); Mohr's circle showing the initial state of stress before any disturbance (on the left) and the Mohr-Coulomb failure criterion (on the right).
A rupture occurs when the inequality no longer holds, i.e., when the circle representing the local stress state intersects the red line.

Where **τ**: shear stress parallel to the fault plane;

- **μ**: friction coefficient, generally between 0.6 and 1 (Byerlee, 1978; Dieterich, 1979);
- $\boldsymbol{\sigma_n}$: normal stress perpendicular to the fault;
- **p**: pressure exerted by the fluid (pore pressure);
- $\boldsymbol{(\sigma_n - p)}$: called effective normal stress ;
- $\boldsymbol{\tau_0}$: cohesion.

Therefore, the fault is stable as long as the shear stress (**τ**) is lower than the friction, shown by the term $\boldsymbol{\mu (\sigma_n - p)}$.

Figure 12 illustrates the principal mechanisms causing stress changes and thus fault shearing resulting from fluid injection (e.g., De Santis et al., 2021; Maury and Branchu, 2020). Generally, the seismic response of the rock mass to anthropogenic activities is complex (chapter 5): underground fluid diffusion depends on several factors, among which the geologic and hydraulic properties of the reservoir. It is therefore frequent that a dominant mechanism is observed to which other mechanisms may be added or subtracted.

In a poorly-porous, fractured environment, for example, fluid diffusion is preferentially controlled by non-linear processes, where a central role is played by hydraulic properties and by the orientation of preexisting fractures. For high temperature (more than 200°C) geothermal fields, thermoelastic mechanisms may play a major role in triggering seismicity, particularly near reinjection wells, due to the significant temperature difference between the injected fluid and the reservoir.

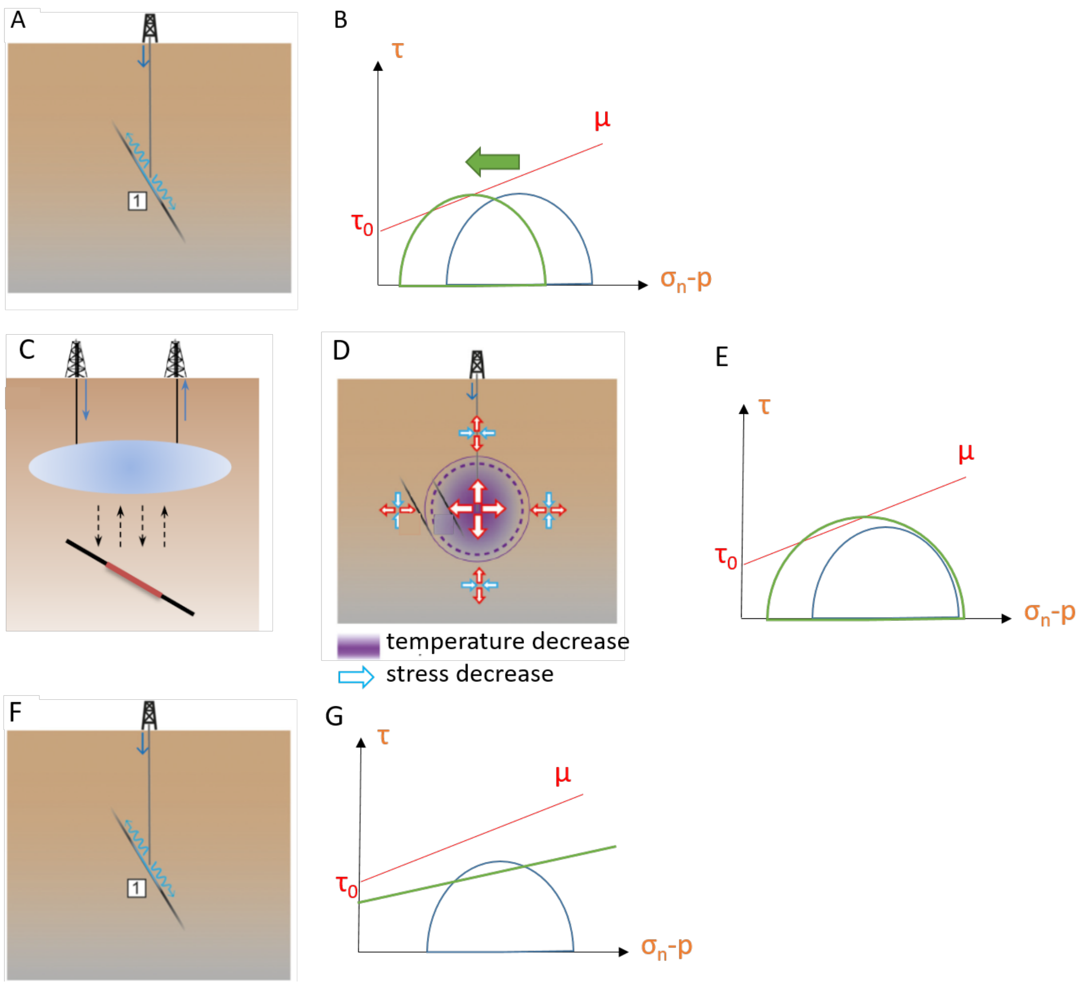


Figure 12: Mechanisms triggering induced seismicity due to fluid injection (from Buijze et al., 2019b and De Santis 2021). First line: under the effect of increasing pore pressure (A) Mohr's circle showing the initial stress state (in blue) is shifted (green circle). Second line: stress (Δσ) under the effect of poroelastic and thermoelastic mechanisms (C) or of a temperature decrease (D). Mohr's circle (E) representing the initial stress state (in blue) changes size and shifts (note that the stress variation Δσ may be positive or negative depending on the location of the fault). Third line: the rupture envelope (slope of the line at its y-intercept, in green) changes under the effect of an alteration of the mechanical properties of the rock resulting from fluid circulation (F).

3.3.2. Aseismic slip

The proper understanding of the fluid-seismicity relationship is also made complex by the presence of aseismic slip along preexisting faults and discontinuities. This slow, stable type of slip **occurs without seismic waves being emitted**; it is frequently accompanied by the slow relaxation of stresses in the medium, as explained by certain laws of friction[13].

Slow slip may be triggered during the fault **loading** phase, but also following an earthquake, due to stress redistribution. It is characterized primarily by a general increase in friction during slip, thereby preventing seismic waves from being emitted.

Various examples have shown that aseismic slips can occur in exploited geothermal reservoirs, such as Soultz-sous-Forêts (Cornet, 2016), Rittershoffen (Lengliné et al., 2017), or North Brawley, in California (Wei et al., 2015). Such aseismic slip may in turn cause induced seismicity in geothermal reservoirs, in a mixed seismic and aseismic process (De Santis et al., 2021; Wynants-Morel, 2021). In this context, this aseismic slip can be identified by analyzing seismic signals to detect events characterized by very similar waveforms resulting from repetitive seismic ruptures along fault segments qualified as asperities. In fact, according to Bourouis and Bernard (2007), such asperities are zones in the fault plane where the slip stops temporarily and locally, whereas the surrounding region slips continually and aseismically, loading the asperity, which then breaks repetitively.

The triggering of post-injection seismicity could be explained in part by these aseismic mechanisms (see section 3.4; Cornet, 2016; Lengliné et al., 2017). In addition, *in situ* fluid injection experiments to depths of several tens of meters in different geologic environments have shown a primarily aseismic deformation (De Barros et al., 2016; Guglielmi et al., 2015). Similarly, in an experiment injecting fluid into a fault conducted in the Philippines, the fault slipped aseismically without causing an earthquake (Prioul et al., 2000). If the conditions of fault slip were better known and well controlled, it could become possible to prevent unstable slip (Cornet, 2016).

In the current state of observations and knowledge, it is not yet possible to anticipate the response of a fault to fluid injection. Monitoring aseismic deformation in geothermal contexts is still a research matter, which is why proposals will be formulated in the following pages of this guide, in order to help acquire data and drive research on this subject (section 7.4).

3.4. General features of seismicity induced by deep geothermal operations

Induced seismicity resulting from fluid injection often occurs near the injection point and may extend up to several kilometers (3 to 5 km in fault and fracture controlled systems) (De Santis et al., 2021). However, induced earthquakes may occur at greater distances (on the order of ten kilometers) from the injection point (Goebel and Brodsky, 2018). The distance at which the induced seismicity occurs is to be related to its causal mechanism (diffusion of pressure or poroelastic phenomena, section 3.3).

Induced seismicity often exhibits spatio-temporal migration, i.e., events first occur near the injection point, and then gradually migrate further away. However, this is not always the case, in several sites having a mixed control system, an earthquake deeper than the injection point occurred immediately (De Santis et al., 2021). This phenomenon would be related to hydraulic connections between the reservoir and the basement that reactivate faults whose orientation is the most critical in terms of mechanical equilibrium with respect to imposed stress changes.

13 *– Friction is the resistance to movement between the two compartments of the fault.*

Concerning the temporal aspects of induced seismicity, it may occur at the same time as fluid injection and/or extraction and stop within weeks after the disturbance terminates, but it may also last for several months or even years (Maury and Branchu, 2020). Such temporal issues are intimately linked to the local geologic context, to the hydraulic properties of the geothermal reservoir, and to operational conditions (volumes, flow-rates, pressures, etc.). One feature unique to seismicity induced during operations conducted to increase the permeability of preexisting discontinuities (section 2.1.2.3) is the occurrence of the maximum magnitude event in the post-injection phase (e.g., Evans et al., 2012; Majer et al., 2007; Mukuhira et al., 2017; Zang et al., 2014). As will be discussed in more detail in chapter 8, the occurrence of significant-magnitude events after the end of operations poses a major problem for managing seismicity on geothermal sites. Indeed, the mitigation solutions employed, based on optimizing operational parameters (pressure, flow-rate, etc.), are ineffective when operations are stopped. Anticipating the occurrence of post-injection seismicity is still the only way to reduce the associated risk, but this remains difficult because its causes are still poorly understood.

3.5. Induced seismicity throughout the world

The on-line Human-Induced Earthquake Database, (HiQuake),[14] (last access June 16, 2021) provides an extensive overview of induced seismicity throughout the world, since it contains more than 1,200 induced events since 1868 that have been published. It confirms that the occurrence of seismic events resulting from anthropogenic activities has been observed for different types of industrial operations.

Among all these events reported in the database, 75, or 6%, are attributed to geothermal operations (Figure 13). It should nevertheless be noted that this database includes all events classified theoretically as induced, i.e., without validation by experts (Foulger et al., 2018), and that it is not exhaustive, since not all cases of induced seismicity have been published.

The low impact of deep geothermal operations on induced seismicity compared to other technologies should be interpreted considering the relatively recent development of geothermal activity compared to other industrial sectors. For example, mining is much older than deep geothermal operations, which could explain the proportional difference in cases of induced seismicity. The unconventional production of oil & gas is clearly recent, but compared to mining, it requires the massive underground flud injection for fracking and the wastewater injection, which are both highly seismogenic. Finally, it should be noted that the number of operations or projects in each of these broad categories of industrial activities is highly variable. Indeed, some activities are more developed than others, making the comparison difficult: these numbers cannot be related to the total number of projects per activity category.

Despite such limitations, the HiQuake database makes it possible to conclude that seismicity induced by deep geothermal operations accounts for a small part of the seismicity induced by underground industrial activities. It is also to be noted that lessons can be learned from these different industrial sectors in terms of hazard mitigation and the risk of induced seismicity. Much of this understanding is based on monitoring microseismic activity in order to limit the stress accumulation in sensitive zones or to help promote their relaxation as much as possible by adapting operational methods (see Contrucci and Klein, 2017 for a review of these aspects). A review of the effects of underground fluid injection has been published by NRC (2012).

In the following chapters, we will see how induced seismicity is distributed among the three principal geothermal systems and will discuss the operational parameters and intrinsic factors that control the occurrence of induced seismicity.

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14 *– https://inducedearthquakes.org/ Each item in the database is a project or the phase of a project (operation). For example, Soultz-sous-Forêts appears twice for seismicity in 2000 and 2003. Some data are not included, such as the date of occurrence of the maximum intensity earthquake or its magnitude. More generally, the database relies on studies published in the scientific literature that usually concern high magnitude events.*

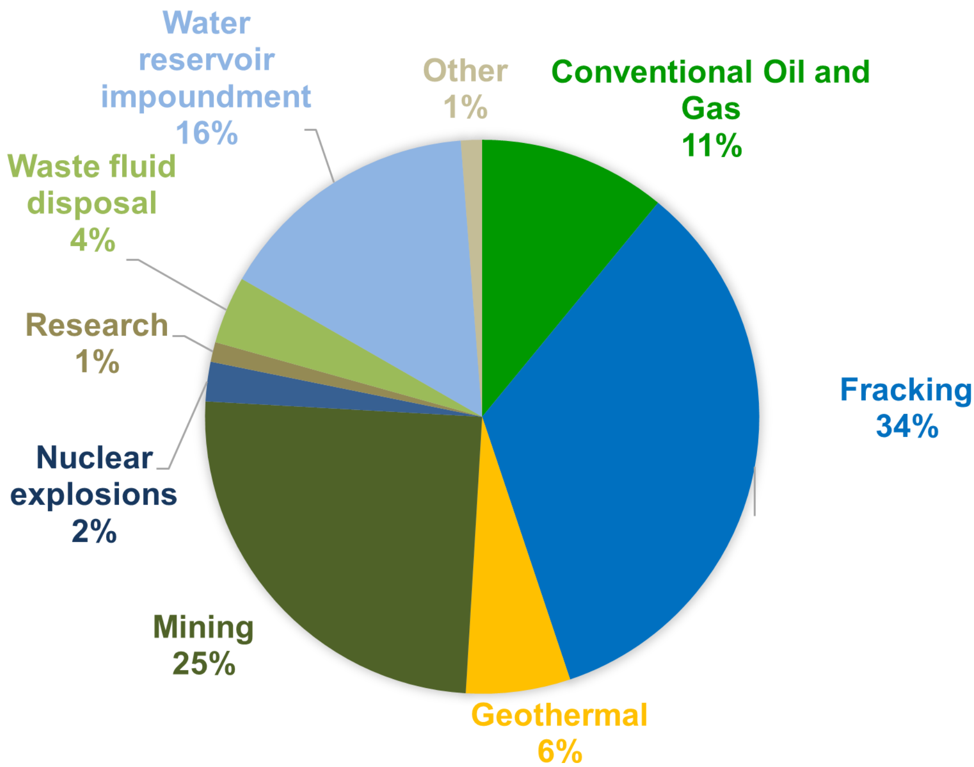

Figure 13: Causes of induced seismicity from the HiQuake database[14]. "Other" includes activities contributing less than 0.5% to induced seismicity (carbon capture and storage, chemical explosions, coal bed methane exploitation, construction, deep penetrating bombs, oil & gas /wastewater injection).

4. Geothermal projects and induced seismicity: overview and case studies

This chapter begins by defining what is a **seismic incident**. We then give an overview of incidents recorded in France and abroad associated with deep geothermal operations. We will show that, ultimately, such incidents are infrequent, despite multiple biases at work in compiling the available data. We continue with a description of the case studies used, in the following chapter, to identify the predisposing factors of seismic hazard. This chapter ends by discussing the relevance and representative nature of such case studies. The results from those case studies ultimately form the basis of the recommendations made in the rest of this guide.

4.1. Overview of seismic incidents

4.1.1. In France

In this section, the number of **seismic incidents** is compared to the number of deep geothermal projects. The term "seismic incident" means **any event that results in complaints or even the shutdown of a project**. One single seismic incident (the earthquake of the highest magnitude) per geothermal project is considered thereafter.

In France, the first deep geothermal wells date back to the 1970s, with most projects located in the Paris Basin supplying district heating systems. Currently, there are 259 wells (Metropolitan France and in Overseas Regions and Departments (DROM)) [15]. Among all these projects, only two, Soultz-sous-Forêts (2003) and Vendenheim (2021), experienced seismic incidents, representing less than 2% of the projects.

We observe (Figure 14) that none of the 115 projects involving systems controlled by matrix porosity and permeability were associated with any seismic incidents. The number of projects in geothermal systems controlled by faults and fractures is more limited. There are just 6 projects, including the Bouillante project located in a volcanic zone, a project for which no incidents have been recorded. Two of the five extensional domain-type projects have been affected by earthquakes that were felt by the local population (Figure 14). Likewise, no incident has occurred in the six mixed-domain projects.

At this stage, however, we should not draw premature conclusions on the relationship between the geothermal system involved and the occurrence of a seismic incident. Firstly, there are too few projects in domains controlled by faults or in mixed domains to be able to produce reliable statistics. Secondly, the conditions in which projects are conducted vary too much depending on the geothermal and geologic context, project objectives, operational organization, and technologies used (section 2.1.2).

15 – These numbers include all projects, either under development, such as Illkirch-Graffenstaden or Bobigny-Drancy, or operational or shut down, such as Vendenheim.

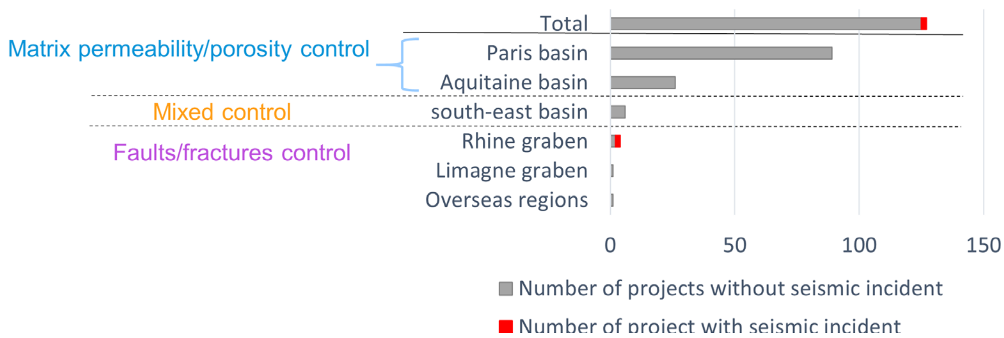

Figure 14: Geothermal projects in France with and without seismic incidents (from the Sybase database, BRGM, plus electricity generating projects in Bouillante (outermost area) and Soultz-sous-Forêts). The associated geothermal system is provided for informational purposes (see text).

4.1.2. In Europe

In **Europe**, most *European GeoSurveys*[16] centralize the national statistics concerning the number of seismic incidents associated with deep geothermal operations. However, it is not easy to directly compare statistics from different countries, because the lower limit of perception at which the population expresses annoyance or unease can vary widely. For example, in Iceland, a country with recurring seismic and volcanic activity, the alert level beyond which operations must be scaled down is magnitude 4 (Peter-Borie et al., 2020b) whereas that magnitude in France is about 2. Therefore, the comparison of data between European countries should be taken with precaution, but it still provides an inventory of the number of projects related to seismic incidents. The *European GeoSurveys*[17] database has been supplemented here by data from the 2020 market report of the EGEC (European Geothermal Energy Council)[18] (EGEC, 2021) containing statistics on the number of deep geothermal projects (heating and electricity systems) comprising projects which are operational and those for which financing has been announced and/or a drilling contract has been signed. After cross-checking these data sources, it appears that **out of 571 projects, only 2% (14 projects** including the two above-mentioned projects in France) **have been the subject of seismic incidents** (Figure 15). This comparison should be taken as an order of magnitude, since **several projects that had been subject to incidents are now permanently shut down and are therefore not included in the number of projects**. In addition, some projects in the development stage may be in the pre-drilling phase, thus in this case, the lack of seismic incidents is not significant. .

16 *– European geological surveys collect the available information on the underground geology in their countries.*
17 *– Where European GeoSurveys did not have this information, we contacted local researchers in order to supplement that database.*
18 *– The EGEC is a European association whose aim is to promote the geothermal energy industry.*

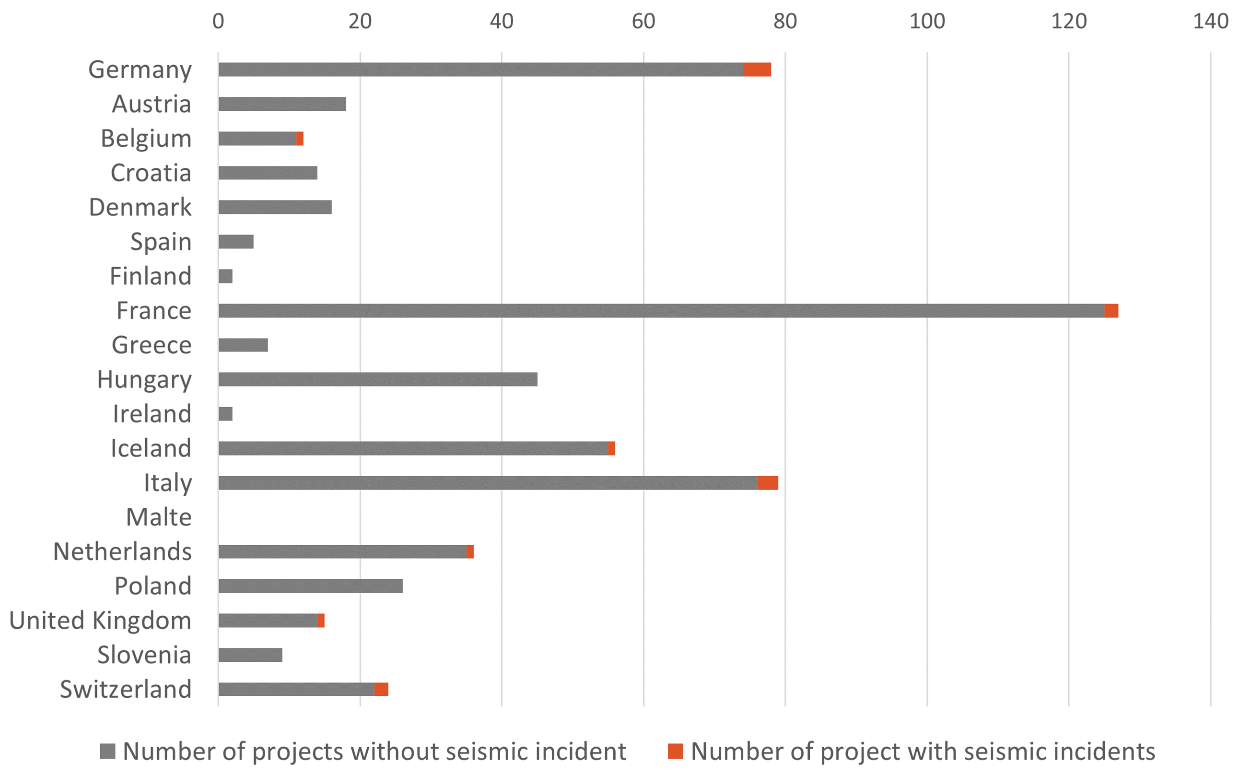

Figure 15: Geothermal projects with and without seismic incidents in Europe (including France). The number of projects (operational and under development) is derived from the EGEC report. The number of incidents is derived from a survey of the various entities in each country in possession of such information.

4.1.3. Throughout the world

Despite the limitations and biases of the HiQuake database[14], it provides information on the evolution of **maximum magnitude** events (Figure 16), starting in the 2000s, with the development of geothermal projects (and therefore installed power). Thus we may note a recent decrease in the number of events over 2015-2020, with about one event per year. Meanwhile, installed power continued to increase in 2015 and probably in 2020 as well, as suggested by the electricity consumption curve. In conclusion, we may note a lack of correlation between the number of induced seismic events and installed power, i.e., even if an increasing number of projects are developed, the number of seismic events remains stable.

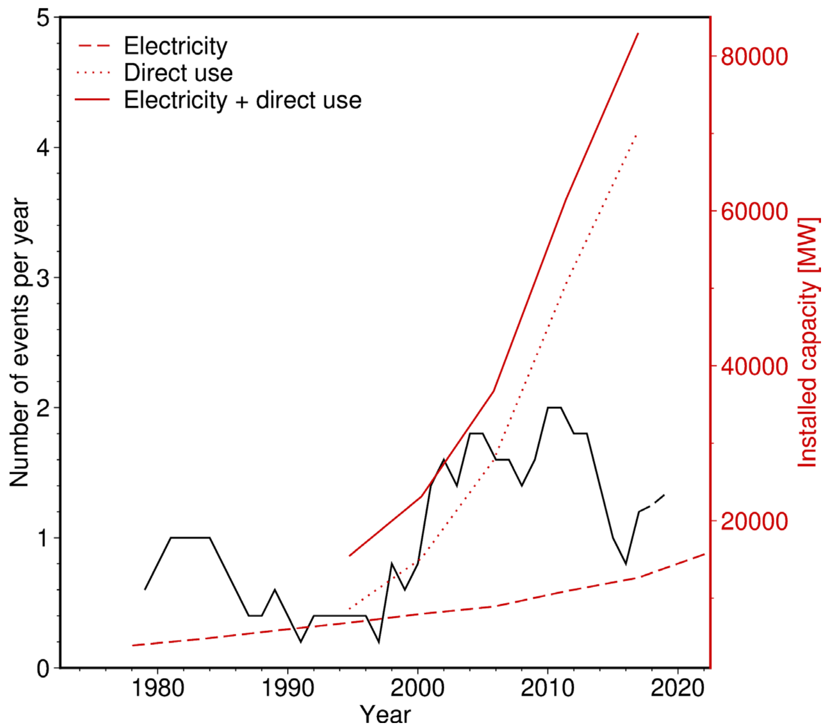

Figure 16: Comparison between the number of seismic events per year attributed to geothermal operations and installed power. In black, 5 year rolling average of the number of seismic events attributed to geothermal operations (source: HiQuake database[14]); just 46 of 74 events have a precise date. The curves in red show the evolution over time in installed power worldwide as a function of usage (Bertani, 2016; Huttrer, 2020, 2001; https://www.geothermal-energy.org/explore/our-databases/geothermal-power-database/#electricity-generation-by-country). This power assessment is conducted every 5 years.

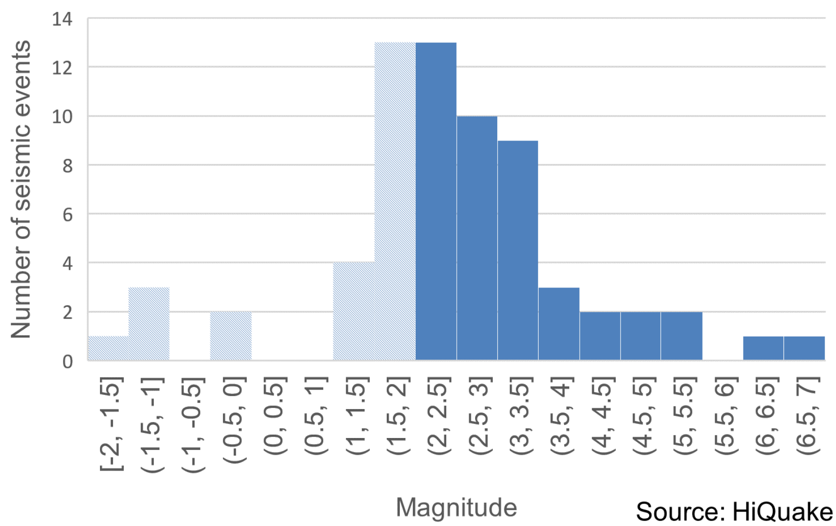

*Figure 17: **Maximum earthquake** magnitude observed where available (source: HiQuake database[14]). It should be noted that there are no data making it possible to link the maximum earthquake magnitude to the **completeness magnitude** of the monitoring network that recorded that event. The hatched bars represent the magnitude range for which the database is very likely incomplete.*

The maximum magnitude is known for 68 of the seismic events in the database (Figure 17). Very few events have a maximum magnitude less than 1. On one hand, this is explained by the fact that not every geothermal project is equipped with a dedicated seismic monitoring system and by the fact that the completeness magnitude of national seismologic networks is generally close to 2. On the other hand, low magnitude values, having little or no impact at the surface, are not published systematically unless specific research studies have been conducted. The large majority of events inventoried (68%) have a magnitude between 1.5 and 3.5. With the exception of Pohang, all suspected induced events of a magnitude larger than 5 occurred in operational geothermal projects located in areas known for having significant natural seismic activity.

In conclusion, and despite all the limitations and biases of the aspects already mentioned, the take-home message is that **seismic incidents concern a small percentage (~2 %) of deep geothermal operations**. The number of seismic incidents does not increase with time, and their proportion compared to the number of projects even tends to decrease. In addition, the large majority of seismic events recorded (70%) have magnitudes less than 3, meaning that even though they can be felt, personal and property damage is limited or nonexistent.

4.2. Presentation of case studies

The selection of case studies in order to better understand and identify key factors associated with the occurrence of seismic incidents was based mainly on one study conducted by INERIS (De Santis et al., 2021). A detailed literature review made it possible to analyze some 30 deep geothermal projects associated with the occurrence of seismic events of magnitudes greater than or equal to 1.5, some of which were felt at the surface. It should be noted that some of these geothermal projects are distinguished by the occurrence of multiple seismic episodes, each related to different **operations**.

In order to analyze not only the conditions in which seismicity occurs, but also to investigate its absence, the work of De Santis et al. (2021) is enriched here by a study of about 20 projects associated with no seismicity or with low magnitude events (M < 1.5). **In total, 53 deep geothermal projects (Figure 18a and b) and 77 operations are considered here**. Beyond the bibliographic references specific to each project and/or seismic episode, the two important information sources used to constitute our database are the work of Buijze et al. (2019a, 2019b), which collected and analyzed a significant amount of data on numerous geothermal projects, as well as the HiQuake database[14]. Figure 19 shows all the projects selected, indicating, for the projects concerned, the **maximum magnitude** of the induced earthquakes. .

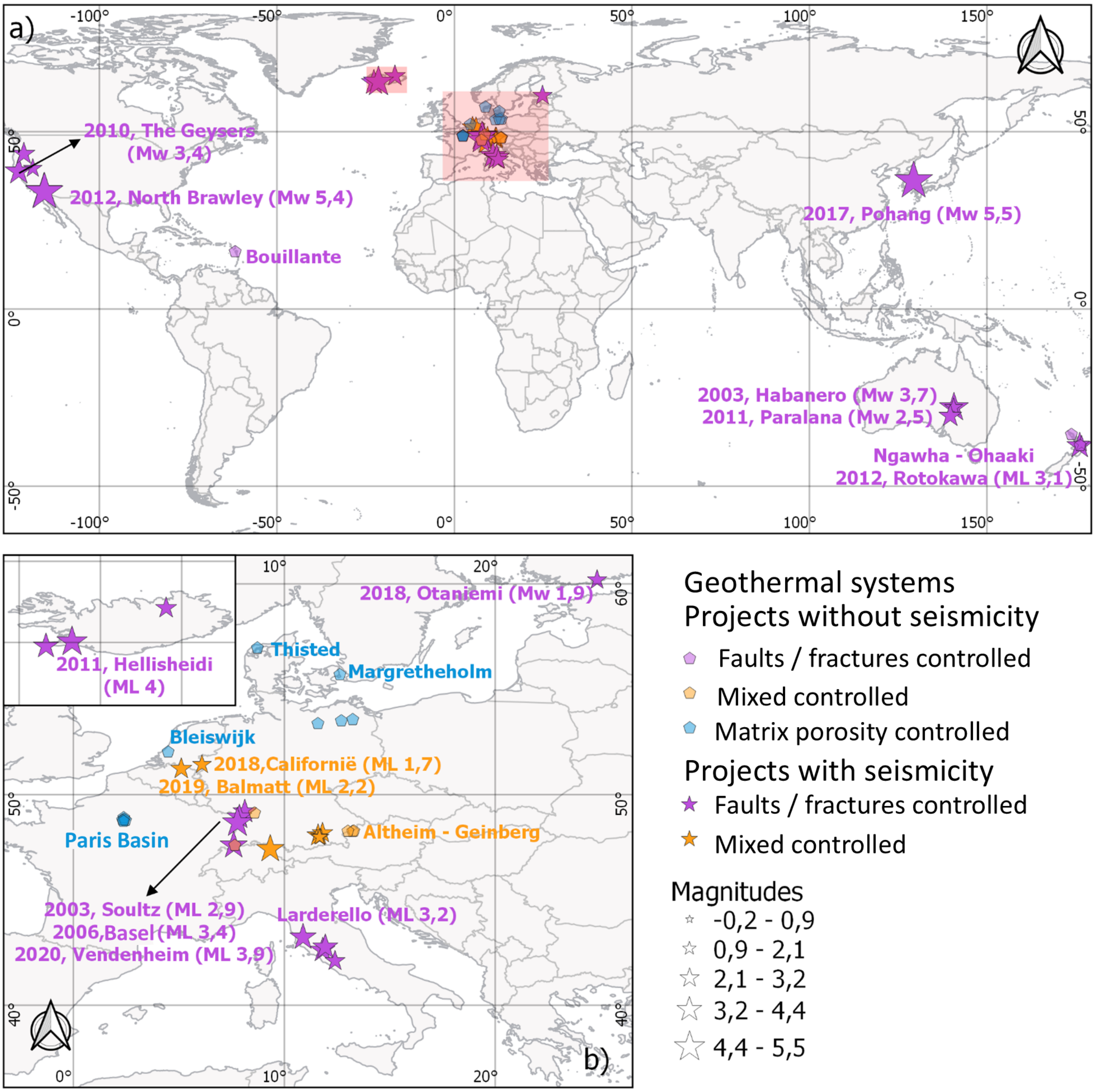

Figure 18: Map of geothermal projects (a) with a focus on Central Europe and Iceland (b). Projects where seismicity has occurred are indicated with a star, the size of which is proportional to the maximum magnitude of the induced events for each project. Projects not associated with seismicity are indicated by a pentagon. The color of the stars and pentagons indicates the geothermal system of each project (legend).

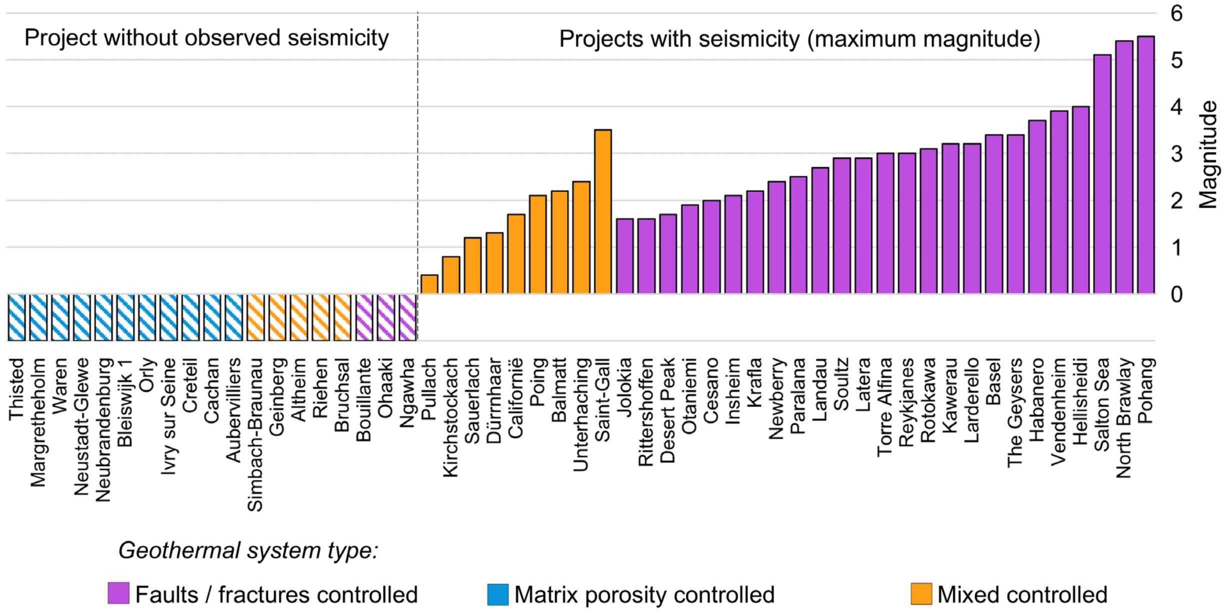

Figure 19: Geothermal projects. Projects without seismicity are shown (on the left) in the histogram with hatched bars. Projects in which seismicity has occurred are shown (on the right) with solid bars. In the latter case, the histogram bar shows the maximum magnitude observed for each project. The color code indicates the geothermal system as in Figure 18.

4.2.1. Classification of the projects selected based on the geothermal system type

The geothermal projects selected were grouped (Figure 18 and Figure 20a) according to the **three types of geothermal systems** described in section 2.1.2.1, based on the geological control of fluid flow within the reservoirs (Table 1):

- **Systems in which flow occurs primarily through matrix porosity and permeability** (blue in Figure 20a, i.e., the Paris Basin);
- **Mixed systems** in which flow is controlled by both faults and fractures, and by matrix porosity and permeability (orange in Figure 20a, i.e., the Bavarian Molasse Basin);
- **Systems controlled by faults and fractures** (violet in Figure 20a) in which flow is controlled by fault/fracture networks in the reservoir and which include all basement type projects (BT in Figure 20a, i.e., Paralana), extensional domain type (EDT in Figure 20a; i.e., Rhine Graben), as well as volcanic type (VT in Figure 20a, i.e., Bouillante) and plutonic type (PT en Figure 20a, i.e., Larderello).

A total of 11 projects were selected for geothermal systems controlled by matrix porosity and permeability (Figure 20a). These projects, which are not associated with the occurrence of seismicity (see Figure 18b and chapter 5), are all located in Europe (Figure 18b), particularly in the Paris Basin, Northern Germany, Denmark, and The Netherlands. All of them target porous sedimentary aquifers (primarily sandstone and carbonates).

All of the **14 projects selected with mixed control geothermal systems** (by faults/fractures and matrix porosity and permeability) (Figure 20a) are also located in Europe. Ten of these projects are in the Molasse Basin between Switzerland, Southern Germany, and Austria (Figure 18b), targeting a porous sedimentary aquifer (primarily limestone), but which is highly karstic and fractured. The remaining four projects selected in the same category are located in The Netherlands, Belgium, and in the Rhine Graben between Germany and Switzerland (Figure 18b). The sites in The Netherlands and

Belgium are Californië and Balmatt, both targeting a karstified and fractured sedimentary aquifer (primarily sandstones and limestones). Finally, the two Rhine Graben projects in mixed control systems are the sites of Bruchsal (Germany) and Riehen (Switzerland), which exploit Triassic sandstones overlying granitic basement rock.

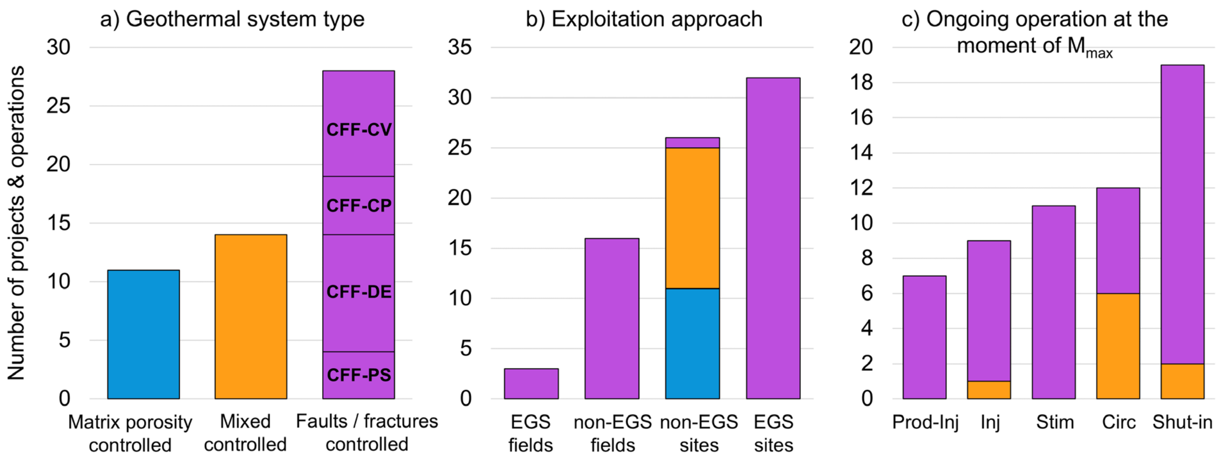

Figure 20: Number of projects and case studies analyzed based on the geothermal system (a), the operating technology (b), and the type of operation under way when the principal seismic event occurred. The color code of figures (b) and (c) is defined by the first three columns of figure (a). In figure (a), for systems controlled by faults and fractures, the geothermal play type of the projects selected is also indicated: BT – Basement type; PT– Plutonic type; VT – Volcanic type; EDT – Extensional domain type. Types of operations in figure (c): Inj – Injection; Prod-Inj – Production and reinjection; Circ – Circulation;
Stim – Stimulation; Shut-in.

The **28 projects having geothermal systems controlled by faults and fractures** (Figure 20a) are characterized by a larger variety of geothermal contexts and are more widely distributed around the world (Figure 18a and b). In Europe there are seven projects in Italy and Iceland, related to plutonic and volcanic contexts, respectively; six extensional domain type projects in the Rhine Graben between France, Switzerland and Germany; and one basement type project in Finland. The seven other plutonic and volcanic type projects selected are located in the United States, New Zealand, and Guadeloupe (Figure 18a), while the other three basement type projects are all located in Australia. As for the extensional domain type projects selected, in addition to the six European projects, four others were selected: three in the United States and one in South Korea.

4.2.2. Characteristics of projects and case studies selected

Table 5 summarizes the characteristics of the geothermal projects selected**. The maximum depths of the projects vary from 1 to 6 km, with reservoir temperatures ranging from 45°C to over 400°C. Projects with systems controlled by matrix porosity and permeability are generally at shallower depths, with reservoir temperatures below 100°C. The mixed control projects selected have temperatures between 80 and 145°C, and average depths, with wells drilled 2 to 4 km deep and generally stopping above the basement.** Considering the different geothermal contexts in systems controlled by faults and fractures, the temperatures and depths of these projects may vary widely. Basement type projects are in fact deeper, with wells drilled to more than 4-6 km and temperatures not exceeding 270°C. In the extensional domain type, depths may vary considerably, from 1.5 to about 5 km, with wells in some cases drilled several hundred meters or even several kilometers below the basement. Finally, for volcanic and plutonic type projects, average depths do not exceed 3 km, and the highest temperatures in most cases range between 200°C and over 400°C.

There is a variety of operating technologies used in the different projects selected. As illustrated in Figure 20b, established based on the definitions in sections 2.1.2.2 and 2.1.2.3, **case studies were labeled as sites or fields depending on the exploitation approach** . We will use "sites" for geothermal projects containing a few wells in proximity (doublets, triplets, or quadruplets) and use "fields" for projects with multiple production and reinjection wells (Figure 4). The difference between these two installation configurations is that the footprint of fields is generally several dozen km², much more extensive than sites, and thus field production rates are usually much higher. As shown in Figure 20b, geothermal sites can be observed in all geothermal system types, while fields are limited to operations in systems controlled by faults and fractures.

Independent of whether the projects selected are organized as fields or sites, **the geothermal resource can be exploited both without EGS technologies or**, when necessary, **by conducting hydraulic, thermal and/or chemical stimulation** to improve the hydraulic properties of the reservoir. In the first case, the projects (fields or sites) selected in the database are categorized as non-EGS, while in the second case, they are categorized as EGS (Figure 20b). It should be noted, however, that the acidizing usually used in systems controlled by matrix porosity, as is often the case in Paris Basin sites, as well as the thermal stimulation consistently used in wells at Icelandic projects, in systems controlled by faults and fractures, are not categorized as EGS because they are used conventionally and systematically before the sites or fields are in production (see section 2.1.2.3). In addition, in many cases, EGS technologies can be used only for certain wells at one site or field. For example, this is the case for the Rittershoffen site, where only one well of the doublet was stimulated, for Bouillante (stimulation of well BO4), as well as the geothermal fields of Hellisheidi (Iceland) and The Geysers (United States). In these cases, the project is categorized as EGS or non-EGS based on the operation (and thus the well) taken into account in the database. That is why we have categorized the Bouillante project as a non-EGS site because the stimulation operations in well BO4 are not specifically considered.

As shown in Figure 20b, among all the projects selected, the systems which do not use EGS technologies are primarily systems with mixed control and control by matrix porosity and permeability, organized as sites. In contrast, projects selected in systems controlled by faults and fractures usually use EGS technologies, particularly in geothermal sites (Figure 20b). Exploitation by fields is used primarily in systems controlled by faults and fractures in volcanic and plutonic type projects (Figure 20b and Table 5). Occasionally, some case studies selected in systems controlled by faults and fractures in extensional domain types may be operated as fields, with or without EGS technologies (Table 5). This is the case for the Salton Sea and North Brawley projects, both in California, that are categorized as non-EGS fields, as well as the Desert Peak project in Nevada which is categorized as an EGS field. It should be noted that operation as EGS fields is very infrequent in the case studies analyzed. In fact, this was found in only three of the cases analyzed, where some wells had to be stimulated before production could begin.

Table 5: Summary of characteristics for the case studies analyzed.

Geothermal system		Number of projects selected	Zone	Exploitation approach[a]	Seismicity[b]
Control by matrix porosity and permeability		5	Paris Basin (France)	Non-EGS sites (11)	None observed
		3	North German Basin		
		1	West Netherlands Basin		
		2	Danish Basin		
Mixed control		10	Molasse Basin (Germany, Switzerland, Austria)	Non-EGS sites (14)	7 ($0.4 \leq M \leq 3.5$)
		2	Rhine Graben (Germany, Switzerland)		None observed
		2	Belgium and The Netherlands		2 ($2.1 \leq M \leq 2.2$)
Control by faults/fractures	Extensional domain type	6	Rhine Graben (France, Germany, Switzerland)	EGS Sites (7) EGS field (1) Non-EGS fields (2)	6 ($2.1 \leq M \leq 2.2$)
		4	Great Basin (United States), Salton Trough (United States), Pohang Basin (South Korea)		4 ($1.6 \leq M \leq 5.5$)
	Plutonic	5	Tuscany-Latium Basin (Italy) and Geysers (United States)	EGS field (1) Non-EGS fields (4)	5 ($0.4 \leq M \leq 3.4$)
	Volcanic	3	Icelandic volcanic zone	EGS site (1) Non-EGS site (1) EGS field (1) Non-EGS fields (6)	3 ($2.2 \leq M \leq 4$)
		6	Newberry Volcano (United States), Taupo Volcanic Zone (New Zealand), Guadeloupe		3 ($2.4 \leq M \leq 3.2$)
	Basement type	4	Poontana Basin (Australia), Cooper Basin (Australia), Finland and Sweden	EGS sites (4)	4 ($1.6 \leq M \leq 3.7$)

(a) Operating technology defined as in Figure 20b. Numbers in parentheses indicate the quantity of geothermal projects using the technology in question. (b) The number indicates the amount of projects selected related to seismicity, while the values in parentheses indicate the maximum magnitude range observed between projects.

Finally, Figure 20c shows the number of case studies based on the **type of operation in use when the maximum magnitude earthquake occurred**. These operations have been classified as follows:

- **Injection**: every injection operation, e.g., injection tests or tracer and interference tests, excluding circulation and stimulation phases;
- **Production-Reinjection**: simultaneous operation, over multiple wells, of geothermal fluid extraction and reinjection of the cooled fluid underground. This is particularly the case for systems controlled by faults and fractures, where the extraction of geothermal energy is organized as fields. Generally, the volume of fluid extracted is greater than the quantity of fluid reinjected;
- **Circulation**: balanced fluid circulation between two or three injection and production wells, with a net volume that can be considered zero. Circulation is at the root of operations in geothermal projects with systems controlled by matrix porosity and permeability, and mixed control, and also with systems controlled by faults and fractures. This is particularly true in an extensional type context, during the production phase, i.e., after stimulation operations are over. Circulation operations are used here only for projects organized as a site;

- **Stimulation**: this category includes all hydraulic, thermal and chemical stimulations as discussed in section 2.1.2.3 whose aim is to increase well injectivity and reservoir permeability;
- **Shut-in**: phase generally following an injection, stimulation, or circulation operation in which the system flow-rate is brought to zero.

4.2.3. Discussion on seismicity and the representativeness of the database

The seismic response of the case studies will be discussed in more detail in chapter 5. Figure 19 shows the selected projects for which no earthquake has been recorded, as well as the maximum magnitude of induced earthquakes for the projects concerned. In addition to projects with systems controlled by matrix porosity and permeability (in blue) that are not associated with seismicity, the other two geothermal system types, those under mixed control (in orange) and those controlled by faults and fractures (in violet) may sometimes be associated with seismic events whose maximum magnitudes for the selected projects vary between 0.4 and 5.5.

It should be noted that the database used here does not include two earthquakes of M_L 6.4 and 6.6, potentially caused by the geothermal projects of Laugaland (Iceland) and Cerro Prieto (Mexico) respectively, for which it is difficult to unambiguously determine a causal link with the operations of the associated projects.

It should also be noted that some earthquakes analyzed in this study were felt at the surface, and in several cases, they caused the geothermal sites to be shut down permanently. This was the case for the projects in Basel (Switzerland) in 2006, St. Gallen (Switzerland) in 2013, and Pohang (South Korea) in 2017, and more recently Vendenheim (France) after the occurrence of an M_L 3.6 earthquake in December 2020.

Finally, it should be noted that the list of geothermal projects chosen here is not exhaustive. The selection was made using, among other things, information published in the scientific literature, which leads to an overestimation of projects associated with significant seismicity, because they are documented more in the literature than projects where no seismicity is observed or reported. Another bias results from differences in microseismic monitoring for the geothermal projects selected. Dedicated monitoring systems are generally nonexistent for projects with geothermal systems controlled by matrix porosity and permeability, and those with mixed control. Consequently, the level of induced seismicity can therefore be assessed only based on national seismologic networks. In contrast, geothermal projects in which higher levels of induced seismicity can be expected are usually equipped with dedicated microseismic monitoring systems. This has two primary consequences. Firstly, the lack of a dedicated seismic monitoring network does not mean there is no microseismicity, since national seismological networks are not designed to record low magnitude events. Secondly, when there are dedicated monitoring networks, their performance is not the same from one site to another. The **detection threshold**, the **completeness magnitude,** as well as the methods used to process and analyze data, vary from one project to another, thus limiting the ability to compare induced seismicity between them. Finally, the magnitudes of the seismic events selected in this study can be expressed both in terms of local magnitude (M_L) and moment magnitude (M_w) (see section 3.2.2), which is another factor limiting the comparison of seismicity between different projects.

5. Feedback from case studies and identification of predisposition factors for seismic incident hazard

This chapter summarizes the lessons learned from the case studies described in the previous chapter. Those lessons make it possible to highlight two families of seismic incident hazard predisposition factors. The first includes intrinsic factors such as geologic, hydrogeologic and structural factors. The second family includes operational parameters, such as the pressures, flow-rates and volumes used, or the exploitation methods. The chapter concludes with an overview of these factors that act on the occurrence and intensity of seismicity in a concomitant, complex way. They will be used throughout the rest of this document to provide recommendations and good practices to assess and manage induced seismicity hazard.

5.1. Intrinsic factors

5.1.1. Influence of the geothermal system type

We observe that **systems controlled by matrix porosity and permeability (MPC)** are not associated with the occurrence of induced seismicity (Figure 21a). This is particularly the case for geothermal projects in the Paris Basin, the North German Basin, the West Netherlands Basin and the Danish Basin, which all target porous sedimentary reservoirs in geomechanical conditions that are far from rupture (also seeTable 5).

Geothermal projects targeting **reservoirs under mixed control (MC)**, i.e., controlled by both matrix porosity and permeability, and by networks of preexisting faults and fractures, may occasionally experience seismicity, which is generally of low magnitude (Figure 21b). Among the 14 case studies involving this geothermal system type, five were not associated with any earthquakes and, for the remaining nine, the maximum magnitudes of earthquakes ranged between 0.4 and 3.5, with only four case studies being associated with an earthquake of M ≥ 2 (Figure 21b). The latter four cases are the geothermal projects of Poing (M_{max} 2.1), Unterhaching (M_{max} 2.4) and St. Gallen (M_{max} 3.5), all exploiting the fractured karstic limestone aquifer of the Molasse Basin, and the Balmatt site (M_{max} 2.2) targeting the Dinantian fractured limestone aquifer in the Ruhr Graben Basin in Belgium. The induced seismicity related to these four projects was felt at the surface, and led to a cessation of operations (temporary or permanent depending on the case) at those sites. The maximum magnitude earthquake at the St. Gallen site, magnitude M_L 3.5, was much stronger than other earthquakes induced by projects within the same geothermal system type (Figure 21b). It should be noted that this earthquake, occurring on July 20, 2013, was a special case. It occurred after the unexpected emergence of methane from the well, which required well-control operations involving the injection of about 700 m^3 of drilling mud to force the gas back underground. These operations increased the seismicity rate, until an M_L 3.5 earthquake was triggered (e.g., Diehl et al., 2017; Edwards et al., 2015; Obermann et al., 2020). Finally, the M 1.7 seismic event occurring at the Californië project (Figure 21b) in The Netherlands, which targets the sedimentary Dinantian aquifer also used by the Balmatt project, was felt at the surface even though its magnitude was lower than 2 (Baisch and Vörös, 2018; Vörös and Baisch, 2019).

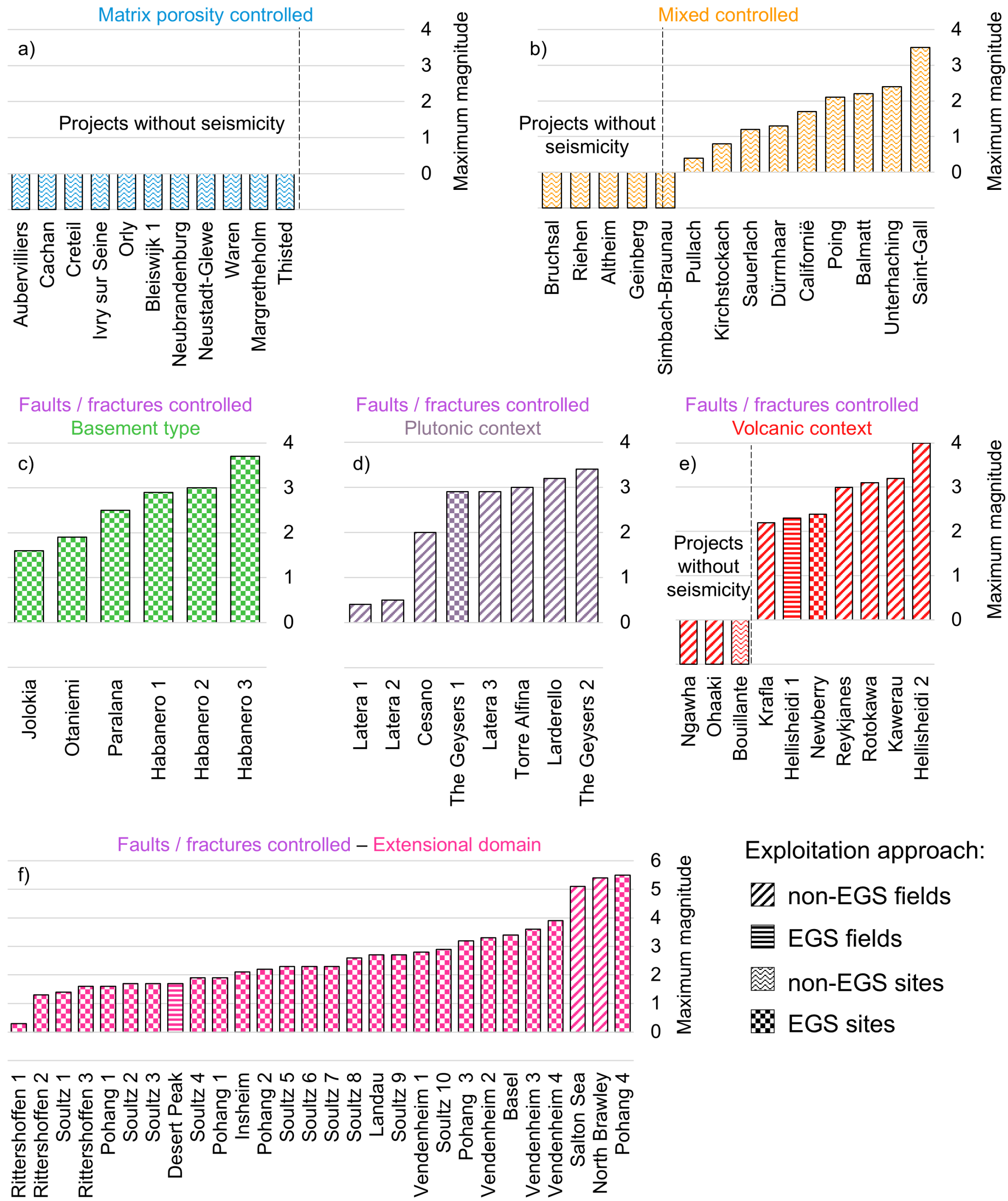

Figure 21: Observed seismicity linked to the case studies described in Chapter 4, based on the geothermal system type. Systems controlled by matrix porosity and permeability (a); mixed control systems (b); systems controlled by faults and fractures (FFC) in a basement system (c); plutonic FFC systems (d); volcanic FFC systems (e); extensional domain FFC system (f). Case studies for which no seismicity has been reported are on the left side of the histograms (figures a, b, e). For case studies involving the occurrence of seismicity, the histogram bar shows the maximum magnitude (M_{max}) of the earthquakes observed. For all case studies, the shading of the histograms indicates the exploitation method used as shown in the legend and described in detail in section 4.2.2.

Finally, it is observed that geothermal projects exploiting **systems controlled by faults and fractures (FFC)** are more frequently associated with earthquakes whose maximum magnitudes may occasionally be higher (Figure 21c, d, e, f). Only three of the 52 case studies selected were associated with no earthquakes, the magnitudes of 14 cases were $M < 2$, whereas in the other 35 case studies (nearly two-thirds of case studies in systems controlled by faults and fractures) the maximum magnitudes of the earthquakes were between $2.1 \leq M \leq 5.5$.

When we consider the diversity of geothermal contexts associated with FFC systems, we see that the magnitude of seismic events in basement type projects (FFC-BT) is not necessarily high, with two out of six cases having a magnitude $M < 2$ and three out of six cases ranging from $2 \leq M$ to ≤ 3 (Figure 21c). A seismic event of $M > 3$ occurred in only one of the cases analyzed. It is the M 3.7 event that occurred in 2003 during hydraulic stimulation on the Habanero site exploiting a tectonic fault. It is noteworthy that geothermal sites in an FFC-BT system are still little developed throughout the world. In most cases, this type of project has been found to be economically unviable.

Case studies in **volcanic (FFC-VT) and plutonic systems (FFC-PT)** exhibit a greater proportion of $M > 2$ seismic events (Figure 21d, e), even though FFC-VT systems are where we find the only three case studies not associated with seismicity in systems controlled by faults and fractures. These are the Ngatamariki and Ngawha projects in New Zealand's Taupo volcanic zone, and the Bouillante geothermal project in Guadeloupe (Figure 21e). With the exception of two operations in the geothermal fields of Latera (Italy) which resulted in seismic events of $M < 2$ (Figure 21d), all the other cases selected in FFC-VT and FFC-PT contexts have experienced earthquakes of $M \geq 2$. It should be noted that, in these geothermal contexts, it can sometimes be difficult to distinguish natural earthquakes from induced earthquakes, which makes it possible to attribute a seismic event to ongoing geothermal operations with certainty. This issue, specific to induced seismicity in general, is found primarily in geothermal sites located in volcanic and plutonic zones. In fact, due to the generally moderate to high level of natural seismicity in this type of context, the occurrence of natural seismic events may be more frequent.

For case studies in **extensional domain-type projects (FFC-EDT)**, the magnitude of earthquakes was $M < 2$ in only 10 cases out of the 28 analyzed. This low-magnitude seismicity was recorded for some operations at the geothermal sites of Soultz-sous-Forêts and Rittershoffen in the Rhine Graben, and for the sites of Pohang in South Korea and Desert Peak in the United States. All other case studies in extensional zones revealed the occurrence of seismic events of $M \geq 2$ (Figure 21f). In addition, we observe that geothermal sites in this type of context may be associated with earthquakes of $M > 5$, which is not the case for the case studies selected in other contexts within FFC geothermal systems. This example is relatively infrequent, however, since it has been observed for only three of the 28 sites analyzed in extensional zones, the geothermal projects of Pohang (M_w 5.5), Salton Sea (M_w 5.1) and North Brawley (M_w 5.4).

Feedback from these case studies in the database can therefore help clarify the role played by the geothermal system on the level of seismic incident hazard induced in different projects (Figure 22). In fact, **seismic incident hazard is very low for porous reservoirs** where the circulation of fluids is controlled by the petrophysical properties of the rock, **which is the case for MPC systems** in which no seismicity has been observed. **Conversely, the hazard is low to moderate for geothermal projects targeting MC systems** where seismicity may sometimes occur, but is generally of relatively low magnitudes. **Finally, seismic incident hazard is moderate to high when reservoirs in non-porous, fractured rocks are targeted in geothermal operations, as is the case for FFC systems**, where seismicity may be frequent and of higher magnitudes.

Induced seismicity hazard

	Matrix porosity controlled systems (MPC)	Mixed controlled systems (MC)	Faults / fractures controlled systems (FFC)
Hazard	Low	Low/Moderate	Moderate/High
Seismicity	Absent	Sometimes observed	Frequent
Observed magnitudes	-	Generally low (few cases with M ≥ 2)	Variable (several cases with M ≥ 2)

Geological control on fluidflow

\+ Matrix porosity / Petrophysical properties -

\- Faults and fractures +

***Figure 22:** Diagram showing seismic incident hazard levels and characteristics of seismicity depending on the geothermal system type. The bottom arrow shows the type of geologic control on fluid flow in the different geothermal system types.*

5.1.2. Influence of natural fluid flow

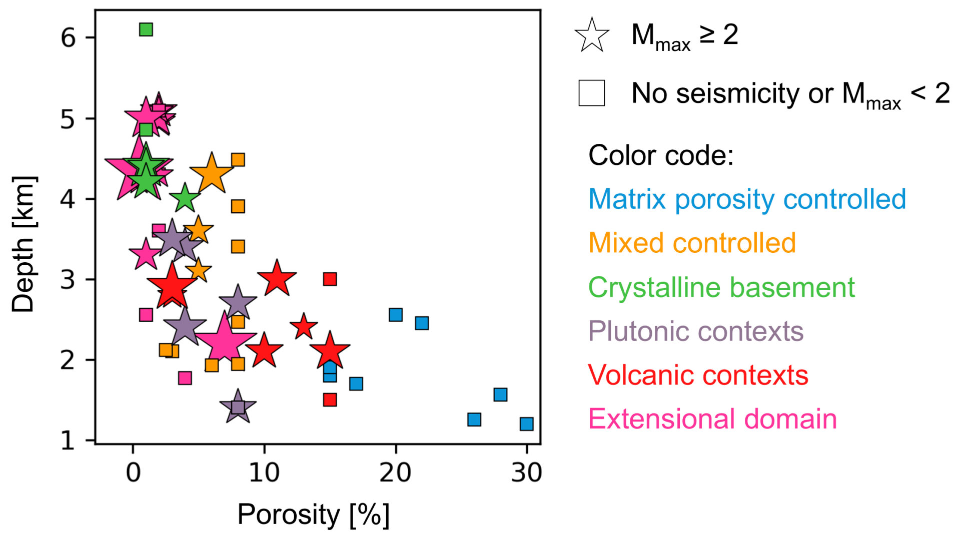

***Figure 23:** Porosity and permeability and depth of the case studies selected. The size of the stars is proportional to the maximum magnitude observed for the case studies associated with the occurrence of earthquakes of M_{max} ≥ 2. In the absence of earthquakes, or for M_{max} < 2, the case studies are shown with a square. For all case studies, the color of the symbols indicates the geothermal system type, as in Figure 21. The porosity and permeability data were published by Buijze et al (2019a).*

Figure 23 shows porosity and permeability of the formation as a percentage, for the case studies selected based on the injection well depth. As expected, porosity is higher in geothermal projects targeting reservoirs at depths of less than 3km, and for which natural fluid flow is controlled by matrix porosity and permeability. In fact, Figure 23 shows that the case studies characterized by a porosity greater than 15%, i.e., which concern all MPC projects, are not associated with the occurrence of earthquakes. In other words, and in line with the preceding section, **the seismogenic potential**

of geothermal projects increases when the porosity of the formations targeted is less than 15%, and when fluid flow is at least partly controlled by networks of faults and fractures.

For all other geothermal system types, including MC types, there is no obvious link between porosity and permeability and the magnitude of seismic events. The maximum magnitude observed for each case study does not appear to increase with lower porosity and permeability (Figure 23). This can be explained by the fact that **porosity and permeability of the target formation in MC and FFC systems affects reservoir permeability to a lesser extent since this depends on other factors.** In this context, **when the circulation of fluids is controlled primarily by faults/fractures, the effective permeability of reservoirs is strongly influenced by the presence or absence of convective circulations in the reservoir**. In fact, in an FFC reservoir, **the presence of convection cells** suggests the existence of hydrothermal fluids circulating naturally underground and **is evidence of good reservoir permeability**. In contrast, **reservoirs** without convection cells **where heat is transferred only by thermal conduction** from the rocks **are characterized by poor hydraulic properties, and thus a higher seismogenic potential**.

5.1.3. Influence of preexisting structures and the stress state

Preexisting structures play an essential role in triggering seismic activity. If there are faults, this means that favorable conditions for naturally causing seismicity have existed or still exist. Feedback from the case studies selected, particularly **in FFC systems, shows that in this geothermal system, seismicity occurs preferentially by the reactivation** (slip) **of preexisting discontinuities**. In fact, these structures have lower cohesion than that of intact rock and therefore constitute zones of greater permeability. As a result, the circulation of injected fluids preferably takes place along these structures, where seismic events are triggered when rupture resistance is exceeded, primarily by the effect of increased pore pressure.

However, the presence of such structures in geothermal reservoirs is not a sufficient condition for the occurrence of seismicity. **The rupture potential of preexisting discontinuities depends on the level of tectonic stress (i.e., natural) to which they are subjected, as well as their orientation with respect to the local stress field** (e.g., Cornet, 2016; Evans et al., 2012). Thus, if discontinuities are already **critically stressed** and favorably oriented to slip, small variations in the stress state due to geothermal operations may be enough to induce a rupture and generate a seismic event. However, this does not necessarily imply the occurrence of high-magnitude seismic events and/or those potentially felt at the surface. In fact, **the number and magnitude of earthquakes depend on the size and level of development or connection of discontinuities, as well as the resistance characteristics (cohesion and friction) and local variability of the stress field** (Cornet, 2016; Evans et al., 2012; McClure et Horne, 2014).

Based on these considerations, and as has been pointed out by several authors (e.g., Baisch et al., 2016; Buijze et al., 2019b; Evans et al., 2012), **the proximity of geothermal wells to preexisting structures which are critically stressed** and favorably oriented with respect to the local stress field is an aggravating factor with respect to seismic incident hazard. **This hazard increases when large faults are present that could generate high-magnitude seismic events. In this context, a distinction can be made between geothermal projects that directly exploit fault zones and those targeting volumes of fractured rocks without major faults. The example of the Jolokia and Habanero geothermal sites (Australia), located about 9 km apart and exploiting the same granite formation, with wells drilled to similar depths, are a good illustration of the variability of the seismic response to injection operations in these two types of configuration. Indeed, at Habanero, where a subhorizontal fault intersects the wells, several thousand seismic events (maximum magnitude M_w** 3.7) have been induced along the fault plane following injections (Figure 24, right side). Conversely, for the Jolokia site, where no major structure is intersected, seismicity is of low intensity, both in terms of magnitude (maximum magnitude M_L 1.6) and number of seismic events (Figure 24, left side) (Baisch et al., 2015).

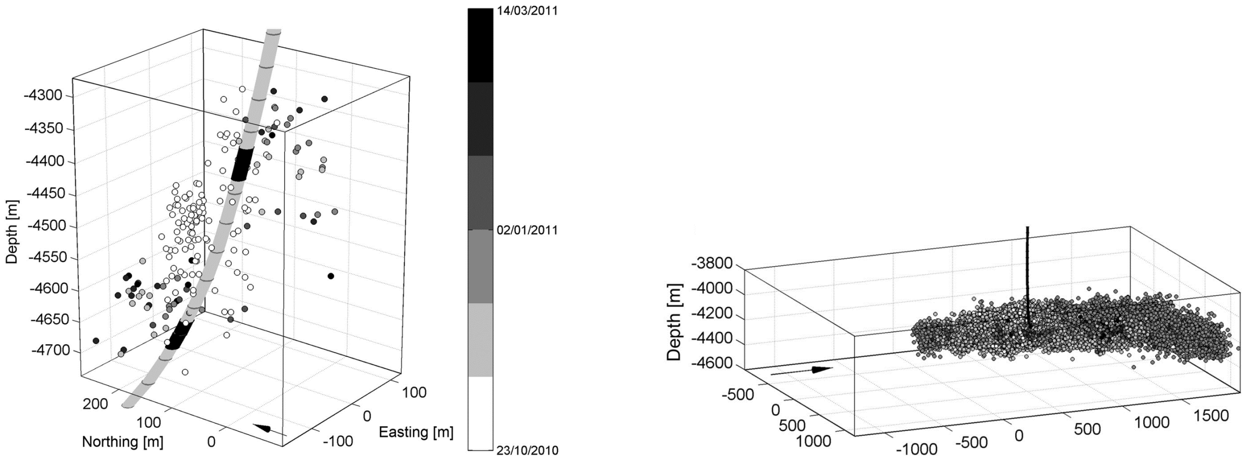

Figure 24: Seismicity (black and white dots) in the geothermal sites (basement type) of Jolokia (left) and Habanero (right) (modified from Baisch et al., 2015). At Jolokia, the induced seismicity magnitudes reached are low (maximum magnitude ML 1.6), as is the number of seismic events; at Habanero, several thousand seismic events (maximum magnitude Mw 3.7) have been induced by injection along a preexisting sub-horizontal fault structure

5.1.4. Influence of the hydraulic connection with the basement, and basement-reservoir distance

As pointed out by several authors (e.g., Baisch et al., 2016), the crystalline crust can be characterized by a critical stress state, where a low stress disturbance is enough to induce seismic events. In this context, **the proximity of geothermal operations to the basement may be an aggravating factor with respect to induced seismicity**. This is well-highlighted for some of the case studies analyzed here, particularly for projects selected in FFC-EDT, MC, and MPC systems. In this case, except for the Salton Sea and North Brawley projects (SSG and NBW in Figure 25), **one earthquake of $M_{max} \geq 2$ was generally observed in the case studies where wells were drilled near the basement or target it directly** (Figure 25).

For projects near the top of the basement, it may be noted that seismicity preferentially occurs at a distance from injection wells and in the crystalline basement. This is true for the case studies selected with MC systems that all exploit the sedimentary layer overlying the basement, generally in proximity to the top of the basement, particularly at a distance of less than one kilometer (Figure 25). In these case studies, seismic activity occurs in the crystalline basement, 1 to 2 km below the reservoir targeted by the geothermal operations, especially for events whose magnitude is higher than 2. This has been observed in the geothermal projects of Unterhaching, St. Gallen, Poing, and Californië. At St. Gallen, microseismic events occurred about 300m[19] below the open-hole section of the well, while in Unterhaching and Californië, seismicity was 1.7 and 3.5 km deeper than the wells, respectively. In the case of the Poing site, microseismic events were also located in the basement, between 1 and 2 km below the reservoir (Seithel et al., 2019).

The same trend has been observed for most case studies in FFC-EDT systems that exploit reservoirs at the boundary between the sedimentary layer and the underlying basement, with injection wells near the top of the basement (Figure 25). For these projects, seismicity is localized primarily in the basement at a distance from the injection wells. This is particularly the case for the sites of Insheim, Landau, and Rittershoffen (Grund et al., 2016; Küperkoch et al., 2018; Lengliné et al., 2017). There, the response to geothermal operations in the sedimentary layer in the upper part of the

__19__ – It should be noted that the location uncertainty concerning depth is estimated to be ± 150m (Diehl et al., 2017).

reservoir remains aseismic, whereas the seismic activity develops entirely in the deeper part of the target reservoir, at the level of the basement. As shown in Figure 25, FFC-EDT type projects in which wells are drilled near the top of the basement, seismicity is generally characterized by M_{max} < 2, except for the Insheim and Landau projects. **For the other FFC-EDT case studies selected** and except for the Salton Sea and North Brawley projects, **seismicity of M_{max} ≥ 2 is generally observed for projects targeting the basement, particularly starting at about 2 km below its top** (Figure 25).

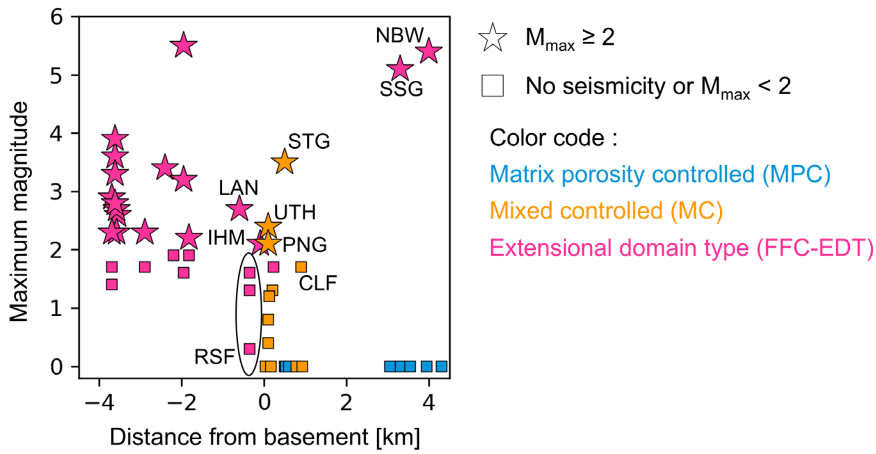

Figure 25: Maximum magnitude observed and vertical distance between the bottom of the injection well and the top of the crystalline basement. A negative distance means that the injection well is under the basement; a positive value means that the injection well is located between ground surface and the top of the basement. The color of the symbols indicates the geothermal system type, as in Figure 21, whereas the type of symbol depends on the seismicity associated with the case studies, as indicated in the legend. Projects without observed seismicity are on the 0 ordinate. Geothermal project abbreviations: Landau (LAN), Insheim (IHM), Rittershoffen (RSF), Unterhaching (UTH), Poing (PNG), St. Gallen (STG), Californië (CLF), Salton Sea (SSG) and North Brawley (NBW). It should be noted that, although the M_{max} of the Californië site was only 1.7, it was still felt at the surface.

These observations are explained by the hydraulic connection mechanisms between the injection point and the earthquake initiation zone, primarily via networks of permeable faults and fractures that may traverse reservoirs between sedimentary layers and the basement (e.g., Diehl et al., 2017; Megies and Wassermann, 2014; Seithel et al., 2019; Zbinden et al., 2020b). In an environment of low porosity rock, **the effects of hydraulic overpressure may extend over a distance of several kilometers along a fault, reaching the basement, where preexisting structures are more prone to being reactivated as a result of the critical stress level**, even for weak disturbances of the stress state. Consequently, when geothermal operations involve MC or FFC-EDT reservoirs near the top of the basement, **the existence of a hydraulic connection between the injection zone and the underlying basement** plays an essential role in triggering seismic events **and therefore constitutes an aggravating factor with respect to induced seismicity**.

In this context, the presence of clay formations without faults between the target reservoirs and the crystalline basement could act as hydraulic barriers, preventing the redistribution of pressures and stresses toward deeper formations of the basement. This mechanism could at least partly explain the lack of seismicity in geothermal projects in the Paris Basin targeting MPC-type reservoirs where a clay layer without faults is intercalated between reservoirs of the Dogger aquifer and the underlying granitic basement (Buijze et al., 2019b).

5.1.5. Influence of reservoir depth

The preceding considerations can be detailed further by examining the seismic response, particularly the maximum magnitude observed for each case study as a function of depth. With the exception of volcanic and plutonic type FFC systems, the seismicity of all other geothermal systems **presents M ≥ 2 only for operations conducted at depths over 3 km**. Exceptions are the Salton Sea and North Brawley projects, where seismicity reached M > 5 despite the relatively shallow depth of operations. However, beyond 3 km in MC, FFC-EDT, and FFC-BT systems, there is no clear-cut trend of magnitude increasing with depth. Finally, in FFC-PT and FFC-VT systems, we observe no clear-cut correlation between the depth of injections and the maximum magnitude of earthquakes induced. The seismic responses differ greatly from one project to another. It should be noted that for the latter two geothermal systems, earthquake magnitudes are generally larger than 2, despite depths less than 4 km.

These observations are consistent with the conclusions reached by other authors (Buijze et al., 2019b, 2019a; Evans et al., 2012) and show that injection depth does not appear to be a decisive parameter for estimating induced earthquake magnitude. It is necessary, particularly for MC and FFC-EDT systems, to consider the distance to the top of the basement and the possible existence of a hydraulic connection between the geothermal reservoir targeted and the basement, in order to make a decision.

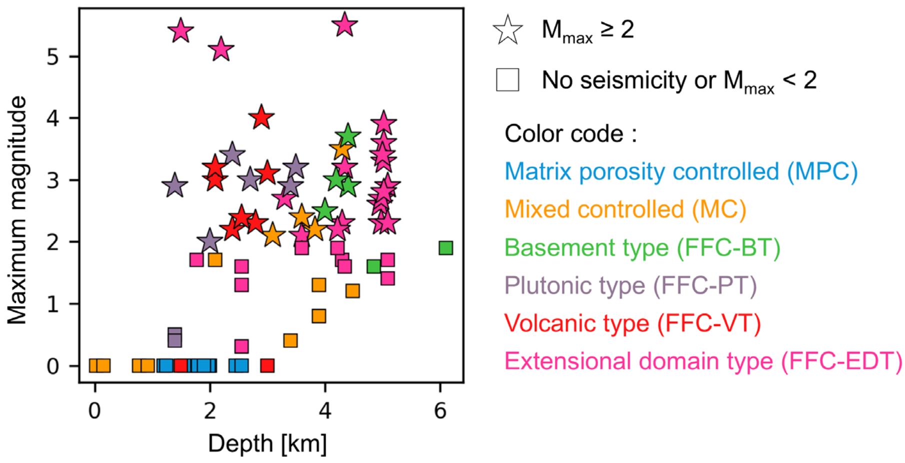

Figure 26: Maximum magnitude observed and maximum depth of the injection well in each of the case studies selected. The size of the stars is proportional to the maximum observed magnitude for the case studies associated with the occurrence of earthquakes where M_{max} ≥ 2. In the absence of seismicity or for M_{max} < 2, the case studies are indicated by a square. Projects without observed seismicity are on the 0 ordinate. For all case studies, the color of the symbols indicates the geothermal system type, as in Figure 21.

5.1.6. Influence of the natural seismic hazard

The natural seismic hazard at the geothermal sites selected varies from one case to another (Figure 27). The projects selected in FFC-VT and FFC-PT-type reservoirs are generally located in active tectonic zones with high natural seismicity. Conversely, the natural seismicity of projects targeting MC and MPC reservoirs is generally low. The natural seismic hazard is considered moderate for all FFC-BT, as well as for most FFC-EDT projects, even if in some cases the natural seismicity rates may be low, as is the case for Pohang, or high, as in Basel (Switzerland), Salton Sea, and Desert Peak (both in the United States).

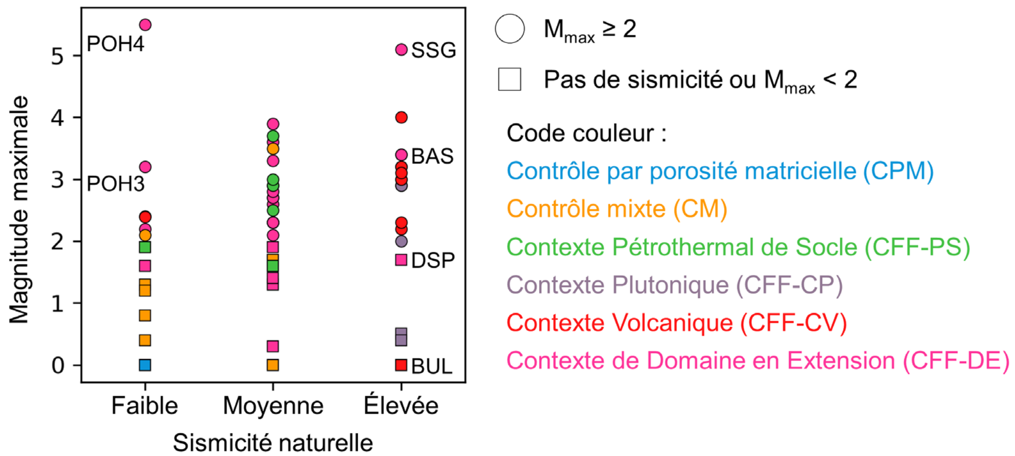

Figure 27: Maximum magnitude of induced seismic events as a function of the natural seismic hazard in the area. Seismic hazard is based on the value of PGA (Peak Ground Acceleration) with a 10% chance of exceedance in 50 years, corresponding to a return period of 475 years: PGA ≤ 0.6 m/s² low seismic hazard; 0.6 m/s² < PGA < 1.3 m/s² moderate seismic hazard; PGA ≥ 1.3 m/s² high seismic hazard. These PGA values were published by Buijze et al. (2019a). The color of the symbols indicates the geothermal system type, as in , whereas the type of symbol depends on the seismicity associated with the case studies, as indicated in the legend. Geothermal project abbreviations: Pohang (POH3 and POH4), Salton Sea (SSG), Basel (BAS), Desert Peak (DSP) and Bouillante (BUL).

As shown in Figure 27, induced seismic events of $M_{max} \geq 2$ can occur in all types of tectonic contexts, even if they are less frequent in zones where the natural seismicity is low. This suggests that high magnitude events may be induced even in a zone where the tectonic load is moderate (Pohang, POH3, and POH4 in Figure 27). In addition, geothermal projects located in an active tectonic zone with high natural seismic hazard are not systematically associated with high magnitude induced events (Desert Peak and Bouillante, DSP and BUL in Figure 27 respectively).

The occurrence of natural seismicity near a geothermal site, however, demonstrates the existence of natural fault zones, potentially seismogenic and in a critical stress state. In such a context, **geothermal exploitation may lead to an increased induced seismic hazard, since an earthquake could be triggered by relatively weak stress disturbances**.

5.1.7. Influence of reservoir temperature

In agreement with other authors (e.g., Buijze et al., 2019a), we observe a link between maximum magnitude events and the temperature of geothermal reservoirs. Seismicity of $M_{max} \geq 2$ is generally observed for projects targeting reservoirs with temperatures higher than 100°C (Figure 28). Beyond 100°C, the trend is that magnitude increases with temperature. In FFC-EDT systems, earthquakes of M > 4 are observed only in reservoirs whose temperature exceeds 250°C (see NBW and SSG in Figure 28), except for the Pohang site (POH4 in Figure 28) whose maximum magnitude is high compared to the relatively low reservoir temperature. However, it should be noted that for the same geothermal site, and therefore for the same temperature, the maximum magnitude observed may vary by more than one order of magnitude, depending on the operations considered. In the 5 km deep reservoir at Soultz-sous-Forêts, for example, where the temperature is around 200°C, the maximum magnitudes of the earthquakes induced by different operations vary, from a minimum of M_L 1.7 to a maximum of M_L 2.9.

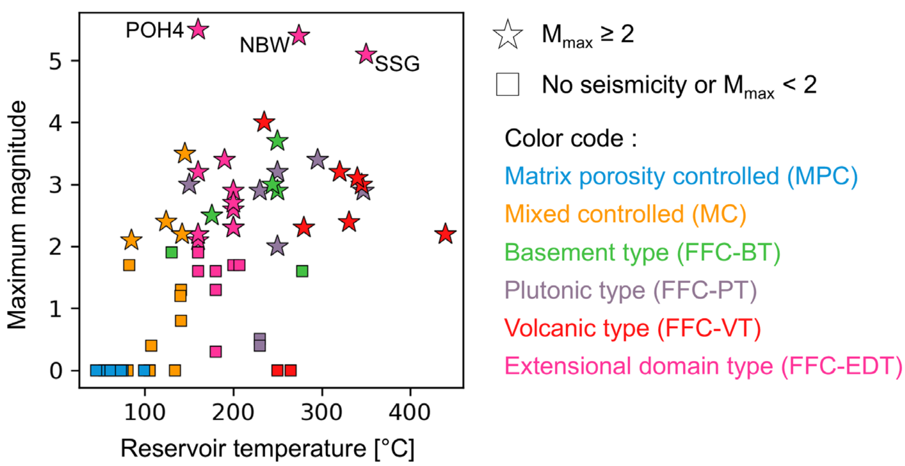

Figure 28: Maximum magnitude of induced seismic events as a function of reservoir temperature. The color of the symbols indicates the geothermal system type, as in Figure 21, whereas the type of symbol depends on the seismicity associated with the case studies, as indicated in the legend. Projects without observed seismicity are on the 0 ordinate. Geothermal project abbreviations: Pohang (POH4), Salton Sea (SSG), and North Brawley (NBW).

The relationship between maximum magnitude observed and the temperature of reservoirs can be explained by the effect of temperature on friction conditions along faults or by significant variations of **thermoelastic stresses** near the injection wells. In fact, such thermoelastic stress changes, which are particularly significant in projects organized as fields (sections 2.1.2 and 4.2.2), have an important influence on triggering earthquakes. In this context, rather than considering temperature, the temperature differences (ΔT) between the reservoirs and the fluids injected should be taken into account. In fact, the higher the reservoir temperature, the greater the temperature difference imposed by injections (the injected fluid being at a much lower temperature) and therefore the change in stresses induced by thermoelastic effects is greater. Unfortunately, the lack of data on the injected fluid temperature does not allow us to reach a conclusion on the link between ΔT and maximum magnitude.

5.2. Operational parameters

5.2.1. Influence of the exploitation methods

The geothermal resource exploitation methods differ, depending on the geothermal system type. As discussed in chapters 2 and 4, we make a distinction here between sites (doublets or triplets) and fields, depending on how the operation is organized, and more specifically on the number of wells used and the surface area occupied by the geothermal projects, depending on whether the geothermal resource uses (EGS) or does not use (non-EGS) **EGS** technologies. Figure 21 shows the type of exploitation method used in each of the case studies selected.

The seismicity observed for each case study was analyzed with respect to the exploitation method. The results summarized in Figure 29 show that **exploitation as geothermal sites without the use of EGS technologies presents a fairly low seismic hazard.** Indeed, for this exploitation approach, seismicity is absent in most cases or of M_{max} < 2. In this category, the four case studies with M_{max} ≥ 2 involved projects in MC systems discussed in preceding sections, including the St. Gallen project (M_L 3.5), which is a special case. **In the case of EGS site and geothermal fields, the seismic hazard is higher.** In fact, these methods are more prone to triggering seismic events of M_{max} ≥ 2 and are associated with practically all events of M_{max} > 3, except for the St. Gallen case discussed previously. These results are consistent with considerations regarding seismic hazard as a function of the geothermal system type (see section 5.1.1) because FFC systems, which are associated with non-EGS fields and EGS sites, are more frequently associated with induced events of M ≥ 2 (see Figure 21 and Figure 22).

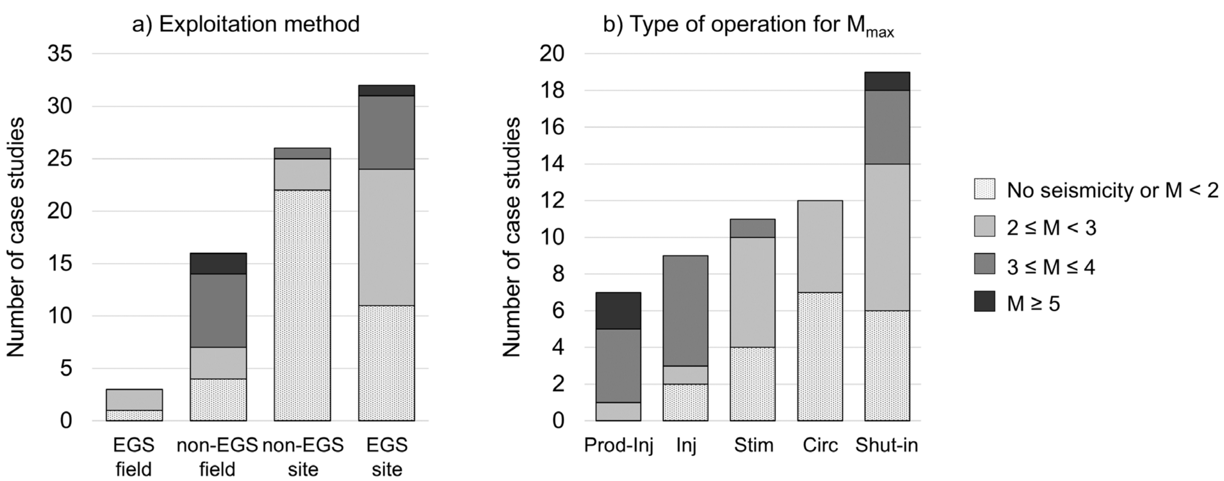

Figure 29: Seismicity recorded as a function of different geothermal resource exploitation methods (a) and for the type of operation under way at the time of the maximum magnitude event (M_{max}) (b). Type of operation: Circ – circulation; Prod-Inj – production and reinjection; Inj – injection; Stim – stimulation.

5.2.2. Influence of the type of operation

For case studies associated with induced seismicity, it is of interest to examine the type of operations under way when the maximum magnitude earthquakes (M_{max}) were triggered for a given seismic sequence, and therefore for a given geothermal operation. To do this, the geothermal operations were differentiated as defined in chapter 4 and analyzed with respect to induced seismicity (Figure 29b).

Simultaneous production and reinjection operations (Prod-Inj in Figure 29b), typical of non-EGS geothermal fields, are systematically associated with events of M ≥ 2 in the case studies analyzed, and comprised two of the most significant earthquakes in terms of magnitude, at Salton Sea (M_w 5.1) and North Brawley (M_w 5.4) (McGuire et al., 2015; Wei et al., 2015). As discussed in detail in section 5.2.4, this could be partly related to the net volumes injected in geothermal fields, which are often significant and generally higher than volumes injected in the other operations considered. However, this analysis was conducted on only 7 case studies for this classification, because it was not possible to unambiguously link seismicity either to reinjection or production in the geothermal fields in question. In fact, when exploitation is organized as fields, and even if seismicity is clearly the result of geothermal operations, it may be difficult to correlate it with a particular operation, i.e., with production or reinjection operations. This is mainly due to the operational complexity of these systems in terms of the number of production and reinjection wells which, in most cases, are in operation at the same time.

Concerning **circulation operations**, they are less often associated with the occurrence of seismic events of M_{max} ≥ 2, and indeed magnitudes of the induced events were always lower than 3 for all the cases analyzed in this category (Figure 29b). The highest magnitude events occurring during the circulation phase were recorded at the sites of Unterhaching (M_L 2.4) and Soultz-sous-Forêts (M_L 2.3). In the cases analyzed, seismicity in the circulation phase was found to be related only to FFC-EDT and MC-type geothermal projects. For these types of systems, events during the circulation phase can occur under stationary circulation conditions, but also after changes in hydraulic parameters, e.g., increases or decreases in injection flow-rate (e.g., Baisch and Vörös, 2018; Cuenot et al., 2011; Gaucher et al., 2015). In some cases, M_{max} in the circulation phase was observed after abrupt circulation interruptions. Such examples are dealt with in the category of seismicity in the shut-in phase (Figure 29b). In many cases of seismicity in the circulation phase, seismic activity may appear several years after circulation operations have begun. For example, this was the case for the Poing site (Germany) where the maximum magnitude event occurred five years after the start of circulation. In this case, thermoelastic and dissolution mechanisms acting over the long term could have led, respectively, to the local variation of the stress field and to degradation of the friction coefficient of fault structures near the geothermal site, which would have made it possible to reactivate them (Seithel et al., 2019).

In the injection phase, the seismic hazard seems to be greater, with most case studies characterized by 3 ≤ M_{max} ≤ 4 (Figure 29b). The highest magnitude events occurring during the injection phase are related to St. Gallen, Switzerland (M_L 3.5) when drilling mud was injected to control the methane leak, and at Vendenheim (France), where an M_L 3.6 event occurred on December 4, 2020, during interwell connectivity tests.

Conversely, the maximum magnitude events in the case studies analyzed, occurring during the **stimulation phase**, were generally characterized by 2 ≤ M_{max} ≤ 3 (Figure 29b). In this case, the strongest earthquake was the M_L 3 occurring at the Habanero site in Australia in 2012, during stimulation operations. In four of the 11 case studies in this category, we also observe seismic events of M_{max} < 2 in the stimulation phase (Figure 29b). It should nevertheless be noted that **most M_{max} events linked to stimulation operations occurred after injections had terminated** and so are categorized as shut-in phase seismicity.

Based on these considerations, **it appears obvious that seismic hazard is lower in the circulation phase**. As discussed in more detail in the following sections, this could be partly due to the lower injection pressure and flow-rate values during circulation operations. Conversely, **the seismic hazard is more significant in production-reinjection operations** conducted in geothermal fields, in which the magnitudes reached can be relatively high, probably resulting from the greater net volumes injected. The injection and stimulation phases are more frequently associated with earthquakes of M_{max} ≥ 2, but it is in the shut-in phase, **after operations have terminated, that most M_{max} events associated with the cases analyzed here occurred**. Post-injection seismicity is discussed in detail in the next section.

5.2.3. Influence of the post-injection phase

In most of the cases analyzed, M_{max} occurred **during the** shut-in phase, i.e., after injection, stimulation, or circulation operations had terminated and flow-rate was null (Figure 29b). The scientific literature contains many examples of seismicity in the shut-in or post-injection phase, particularly for hydraulic stimulations in EGS systems. However, this phenomenon can also be observed during the circulation phase, particularly after an abrupt shutdown of the pumps. Among the cases analyzed in this study, we observe that **12 of 19 cases analyzed in the** shut-in **phase are related to hydraulic stimulations** in EGS sites preferentially targeting reservoirs in FFC-EDT systems (10 out of 12 cases) and occasionally FFC-PT systems (2 out of 12 cases). **On the other hand, 4 cases out of the 19 total cases in the shut-in phase are related to injection interruptions following circulation operations** at EGS sites (Landau and Soultz-sous-Forêts) and non-EGS sites (Balmatt and Californië), in FFC-EDT, and MC systems, respectively. Finally, **the three remaining cases in the shut-in phase involved interwell connectivity tests** at the Vendenheim site in late 2020. In most of the cases analyzed, M_{max} occurred several hours, and as long as two weeks after shut-in. More rarely, it can also occur several months later. This was the case for the M_w 5.5 and M_L 1.6 earthquakes at the sites of Pohang (South Korea) and Jolokia (Australia) respectively, 2 to 4 months after injections had stopped (Baisch et al., 2015; Ellsworth et al., 2019), as well as at the Vendenheim (France) site, where two seismic events, of M_L 3.3 (January 22, 2021) and M_L 3.9 (June 26, 2021) occurred 20 days and over five months after shut-in, respectively.

Abrupt operational changes cause a switch from a pseudo-permanent regime to a transitional regime, favoring the occurrence of induced seismicity. Generally, and **independent of the operation type, an abrupt, non-stepwise cessation of injections appears to be an aggravating factor that may increase the probability of a significant earthquake occurring in the post-injection phase**. **The seismic hazard therefore can be high in the shut-in phase.** This is especially true when we consider that the occurrence of seismic events of significant magnitude during the post-injection phase renders seismicity mitigation solutions (e.g., TLS) ineffective because they are often based on optimizing operating parameters (pressure, flow-rate, etc.). **Anticipating the occurrence of post-injection seismicity in order to reduce the related risk is a difficult task, since the related mechanisms remain poorly understood**. Post-injection seismicity is generally explained in terms of pore pressure diffusion phenomena (section 3.3) which do not stop immediately after injections have terminated (e.g., Mukuhira et al., 2017; Parotidis et al., 2004). Some authors, however, consider more complex phenomena such as poroelastic mechanisms (e.g., Segall and Lu, 2015) and a coupling between mechanical, hydraulic, and thermal phenomena (e.g., De Simone et al., 2017). Finally, other authors suggest attributing the occurrence of post-injection seismicity to aseismic deformation mechanisms induced by injection operations (e.g., Cornet, 2016; Lengliné et al., 2017).

5.2.4. Influence of the total injected volume

The influence of the injected volume on the characteristics of induced seismicity has been discussed by several authors using data in different types of industrial projects involving underground fluid injection. In the event of an injection into a completely saturated environment, where seismicity is triggered by the effect of increased pore pressure, McGarr (2014) used an empirical approach to show that the cumulative seismic moment (M_0), and therefore the maximum magnitude[20] expected from induced earthquakes, increases with the total injected volume, according to the following formula:

$$M_0\,(\max) = G\Delta V \qquad (3)$$

where G [Pa] is the modulus of rigidity and ΔV [m^3] is the total injected volume. Figure 30 illustrates this relationship for G = 30 GPa, with an estimate of the expected maximum earthquake magnitude as a function of the injected volume, and a comparison to the data from different sites. **In other words, this relationship makes it possible to estimate the expected maximum magnitude for a given project, based on the total injected fluid volume.**

Based on numerical simulations, on a single fault, taking into account the physical rupture propagation mechanisms, Galis et al. (2017) studied and theoretically estimated the size of ruptures induced by local pore pressure disturbances. These authors make a distinction between self-arrested ruptures, which spontaneously stop at a finite distance from the nucleation zone, and runaway ruptures, which propagate beyond the pore pressure disturbance zone, along faults subject to a high stress state. Based on these observations, Galis et al. (2017) developed a scalar equation between the maximum earthquake magnitude characterized by self-arrested ruptures and the fluid volume injected:

$$M_0^{max\text{-}arr} = \gamma(\Delta V^{3/2}) \qquad (4)$$

where $M_0^{max\text{-}arr}$ is the maximum seismic moment for a self-arrested seismic event ΔV is the total injected volume, and γ is a parameter that depends on the stress drop, the size of the reservoir, the dynamic friction coefficient, and the bulk modulus of the reservoir rock. Using data from different fluid injection projects, the authors show that the maximum estimated magnitude using equation 4 is consistent with the maximum magnitudes observed in the projects in question. This indicates that seismicity induced by reinjection operations is controlled mainly by a process of self-arrested rupture propagation, where the size of the earthquakes is proportional to the injected volume.

However, according to van der Elst et al. (2016) the maximum magnitude generated by an induced seismic event along a fault (favorably oriented in the local stress state) will be controlled only by regional tectonics, fault connectivity, and the number of induced events, as it is the case with natural earthquakes. This behavior is typical of induced seismicity qualified as triggered. In other words, injection controls only the nucleation of induced earthquakes, while their propagation and therefore their magnitude are only related to tectonics and the size of preexisting faults. Therefore, following the Gutenberg-Richter law[21], the higher the number of induced events, the greater the possibility of triggering a high-magnitude earthquake. In this sense, these authors demonstrate that the injected volume controls the total number of induced seismic events to a greater extent than the total seismic moment released. The maximum magnitude can then be defined empirically as a function of the injected volume, according to the following formula:

$$M_0^{max} = \frac{1}{b}(\Sigma + \log_{10} V) \qquad (5)$$

where M_0^{max} is the maximum expected magnitude, Σ is the seismogenic index (Shapiro et al., 2010), which links the number of seismic events to the injected volume, b the **b-value** of the Gutenberg-Richter law and V the injected volume.

20 *– The seismic moment is linked to the moment magnitude (M_w) through the following equation (Kanamori, 1977): $M_w=2/3\,(\log_{10}M_0) - 6.07$*
21 *- Gutenberg-Richter law (Gutenberg and Richter, 1944): $\log_{10}N(M) = a + bM$, where N is the number of earthquakes with a magnitude greater than or equal to M, whereas a and b are respectively the y-intercept and the slope of the line that defines the relationship between M and $\log_{10}N(M)$.*

Regardless of the equations used, these observations show that the seismic response of reservoirs to injections is at least partly controlled by the injected volumes. In agreement with previous studies, the data from the geothermal projects analyzed in this report show that **maximum magnitude increases with the injected volume,** (Figure 30) and that in most cases the data follow the models of McGarr (2014), Galis (2017) and van der Elst et al. (2016). It should be noted that these latter models have been established not only using data from geothermal sites but also by considering wastewater disposal or CO_2 injection operations, as well as hydraulic fracturing operations for the extraction of unconventional hydrocarbons.

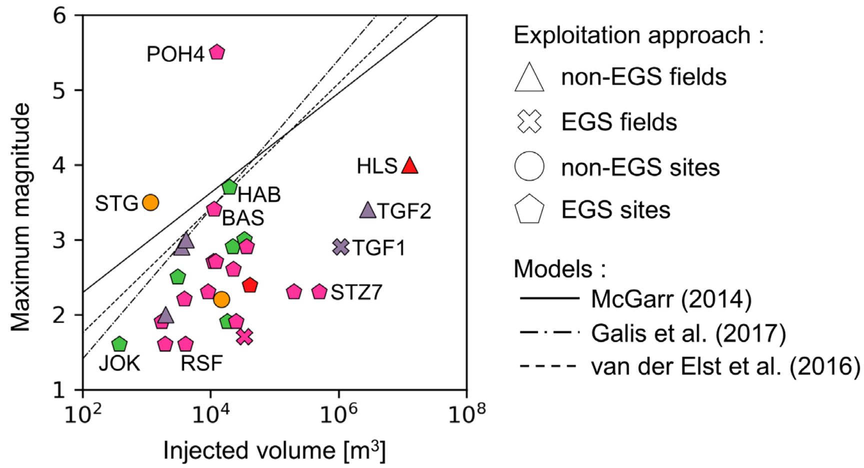

Figure 30: Maximum magnitude observed as a function of total injected volume. The lines indicate the maximum estimated magnitudes based on the three models indicated in the legend: the McGarr model for G = 30 GPa (Equation 3), the Galis model with $\gamma = 1.5*10^8$ (Equation 4), the van der Elst model with b = 1.2 and $\Sigma = 0.1$ (Equation 5). The color of the symbols indicates the geothermal system as defined in the legend of Figure 28. The shape of the symbols indicates the operating method as described in the legend. Project abbreviations: Pohang (POH), St. Gallen (STG), Habanero (HAB), Basel (BAS), Berlin (BGF), Hellisheidi (HLS), The Geysers (TGF), Soultz (STZ), Balmatt (BAL), Rittershoffen (RSF) and Jolokia (JOK).

However, we observe that, for comparable injected fluid volumes, the maximum magnitude of the observed earthquakes can vary significantly from one case to another, since the net volume injected is not the only parameter influencing the seismic response of the geothermal system, as seen previously. In addition, for many case studies considered, the magnitudes are well below the expected values based on the injected volumes. **These equations should therefore be considered when assessing the upper bound of the expected maximum magnitude. They cannot be used for a precise estimate of this magnitude value**.

The cases of Pohang and St. Gallen (POH5 and STG in Figure 30), for which the magnitude reached is several orders of magnitude higher than that predicted by the models of McGarr (2014), Galis (2017), and van der Elst et al. (2016), are good illustrations of their limitations. In this sense, the case of Pohang is emblematic because the magnitude M_{max} exceeds, by almost two orders of magnitude, the value of 3.7 that should have occurred according to McGarr's equation (2014). Following the terminology of Galis et al. (2017), and McGarr (2014) the earthquakes induced at the St. Gallen and Pohang sites are therefore characterized by runaway ruptures which, once initiated, propagate well beyond the zone concerned by the pore pressure disturbance, because the rupture size is controlled by the relaxation of tectonic stresses and by the dimension and connectivity between preexisting faults, rather than by the injected volume. This is typically the phenomenon of triggered seismicity.

On the basis of these considerations and the data analyzed, it can be concluded that **the probability of triggering a high-magnitude earthquake increases with the volumes injected, even if significant differences may be observed on a case-by-case basis**. This does not call into question the validity of the trends observed, but it suggests using these models with caution.

5.2.5. Influence of injection pressure and injectivity

The relationship between maximum magnitude and injection pressure has also been reported in the literature. After analyzing data from Basel, Mukuhira et al. (2013) indicate that the magnitude of seismic events shows no clear correlation with the difference between injection pressure and hydrostatic pressure of the reservoir. Similarly, by analyzing data from over 40 European geothermal sites, Evans et al. (2012) observe no direct relationship between injection pressure and maximum magnitude of the induced earthquakes. Conversely, Xie et al. (2015) and Buijze et al (2019a) report that injection pressure can have a significant influence on the maximum magnitude of seismic events.

For the case studies analyzed in this guide, we observe a trend of maximum magnitudes increasing with injection pressure for EGS sites (Figure 31a). However, for other exploitation methods, namely non-EGS sites and geothermal fields, as well as EGS fields, no relationship was seen between injection pressure and the maximum observed magnitudes. However, it should be emphasized that in these latter cases, the amount of data available is too limited to reach a definitive conclusion. This trend suggests that **a maximum magnitude threshold can be defined using the maximum wellhead pressure value, at least for installations organized as sites using EGS technologies**.

As already discussed, the magnitude of the M 5.5 earthquake at Pohang is markedly greater than expected, compared to the magnitudes observed in other geothermal projects, where hydraulic stimulations were conducted using comparable injection pressures. This implies that the magnitude of this earthquake was controlled neither by the injected volumes nor by the maximum wellhead pressures, which is in line with the runaway earthquake concept (see section 5.2.4), where the earthquake magnitude is related primarily to the structural characteristics of the reservoir (namely the size of preexisting faults).

Injection pressure is one parameter that depends on the injection flow-rate and permeability of the target environment. For this reason, and considering the relationship observed between injection pressure and the induced earthquake magnitude(Figure 31a), one might expect a magnitude increase with increasing injection flow-rate. However, an analysis of case studies for EGS sites does not show any clear links between flow-rate and the maximum magnitudes observed. Similar conclusions were reached by Buijze et al. (2019b) based on data from 40 geothermal sites. For each case study, we therefore compared maximum magnitude to injectivity, which is calculated here as the ratio between the maximum flow-rate and the maximum injection pressure value. The data show that magnitude at EGS sites tends to decrease as injectivity increases (Figure 31b). This trend, which was also highlighted by Zang et al., (2014), indicates that the greater the capacity of reservoirs to “accept” the injection of fluids, the lower the induced earthquake intensity. In other words, the more the reservoir has a network of well-connected fractures, the less this network will need to be arranged to allow the fluid circulation along such structures, and the lower the magnitude and frequency of induced earthquakes.

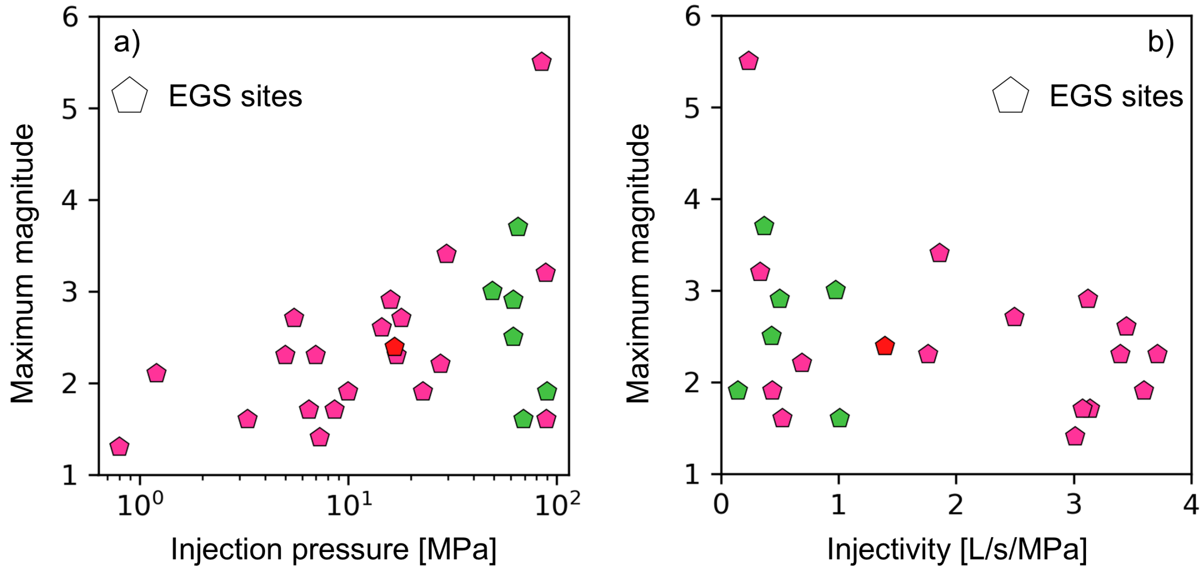

Figure 31: Maximum magnitude observed as a function of maximum wellhead pressure (a) and injectivity (b), only for EGS sites. The color of the symbols indicates the geothermal system type: extensional domain type (FFC-EDT) in pink, basement type (FFC-BT) in green, and volcanic type (FFC-VT) in red.

5.3. Summary about predisposition factors

The analysis of case studies has helped to highlight the intrinsic and operational factors playing a significant role in triggering induced seismicity, and which therefore impact the seismic hazard of geothermal projects. **To summarize the preceding sections, it seems evident that the occurrence and intensity of induced seismicity are the result of the interaction between several factors, both natural and anthropogenic**, which are concomitant and often mutually dependent. As a result, **the seismicity linked to geothermal projects cannot be explained by just one of these predisposition factors**.

The factors identified in the preceding sections are summarized in Table 6, where their influence on the seismic hazard is shown qualitatively (color code) with the geothermal system type in question. In fact, hydraulic, petrophysical, and geological features, as well as the exploitation methods and the operations conducted, differ depending on the geothermal reservoir type targeted, and contribute to determining the seismic hazard of a given project. In other words, the key intrinsic and operational factors with regard to induced seismicity will have a different influence on the hazard level depending on the geothermal system type, as shown in Table 6.

Based on these considerations and the elements discussed in the preceding section, geothermal projects may have the following different seismic hazard levels:

- **seismic hazard is low** for **projects involving porous aquifers without faults** connected to the geothermal reservoir, and which are **exploited without the use of EGS technologies**. In France, this category includes geothermal sites in MPC systems, including those exploiting the Dogger sedimentary aquifer in the Paris Basin;
- **seismic hazard is moderate** for **projects exploiting porous reservoirs with faults potentially connected to the reservoir**, which may sometimes be the target of geothermal operations, but which are not **presumed to be critically loaded or connected to the basement**, and for which **no natural seismic activity** is observed. Furthermore, these

projects do not plan on using EGS technologies for exploiting the geothermal resource. This applies to certain projects in mixed control systems (MC);

- **seismic hazard is high** for projects that exploit:
  - **All reservoir types** (mixed control, controlled by matrix porosity and permeability, controlled by faults and fractures) **characterized by good hydraulic properties but in which faults may be connected to the basement and/or be critically loaded.** Geothermal projects in this type of formation may be more frequently associated with seismic events (e.g., St. Gallen and Unteraching);
  - **Reservoirs** controlled by faults and fractures **with low natural fluid circulation** (i.e., absence of convection cells) **and/or low injectivity values**;
  - **Reservoirs** with mixed control and/or controlled by faults and fractures **and where EGS technologies are used** to exploit the geothermal resource. These examples do not include projects in porous reservoirs, where EGS technologies are generally not used;
  - **Reservoirs** controlled by faults and fractures **operated as geothermal fields** with **net injected volumes and generally high temperature differences between the reservoir and the reinjected fluid**.

Table 6: Influence of intrinsic and operational factors on the seismic hazard level as a function of the geothermal system type targeted. The colors of the boxes in the table indicate the seismic hazard level for each factor identified and for each geothermal system: green, yellow, and salmon indicate low, moderate, and high induced seismic hazards respectively. Boxes with diagonal lines are those for which factors cannot be assigned to certain geothermal systems. The text in the table boxes makes it possible to provide details on the factors and parameters of the most representative but non-exhaustive cases for each of these contexts.

Induced seismic hazard

			Matrix porosity controlled systems (MPC)	Mixed controlled systems (MC)	Faults / fractures controlled systems (FFC)
Intrinsic factors		Fluid flow	Matrix porosity controlled	Mixed controlled by porosity and faults / fractures	Faults / fractures controlled
		Convection (heat transfer)			Good hydraulic properties
		Conduction (heat transfer)			Bad hydraulic properties
		Favorably oriented and critically stressed faults	Generally not observed	Can be frequent	Can be frequent
		Hydraulic connection to the basement	Generally not observed	Can be frequent	Wells close to or within the basement
		Reservoir-basement distance	Generally far from basement	Generally close to basement	Wells close to or within the basement
		Natural seismic hazard	Low	Moderate	High
		Reservoir temperature	Low	Moderate	High, especially for FFC-VT systems
Operational factors	**Exploitation approaches**	non-EGS sites	No cases of seismicity observed	Very few cases of seismicity observed	
		EGS sites			Especially for FFC-BT and FFC-EDT systems
		non-EGS fields			Especially for FFC-PT and FFC-VT systems
		EGS fields			Infrequent exploitation approach
	Operations	Circulation	No cases of seismicity observed	Very few cases of seismicity observed	Very few cases of seismicity observed
		Production-injection			Especially for FFC-PT and FFC-VT systems
		Injection/Stimulation			Several cases of seismicity observed
		Shut-in	No cases of seismicity observed	Several cases of seismicity observed	Several cases of seismicity observed
		Net injected volume	Low	Moderate	High
		Injection pressure	Low	Low	High
		Injectivity	High	High	Low

6. Definition and assessment of seismic hazard

As the case studies show (chapters 4 and 5), not all geothermal projects have the same predisposition for the occurrence of a seismic incident. This depends on the predisposition factors of the geothermal system targeted by the project and the technologies employed. Assigning a **seismic hazard** to a project helps to manage it by defining appropriate mitigation measures. This chapter begins with a brief description of the state of the art about already existent methods for induced seismic risk and hazard assessment, which have been developed specifically for deep geothermal operations. It continues by presenting the method proposed in this guide. Thus, in what follows, the term “hazard level” will designate the seismic hazard level associated with a given project. **Based on a multicriteria approach applicable to all types of geothermal contexts, the method proposed here uses decision trees to assess the hazard level at each key step of a project**. At the end of this chapter, the method is applied as an example to several case studies in various geothermal contexts.

6.1. State of the art of existing methods for induced seismic hazard assessment

Methods for assessing the seismic hazard specific to the context of deep geothermal operations have been established in Switzerland (GRID, Trutnevyte and Wiemer, 2017) and The Netherlands (Quickscan, Baisch et al., 2016). Their principle, explained in Figure 32, is to establish indicators used to quantify the risk or hazard level for a geothermal project (Table 7). These indicators are rated on a 3 (GRID) or 4 (Quickscan) level scale: for example, in GRID, the indicator will have a score of 0, 1 or 2, depending on whether the reservoir is at a depth less than 1 km, between 1 and 3 km, or over 3 km. Depending on the final score, projects are assigned a specific hazard or risk level, for which specific management measures are applied. For example, the GRID method proposes management adapted to the risk level, with measures that are qualified as obligatory, voluntary, or not necessary. The categories of participants involved in such measures are explained in detail, as is the project phase in which the measures should be implemented. Those measures include technical actions (risk level evaluation, **TLS**, seismic monitoring) and non-technical actions (informing stakeholders, outreach, implementing an insurance system, “two-way commitment”, social characterization of the site). Examples of two-way commitments are gathering the public’s concerns and responding openly on suitable websites, face-to-face interactions between the public and experts, or public discussions between outside experts with divergent opinions. **Since the present guide focuses on the technical measures** to **be implemented to manage induced seismicity, it does not discuss this management** aspect, which is still an important point for successfully running a deep geothermal project.

Getting back to the hazard assessment, the Quickscan method considers only the factors that could affect seismic hazard (single-entry table), while the GRID method simultaneously considers the hazard, and the vulnerability and concerns of the public (triple-input table). The advantages of the Quickscan method are that it is quicker and can be conducted directly by operators, while specific studies (e.g., expertise in social science and geosciences) are required for the GRID method, the trade-off being that the latter’s results are more thorough.

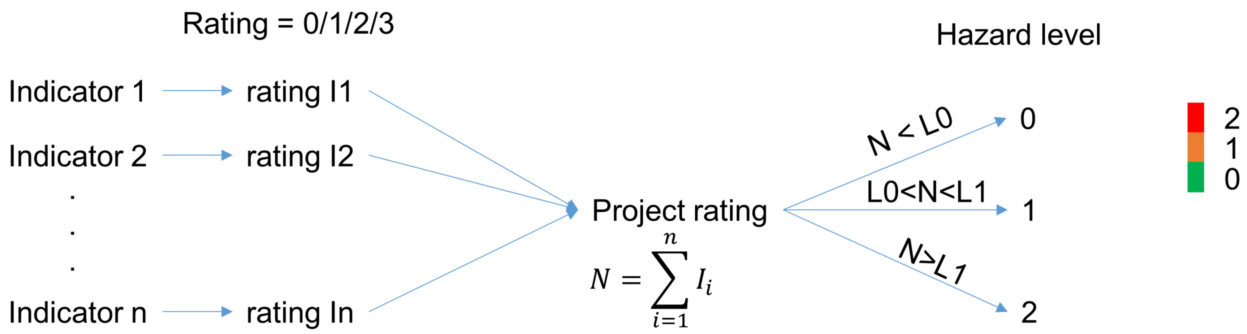

Figure 32: Diagram explaining the principles of the GRID and Quickscan methods.

In addition to scoring methods such those described above, approaches exist for determining the hazard and/or risk level of a geothermal project. For example, the approach proposed for EGS projects by Majer et al. (2016, 2012) is based on different steps that may or may not be applied, depending on the nature of the project. Among those steps are a preliminary screening evaluation, a communication program, a probabilistic seismic hazard assessment[22], and a mitigation program. The aim of the preliminary screening evaluation is to place projects in four categories, from the start of the project until its end. However, the indicators of this preliminary screening evaluation are not as clearly detailed as with the GRID and Quickscan methods, and are left up to the operator's judgement, depending on the planned project type. Mitigation measures are classified into direct measures and indirect measures by Majer (2012). Direct measures are those used to run operations in order to control seismicity, such as TLS (chapter 8), while indirect measures are measures for handling seismicity if it occurs (monitoring, increased communications in the case of seismicity, compensation measures, insurance system, etc.).

The above methods are specific to one geothermal system type or technology (Quickscan for a geothermal system controlled by matrix porosity, GRID for geothermal systems controlled by faults and fractures, and Majer for EGS), and the scoring system created is highly dependent on that context. To bring these methods into broader use, it would be necessary to determine which indicators are independent of the context (e.g., orientation of faults with respect to the stress field is one indicator that can be used in all geothermal system types) and which indicators and their associated limit values must be adapted (in chapter 5 we showed that, depending on the geothermal system type, the permeability of the formation is not controlled by the same structures, and so the scale to be considered will be different).

6.2. The approach of this guide's hazard assessment method

The approach proposed in this guide for assessing the hazard level of a project is based on decision trees, as illustrated in Figure 33. **It has the advantage of accounting for interactions between indicators, without defining a scoring system** (as in the Quickscan or GRID methods), **making it applicable regardless of the geothermal systems and technologies involved** (chapter 2). This method was partly inspired by the Quickscan method, and is based on determining the hazard level and not the risk level, for the reasons mentioned in section 3.2.1.

22 – Hazard is expressed as a probability of exceeding a fixed seismic movement, this is the method used to determine seismic zoning in France.

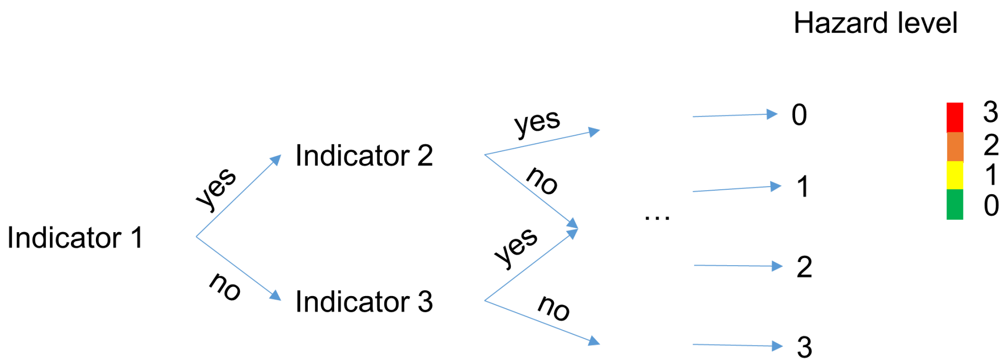

Figure 33: Diagram explaining the principle of the method proposed in this guide for determining seismic hazard .

Table 7 below compares the indicators used in the Quickscan and GRID methods with the method proposed in this guide, where an essential difference can be seen. It concerns the fact that the geothermal system type is considered, rather than just the two criteria of reservoir depth and rock type. This criterion based on the system type is more complete and inclusive, since it considers the modes of heat transfer and fluid circulation in the reservoir, thereby covering all system types exploited in France.

It should also be noted that the method proposed, as for the GRID method, **makes it possible to determine the hazard level at each key step of a geothermal project**. This reevaluation is essential, because the understanding of the reservoir's behavior increases as a project advances.

Table 7: Indicators used by the Quickscan and GRID methods and this guide's method for determining seismic hazard.

Indicators for determining seismic hazard	Quickscan method	GRID method*	Method proposed in this guide
Reservoir depth	-	X	-
Rock type	-	X	-
Geothermal system type	-	-	X
Reservoir connected to the basement	X	-	X
Natural seismicity level	X	X	X
Induced seismicity level (previous occurrences)	X	-	X
Distance from known and potentially active faults	X	X	X
Orientation of faults with respect to the current stress field	X	-	X
Daily volume injected or extracted during operations	-	X	-
Total injected volume	X	X	X
Reservoir injection pressure/overpressure	X	X	X
Circulation flow-rate	X	-	-
Interference between wells	X	-	X

** for the GRID method, only the indicators associated with the hazard are detailed.*

In order to complete this hazard evaluation in the spirit of the Majer (2016, 2012) approach, we therefore propose recommendations to follow at different steps of the project (chapter 7) in terms of data to acquire and parameters to monitor. These recommendations are supplemented by advice for running operations (chapter 8) in order to help prevent a seismic incident. The following sections describe the principle of the procedure and how the various components interact.

6.3. Defining hazard levels

This guide defines four seismic hazard levels (Table 8); they characterize the predisposition for the occurrence of a seismic incident, i.e., an event whose intensity could cause nuisances for the population and exposure issues, and which could adversely affect the operating conditions and even the continuation of the project. When geothermal installations are located in urban areas, as close as possible to the heating and energy needs, the seismic incident could therefore be the occurrence of an induced event of intensity ≥ III on the EMS scale (scarcely felt events, Table 4). When geothermal projects are developed in areas of low exposure issues (e.g., sparsely populated and industrialized rural areas), the reference intensity for the seismic incident could be higher, e.g., ≥ IV. It is up to the operator to determine this seismic intensity level.

Predisposition for the occurrence of a seismic incident for a given project may be very low (hazard level 0), low (hazard level 1), moderate (hazard level 2) or high (hazard level 3), and the hazard level dictates the measures to be implemented to control induced seismicity. Thus, for hazard level 0, there is no specific measure to take; for levels 1 and 2, measures in terms of monitoring, data to acquire and TLS are to be planned. For level 3, a temporary shutdown is necessary for an accurate examination of the situation by the operator and a review of the work program in order to return to a maximum hazard level of 2, which is compatible with continuing the project (Table 8).

The hazard level evolves during the project lifetime (section 6.4) as new knowledge is acquired.

Table 8: Hazard levels and related mitigation measures to minimize the likelihood of a seismic accident.

Hazard level	**0**	**1**	**2**	**3**
Description	Very low	Low	Moderate	High
Overall advice/ recommendation	Applying the good practices and recommendations specified in Hamm et al. (2019)	Implementing appropriate preventive and corrective measures (monitoring, good practices, etc.) (section 7.3 and chapter 8)		Mandatory adjustment of the work program to reduce the hazard level and thus prevent a seismic incident as far as possible

6.4. Key moments for hazard level evaluation and reevaluation: recommendations

The initial assessment of the seismic hazard for a project can be conducted during the exploration phase. The hazard level must then be regularly reevaluated based on the new knowledge acquired over the lifecycle of the project (Figure 34).

This guide defines **the key moments (milestones) for the evaluation and subsequent re-evaluations of the project hazard level** (Figure 34). It is the operator's responsibility to **inform the competent authorities about the seismic hazard level of the project** , at least **when each of these milestones is reached.** In addition, if operational data reveal a **significant divergence** from the previous hazard level estimate, it is recommended to conduct a new hazard assessment, even for phases not identified as milestones.

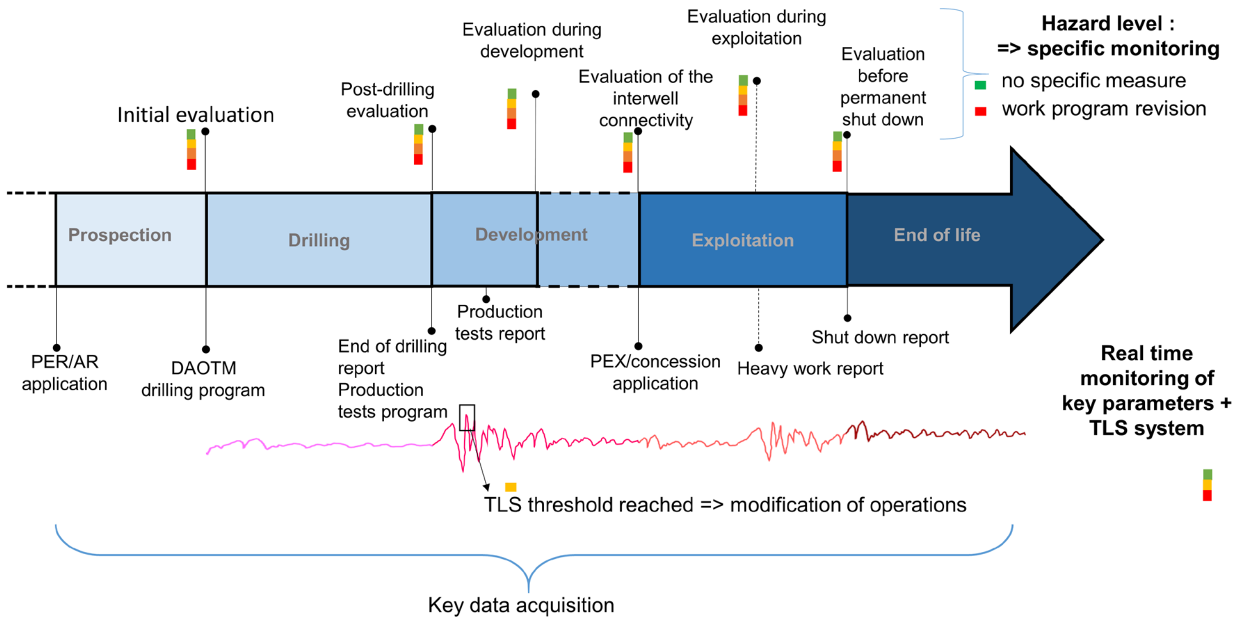

Figure 34: Diagram illustrating the iterative principle whereby the operator evaluates and reevaluates the seismic hazard level at key steps of the project. The project phases are defined in chapter 2 (section 2.2.1). The dashed lines indicate an optional phase: if the initial testing program was not satisfactory, a new testing cycle may be required. The main regulatory documentation to be provided are based associated with each hazard assessment milestone (if the exploration phase does not contain geophysical investigations of the zone, the PER/AR and DAOTM requests may be combined). This hazard level determines the monitoring recommendations. In parallel, and throughout the project, key parameters are monitored and evaluated based on a TLS system and data to be acquired. When a TLS threshold is reached, immediate operational actions are conducted.

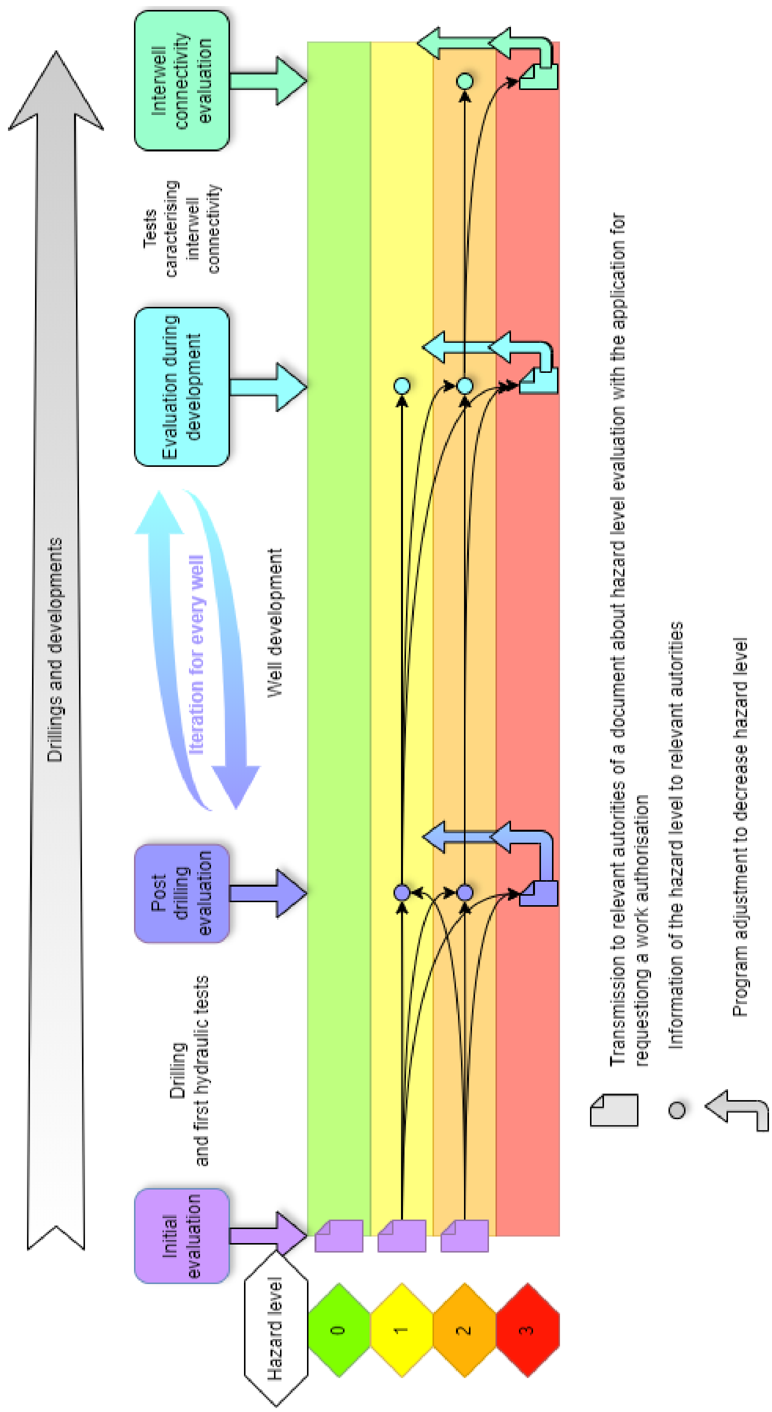

Figure 35: Diagram of the timeline and possibilities of evaluating the "seismic incident" hazard level during the most sensitive project steps. It is recommended to transmit an initial hazard assessment to the competent authorities along with the required documentation for the first drilling request. Next, and as long as the seismic hazard level remains less than or equal to 2, it is recommended to inform the competent authorities about the hazard level at each milestone. If the project reaches hazard level 3, it is strongly recommended to reexamine and adjust the work program, so that the project hazard level comes down to no more than 2.

In practice, two milestones are especially important. The first involves the initial hazard evaluation that determines the conditions for conducting the project. **The second step is the post-drilling assessment** that determines the conditions of conducting operations to improve well injectivity and/or productivity if necessary, as well as the evaluation during development. In fact, it has been established that the probability of a seismic incident is especially high during the well development phase (chapter 5), which is why special attention must be paid to the hazard assessment during that phase.

An initial assessment (which can be based on a literature review, an analysis of existing data, and/or on geophysical investigations depending on the contexts, chapter 7) of the project hazard level (section 6.5.1) is recommended **after exploration and before drilling the first well** in the target reservoir. Compared to the regulatory timeframe, it is recommended to conduct the initial hazard assessment **when the authorization application to begin works (DAOTM) is prepared, in order to form a separate part of the technical brief (section 6.6) associated with the DAOTM**.

Then, the number of milestones will depend on the hazard level, which may change throughout the project lifecycle (Figure 35):

- Level 0: **no hazard reevaluation**. However, a reevaluation at the operator's discretion and in light of new elements is recommended if the hazard level increases (particularly if an induced seismic event felt at the surface is suspected).
- Level 1: it is recommended that the operator **reevaluate** the hazard level at the following steps:
  - During the drilling and development phases:
    - After each drilling operation and **hydraulic tests** (section 6.5.2) used to characterize the hydromechanical behavior of the reservoir;
    - **Before** any operation aimed at **improving well injectivity and/or productivity** (section 6.5.3).
  - During the operational phase, and if no deviation from the expected situation occurs (section 6.5.5):
    - **Annually** for 5 years (at least),
    - **Every 5 years** after 5 years of operation (at least),
    - Before **conducting significant work or restarting after an unexpected shutdown and/or a shutdown for a long period** that could cause substantial overpressures in the well (particularly during new stimulations or new reinjections).
  - At the end of the project, before shutdown (section 6.5.6):
    - Before conducting operations to shut down one or more wells,
- Level 2: it is recommended that the operator reevaluate the hazard level at the steps described for level 1, to which the following milestones are added:
  - During development:
    - After conducting tests proving pressure connectivity between the injection and production wells, and before long-term circulation begins (section 6.5.4).
- Level 3: level 3 can be reached only after the first well is drilled and after the first tests run to characterize the hydromechanical behavior of the reservoir. It is reached when reservoir behavior diverges significantly from what is expected. In this case, it is recommended that the operator not initiate new operations before analyzing the

situation in detail if necessary, analyzing new measures, and **reviewing the operational program in order to come down to a lower hazard level**. If there is a new work program better adapted to the reservoir conditions, keep in mind that it must be sent to the Prefecture (in France) and a copy sent to the Mines Police (section 2.2.2.2). In addition, **the hazard reassessment could form a specific part of the documentation to be submitted to the competent authorities**.

For each of the above milestones, an assessment method based on decision trees is proposed in the following sections. Such decision trees help operators to evaluate hazard at each milestone, using knowledge and data available at each of the corresponding steps.

6.5. Recommendations for hazard level evaluation and reevaluation at each key moment

This section defines the criteria to be evaluated to determine the seismic hazard. The data to acquire for the evaluation of such criteria are mentioned in chapter 7.

6.5.1. Initial hazard evaluation (before any drilling operation)

Figure 36 illustrates the recommended method for evaluating the seismic hazard level of a project before any drilling operation.

Criterion E0: The entry point for the initial hazard assessment is strongly guided by the **geothermal system type** in question (chapter 2). Of course, this criterion is indirect from the point of view of required conditions for rupture processes to occur. However, it has the advantage of being more easily understood than the local stress state and loading of the system. This is why the first criterion proposed (Figure 36 - E0) is based on the geologic control on fluid circulations. Such circulations may be controlled by faults and/or fractures or by the matrix porosity and permeability of the rock:

- No → criterion E1: if fluid circulation is mostly controlled by matrix porosity and permeability, the following criterion (Figure 36 - E1) involves understanding the geothermal system:
  - Yes → Level 0: once the system is known and already in operation (intercalation between preexisting geothermal wells using the same system) in the absence of significant induced seismicity (no seismic incident reported, no induced seismicity of magnitude M > 1.5 recorded), the project is assigned a **hazard level of 0** (very low). In France, for example, Paris Basin projects follow this decision path;
  - No → criterion E3: if the project is located in a zone where no other geothermal wells exploiting the same system are present or in a new, geothermal reservoir, little-used or as yet unused, the following criterion involves the proximity of faults potentially connected to the reservoir (Figure 36 - E2). At this stage of the project, faults can be detected either by identification on regional geological maps, or during geophysical studies (e.g., active seismic surveys, chapter 7):
    - No → Level 0: if there is no obvious proof of the presence of faults, the project is assigned a **hazard level of 0** (very low). Nevertheless, it is recommended that the operator reevaluate the hazard level if subsequent operations reveal the presence of a fault(s) having a role in geothermal fluid circulation.
    - Yes → criterion E4: if faults are present that are presumed to be connected to the reservoir, the hazard level is 1 or 2 depending on the estimated characteristics of the fault; the evaluation criteria applicable to levels 1 and 2 are criteria E4, E5 then E6 explained in detail below (Figure 36 - E4, E5, E6).

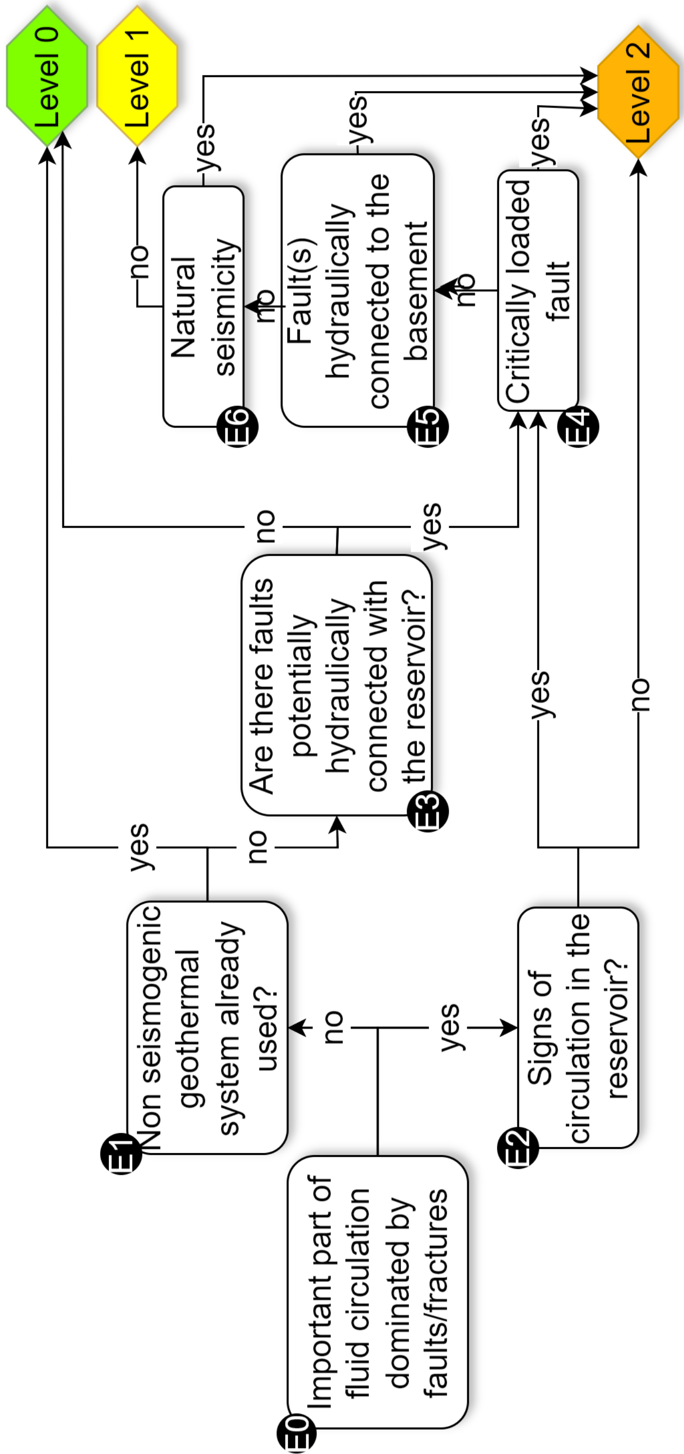

*Figure 36: Decision tree for the evaluation of the hazard level of a project before any deep drilling. This evaluation uses available data on the geothermal reservoir targeted (e.g., scientific publications) and data acquired during the exploration phase (section 7.1.1). *No seismic incident reported, no induced seismicity of magnitude M > 1.5 recorded.*

- Yes → criterion E2: if fluid circulations are controlled primarily by faults/fractures, the hazard level is 1 or 2. The first element determining the seismic hazard level is the presence or absence of fluid circulations in the reservoir (Figure 36 - criterion E2):

  - No → Level 2: the lack of an indication of the presence of circulations within the target reservoir leads to a **hazard level 2** (moderate): *theoretically,*, the hydraulic characteristics of the reservoir are poor and the injection of fluid in this type of environment may cause pressure in the reservoir to increase rapidly;

  - Yes → criterion E4: if there are indications of the presence of convective circulations within the target reservoir, then discriminating between hazard level 1 or 2 will be based on the mechanical, geometric and **seismotectonic** characteristics of the faults. First, it is recommended to conduct an omnidirectional evaluation of the shear potentiality of discontinuities (slip tendency type, e.g., Moeck et al., 2009), based on regional, and ideally local, knowledge of the stress state (obtained by a literature review, a study on **focal mechanisms** of local earthquakes if possible, knowledge provided by nearby wells etc.). Evaluation criterion E4 is based on the loading of the fault(s):

    - Yes → Level 2: if the fault(s) known to be in the reservoir or connected to it is(are) critically loaded (e.g., a slip tendency value greater than or equal to 0.6[23]), or if an orientation seems to be critically loaded (e.g., a slip tendency value greater than or equal to 0.8), then the project is assigned a **hazard level of 2** (moderate).

    - No → criterion E5: if the fault(s) present in the reservoir or connected to it is(are) not critically loaded and no other orientation seems to be critically loaded, then the eventual connection of the fault to the basement should be evaluated (Figure 36 - E5). Indeed, the analysis of predisposition factors has helped to show that the hydraulic connection of faults with the basement (i.e., extension of the fault into the basement and proximity of the reservoir and basement and/or hydraulic connection indicator) is an aggravating factor for induced seismicity (chapter 5): fluids can migrate toward the basement, where the stress state is close to critical, and thus it can be responsible for a seismic incident. In the case of volcanic or plutonic type reservoirs, where the concept of basement has no real significance, the answer to this question should be 'no'.

      - Yes → Level 2: if there is an indicator of a connection between the fault(s) of the reservoir with the basement, this constitutes a seismic incident predisposition factor. The project is assigned a **hazard level of 2** (moderate).

      - No → criterion E6: if there is no evidence or suspicion of a hydraulic connection between the fault(s) and the basement, this last criterion involves the natural seismicity and history of the site (Figure 36 - E6). In fact, in a historically or naturally seismic zone with a predisposition to fault slip, there is a greater risk that faults in or near the reservoir will be reactivated. In order to determine whether or not natural seismicity exists, operators may refer to national databases and maps such as SisFrance (https://www.sisfrance.net/) and Géoportail (https://www.geoportail.gouv.fr/donnees/zones-de-sismicite), which contain all known historic earthquakes and the of natural seismicity level, respectively. A literature review is also recommended in order to identify possible local earthquakes. For level 1 or 2 projects, this characterization of natural seismicity can be refined by an analysis of data in the permanent seismic monitoring network installed before any deep well has been drilled (chapter 7).

23 *– In this preliminary study including all orientations (even those theoretically not existing in the reservoir), a relatively high coefficient can be used for the threshold. Nevertheless, this threshold should be considered in terms of known structural orientations: if the orientation is known, a threshold of 0.6 is recommended.*

- Yes → Level 2: if the project is located in a zone of moderate or higher seismicity (within the meaning of French seismic zoning) or if the presence of strong seismic swarms or historic earthquakes is established based on a literature review, then the project can be assigned a **hazard level of 2** (moderate);
- No → Level 1: when the presence or proximity of faults in the reservoir is known, but if these faults seem to be not susceptible to shear (zone of low to very low seismicity within the meaning of French seismic zoning and no observed seismic swarms or historic earthquakes), then the project can be assigned a **hazard level of 1** (low).

6.5.2. Post-drilling hazard assessment

The induced seismic hazard assessment during the post-drilling phase is recommended for projects initially given a level 1 or 2 score during the preceding milestone, (pre-drilling phase). The communication to the competent authorities about this new hazard assessment and could be given as a complement to the production testing program, which is a mandatory regulatory document.

Table 9 illustrates the recommended method for assessing the seismic hazard of a project after drilling and once the first tests to characterize the reservoir have been done.

Table 9: Decision tree for evaluating the hazard level of a project after drilling and the first tests to characterize the reservoir.

F0 - Critically loaded fault	F1 - Microseismicity during drilling*	F2 - "Insufficient" injectivity index	Hazard level
Yes	Yes	Yes	3
		No	2
	No	Yes	2
		No	2
No	Yes	Yes	2
		No	2
	No	Yes	If EGS technologies 2, if not 1
		No	1

**If an event is felt during drilling, the hazard level is immediately raised to 3.*

This decision tree is a table read from left to right and is used to determine hazard level with respect to the column header criteria.

Initial criterion F0 is a **mechanical criterion**: it involves **the loading (in terms of stresses) of faults** intersected by or located close to the well(s). This criterion was evaluated in the preceding decision tree (section 6.5.1, criterion E4) and is reevaluated here in light of recently acquired data. This includes structural geology information on the reservoir, used to identify the orientations of major discontinuities intersected by the well, as well as the stress measurements taken in the well.

The second criterion F1 is a **seismic criterion**: it evaluates the reservoir's sensitivity to slight stress changes based on the presence or absence of seismicity induced by drilling operations. The occurrence of significant microseismicity during drilling operations indicates an unstable mechanical state of the rock mass and may thus be an indicator of proneness to the occurrence of a seismic incident. If the magnitude of seismicity recorded during drilling operations in a radius of 1 km around the well is over 0.5 and/or the surface PGV is over 0.5 mm/s at two or more stations (chapter

8), then the hazard level increases to 2 (if the project hazard level is lower), whereas if that seismicity is felt at the surface, the hazard level increases to 3.

The third criterion F2 is a **hydraulic criterion**: at this stage of operations, only hydraulic tests can characterize the hydraulic behavior of the well-reservoir system. An initial evaluation of the injectivity and/or productivity index is available. If this index appears too low with respect to the one targeted for the exploitation, then it is likely that the operator will use methods to improve injectivity/productivity. These methods, particularly EGS technologies, can be seen as an aggravating factor of seismic hazard. A "yes" response to this criterion places the project at hazard level 2, even 3, depending on the number and type of aggravating factors, unless all the other factors are negative. If all other criteria are negative, and if the operator plans to apply EGS technologies, such as hydraulic and/or thermal stimulation, then the hazard level to be considered is 2. If all other criteria are negative and the operator will use non-EGS improvement technologies (according to the definition in section 2.1.2.3), e.g., aimed at increasing well length in the reservoir, or use only chemical stimulation without significant overpressure in the reservoir, the hazard level to consider remains the level determined in the preceding step. Finally, if all criteria are negative, the hazard level to consider is 1.

6.5.3. Hazard assessment during well development

Conducting and submitting this evaluation is recommended for projects with a hazard level of at least 1 during the preceding milestone, and for which the initial injectivity and/or productivity index appears insufficient. At this stage, **hydraulic tests** have already been conducted. This assessment is recommended before the application of any stimulation program, and it is an iterative process. It is recommended to repeat this hazard assessment procedure before applying any new protocol to increase injectivity/productivity. For the first stimulation program, this evaluation can be conducted at the same time as the post-drilling evaluation.

The decision tree in Figure 37 shows the recommended method for evaluating the seismic hazard level of a project after a low flow-rate test, and before any new **EGS stimulation** or non-EGS stimulation:

Criterion D0: reaching the target injectivity/productivity index is one criterion used to determiner if the reservoir behaves as expected or not.

- If the injectivity and/or productivity index is reached, then the seismic hazard level remains the same level as previously estimated.
- If the injectivity and/or productivity index is not reached, it is recommended to first:
  - Criterion D1: Conduct a series of analyses to determine the reservoir's mechanical response to the stresses previously applied and to predict its behavior under new stresses, particularly by:
    - evaluating the potential consequences and effects of a new increase in the total net volume of fluid injected. In fact, as shown in chapter 5 (section 5.2.3, also McGarr, 2014), under certain conditions, the more fluid injected into the reservoir, the higher the magnitude of induced seismic events can be. This evaluation may be obtained, for example, by numerical hydraulic modeling of the reservoir (chapter 7) in order to predict the overpressure field in the reservoir, which would be useful to compare with the slip tendency of the faults/structures of the reservoir;
    - Evaluating the effectiveness of the protocol previously implemented, if there was one: ineffectiveness or low effectiveness of the methods previously used is one valuable indicator of reservoir behavior to consider when determining the new protocol;
    - Evaluating the reservoir's capacity to withstand thermo-hydro-mechanical disturbances by analyzing its response in terms of induced seismicity. Evaluating this capacity makes it possible to design of the next

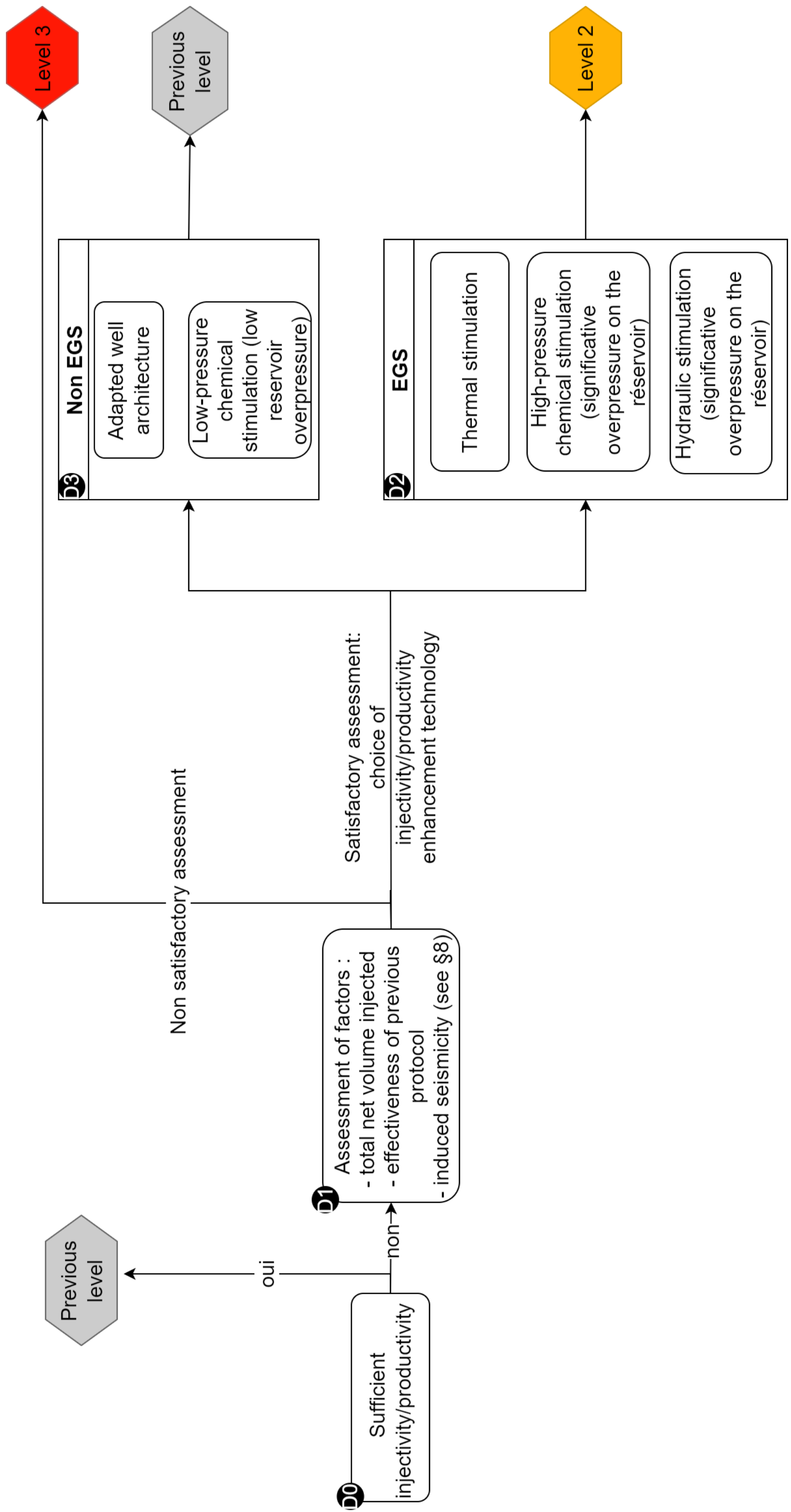

Figure 37: Post-well development decision tree

well development cycle by minimizing hazards. This evaluation may involve an analysis of seismicity, using stimulation histories and/or hydro-mechanical modeling.

– The results of these analyses will enable the operator to:

  - Classify the project at hazard level 3: if an evaluation of all the factors of criterion D1 leads the operator to identify a particularly complex situation, where the risk of inducing seismic incidents appears non-negligible, then in this case it is recommended to increase the hazard level to 3 and stop to revise the work program. For example, this may be the case when the protocol(s) previously implemented did not result in a sufficient injectivity increase, and there was induced seismicity exceeding one of the thresholds of the TLS and/or a seismic incident.

  - Continue using a well development protocol: if these evaluations appear satisfactory (the injectivity/productivity increase is insufficient but an analysis of previous stimulations and/or tests did not reveal an increased risk of induced seismicity), then a protocol for increasing well injectivity/productivity may be proposed and the hazard level will be based on the planned technologies:

    - Criterion D2: using EGS technologies (hydraulic, high pressure chemical or thermal stimulation) in the well development protocol places the project at hazard level 2,

    - Criterion D3: the use of non-EGS technologies which are less destabilizing for the rock mass (low-pressure chemical stimulation or appropriate well architecture) enables the project to remain at the hazard level previously determined.

6.5.4. Hazard assessment regarding interwell connectivity

Once all wells are drilled, and particularly when the installation is operated as a site and not as a field (chapter 2), the connection between selected wells must be verified before starting fluid circulation. This hazard assessment is required for geothermal sites (not for fields) for which as least one well is at hazard level 2 (Figure 35). **Seismic hazard is evaluated at this milestone for the entire project and no longer well-by-well, as was the case for all preceding evaluation steps.** This hazard should be determined after running an interference test (between the wells that will be used during the operational phase) and by taking into account all prior tests on those wells. This hazard assessment clearly depends on the quality of the **pressure connection between the wells.** More specifically, this involves verifying that the pressure connection between wells is effective at the pressures planned for operations; if not, the project hazard must be raised to level 3. A weak connection means that, once in circulation, there will be no equilibrium and that pressure differentials could be generated in the reservoir, leading to a heightened seismic risk.

6.5.5. Hazard assessment during reservoir exploitation

For this project phase, the seismic hazard is determined for the entire project and no longer on a well-by-well basis. When circulation is started, it is recommended that the hazard level remain the same as for the preceding operations. If the hazard levels of two (or more) wells are different, the higher level should be applied to the entire project. It is also recommended to reevaluate this level:

- Before any substantial operation causing significant changes to circulation (e.g., work-over, operating design change, etc.);
- Yearly during the first five years, and then every five years;
- In case of a strong and/or unexpected seismic event.

The following must be considered when reevaluating this hazard level:

- The seismicity level: if the red TLS threshold is exceeded, the hazard level automatically increases to 3;
- Change in the injectivity index: if it decreases and induced seismicity increases, the project is raised to level 2 if it was initially at level 1.

The following must also be considered in the case of a major operation:

- Evaluating the potential consequences and effects of a new increase in the total net volume of fluid injected;
- If a new well is drilled, the entire process must be repeated (section 6.5.1).

If the hazard level is 2 and no incident (earthquake felt and/or red TLS threshold exceeded) has occurred after five years, it is recommended to lower the hazard by one level. For a level 1 project, if the level of induced seismicity after five years is negligible (seismicity level recorded identical to that recorded during the six months prior to drilling), it is recommended to reduce the hazard level to 0. It is therefore possible for a level 2 project with no seismicity to become a hazard level 0 project after 10 years.

6.5.6. Hazard assessment before permanent installation shutdown

In the event of a permanent shutdown of the project because of the occurrence of a seismic incident, the situation should be evaluated on a case-by-case basis. If the permanent shutdown occurs at the end of a project's lifecycle, the only case dealt with in this section, it is recommended to maintain the previous hazard level during the shutdown phase. If the installation has been exploited until the end of its lifecycle without notable seismic activity, the project will be shut down at hazard level 0 (no monitoring required).

However, if the project is shut down while it has a hazard level of 1 or 2, it will require monitoring by a permanent seismic network (chapter 7). Once the installation is shut down, it is therefore recommended to continue monitoring for at least one year and to follow changes in seismicity using seismicity criteria and thresholds specified in the TLS during operation (chapter 8). If seismicity remains below thresholds during the first 12 months after shutdown and especially if the level of induced seismicity is negligible (level recorded identical to the level recorded during the six months preceding drilling), the hazard level may be set to 0. Otherwise, it is recommended to maintain the previous level and revaluate the situation yearly until hazard level 0 is reached.

6.6. Hazard level and technical brief: few keypoints

In the context of an authorization application to begin mining work (DAOTM), Article L. 164-1-2 of the Mining Code stipulates that the applicant must submit a technical brief (see section 2.2.2.2):

- Stating the measures taken and considered in order to understand the underground geology;
- Enabling an understanding of the natural phenomena, particularly seismic, that could be activated by the work, in order to minimize their probability and intensity, as well as the risk of reappearance of such phenomena after their possible occurrence.

On this basis, and in relation to the methodology for evaluating seismic hazard described above, we may formulate a few framework aspects for preparing this technical brief:

- The seismic hazard can be initially evaluated using the decision tree proposed in section 6.5.1. In all cases, the indicators selected will be explained and argued as much as possible;
- Based on the assumptions underpinning the geothermal project, particularly associated with its objectives, resources planned for exploiting it, and the knowledge at the start of the project, the operator will have to make a theoretical forecast of the hazard level during the drilling and development phases, using the decision trees in sections6.5.2 and 6.5.3. As a result, this theoretical forecast will necessarily be based on assumptions about the expected behavior of the reservoir and the planned mode of development. Data, information and/or models used to back up key assumptions will be clarified and discussed as much as possible.

This initial estimate and theoretical forecast of seismic hazards at subsequent steps may be useful for determining the data to acquire in order to understand the behavior of the reservoir and to anticipate and describe measures for controlling and preventing seismicity, including the operational strategies that can be used. These aspects can be dealt with by using the recommendations made in the following chapters (chapters 7 and 8). Additional recommendations for the technical brief, concerning the data to acquire, are discussed in section 7.5.

6.7. Examples of application to case studies

In order to illustrate the hazard level assessment methodology using practical cases, five geothermal projects were selected that cover all contexts that may be observed in France. These projects are listed in Table 10 along with the seismicity level recorded so far.

Table 10: Case studies for evaluating seismic hazard level.

Geothermal system type	Site	Associated seismicity
Control by matrix porosity and permeability	Cachan (France)	No seismicity
Mixed control	Bruchsal (Germany)	No seismicity
	Unterhaching (Germany)	Seismicity during operation
Control by faults/fractures	Bouillante (France)	No seismicity
	Soultz-sous-Forêts (France)	Seismicity during multiple phases

In each of the case studies, the hazard level was evaluated at each step using published data. The hazard level was determined using the method recommended in this guide, but since it is an *a posteriori* analysis, there may be a difference in some examples between recommendations for monitoring (Bouillante) or operations (Soultz-sous-Forêts) and drilling wells. Table 11 summarizes the hazard levels determined for each case study, at each step of the project. .

Table 11: Example of the seismic hazard level assessment for each case study. Boxes in gray show the steps for which the hazard reevaluation is not necessary. Wells in parentheses are those for which the hazard is determined in the initial, post-drilling, and post-development evaluations. Green, yellow, orange, and red correspond to hazard levels of 0, 1, 2 and 3, respectively. Colorless boxes mean that reevaluation is not necessary.

	Cachan (GCA1)	Bruchsal (GB II)	Unterhaching (Gt Uha2)	Bouillante[(1)] (BO2)	Soultz-sous-Forêts[(2)] (GPK3)
Initial evaluation	E0: no E1: yes → Level 0	E0: yes E2: - E4: no E5: yes → Level 2	E0: yes E2: - E4: yes → Level 2	E0: yes E2: yes E4: no E5: no E6: yes → Level 2	E0: yes E2: yes E4: yes E5: yes → Level 2
Post-drilling evaluation		F0: yes F1: no F2: no → Level 2	F0: yes F1: no F2: yes → Level 2	F0: no F1: no F2: no → Level 1	F0: yes F1: no F2: yes → Level 2
Post-development evaluation			D0: yes → Level 2		D0: no D1: criteria achieved → Level 3
Well connectivity evaluation			Yes → Level 2	NA[(3)] (no reinjection)	Yes → Level 2
Operating evaluation		Level 0 because no seismicity after 10 years of operation	Seismic incident in 2008, none after that → Level 1 after 5 years, level 0 after 10 years	Level 0 because no seismicity after 10 years of operation	No seismic incident → Level 1 after 5 years of operation
End of life evaluation					Level 1 during at least the first year

[(1)]For the evaluation during operation and evaluation of the entire project, level 2 was reached because EGS technologies were used for well BO4.

[(2)]The evaluation of Soultz-sous-Forêts was limited to GPK3 in the initial phases, and then involved the entire project as recommended after the connectivity evaluation. Following the post-development earthquake, hazard level 3 was reached, requiring the stimulation protocol to be reevaluated.

[(3)]NA: not applicable

7. Reservoir characterization and monitoring: recommendations and good practices

This chapter contains the basic concepts for a better acquisition and use of technical and scientific knowledge required to evaluate seismic hazard level (chapter 6) and to assist in decision-making while operations are under way (chapter 8). Indeed, preventing seismic hazard is based on the acquisition and use of available knowledge to understand, to the extent possible, reservoir behavior and, more broadly, the geothermal system behavior in response to imposed stress changes. This knowledge comprises the various types of data to be acquired, interpreted, and integrated into various reservoir models. It also includes the measures to be implemented for monitoring microseismicity and operational parameters, also referred to as exploitation parameters.

7.1. Measurements, data, and knowledge required at each step of the project

Running a project with the goal of minimizing the occurrence of a seismic incident requires a sufficient understanding of the target reservoir and its behavior. Depending on the geothermal system type and the seismic hazard level of the site, “sufficient” can cover different levels and types of knowledge. **This section lists the data and knowledge required to at least prepare and update the reservoir models at each stage of the project (section 7.2). It is not possible to be exhaustive, however, due to the specific features of each site. As a result, it is the operator’s responsibility to obtain and acquire the relevant data necessary to evaluate and manage the project’s seismic hazard.**

7.1.1. Data and knowledge to be acquired in the exploration phase, before any drilling

At this stage of the project, the target geothermal reservoir is known from previous projects, if any, and from the data acquired, compiled, and integrated during the exploration phase. The investigations to carry out in order to be able to determine the seismic hazard level are listed in Table 12. Data obtained from such investigations also make it possible to prepare the first models of the geothermal reservoir (section 7.2).

The minimum goals of this initial data acquisition, and the associated models, are to:

- Identify nearby faults, and define their features (length, thickness, permeability) as thoroughly as possible. Identify potential fracture zones/orientations;
- Make a first estimation of the stress tensor which those faults are subjected to. To do this, the values and orientations of the main local stresses must be estimated. If the stress field cannot be precisely estimated, the tectonic regime (normal, inverse or strike-slip) at the depth of the reservoir must be determined in order to define a range of values as a function of depth (Zoback et al., 2003);
- Have an initial idea of circulations in the reservoir;
- Identify and characterize natural seismicity.

Table 12: Recommendations on the level of data to be acquired and calculations to be performed before drilling

System type / Investigation subject	Control by matrix porosity and permeability	Mixed control	Control by faults/fractures
Behavior of the reservoir, particularly the potential for seismic incidents	Integrate feedback from nearby projects or with similar projects. This feedback must be based on available scientific publications and public reports. In addition, **it is recommended to establish information-sharing among the operators using the same reservoir** (section 7.6).		
Presence and location of faults	Search for indicators of the presence of faults through a literature review of available scientific publications and public reports, as well as the geological map of France for major structures. Consulting the BRGM's underground database (Banque du Sous-Sol - BSS [24]) to include nearby projects (especially data on wells).	Literature review of available scientific publications and public reports, as well as the geological map of France for major structures. Consulting the BSS to include nearby projects (particularly data on wells). Producing a 3D representation of the reservoir (seismic, electromagnetic methods, gravimetry, depending on the system) in order to visualize and locate faults and lithological interfaces	
Hydraulic behavior of the reservoir	Literature review of available scientific publications and public reports.	Literature review of available scientific publications and public reports. Consulting the BSS and National Groundwater Data Access Portal (ADES) to obtain temperature and hydrodynamic parameter measurements, if any, that will help to refine the reservoir models. Depending on the system, search for surface indicators (hot springs, fumeroles, gas emanations, etc.), and geochemical analyses to identify the origin of fluids, **measure temperature variation with depth within wells**.	
Geomechanical state	–	Literature review to determine the state of stresses (orientation and magnitude) based on available scientific publications and public reports, as well as data of the World Stress Map (WSM)[25]. The Stress2Grid[26]tool for estimating the maximum horizontal orientation on a grid, based on WSM, could be useful. A range of magnitudes for the maximum horizontal stress values can be estimated by assuming that the main stress is vertical [27] (Moos and Zoback, 1990). Other operators exploiting the same reservoir could provide information they have on the stress field. Initial estimates of the susceptibility of faults to slip (e.g., omnidirectional, based on a slip tendency estimate). If the stress tensor is not well defined, multiple estimates can be made.	
Natural seismicity	Review of natural seismicity and historical seismicity in the study area (e.g., in SisFrance (https://www.sisfrance.net/) and Géoportail (https://www.geoportail.gouv.fr/donnees/zones-de-sismicite))		

24 – *https://infoterre.brgm.fr/page/banque-sol-bss*
25 – *https://www.world-stress-map.org/*
26 – *https://dataservices.gfz-potsdam.de/wsm/showshort.php?id=escidoc:4175894*
27 – *Note, this assumption is not always valid, especially when topography is considerable (mountainous zone).*

7.1.2. Data and knowledge to be acquired during and just after drilling

Drilling the first well is an opportunity to obtain direct data on the geothermal reservoir, which will help improve understanding and update reservoir models. There may be fewer acquisitions in subsequent wells but this will nevertheless expand the dataset, by broadening spatial knowledge (one well enables only a local, 1D data point to be acquired) thereby highlighting the variability of reservoir characteristics.

Table 13 and Table 14 contain the data to be acquired when the first and subsequent exploration wells are drilled in order to evaluate the seismic hazard level as a function of the hazard level determined during the pre-drilling phase. These data are to be compared and interpreted in light of the initial understanding, and will also enable models of the geothermal reservoir to be updated (section 7.2).

The goals of this data acquisition, and the associated models, are to:

- Characterize reservoir faults and fractures with more accuracy;
- Better determine the local stress field;
- Identify faults that are open to fluid circulation and those that are less so;
- Gain an initial assessment of the reservoir's response to hydraulic stresses.

This information should make it possible to re-evaluate the seismic hazard (section 6.5.2) and, if necessary, prepare a stimulation protocol that takes the seismic hazard into account (section 8.2.5 and section 8.2.6).

Table 13: Recommendations on the level of data to be acquired and calculations to be performed when drilling the first exploration well.

Hazard level / Investigation subject	Hazard level 0	Hazard level 1	Hazard level 2
Geological context	No recommendations in addition to those found in the "Good practices guide about feedback from deep geothermal drilling" (Hamm et al., 2019)	**Analysis of drill cuttings and/or core samples**. **Interpreting mud losses recorded** with respect to knowledge of the geological formation intersected by the well. **Locating and interpreting the** rate of penetration break **(abrupt variations in drilling velocity within the well**). **Conducting suitable well logging** to provide information on the petrophysical and geologic characteristics of the reservoir. Special attention is paid to locating and characterizing the system of faults/fractures (principal orientation, dip, thickness, complexity of the subsystem, if any) particularly through the use of **well imaging** (seismic, acoustic or electric, depending on contrast differences enabling better discontinuity visualization) coupled with suitable well logging results, including temperature and flow-rate logs. Special attention is paid to the search for faults near the well that were not detected from the surface.	
Hydraulic context	No recommendations in addition to those found in the "Good practices guide about feedback from deep geothermal drilling" (Hamm et al., 2019)	Location and **characterization of feed zones** particularly by **interpreting flow logs and temperature logs** in the well. Interpreting them with respect to the understanding of the local geology. The objective is to identify permeable faults and fractures. . Running **low flow-rate well tests** to determine the hydraulic parameters of the reservoir **to estimate the injectivity/productivity index** (the goal being to prevent imposing excessive pressure changes on the reservoir before getting an initial assessment of its behavior). **Monitoring and archiving pressure, flow-rate and temperature data, with bottom-hole and wellhead measurements**. It is recommended to continuously monitor these parameters with wellhead instruments. It is also recommended to install equipment (such as fiber optics) in order to continuously monitor them in the bottom-hole, at least during the development phase. One point to remember when interpreting tests: consider using models suited to the geology, i.e., including circulations and fault/fracture environments.	
Physicochemical state of the reservoir		Bottom-hole temperature measurement	
Geomechanical state		**Measuring** and characterizing **the stress state**. It is recommended to follow the recommendations of the ISRM (International Society for Rock Mechanics and Rock Engineering) for this characterization (Hudson et al., 2003). **Estimating the vertical stress value based on rock density and depth.** **Measurements of well deformation** (well diameter determinations and imaging) to identify principal stress orientations, by interpreting breakouts and drilling-induced fractures, if these are observed. Stress values can be estimated by using **direct models** to explain breakout observations (Blanksma et al., 2018; Peter-Borie et al., 2018) or by the width of breakouts (Valley and Evans, 2019). If the stress value is not well known and it is planned to use **EGS stimulations, *ad hoc*** tests such as **XLOT** (Extended Leak-Off Test, e.g., Zoback, 2011) or **HTPF** (Hydraulic Testing of Pre-existing Fractures, Haimson and Cornet, 2003) can be used. Initial estimates of the susceptibility of faults to slip (e.g., based on a slip tendency estimate).	
Seismicity	–	Monitoring seismicity during drilling with the seismic monitoring network (section 7.3). Detecting and locating seismicity in near real time (see section 8.3.1). *A posteriori* and in the case of earthquakes of M > 0.5 and PGV > 0.5mm/s, correlating the locations of events with well imaging to identify structures potentially in a critical stress state.	

Table 14: Recommendations on the level of data to be acquired and calculations to be performed starting with the second well.

Hazard level / Investigation subject	Hazard level 0	Hazard level 1	Hazard level 2
Geological context	No recommendations in addition to those found in the "Good practices guide about feedback from deep geothermal drilling" (Hamm et al., 2019)	**Analysis of drill cuttings and/or core samples**. **Interpreting mud losses recorded** considering the understanding of the crossed geological formation. **Locating and interpreting abrupt variations in the velocity of progress** of the drill in the well (**rate of penetration break**).	**Analysis of drill cuttings and/or core samples**. **Interpreting mud losses recorded** considering the understanding of the crossed geological formation. **Locating and interpreting the** rate of penetration break **(abrupt variations in drilling velocity within the well**). **Conducting suitable well logging** to provide information on the petrophysical and geologic characteristics of the reservoir. Special attention is paid to locating and characterizing the network of faults/fractures, especially through the use of **well imaging** coupled with suitable well logging results, including temperature and flow logs.
Hydraulic context	–	Running **low flow-rate well tests** in each well in order to determine the hydraulic parameters of the reservoir and **to estimate the injectivity/ productivity index** (the goal being to prevent imposing excessive pressure changes on the reservoir before getting an initial assessment of its behavior). **Monitoring and archiving pressure, flow-rate and temperature data, with bottom-hole and wellhead measurements**. It is recommended to continuously monitor these parameters with wellhead instruments. It is also recommended to install equipment (such as fiber optics) in order to continuously monitor them in the bottom-hole, at least during the development phase.	Location and **characterization of feed zones** particularly by **interpreting flow logs and temperature logs** in the well. Interpreting them with respect to the understanding of the local geology. The objective is to identify permeable faults and fractures. . Running **low flow-rate well tests** in each well in order to determine the hydraulic parameters of the reservoir and **estimate the injectivity/productivity index** (the goal being to prevent imposing excessive pressure changes on the reservoir before getting an initial assessment of its behavior). One point to remember when interpreting tests: consider using models suited to the geology, i.e., including circulations in fault/fracture environments. **Monitoring and archiving pressure, flow-rate, and temperature data, with bottom-hole and wellhead measurements**. It is recommended to continuously monitor these parameters with wellhead instruments. It is also recommended to install equipment (such as fiber optics), in order to continuously monitor them in the bottom-hole, at least during the development phase.
Physicochemical state of the reservoir	–	Bottom-hole temperature measurement	

Hazard level / Investigation subject	Hazard level 0	Hazard level 1	Hazard level 2
Geomechanical state	–	–	**Measuring** and characterizing **the stress state**. **Measurements of well deformation** (well diameter determinations and imaging) to identify principal stress orientations, by interpreting breakouts and drilling-induced tensile fractures, if these are observed. Initial estimates of the susceptibility of faults to slip (e.g., based on a slip tendency estimate)
Seismicity	–	Monitoring seismicity during drilling with the seismic monitoring network (section 7.3). Detection and location of seismicity in near real time (see section 8.3.1). *A posteriori* and in the case of earthquakes of M > 0.5 and PGV > 0.5 mm/s, correlating the locations of events with well imaging to identify structures potentially in a critical stress state.	

7.1.3. Data and knowledge to be acquired during well development

During this phase, stress changes imposed on the reservoir that may help to improve the operator's understanding of the (thermo-)hydromechanical behavior of the reservoir.

The data to be acquired during well development, to determine the seismic hazard level and optimize operations, are described in Table 15 as a function of the hazard level determined after the drilling phase.

The goals of this data acquisition, and the associated models, are to:

- Evaluate the reservoir's response to hydraulic stresses;
- Evaluate the reservoir's capacity to withstand new stresses;
- Manage well development.

Table 15: Recommendations on the level of data to be acquired and calculations to be performed during well development

Hazard level / Investigation subject	Hazard level 0	Hazard level 1	Hazard level 2
Hydraulic context	No recommendations in addition to those made by Hamm et al., 2019.	**Continuous monitoring (frequency from several seconds to several minutes) of bottom-hole and wellhead pressure, temperature, and flow-rate** (results interpretation based on the understanding of the local geology). Running **tests to characterize the increase in injectivity/productivity after each sequence** of operations done to improve them (hydraulic, chemical, or thermal stimulations, multi-drain, etc.). **Preparing *flow-rate/temperature logs*** to characterize hydraulic changes in *feed zones*.	
Seismicity	–	Periodic consultation of regional and national databases. **Non-EGS technologies** → Monitoring seismicity with the main network. Estimating locations and magnitudes of events in near real time. *A posteriori*, if a TLS threshold is exceeded, correlating the locations of events with operational parameters (see sections 8.3.3 and 8.5). **If EGS technologies are used** → Seismicity monitoring improved by the extended monitoring network. Event localization, magnitude calculation and PGV measurements in near real time, as well as estimation of other key variables, such as: seismic moment, seismic energy, **b-value**, etc. *A posteriori*, interpreting results to improve understandings of the reservoir's seismic response (section 8.4.4).	

7.1.4. Multi-well site: characterizing the connection between wells

Well tests can characterize the reservoir only in an area close to the well. Inter-well tests, on the other hand, can characterize an extended area of the reservoir.

Table 16 summarizes the recommended data to be acquired when multiple wells from the same project are available. These recommendations are applicable to projects organized as a site and not as a field. Ideally, if projects that are similar and/or target the same reservoir are accessible, the tests recommended can also be conducted between different sites. The goal of this data acquisition, and the associated models is to characterize the pressure and/or fluid connection between wells.

Table 16: Recommendations on the level of data to be acquired and calculations to be performed between wells

Hazard level / Investigation subject	Hazard level 0	Hazard level 1	Hazard level 2
Hydraulic context	No recommendations in addition to those made by Hamm et al., 2019.	Running tests to **characterize the pressure and/or fluid connections between wells** (e.g., interference tests, circulation tests, tracing tests, etc.) and interpretation using models that take circulations in discontinuities into account.	
Seismicity	–	Monitoring seismicity with the main network. Correlation between seismic data observed and interpretations derived from hydraulic tests.	

7.1.5. Exploitation phase

Once drilling and development have terminated, and if production and injection are satisfactory, the project advances to the operational phase, i.e., long-term circulation to exploit the thermal energy of the reservoir.

Table 17 summarizes the data recommended to be acquired during the operational phase. The objective of this data acquisition is to manage operations by taking observed seismicity into account.

Table 17: Recommendations on the level of data to be acquired during the operational phase.

Hazard level / Investigation subject	Hazard level 0	Hazard level 1	Hazard level 2
Hydraulic context	No recommendations in addition to those made by Hamm et al. (2019).	Monitoring and archiving production and injection data (flow-rate, pressure, temperature, physicochemical parameters, etc.).	
Seismicity	–	Periodic consultation of regional and national databases. Monitoring seismicity with the dedicated network. Estimating locations and magnitudes of events in near real time. *A posteriori*, if a TLS threshold is exceeded, correlating the locations of events with forcing parameters (see sections 8.3.3 and 8.5).	

7.2. Models and calculations required to evaluate reservoir behavior and operations management, dealing with uncertainty

Preventing seismic hazard also involves the use of models and calculations that must be constructed and updated (when new information becomes available) in order to formulate a relevant forecast of the reservoir's behavior during drilling, well development, and exploitation. Since an earthquake is a mechanical response to a thermo-hydro-mechanical stress, to anticipate the occurrence of seismicity, it is necessary to realize models that take these physical aspects into account. **These models may range from relatively simple analytical calculations to the most complex multi-physical numerical simulations**.

In all cases, the **conceptual model** of the reservoir is the basis for all other models and calculations, such as (Figure 38):

- Geological model(s), which integrate knowledge about the geological characteristics of the reservoir and of neighboring formations, as well as about the petrophysical characteristics of the geological formations (porosity, permeability);
- Reservoir model(s) or hydrogeological model(s) that simulate fluid flows in the reservoir and their effects in terms of pressure, and that may also include the effects of temperature;
- Geomechanical model(s), which are strongly recommended to use in mixed control systems and in systems controlled by faults and fractures. It is used to determine the susceptibility of faults to shear in the initial state (before

any geothermal operation) and as a result of the planned project operations (pressure and volume variations possibly estimated by the reservoir model, temperature variation, etc. section 3.2).

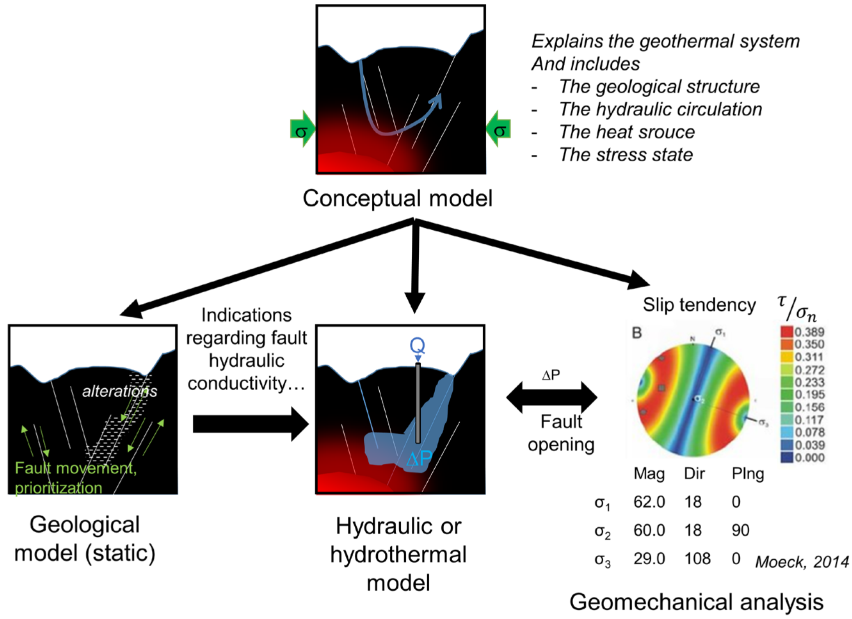

Figure 38: Models and calculations required to anticipate the seismic response of the reservoir in mixed control systems and in faults and fractures in controlled systems.

Dealing with uncertainty is an essential point of these models, to be able to estimate their reliability. When the reservoir is poorly known and uncertainty is high, it is recommended to include this uncertainty in the results and interpretations, ideally with a probabilistic approach (that yields a distribution of possible results) rather than a deterministic one (which provides a single solution) in the models. It is necessary to clearly identify where the uncertainties are and propose several possible models with parametric studies (at least two, at the extremes) to cover the full extent of the range.

7.3. Microseismic monitoring: good practices and recommendations

The monitoring of operational parameters is a permanent feature for all projects. It is based on the recommendations in section 7.1 and evolves during the lifetime of the project. Monitoring microseismic activity has the dual goal of managing seismic risk (verifying that TLS thresholds are not reached) and operational strategies (real-time adjustment of operational protocols depending on seismicity). When **monitoring microseismic activity** is implemented, **it is subjected to a cross-interpretation with data acquired during operations,** such as injection pressures, volumes, and products injected or injection temperature**. This compared analysis between microseismic and hydraulic data is fundamental for the correct understanding of the physical mechanisms involved** and to improve knowledge of the reservoir's development and its response to different operations. **It is also a necessary condition for managing geothermal operations** based on recorded seismicity (chapter 8).

Table 18: Summary of recommendations for the main and the extended seismic monitoring networks depending on the hazard level of geothermal projects. M refers to the magnitude of the events.

	Pre-drilling phase	Drilling phase	Development phase[1]	Operational phase
Hazard level 0 projects				
Main network	Not applicable			
Extended network[3]				
Hazard level 1 projects				
Main network	Yes (6 months before)	Yes	Yes	Yes
Extended network[3]	No	If M > 0.5 and PGV > 0.5 mm/s	If orange TLS threshold is exceeded[2]	If orange TLS threshold is exceeded[2]
Hazard level 2 projects				
Main network	Yes (6 months before)	Yes	Yes	Yes
Extended network[3]	No	If M > 0.5 and PGV > 0.5 mm/s	Always	If orange TLS threshold is exceeded[2]

[1] *Note that for hazard level 1 projects, the development phase does not necessarily include the use of EGS technologies, while this is always the case for the development phase of hazard level 2 projects;*

[2] *See chapter 8 for operation management with a TLS (Traffic Light System).*

[3] *The extended network can be installed at any time before the phase in which it is required*

Requirements concerning **microseismic monitoring concern only projects with hazard levels of 1 and 2** (chapter 6). Depending on the situations explained below, these requirements are based on installing a dedicated main microseismic monitoring network that can be extended in terms of the number and position of sensors at the most sensitive steps of the project (Table 18).

For hazard level 0 geothermal projects, developed in porous aquifers in the absence of faults connected to the geothermal reservoir, **it is not necessary to install a dedicated microseismic monitoring network**. In France for example, this is applicable to projects in the Paris Basin.

It should be recalled that **hazard level 3** can be reached only in projects initially with a hazard level of at least 1, but generally 2, in which a substantial deviation from the **theoretical** understanding and the reservoir's expected behavior is observed after drilling or during the first well development tests. Such projects must therefore be placed under microseismic monitoring; they can be continued only if the work program is revised so that hazard level comes down to 2 at the most, as explained in chapter 6, and after a detailed analysis of the situation.

The following sections contain recommendations for microseismic monitoring. Annexe 9 summarizes the characteristics of seismic networks installed in certain geothermal projects and previously analyzed in this guide.

7.3.1. Basic requirements

For projects with hazard levels of 1 and 2, the dedicated seismic network must have the following characteristics (Table 19) :

- Installed at least 6 months before drilling begins, in order to better characterize the natural seismicity baseline level in the area of the geothermal project;
- Functional for the entire lifetime of the project, particularly during the phases of drilling, development, exploitation, and end of life, in order to monitor microseismic activity that could potentially affect the different geothermal operations, and to identify possible variations in the seismicity characteristics when work begins;
- Detect, locate and, estimate the magnitude of the microseismicity;
- Guarantee the precise location of events that could be felt;
- Compatible with managing operations using a TLS (section 8.1).

In addition to the previous recommendations, for hazard level 2 projects which target reservoirs with mixed control and/or reservoirs controlled by faults and fractures, with faults potentially connected to basement and/or critically stressed, requiring the use of EGS technologies because of low natural fluid circulation, **the seismic network must be designed in order to enable** (Table 19):

- An estimate of source parameters and the focal mechanisms of the strongest events ($M > 1.5$);
- An accurate monitoring and characterization of possible spatio-temporal and energetic changes of microseismicity (see section 8.1 dealing with statistical approaches) and controlling operations using a TLS with a predictive approach in the case of EGS stimulation (see section 8.2).

7.3.2. Extension of the seismic network

The extension of the seismic network by adding stations, must be realized as a function of the project phases and the hazard level. **This network extension can be done either by adding permanent stations, or by installing a temporary network.**. Extension of the seismic network is particularly necessary in the following cases:

- If an event of $M > 0.5$ and $PGV > 0.5$ mm/s is recorded by at least two stations, within a radius of 1 km during the drilling phase, if the network is not yet extended, when changes in the stress state are generally weaker than in the operational phase;
- Systematically, when EGS technologies are used in the development phase (hazard level 2 projects), network extension can be implemented at any time before EGS stimulations;
- If the orange threshold of the TLS is exceeded (section 8.2.2) in the development phase (without the use of EGS technologies) and/or in the exploitation phase;
- If an earthquake is felt at the surface [28] (regardless of its magnitude) at any time during the project.

Network extension can be planned with a two-fold objective, depending on the context of the project and the situation encountered (Table 19): on one hand, to improve performance in terms of detectability (minimizing the magnitude of completeness (Mc)) and location of microseismic sources, and on the other hand, to extend the area of network coverage in order to be able to identify induced events at a distance from the wells (chapter 3).

28 *– It should be noted that the occurrence of an earthquake felt at the surface during the drilling phase is a very rare phenomenon, with few published references.*

When additional stations are used to manage operations, **they must be integrated into the main monitoring network data treatment and processing protocol**, in order to optimize the operations management in near real time.

Table 19: Summary of objectives and technical requirements for seismic networks depending on the hazard level of geothermal projects.

	Objectives and technical performances targeted	
	Hazard level 1 projects	**Hazard level 2 projects**
Main network	Detecting, locating and estimating the magnitude of the microseismicity with a **magnitude of completeness** Mc ≤ 0.5 using 5 seismic stations. A location accuracy of ±300 m horizontally and ±1 km vertically is expected, within a radius of 2 km around the well should be expected. Guaranteeing a precise location of events potentially felt, with an accuracy lower than the extension of the exploitation. Enabling the functioning of a TLS (section 8.2) for managing operations.	Detecting, locating and estimating the magnitude of the microseismicity with a **magnitude of completeness** Mc ≤ 0.5 using 7 seismic stations, of which one is an accelerometer at least. A location accuracy of ±100 m horizontally and ±500 km vertically, is expected within a radius of 2 km around the well. Enabling the estimation of parameters at the source and the focal mechanisms of the strongest events (M > 1.5); Enabling the monitoring and characterization of spatio-temporal and energetic changes of the microseismicity (seismic statistics), as well as management with a TLS, using a predictive approach for EGS stimulations.
Extended network	Improving the performance of the network in terms of detectability and location. Broadening the coverage area of the seismic network.	

7.3.3. Expected technical performance of seismic networks and best practices associated with microseismic monitoring

For the main network, a magnitude of completeness Mc ≤ 0.5 is recommended for a minimum of 5 seismic stations equipped with geophones, for hazard level 1 projects, and 7 stations for hazard level 2 projects. This magnitude of completeness is expected in normal operational conditions, i.e., in the absence of drilling, the noise from which could interfere with the seismicity recording. Hazard level 2 projects are also equipped with an accelerometer at the surface in order to record any strong events (M > 3) whose signal could be clipped by velocimeters. One of the stations must be placed in the center of the network, directly over the reservoir, i.e., as close as possible to the expected source of seismicity. Azimuthal gaps larger than 120° must be avoided. In general **triaxial sensors should always be preferred to uniaxial sensors**. In fact, they enable a better waveform characterization, as well as the estimation of source parameters and focal mechanisms (estimations not possible with single-component sensors).

Network coverage must be sufficient to monitor seismicity over the entire surface involved by operations, including faults identified nearby which could be impacted by operations. For hazard level 1 projects, a location accuracy of at least 300 m horizontally and 1 km vertically, within a radius of 2 km around the probable source of seismicity should be targeted. For hazard level 2 projects, this accuracy must be at least 100m horizontally and 500m vertically. Before installing the monitoring network and prior to any modifications to an existing network, a conception study must be conducted using numerical simulations, in order to determine the optimal geometry of the seismic network (number and position of sensors) as a function of the target magnitude of completeness and the location error. There are several published numerical approaches for determining the optimal geometry of networks depending on target requirements, as well as for evaluating the location and detection performances for a given geometry (e.g., D'Alessandro et al., 2011; De Santis et al., 2017; Schorlemmer and Woessner, 2008; Stabile et al., 2013).

This conception study must take into account technical installation constraints (which can be numerous, especially in an urban environment) and ambient noise measurements, in order to install stations in silent locations, far from noise sources (natural and anthropogenic), and to optimize station sensitivity with respect to environmental conditions In areas where noise sources are significant, borehole probes should by preferred, in order to optimize the signal-to-noise ratio and thus be able to detect low magnitude events. The network conception study must also account for uncertainties in the seismic wave propagation **velocity model**. The velocity model is necessarily site-specific, i.e., defined using geological and structural models, as well as existing drilling data (Vertical Seismic Profiling (VSP), suitable well logging, etc.). Regional velocity models are not sufficiently accurate at the scale of the geothermal reservoir, and therefore can generate substantial errors for locating seismic events. Ideally, the velocity model used to design the network is optimized and updated after its installation, using calibration data and/or new information acquired.

7.4. Proposal for monitoring aseismic slip

Based on current knowledge (section 3.3.2) on the rupture mechanics and the hydro-mechanical properties of faults and geological discontinuities, deep fluid injection can cause aseismic slip phenomena. It is currently accepted by the scientific community that aseismic slip can have a large-scale effect on geothermal reservoirs and cause the accumulation or the release of stresses on asperities that could initiate seismic slip and rupture.

Under these conditions, and even though the understanding of interactions between aseismic and seismic slip is still a research matter, it is recommended to gather data that could be useful in the near future to better prevent seismic incidents, and to at least provide elements to populate analyses in the case of unexpected seismicity (section 8.5). Aseismic slip can be shown by different methods, e.g., the analysis of continuous seismic traces (typically for detecting and analyzing seismic repeaters) or by geodesic surface measurements (e.g., GNSS and SAR radar images).

7.5. Data acquisition, model and technical brief: few keypoints

As part of the authorization application to begin mining work (DAOTM), Article L. 164-1-2 of the Mining Code stipulates that the applicant must submit a technical brief (see section 2.2.2.2).

Some aspects about the content of this brief are discussed in section 6.6. Based on this framework, and considering data acquisition, analysis and interpretation to improve knowledge, as discussed above, we here formulate additional indications for preparing the technical brief:

- In order to understand the seismic phenomena that could be activated, the minimum requirement is to achieve the objectives defined in section 7.1.1 by acquiring the data described;
- This data acquisition should make it possible to prepare a conceptual model of the reservoir as well as other models required to understand the reservoir's behavior, particularly a geomechanical analysis (see section 7.2);
- The operator must also indicate the measures that are planned to be taken during well drilling and development, based on the recommendations in sections 7.1.2 and 7.1.3;
- If the initial hazard level requires it (level 1 or 2), the installed seismic monitoring network must be described in terms of the number of stations and their characteristics, based on the recommendations in section 7.3;
- The approaches used to monitor aseismic slip (section 7.4) must also be specified for hazard level 2 projects.

7.6. Data and model management

Here, it is useful to remind operators to implement a system for the proper management of data and models throughout the lifetime of the project, ideally by using the FAIR principle (Findable Accessible Interoperable Reusable).

In this context, **the rigorous, consistent management of the models and the various data acquired and used is a central process** along the lifecycle of the project and **must obligatorily be included in the project management plan**.

Concerning data, the operator must pay special attention to aspects involving the traceability and control of the following processes:

- Data acquisition particularly concerning the equipment used (reference number(s) of sensors, calibration date, installation modalities, etc.) and acquisition parameters (acquisition frequency, microseismic triggering criteria, time-stamping, data structuring and format, etc.). Data produced in proprietary formats must be easily convertible and usable in standard formats (e.g., mini-seed or SAC format for microseismic data and continuous traces);
- Well instrumentation during testing, in order to be able to directly measure key parameters, particularly the overpressures applied to the reservoir and its temperature (e.g., PTS[29] at the well bottom or the casing shoe). Wellhead operational parameters must be measured continuously and not only during injection phases. If continuous bottom-hole measurements are not taken, bottom-hole pressure and temperature measurements must be acquired during hydraulic tests at the casing shoe or if necessary at the strainers, in parallel to wellhead measurements. It is recommended to install equipment, such as fiber optics, to continuously monitor down-hole pressure and temperature, at least during the well development phase.

29 *- Pressure-Temperature Sensor*

- Data processing, which must be compatible with the near real time monitoring requirements. In particular, this involves:
  - The use of automatic algorithms for the detection, location, and magnitude calculation of seismic events and validating processing results by an operator at a frequency suited to the operation under way (the validation time by an analyst may vary from several hours to several days, depending on the type of work under way and the situation encountered). If necessary, this validation may include reprocessing to refine results obtained by automatic tools;
  - Seismic data treatment and analysis (source mechanisms , energy calculation, and statistics, possibly 4D imaging) particularly in the well development phase. When necessary, these seismic data treatments should be coupled to protocols for operations management, to be applied at a frequency adapted to the operation under way and the situation encountered.
- Data reporting and consolidation using formats and frequencies adapted to the stages of the project, in order to facilitate information sharing between various project participants (well drillers, geologists, geotechnicians, and seismologists) and to facilitate decision-making;
- Keeping and archiving continuous traces, data and metadata, for a back analysis if necessary.

In general, topics concerning data and model management require specific skills and technical expertise. It is recalled here that the operator can ask external experts to prepare all or part of the authorization application to begin mining work. and conduct the analyses and studies required. It should also be remembered that, as stipulated in Article 11-1 of Decree No. 2006-649 of June 2, 2006, the authorization application to begin mining work may entail costs invoiced to the operator by a third-party expert approved by the operator, for a critical analysis of all or part of the documents in the authorization application to begin mining work, for studies, technical data, programs, or reports requiring special verifications.

Knowledge exchange among operators using the same reservoir is strongly encouraged. Implementing an information sharing system to evaluate the potential for a seismic incident in this local context and to better manage operations with respect to the risk of induced seismicity, may be one factor for success, especially for projects targeting systems controlled by faults and fractures. **This knowledge exchange should particularly involve elements for characterizing the geomechanical state locally and the hydraulic behavior of the reservoir.**

Finally, in agreement with other authors (e.g., Wiemer et al., 2017), **it is suggested that operators publish seismic databases, recorded in near real time, on open access websites** (with information on the location, time of occurrence, and magnitude), **as well as a map of the epicenters**.

8. Management of deep geothermal operations: good practices for preventing seismic incidents

Preventing a seismic incident involves determining and implementing operational protocols that are adapted to the reservoir's geomechanical behavior and that can be adjusted during operations in order to minimize induced seismicity. This operational management is based on installing a Traffic Light System (TLS) that couples hydraulic parameters with variables that are representative for the reservoir's seismic response. These aspects are described in the first part of this chapter, based on existing publications. The chapter provides, then, practical recommendations for TLS application Finally, the chapter terminates with recommendations for operational protocols and points to remember at each key step of the project.

8.1. State of the art about Traffic Light Systems (TLS)

8.1.1. Traffic Light Systems: principles and examples

Traffic Light Systems are management tools used for the near real time adjustment of operational parameters, particularly flow-rate, injection pressure, and injected volume, as a function of seismicity recorded by the seismic monitoring network(s), in order to prevent the occurrence of a seismic incident. This type of system was first introduced by Bommer et al. (2006) for managing the geothermal site of Berlin (El Salvador). Since then, it has been tested in several geothermal projects and is currently the most widely-used tool for managing and mitigating induced seismic hazard on geothermal sites (Douglas and Aochi, 2014; Grigoli et al., 2017), even if it is not yet systematically applied.

Generally, a TLS is based on an action plan with three or four thresholds, ranging between **Green**, meaning there are no problems, and **Red** for which the seismic response requires operations to be shut down, under safety conditions, and to analyze the situation before restarting the operations. There are generally one or two intermediate thresholds, **Yellow** and/or **Orange**, the purpose of which is to lower injection/production parameters to prevent reaching the **Red** level. The most recent prefectoral orders in France have been based on three thresholds, while examples exist in the literature about TLS with 4 thresholds (Table 20 and Table 21).

Passing from one TLS threshold to another is generally based on one or more microseismic monitoring parameters, the most-often used of which are magnitude and/or PGV[30] (Peak Ground Velocity). PGV characterizes surface vibrations and therefore the potential impact of a seismic event on populations and buildings (section 3.2.4). It should be noted that in some cases, the red PGV threshold is generally below the limit of human perception (e.g., Ader et al., 2020; Bommer et al., 2006; Kim et al., 2018).

Other criteria in addition to magnitude and PGV/PGA are sometimes used. In the cases of Basel and St. Gallen, public response was used directly in the TLS by considering the number of calls by the population following the occurrence of seismicity (Häring et al., 2008). Concerning the Balmatt site, in addition to PGV, the TLS was also based on the earthquake rate and the horizontal distance between epicenters and the injection well (Heege et al., 2020). The latter criterion is justified primarily by the presence of two faults, about 600m to the east and west of the injection well (Kinscher, 2020).

30 *– Note that ground vibrations are sometimes expressed as PGA (Peak Ground Acceleration) instead of PGV.*

The thresholds for each criterion must be both conservative, in order to limit potential nuisances, but also practical, allowing operations to proceed safely, shut-downs (Ader et al., 2020). Table 20 lists the PGV and magnitude thresholds of the TLS for some geothermal projects already mentioned in this guide. It is shown that these values may vary considerably from one site to another.

Table 20: Examples of PGV and magnitude thresholds used in the Traffic Light Systems for certain geothermal projects. It should be noted that, in addition to PGV and magnitude, other criteria may be used to trigger yellow, orange and red levels of the reported TLS It should also be noted that the TLS thresholds listed may be related to different operational phases (e.g., development, circulation, production, etc.) from one project to another.

Project	PGV threshold [mm/s]				Magnitude threshold			
	Green	Yellow	Orange	Red	Green	Yellow	Orange	Red
Basel	< 0.5	≤ 2.0	≤ 5.0	> 5.0	< 2.3	≥ 2.3	≤ 2.9	> 2.9
Pohang	≤ 0.8	≤ 5.0	≤ 10	> 10	≤ 1.0	≤ 1.4	≤ 1.7	> 1.7
Otaniemi	< 1	-	≥ 1	≥ 7.5	< 1.0	-	≥ 1.0	≥ 2.1
Californië	< 0.1	-	≥ 0.1	≥ 0.3	No magnitude criterion			
Balmatt	< 0.4	-	≤ 1.0	> 1.0	< 1.5	-	≤ 2.5	
Rittershoffen	< 0.5	≥ 0.5	≥ 1.0	≥ 1.5	No magnitude criterion			
Vendenheim	No PGV criterion				-	-	≥ 1.5	≥ 2.0
Newberry	No PGV criterion				< 2.0	≤ 2.7	≤ 3.5	> 3.5

Actions to be taken for each TLS level are fairly similar from one project to another, as shown in Table 21. Note the particularity of the Otaniemi project, where the actions implemented if the orange level is exceeded were established on a case-by-case basis after analyzing the situation (Ader et al., 2020; Kwiatek et al., 2019).

Table 21: Examples of actions to be undertaken when different TLS thresholds are reached in certain geothermal projects. It should be noted that, beyond the examples shown, bleed off is not systematically performed when the red TLS threshold is exceeded.

Project	Actions to be undertaken			
	Green	Yellow	Orange	Red
Basel	Proceed as planned	Do not increase flow-rate	Maintain wellhead pressure below stimulation pressure[1]	Bleed off at the minimum wellhead pressure
Pohang	Proceed as planned	Constant flow-rate and pressure	Flow-rate reduced or stopped	Bleed off
Otaniemi	Proceed as planned	-	Case-by-case evaluation, determining if and how a mitigation strategy is to be implemented	Injections stopped and optional bleed off

[1] *Stimulation pressure is defined here as the wellhead pressure at which the first seismic event occurred.*

8.1.2. TLS combined with proactive statistical and/or empirical approaches

Theoretically, TLS effectiveness can be improved by the use of statistical and/or empirical models to estimate changes in the seismic response of the reservoir over time, and depending on the operations conducted (e.g., Bentz et al., 2020; Drif et al., 2021; Kwiatek et al., 2019). This approach involves the real time or near real time monitoring of seismicity and of its characteristic variables, and the modification or the shut-down of operations if any deviation from one or more predefined models/trends is observed. Operation control is thus not regulated based on threshold values of one or more parameters as described above (Figure 39).

For example, these statistical and/or empirical models are used to estimate the probability that a given magnitude event will occur based on purely seismologic laws, such as the Gutenberg-Richter law (Gutenberg and Richter, 1944) or the modified Omori law (Utsu, 1961), or based on models that also include the effect of operational factors on the seismic response. In the latter case, we can cite the model of Shapiro et al. (2013, 2010), which estimates the rate of induced seismicity during injection using a site-specific parameter (the seismogenic index) and the volume of fluid injected, as well as the models of McGarr (2014), van der Elst et al. (2016) and Galis et al. (2017), previously discussed in chapter 5, that link the magnitude of earthquakes to the volume of fluid injected. The above models are only examples, and therefore do not represent a thorough list of all published models and approaches. .

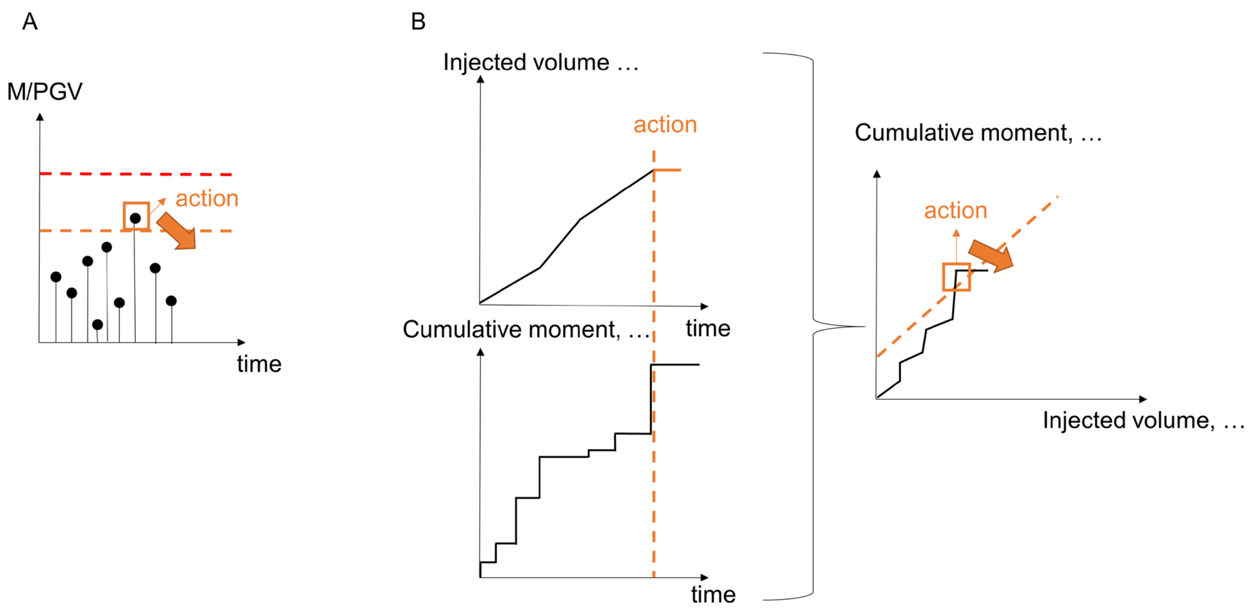

Figure 39: A. Principle of the TLS. B. Principle of the TLS combined with forecasting approaches.

Relatively recent studies (e.g., Aochi et al., 2017; Bentz et al., 2020; Drif et al., 2022; Kwiatek et al., 2019) show that the use of these statistical and/or empirical approaches opens up interesting paths for better controlling induced seismicity, in particular for preventing seismic incidents. However, as will be discussed in more detail in the following section, it is important to point out that these approaches are still difficult to use, especially in real or near real time. In the current state of knowledge, these approaches are used more when back-analyzing data.

8.1.3. Strengths and drawbacks of TLS

TLS are a preferred tool for managing geothermal operations and for controlling induced seismicity, but **they do not provide absolute protection against a seismic incident**. **Their goal is to create the conditions for minimizing induced seismicity** as much as possible, by using a conservative approach by modulating injection and production parameters as a function of the seismic response of the geothermal system.

TLS have the advantage of being simple to use and easily understood and explainable. The simple measures usually associated with them (e.g., flow-rate reduction) enable a rapid response to an unexpected seismic event.

However, even if managing operations with TLS is increasingly widespread, this does not guarantee the total prevention of a seismic incident. Seismicity in several geothermal projects have sometimes exceeded TLS threshold values. For example, during one of the hydraulic stimulations on the Pohang site, two events of M 1.4 and 1.8 triggered orange and red TLS levels respectively. Consequently, pressure was reduced (orange threshold), and then injection was stopped and the well was depressurized (red threshold) (Hofmann et al., 2019). At Basel, a seismic event of M 2.6 triggered the orange TLS threshold, after which flow-rate was reduced and the well was shut down. Nevertheless, this did not prevent the occurrence of an earthquake of M 3.4 in the shut-in phase, once injections had stopped (Häring et al., 2008). Similarly, the red TLS threshold of the Balmatt site was reached two days after the abrupt interruption of injections following an electricity outage, with an event of M 2.2 (Kinscher, 2020).

These examples show both the limits of TLS during operations, and the difficulty in managing post-injection (i.e., in the shut-in phase) seismicity, which may occur several hours, even months after the end of operations. The strategy for managing operations, especially the design of operating protocols and the choice of TLS thresholds, should therefore enable post-injection seismicity to be anticipated and limited, which is difficult. As a result, TLS based on a single parameter comparison between recorded seismicity and hydraulic data, although simple to implement, discard the multi-parametric nature of induced seismicity, which is the result of complex interactions between several operational parameters and geological factors (see chapter 5).

In addition, although the use of statistical and/or empirical approaches to seismicity as discussed in section 8.1.2 could offset certain limitations, it is important to point out that their real or near real time application remains difficult. Indeed, deviations in the behavior of a geothermal reservoir from a presumed stable behavior, based on the evolution of a set of measured parameters, may be difficult to detect due to the many uncertainties in our understanding of the deep underground (chapter 7). This is notably the case for projects in areas not previously exploited, for which little feedback is available. Similarly, a deviation is not always a sign of a mechanically and seismically unstable system. Furthermore, the physical processes in play that control induced seismicity are only partly taken into account by these seismicity models, which limits their capacity to anticipate the reservoir's response. The link between parameters measured in the well (pressure, flow-rate, injected volume) and seismicity is not always direct and easy to establish.

Based on these considerations **and recognizing the usefulness of these approaches but also their limitations**, recommendations are provided in the following sections for managing operations using properly-designed Traffic Light Systems (section 8.2), as well as for operational protocols to minimize induced seismicity, defined based on the knowledge acquired (section 8.4).

8.2. General recommendations for TLS application

8.2.1. General principles

The following recommendations are applicable to hazard level 1 and 2 projects, for which the seismic hazard is low to moderate and for which the state of knowledge and the monitoring resources are consistent with the requirements found in chapter 7. **These recommendations are defined for each phase of the geothermal project**[31] and therefore the operations conducted; **they require the crossed and near real time monitoring of microseismic activity using key seismic variables and hydraulic parameters**. The objective is to be able to analyze and interpret the behavior of a geothermal reservoir in response to the operations conducted.

The use of a TLS is based on the definition of a certain number of seismic and/or hydraulic criteria (see section 8.2.3) that govern the transition between the different thresholds (or levels) of the TLS for which actions to manage operations are linked (see section 8.2.2).

8.2.2. TLS thresholds and associated operational actions

Taking feedback into account (see section 8.1), **it is recommended to base the TLS on a three-threshold action plan** (**Green**, **Orange** and **Red**), for projects not requiring EGS stimulation, and **with four thresholds** (**Green**, **Yellow**, **Orange** and **Red**) **only during the EGS stimulation phases** (Figure 40).

The following generic recommendations are to be taken into account for defining the actions or follow-up to be implemented when one of these thresholds is reached, by proposing **a mitigation strategy adapted to the project**:

- **Yellow** or **Orange** threshold: the actions may, for example, involve **reducing certain key operational parameters**, such as **overpressure on the reservoir** and/or **injection flow-rate**, or on **maintaining these parameters at constant values.** These recommendations call for adapting the operational protocol to the reservoir's seismic response ;
- **Red** threshold: this limit requires **stopping operations** (injection and/or production) in the wells affected. **Bleed off** may also be considered if relevant, but this **requires case-by-case decisions**, depending on the possible positive and negative consequences of such an action.

In all cases, an unexpected variation of an operational parameter (e.g., pressure) requires an analysis and interpretation in terms of the reservoir's behavior and seismicity.

It should also be remembered that the **Red** threshold automatically forces a project to hazard level 3, regardless of the initial hazard level.

31 – Except for the drilling phase, for which implementing a TLS is unsuited because no operational parameter can really help minimize seismicity.

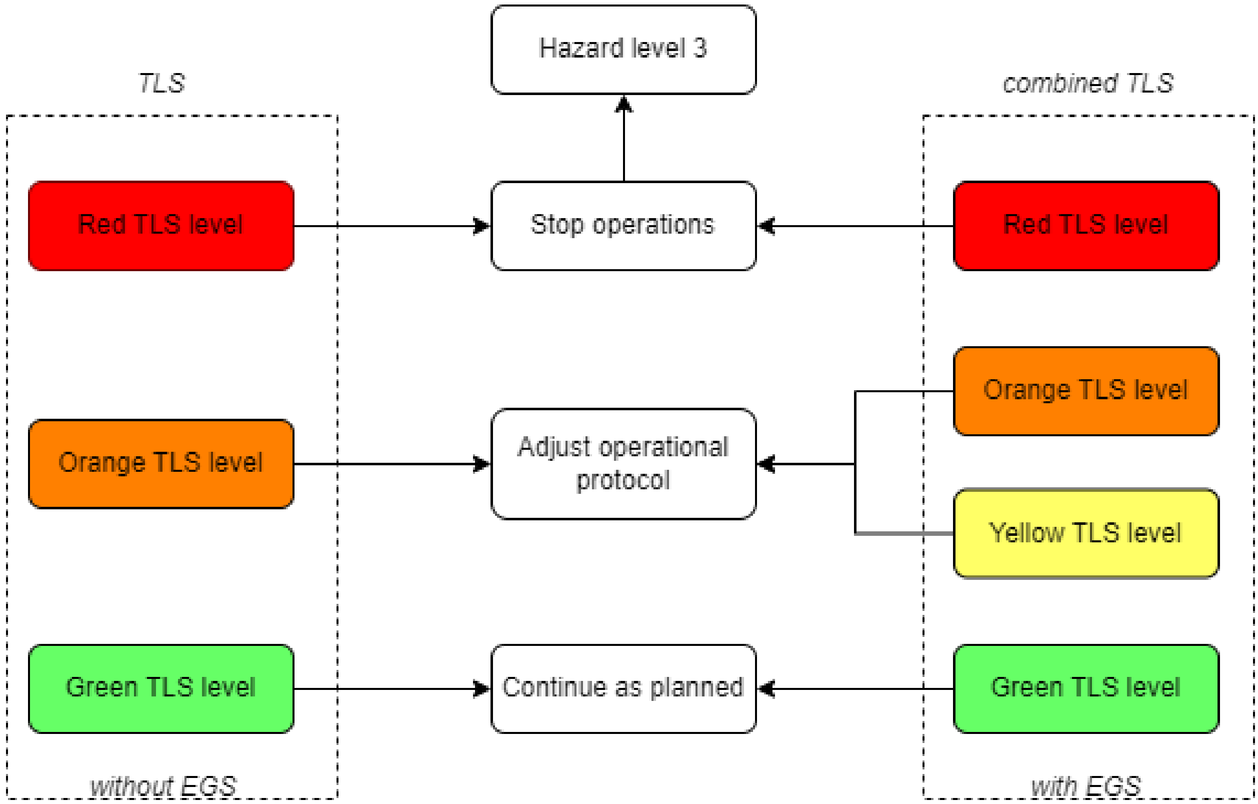

Figure 40: Relationships between TLS thresholds and geothermal operations.
The Yellow threshold is applied only during EGS stimulation and requires the use of a forecasting approach in the TLS.

In the stimulation phase with the use of EGS technologies (only for hazard level 2 projects), **it is recommended to use a forecasting approach (statistical and/or empirical) in the TLS**. In practice, this requires dynamic monitoring (which changes over time) of seismic variables with respect to operational parameters **such as volume, flow-rate, or pressure**. The approach used must be both **robust and simple to implement, adapted to the operators' skills, resources, and experience and to the analysis of recorded seismicity**. Regardless of the approach adopted (e.g., Galis et al. (2017), McGarr (2014), van der Elst et al. (2016) or other), attention should be paid to its relevance with respect to the context, available knowledge, and uncertainties of the key parameters to be considered.

8.2.3. Key seismic and hydraulic criteria of the TLS

The key seismic variables for managing operations with a TLS are magnitude and PGV (Table 22). The limit values of each threshold cannot be defined a priori. They **must be set** by considering, among other things, that the **Red TLS threshold must be consistent with the seismic incident in question**. In addition, the limit values for magnitude must also be defined with respect to the depth of the target reservoir and possible site effects that could amplify vibrations due to seismic events and thus their perception on the surface.

Table 22: Summary of parameters and procedures for managing operations at each step of a project. Table valid for hazard level 1 and 2 projects. M is the magnitude of the seismic events.

	Drilling phase	Development phase (excluding EGS technologies)	Development phase (EGS technologies)	Operational phase
Management approach	No TLS	TLS	TLS with forecasting approach	TLS
Recommended number of TLS thresholds	-	3	4	3
Seismic variables of interest (minimum)[1]	M	M, PGV (Distance of earthquake, earthquake rate, etc.)[2]	M, PGV, application of forecasting laws (such as those of McGarr, Galis et al., van der Elst et al., etc.)	M, PGV
Operational and hydraulic parameters of interest	Weight of drilling mud	Volumes injected Reservoir overpressure Injectivity index	Volumes injected Reservoir overpressure Rate of overpressure variation Injectivity index Fault reactivation pressure	Volumes injected Reservoir overpressure

[1] These seismic variables must be estimated in near real time and thus form the base of the real time seismic data processing chain;
[2] other seismic criteria can be proposed by operators to reinforce the TLS, particularly for hazard level 2 projects.

Furthermore, and particularly **for hazard level 2 projects,** it could be useful to supplement the TLS with relevant secondary **seismic variables taking into account knowledge acquired on the site and operations to be conducted (Table 22)**. For example, this may include criteria based on the seismic events' location and their distance from the wells and/or known geological structures, the earthquake rate or the spatiotemporal migration of seismicity. These criteria could then be used to define transitions between the different TLS thresholds.

In addition to seismic criteria, **key hydraulic parameters can also be defined and associated with limit values** to define changes in TLS thresholds (Figure 41). For example, injection pressure and its possible increases during the injection phase may be regarded as key hydraulic parameters.

In every case, and particularly during EGS stimulations, key seismic variables must always be correlated with the operational parameters, reservoir overpressure and total volume injected, in order to compare their respective changes during operations.

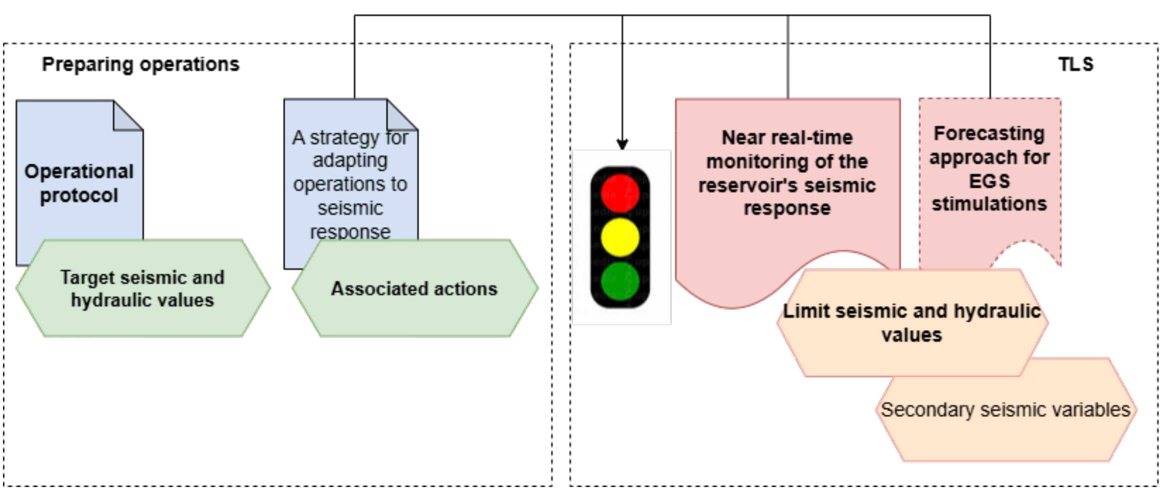

Figure 41: Schematic representation of the components required to implement a TLS and control geothermal operations The operational protocol sets target values and modalities to be used to reach them. The adaptation strategy defines the actions to be conducted if the threshold values or TLS thresholds are reached.

8.3. Recommendations for managing operations, links with the TLS

8.3.1. Special case of the drilling phase

During the drilling phase, the use of a TLS is inappropriate, because no operational parameter can really minimize seismicity. Although infrequent, seismicity may occur when dynamic mud/fluid pressure is such that losses of these fluids in the reservoir are possible, particularly in faults intersected by drilling.

In all cases, **the occurrence of seismicity near the well,** typically **magnitude M > 0.5 and surface PGV > 0.5 mm/s** event(s) within a radius of 1 km considering location uncertainties, **should be considered as the manifestation of a potentially unstable system.** In fact, stress changes due to drilling operations are weak compared to those caused by well development and fluid circulation.

This situation should lead to:

- **Extension of the seismic network** (section 7.3) if not already done. The continuation of drilling work will then depend on this extension;
- **Increasing the project to hazard level 2** if it was previously at level 1. The hazard level does not change for projects already in hazard level 2.

It should be noted that the occurrence of an event felt at the surface automatically causes the project to pass to hazard level 3, regardless of its initial level, and causes **the immediate interruption of drilling work.** If this happens, operations are suspended waiting for the review of the drilling protocol on the basis of all the data acquired (e.g., well logging data coupled with the seismic data recorded).

8.3.2. Special cases during the operational phase and at the end of the project

Seismicity during the circulation phase may occur following variations in hydraulic parameters, such as rapid increases or decreases in injection flow-rate, after abrupt circulation interruptions (see chapter 5) or even when circulation conditions remain stable. Interventions involving maintenance, upgrading or correction of identified well problems (work-over), may also be responsible for modifying the mechanical solicitations on the reservoir.

This is why **it is recommended to include the following aspects in the operational protocol**:

- Solutions to **overcome possible failures and external incidents that could suddenly modify operations** (power outage, etc.);
- Suitable measures for every intervention on a well;
- Adapting it to observed changes in reservoir behavior.

For the gradual shutdown phase, that precedes the end of a project, it is recommended that the TLS used during the operational phase be left in place and applied.

After shutdown, management in the strict sense of the word is no longer applicable, but it is recommended to maintain seismic monitoring for at least one year after operations have terminated. This implies that near real time estimation of magnitude and location of any event recorded must be performed, to follow and evaluate pressure adjustments within the reservoir. Seismic monitoring can be stopped and the microseismic network dismantled if, after 12 months, magnitudes remain lower than the limits defined in the TLS used in the operational phase (before shutdown) and if seismic background noise is comparable to that recorded before the beginning o the project.

8.3.3. TLS and management: implications for monitoring, data processing and interpretation.

Managing operations using target seismic variables has several important implications for the seismic data processing chain.

By default, the seismic data processing chain **must in particular enable the near real time detection and location of events and magnitude estimation. With regard to PGV, it is recommended to qualify TLS threshold exceedance using PGV measurements from two monitoring stations that are representative in terms of ground movement**. In addition, if the variability of ground movements on a site is significant, at least one station must be in an area subject to site effects, if there are any, to be representative of maximum movements in the area. If there are no stations in areas subject to site effects, a ground motion prediction equation (GMPE) can be calibrated (and modified over time if necessary) to determine ground movements as close as possible to surface vulnerability issues, if any.

For TLS with a forecasting approach, it will also be necessary to calculate in near real time the parameters that characterize the seismic source and that account for its variations, such as seismic moment, source parameters, seismic energy, or b-value. As pointed out in sections 7.6 and 8.1.2, calculating these parameters requires specialized expertise. The interpretation of changes in key seismic variables with changes in operational parameters using different predictive approaches is also the domain of specialists. Concerning this subject, it is important to state that **TLS with a forecasting approach may perform better if it can be calibrated** using microseismic data acquired on the site, e.g., during the first low flow-rate tests, in previous stimulations and/or based on studies to estimate expected seismicity on the site. Indeed, calibration using data external to the project can be inappropriate in certain complex situations.

From the point of view of the administration, seismic and hydraulic variables used for TLS can be specified in the prefectoral order authorizing mining work. In these situations, **the prefectoral order is established by the administration after the proposal and technical exchanges with the operator**. For example, this was the case for deep geothermal projects in Alsace (e.g., Maury and Branchu, 2020).

8.4. Recommendations for the initial definition of operational protocols and for knowledge build-up

8.4.1. General considerations about operational protocols

Implementing a TLS and defining limit values require perfect consistency with the operations workflow. Operations must therefore be conducted according to **operational protocols adapted to the project, to the geothermal system, to the technologies used and to the objectives** targeted (e.g., target flow-rate and pressure values) by such operations. This operational protocol should be **determined before starting an operation** while based on data acquired in previous operations.

As already mentioned many times in this guide, induced seismicity management requires a good understanding of the deep underground and the implementation of technologies and protocols specifically defined for each project.

How knowledge must be improved and built-up has been discussed extensively in chapter 7 **In the following, additional recommendations are provided to establish operational protocols that are best suited** to the underground geological conditions and to project objectives

Only general recommendations can be here provided for the definition of these operational protocols In particular, it is important to define them based on the following aspects:

- Feedback from similar projects or from projects in similar contexts;
- Results of hydraulic and geomechanical models, accounting for the validity and significance of the models with respect to uncertainties;
- If available, the history of operations conducted, total volumes, fault activation pressures, as well as the characteristics of any earthquake that was recorded.

Regardless of the geothermal system exploited, it is recommended to adopt a safe approach. Operational protocols based on an **iterative** strategy are highly recommended when there are many uncertainties concerning the reservoir's geomechanical stability, **since this can determine the reservoir's response to stresses of increasing intensity**. It also has the advantage of providing useful data (e.g., seismicity activation pressure) to populate models (see section 7.2) and therefore **to optimize operating protocols** as the project advances.

Finally, if several seismic response scenarios are considered, it will be absolutely necessary to plan on a strategy in order to adapt the operational protocol to the reservoir's seismic response for each scenario.

8.4.2. Preparing an operational protocol

In general, all steps after the drilling phase must be the subject of **an operational protocol** that precisely states (Figure 42 and Figure 43):

- target objectives (e.g., cleaning the well, injectivity tests , production/circulation, etc.) with well identified target and limit values (Figure 41), in terms of injected/produced volumes, overpressures imposed, etc.;
- The resources to be implemented (e.g., surface storage capacity needs) including the required measurement instruments;
- The planned operational modalities in terms of flow-rate, pressure, duration, etc. for injection and/or production.

The operational protocol is mandatory accompanied by an action plan for adapting operations (Figure 41). This plan must be able to respond to the following situations**:**

- If the **Yellow** or **Orange** TLS threshold is reached, the action plan is based on one or more seismic response scenarios depending on the level of uncertainties on the geomechanical and geological conditions;
- If the **Red** threshold is reached, it must contain indications on how to shut down operations (also see section 8.5).

The elaboration of an operational protocol (Figure 42 and Figure 43) must be based on knowledge acquired by the operator during any previous operations, as well as on geological, hydrogeological, and geomechanical models (chapters 6 and 7).

Generally, operations resulting from rapid pressure variations in the reservoir should be avoided in order to minimize seismicity (suddenly stopping injections without using decreasing steps, rapid pressure increases in the well, etc.). When relevant, the operational protocol must also include the durations of stepwise pressure and/or flow-rate stabilization.

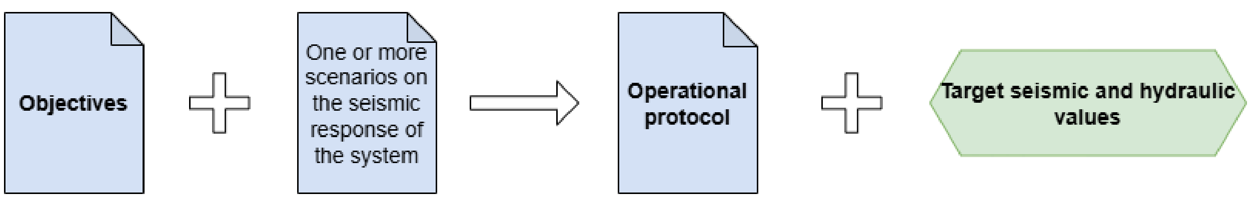

Figure 42: Schematic diagram illustrating how to set up an operational protocol and define target values.

Finally, if there is a divergence from all of the scenarios considered (in terms of seismicity or if operational objectives are not reached) **even if the TLS Red threshold is not reached, time is required** to analyze and interpret the system's response without continuing operation. In such a context, rapid sequencing of several operations, , without an overall understanding of the system response, should be avoided.

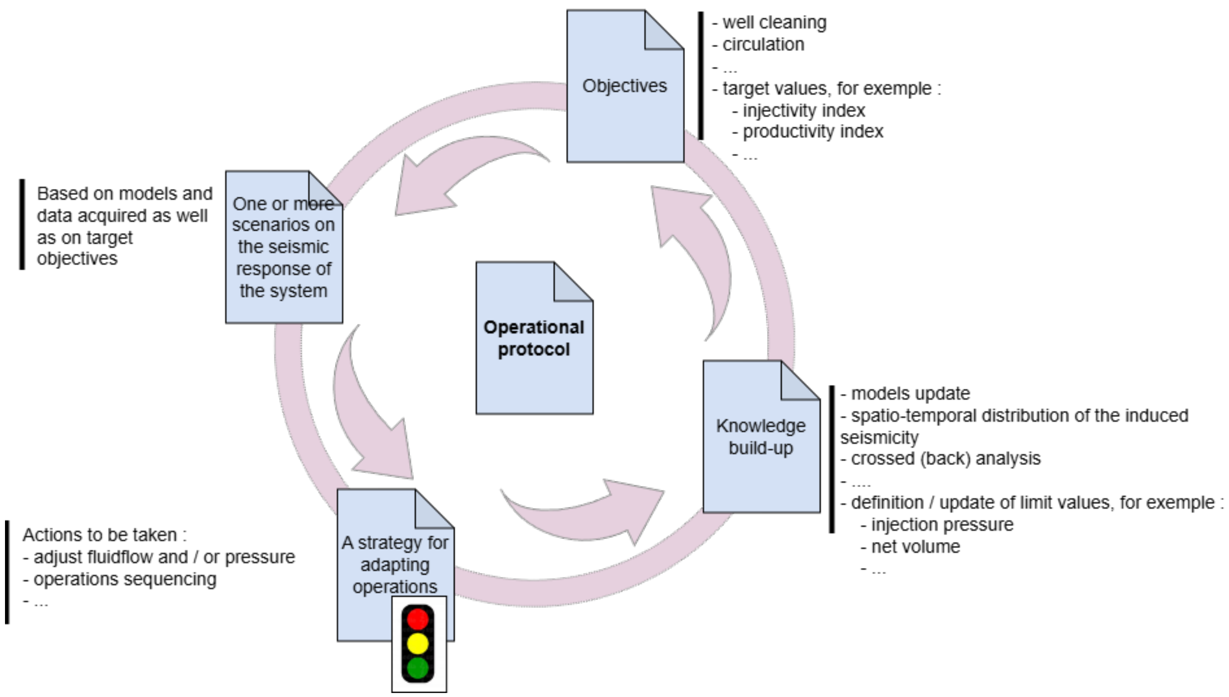

Figure 43: Virtuous cycle for establishing an operational protocol.

8.4.3. Additional elements for preparing a stimulation protocol

In addition to the above recommendations, the stimulation protocol must specify the quantitative objectives in terms of increased injectivity/productivity, as well as:

- Planned injection duration and cycles;
- Volumes injected over time;
- Planned flow-rate variations and the durations of increasing (and decreasing) flow-rate steps;
- Expected responses in terms of pressure and seismicity;
- In case of a deviation from the expected response: any possible effect on continuing operations (e.g., in terms of changing steps or sequencing of operations).

In general and even more in the case of a stimulation, since **a seismic incident may occur once injection operations have terminated** (chapter 5), **it is important to prepare the stimulation protocol by accounting for the history** of seismicity on the site, fault reactivation pressures, and also total volumes throughout operations on the site.

Knowledge build-up (chapters 6, 7 and section 8.4.4) is therefore an essential prerequisite for estimating pressure values (limit values) not to be exceeded, for minimizing the probability of reactivating known underground structures, and for estimating maximal magnitudes that could be reached depending on volumes injected, e.g., using the models of Galis et al. (2017), McGarr or van der Elst et al. (2016).

8.4.4. Knowledge build-up on the seismic response at each step of the project

Hazard assessment and reevaluation over time, including a back analysis on seismic and hydraulic data, is recommended at each step of a geothermal project.. It is essential to characterize the reservoir's response to operations, in order to better understand its changes and to better planning subsequent operations on the reservoir in the aim of limiting the occurrence of seismicity. Implicitly, it requires that all actions on wells that may induce seismicity be documented as precisely as possible throughout the life of the project.

Table 23 summarizes these recommendations.

If seismic events occur during the drilling phase and can be located, their location, and especially their depth, must be correlated with well imaging in order to identify and possibly characterize potential geomechanically unstable structures.

In the development phase, it is recommended to conduct a **regular back analysis of seismic catalogs to be correlated with operational parameters** (reservoir overpressure, volumes injected, temperature variation, etc.), **as well as with changes in the injectivity/productivity index** related to the development operation. If EGS technologies are used, it is also recommended to:

- Determine the **focal mechanisms** of the strongest earthquakes (M > 1.5), to better understand the orientation of the reactivated structures and obtain additional information on the local stress field;
- Estimate source parameters[32] (corner frequency, seismic moment, moment magnitude, etc.), at least for the highest magnitude events;
- To **use the double-difference method** to **relatively relocate microseismic events with respect to each other** in order to improve the **spatial resolution of seismicity and to obtain a more precise image of the reservoir's active structures**.

Table 23: Summary of back analyses that can be conducted on data at each step of a project. Table valid only for hazard level 1 and 2 projects.

	Drilling phase	Development phase (excluding EGS technologies)	Development phase (EGS technologies)	Operational phase
Back analyses of seismic and operating data (at least)	Correlation of seismicity location with well imaging and models	Correlation of seismicity location with well imaging and models **Cross-analysis of seismicity with operational parameters and injectivity index**	Correlation of seismicity location with well imaging and models Cross-analysis of seismicity with operational parameters and injectivity index **Focal mechanisms** **Relocation using the double-difference method**	Cross-analysis of seismicity with operational parameters

32 – In order to estimate source parameters, the seismic event must be recorded by at least four seismic sensors.

8.5. Actions to undertake in case of unexpected seismicity

If the **Red** TLS threshold is triggered, it is recommended to stop all operations on the site. Since post-injection seismicity is often observed in deep geothermal operations, however, it is important to stop injection in accordance with mechanisms adapted to site's seismicity history, and knowledge of the reservoir's response. This is done by taking into account:

- The potential impact of an abrupt shutdown in terms of seismicity;
- The potential impact of a gradual shutdown in terms of seismicity, which involves the injection of a larger volume of fluid than in the case of the previous point.

The choice between the two shutdown scenarios is not trivial. In fact, in certain cases, it has been observed that abrupt injection stops have resulted in felt seismicity, or even in seismic incidents in the shut-in phase. Even a gradual shutdown does not guarantee that an incident will not occur in the post-injection phase. At the same time, a gradual shutdown requires injecting a larger volume of fluid than in the case of an abrupt shutdown, which can result in induced seismicity. In order to select the optimal shutdown protocol for a project in unexpected conditions, the impact of these two scenarios must be evaluated. It should be noted, however, that in this situation, every decision must be made in a short time, which is clearly inconsistent with using complex calculations or advanced models to evaluate the two scenarios.

If a seismic incident occurs in the shut-in phase, the hazard level of the project automatically goes to 3, regardless of the hazard level of the project at the time of the seismic incident.

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10. Glossary

All words in color in the text are defined in this glossary (also as hypertext link in the digital version of the document).

Aquifer: geologic formation with the capacity to store water and allow vertical and lateral water flow.

b-value: relative proportion between small and large magnitude events. This is parameter b ($log_{10}N = a - bM$) in the Gutenberg-Richter law describing the relationship between small and large magnitude events.

Basement: a geological structure composed of old hard rocks (**magmatic** and/or metamorphic rocks), formed during one or more orogenic cycles then flattened by erosion.

Basement (type): old rock masses with very low porosity and permeability and whose fracturing precludes significant circulation of fluids (fouling, sealing by precipitation of minerals, stresses no longer enabling discontinuities to be reopened), but whose temperature may be elevated, in particular as a result of radiogenic energy emitted by the rock. This system is controlled by **conductive heat transfer.**

Conceptual model: conceptual modeling is the decision about what to model and not model (model abstraction). A conceptual model is the description of the digital simulation model (that is or was developed) that does not depend on the simulation software, describing objectives, inputs, outputs, content, hypotheses and simplifications of the model (Robinson, 2008; 2010).

Concession: an act in which the State grants a person or company the right to extract a substance from mines. It is granted by an order by the Council of State following a procedure defined by Decree No. 2006-648 of June 2, 2006.

Conductive: heat transfer mode due to a temperature difference between two regions in the same medium, or between two mediums in contact between each other, and it occurs without motion of the matter (in contrast to convection).

Convective: advective heat transfer mode by the displacement of molecules in the **energy vector.** This mechanism is associated with a characteristic fluid flow pattern known as convection cells. This flow pattern is due to density and volume changes of the fluid with the temperature (the hot fluid, which is less dense, tends to move upwards, then, when going upward, the fluid cools down, becomes denser, and the movement becomes downwards).

Critical stress (fault in a state of): fault close to the rupture so that even small stress changes can cause its shear slip.

Detectability threshold: minimum magnitude that can be detected by a given seismic network.

Development (of a well): operations from filling the well with water to heat production, including also the methods used to improve the productivity/injectivity index (hydraulic, chemical or thermal stimulations; multi-drains). Well development encompasses a wide range of operations with several objectives (Hamm et al., 2019):

— Removing drilling wastes from the well;

– Increasing the productivity of an installation;

– Stabilizing the formation and/or equipment, especially in clastic reservoirs.

Directivity: Doppler effect applied to a seismic wave, leading to seismic movements of varying intensities depending on site location compared to the seismic source and to the propagation direction of the seismic rupture.

Doublet: well geometry for geothermal resource exploitation composed of two wells, one for injection the other for production.

EGS (Enhanced Geothermal Systems): refers to geothermal projects in which hydraulic stimulation and/or thermal and chemical stimulations take place at fluid pressures significantly higher than the initial pressure of the reservoir in new or unusual contexts (they will be stated) to increase reservoir permeability around the well.

EGS stimulation: phase of hydraulic, thermal and/or chemical stimulation at fluid pressures significantly higher than the initial pressure of the reservoir in new or unusual contexts (they will be stated) in order to increase reservoir permeability around the well.

Energy vector: support for energy transport. In the context of geothermal operations where the energy is heat, the energy vector is most often the fluid naturally circulating in the reservoir (water, brine), but it can also be the rock itself, via the intermediary of an injected fluid, as in basement type geothermal systems for example, or when closed-loop technologies are used.

Enthalpy: thermodynamic measurement of the variation of the quantity of heat in a physical or chemical system.

Epicenter: point on the Earth's surface directly above the earthquake hypocenter.

Exergy: in thermodynamics, exergy is a physical parameter that measures energy quality. It is the usable part of a joule.

Extension (zone or domain): tectonic zone in which the deformation of geological structures results from the horizontal expansion of Earth's crust. Tectonic zones undergoing extension are most often (but not only) associated with rifts (characterized by the presence of trenches caused by collapse delimited by normal faults) at the frontiers of divergent plates, or in zones of strike-slip movements (pull-apart basins). Their characteristic as a geothermal system is the presence of numerous normal faults and the graben topography that exert a certain control of the flows of geothermal fluids.

Fault: tectonic structure composed of a plane (single discontinuity) or a rupture zone (network of discontinuities organized depending on the deformation) along with two rock compartments move against each other in response to shear stresses. There are three types of faults depending on the movements of each compartment: normal fault, reverse fault and strike-slip fault. These structures exist in all sizes, from grains of rock to tectonic plates. They greatly interfere with fluid circulations, either as hydraulic barriers (when discontinuities are closed due to high intensity of the associated deformation or by precipitations from prior circulations) or as preferred fluid paths when faults discontinuities allow fluid circulation. So-called "fault zone" reservoirs are associated with predominant flows in a limited number of interconnected faults.

Fault wall: each of the walls delimiting a fault/fracture. The roughness of these walls varies with the type of fault and rock.

Field: zone of the same geothermal system containing a large quantity of whose extraction is made by several wells connected to the same heating network/power plant. A geothermal field may extend over several kilometers with the presence of several production and reinjection wells.

Focal distance: distance to the earthquake hypocenter, the point where the fault starts to rupture.

Focal mechanism: graphic representation, as a hemisphere, of movement of the earthquake source along the primary and secondary rupture planes. It is obtained from seismic station recordings (seismograms).

Fracture: generic term for all discontinuities with or without movement of separate compartments. The same as for faults, these structures interfere considerably with the circulations of fluids. The term 'fractured reservoir' in the language of geothermal operations most often refers to a reservoir in which fluid circulations are controlled by the discontinuities of a rock mass regardless of their origin, in contrast to reservoirs in fault zones localized close to some major faults.

Geothermal deposit: underground deposit from which thermal energy can be extracted or exchanged by conduction or by using the hot water or steam they contain.

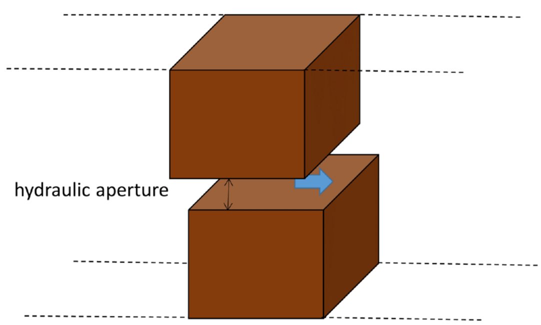
Geothermal gradient: underground temperature increases with depth, usually around 3°C per 100 m in non-volcanic regions, while the increase can be much higher in volcanic zones.

Geothermal reservoir: hot, porous and/or fractured rock environment. The heat energy in this environment can be collected by the transfer of heat and mass by the geothermal fluid (e.g., the geothermal doublet principle) or by conductive exchange (closed-loop probe type exchanger) for the production of heat and/or electricity. Depending on the geothermal systems, reservoirs may have different geological characteristics and hydraulic properties (particularly porosity, permeability, natural fracturing of the rock and fluid in liquid, vapor or supercritical form). In the case of an open system, technologies to improve insufficient permeability can be used for the economic production of energy. The number and spatial organization of wells may differ depending on the quantity of geothermal energy to be extracted and the geothermal system.

Geothermal system: underground system from which thermal energy from the earth's crust is obtained, including all elements creating usable thermal energy and generally composed of zones of fluid infiltration, zones where fluids are heated, paths of least resistance to the circulation of geothermal fluids, and reservoirs considered the main sites for the extraction of geothermal energy.

Graben: see **tectonic rifts**.

Hydraulic opening: space available for fluid circulation.



Hydraulic tests: tests run to determine capacities of the well after drilling and the injectivity/productivity increase resulting from a stimulation cycle. These tests may involve stepwise tests or long-term tests (see Hamm et al., 2019 for more information on these tests). When conducting injectivity tests, special attention must be paid to the volume injected and the pressure applied during the tests to avoid stimulating the reservoir.

Hypocenter: point at depth where a fault starts rupturing causing the earthquake.

Industrial operations: all industrial operations that modify the natural equilibrium of the deep underground. These operations affect thegeological, hydrological and geomechanical conditions of the underground environment.

Injectivity, Injectivity index: injectivity is the absorption capacity of a fluid by a well and corresponds to the maximal flow-rate of an absorbent well. The injectivity index (Ii) of a well (often expressed as [L/s/bar]) is defined as the injection flow-rate divided by the difference between the pressure in the well and that in the reservoir:

Where q is the injection flow-rate [m3/s], Pw the pressure in the well [bar] and Pr the pressure in the reservoir [bar].

Intensity: statistical measure of the effects of an earthquake on the population, structures or the environment. Intensity at a point of the surface varies with the size of the earthquake (magnitude), the **focal distance** or the local conditions of the site (geology, topography). There are several intensity scales.

Intracratonic basin type (Hydrothermal system of ~): system in which **aquifers** develop in porous and permeable layers deposited in the basin. This system is controlled by **conductive heat transfer.**

Loading (a fault): increase in the forces acting on a fault until the breaking point, or nucleation point of an earthquake.

Magmatic: pertains to rocks resulting from the crystallization of magma at depth (plutonic rock) or at the surface (volcanic rock).

Magnitude: Introduced in 1935 by the American, Charles Francis Richter, for local earthquakes in California, the scale involves a calculation using recordings from seismic stations. It estimates the energy released by an earthquake and enables earthquakes to be compared. It characterizes the 'power' of an earthquake. Since then, we speak of the Richter scale. There are several types of magnitudes depending on the wave type used (local magnitude ML; body magnitude MB, surface magnitude MS), depending on the duration of the signal (duration magnitude MD), or based on a seismic source model (moment magnitude Mw). For the same type of magnitude, uncertainty of its value is generally on the order of 0.3. Magnitude does not vary with distance or local site conditions.

Magnitude of completeness: magnitude value above which all seismic events within a certain region can be reliably recorded by a given seismic network.

Maximum earthquake: among a sequence of earthquakes, the one with the highest magnitude.

Maximum magnitude: the highest magnitude in an event sequence.

Model: representation or simulation of a physical object that can be used for predictions and/or to compare observations with hypotheses.

Operation: everything done on a well, which include the action of drilling, tests and trials, well development by stimulations, production, injection or fluid circulation between wells, maintenance work or well shutdowns.

Orogenic belt (Hydrothermal system of ~): characterized by both potentially **aquiferous** sedimentary deposits (porous and permeable) and by the presence of numerous faults accommodating tectonic deformations of the area and controlling part of the flows in the geothermal system. This system is controlled by **conductive heat transfer.**

Permeability: capacity of a medium to be traversed by a fluid under the effect of a pressure gradient or a gravity field.

Petrophysical: refers to the physical properties of rocks, such as porosity, permeability, acoustic properties or electric properties.

PGA (Peak Ground Acceleration): maximum acceleration of the ground or peak acceleration at a given point. **PGD**

(Peak Ground Displacement): maximum displacement of the ground or peak displacement at a given point. **PGV**

(Peak Ground Velocity): maximum velocity of the ground or peak velocity at a given point.

Plutonic domain: reservoir formed by hot or recently cooled igneous rock, primarily in the context of a recent collision. Composed or rocks that are primarily granites or gabbros, these domains are controlled by the interaction between faults, fractures and igneous rock.

Porosity: volume of voids compared to the volume of the rock.

Productivity, productivity index: capacity of a well to produce a fluid and corresponds to the maximum flow-rate of a producing well. The productivity index of a well (PI in geothermal energy and J in the oil & gas industry, often expressed in [L/s/bar]) is defined as the injection flow-rate with respect to the pressure drop in the well compared to pressure of the reservoir:

$$Ip = q/(Pr-Pw)$$

Where q is the injection flow-rate [m3/s], Pw is the pressure in the well [bar] and Pr is the pressure in the reservoir [bar].

Project: a site or a field, composed of one or more wells in which operations are conducted (drilling, tests and develop- ment before operation, circulation, maintenance during operation end-of-life work…).

Sedimentary basin: depression in the earth's crust formed by thermal or tectonic subsidence containing relatively large quantities of sedimentary materials.

Seismic incident: a seismic event whose intensity can cause nuisances for the population and for exposed issues, and which can adversely affect the operating conditions and even the continuation of the project.

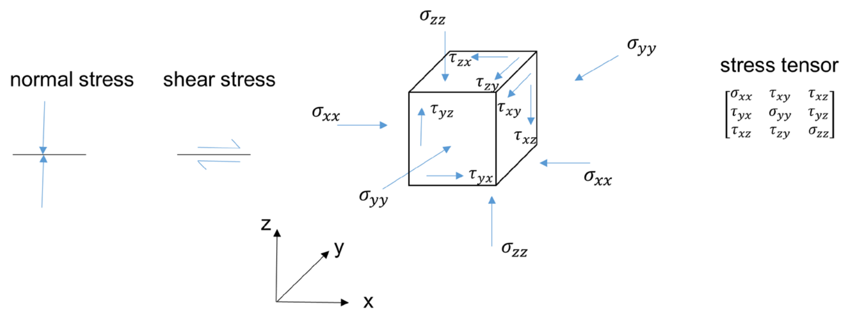
Seismic waves: vibrations resulting from ground movement caused by the earthquake.

Seismotectonics: analysis of the relations between active geological structures and seismicity. It is used to identify active or seismogenic faults and seismotectonic domains.

Site effect: local modification of seismic movement depending on the properties of the site in question. This modification generally results in an amplification, occasionally an attenuation, of certain parameters characterizing ground movement (spectral acceleration, movement duration, maximum velocity, maximum displacement) that depend on the local features of the site: topography, stratigraphy and mechanical properties of the ground.

Slip tendency: the slip tendency method is an approach for the initial evaluation of the susceptibility of faults to slip (e.g., Moeck et al., 2009). Slip tendency is defined as the ratio of shear stress to normal effective stress. A slip will occur if the slip tendency is greater than the friction coefficient of a preexisting fault (the value of the friction coefficient is generally between 0.6 and 1).Supercritical: state reached by pure water at a temperature higher than 374°C and a pressure higher than 221 bars and that combines the properties of a liquid and a gas.

Stress state: set of forces acting on a body and that tends to deform it. A stress is a force acting on a given surface. The stress state is in fact a tensor; stress at a given point in the rock mass presents three normal components acting perpendicularly to the sides of a small cube and six shear components acting along its sides (from Hudson et al., 2003; see figure below). Stresses acting on a rock mass are primarily due to tectonic forces and the effect of gravity. Stresses are higher with increasing depth because of the gravitational effect.



Thermoelastic stress: stresses due to temperature changes. Most materials dilate when heated and if this dilation is prevented, thermal stresses appear. Temperature variations in rock therefore cause thermal stresses.

Tectonic rifts (also called graben): tectonic structure composed of roughly parallel normal faults delimiting a valley formed by the displacement of a block of land downward. The Rhine Graben and Limagnes are typical examples.

TLS (Traffic Light System): system indicating alert levels based on criteria and thresholds that trigger green, orange (sometimes yellow) or red traffic lights to attenuate the possibilities of induced seismicity.

Triplet: geometry of a geothermal installation composed of three wells, at least one of which is for injection.

Velocity model: model giving the value of seismic wave propagation velocities for different geological layers as a function of depth. Velocities generally increase with depth.

Volcanic (domain): domain associated to active volcanoes (that have erupted at least once in the last 10,000 years).

Well for temperature profile measurements: shallow well (between 150 and 300 m) used to measure the temperature profile and estimate this profile to greater depths.

Following the 2021 reform of the Mining Code and the Climate Resilience act, INERIS and BRGM published a good practices guide for the management of seismicity induced by deep geothermal operations. This guide has been commissioned by the General Direction for Risks Prevention (DGPR) of the Ministry of the Ecological Transition and by the General Direction for Energy and the Climate (DGEC) of the Ministry for the Energy Transition.

This guide is intended to be a reflection of the state of the art, addressed to deep geothermal energy professionals. It can also provide information to all stakeholders (associations, residents, authorities including decentralized services of the State) on the risks of induced seismicity and the means of preventing it.

This guide covers different types of geothermal reservoirs and methods of exploitation operating in continental France and overseas Departments and Territories. It is based on feedback from many projects in France and abroad, and on the current state of scientific knowledge in the field of seismicity induced by the deep underground fluid injection.

It proposes a method for evaluating induced seismicity hazard and a strategy for hazard revision at each key phase of development of a geothermal project. Based on factual data and criteria, this approach allows to adapt the exploitation method and the tools for seismicity prevention and management to the project and its development.

This guide also contains recommendations concerning essential data to be acquired at each step of the project in order to optimally anticipate the hydromechanical behavior of the reservoir during operations and to design and manage a microseismic monitoring network when the hazard level requires it. It also gives the basic concepts for determining operating protocols for conducting and managing operations depending on the technologies used and the microseismicity detected.

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