Low carbon subsurface technologies: identifying potential environmental impacts

Chief Scientist's Group report

Date: October 2021

Version: SC200005/R

We are the Environment Agency. We protect and improve the environment.

We help people and wildlife adapt to climate change and reduce its impacts, including flooding, drought, sea level rise and coastal erosion.

We improve the quality of our water, land and air by tackling pollution. We work with businesses to help them comply with environmental regulations. A healthy and diverse environment enhances people's lives and contributes to economic growth.

We can't do this alone. We work as part of the Defra group (Department for Environment, Food & Rural Affairs), with the rest of government, local councils, businesses, civil society groups and local communities to create a better place for people and wildlife.

Published by:

Environment Agency
Horizon House, Deanery Road,
Bristol BS1 5AH

www.gov.uk/environment-agency

Further copies of this report are available from our publications catalogue: www.gov.uk/government/publications or our National Customer Contact Centre: 03708 506 506

Email: research@environment-agency.gov.uk

Author(s):
Dr Michael Simioni, Dr Rachel Gavey, Xiaojing Wang

Keywords:
Energy, low carbon, technology, subsurface, environment, impacts, geology, source, pathway, receptor

Research contractor:
WSS Energy Consulting, Export House, Cawsey Way, Woking, GU21 6QX, +44 (0) 1483 380 031

Environment Agency's Project Manager:
Dr Sian Loveless

Project number:
SC200005

Citation:
Environment Agency (2021) Low carbon subsurface technologies: identifying potential environmental impacts. Environment Agency, Bristol.

Research at the Environment Agency

Scientific research and analysis underpins everything the Environment Agency does. It helps us to understand and manage the environment effectively. Our own experts work with leading scientific organisations, universities and other parts of the Defra group to bring the best knowledge to bear on the environmental problems that we face now and in the future. Our scientific work is published as summaries and reports, freely available to all.

This report is the result of research commissioned by the Environment Agency's Research, Analysis and Evaluation group.

You can find out more about our current science programmes at https://www.gov.uk/government/organisations/environment-agency/about/research.

If you have any comments or questions about this report or the Environment Agency's other scientific work, please contact research@environment-agency.gov.uk.

Professor Doug Wilson
Chief Scientist and Director of Research, Analysis and Evaluation

Contents

Executive summary

The UK government's ambition to reduce greenhouse gas (GHG) emissions by 68% of 1990 levels by 2030 is likely to result in changes to the energy mix in the near future. The commitment to move to more sustainable energy sources is clear, and many new 'low carbon' technologies that use the subsurface for green energy extraction, storage and carbon dioxide (CO_2) abatement are likely to be demonstrated and potentially commercialised in the UK in the coming years.

The Environment Agency needs to understand and effectively manage the environmental risks associated with these technologies, including their subsurface use, to prevent environmental harm and/or unintended barriers to their development. This report examines 3 low carbon technology areas that could potentially be developed in England in the coming years:

- Energy extraction and production, including:
    - mine water geothermal heating and cooling
    - hydrothermal
    - petrothermal
- Retrievable energy storage, including:
    - compressed air energy storage
    - underground hydrogen storage
    - underground bio-methanation
    - underground hydropower storage
- Permanent underground storage of carbon dioxide – namely CO_2 storage associated with carbon capture and storage (CCS)

A quick scoping review (QSR) of available literature, mainly from 2016 to 2021, was carried out for these technologies and their environmental impacts.

This report summarises the characteristics of the subsurface technologies and their status in England and other relevant regions. It describes potential environmental impacts identified through the QSR and presents detailed source-receptor-pathway (SPR) models to describe potential environmental impacts. The report provides observations regarding gaps in the collective understanding of the potential environmental impacts for the technologies presented. The following sections summarise the main findings of this report.

The QSR included literature specific to each technology area and attempted to provide a suitable overview of relevant activities and developments in each. The study does not attempt to be an exhaustive account of global developments or state of the art.

Energy extraction and production

This technology area comprises mine water geothermal heating and cooling, hydrothermal (or hot sedimentary aquifers) and petrothermal (enhanced geothermal systems (EGS), or hot dry rock (HDR) systems).

There is a large amount of research being carried out into geothermal resources in the UK, mainly focused on developing the potential of resources such as hydrothermal and mine water resources.

Main observations relating to the status of the industry and technology include:

- The UK possesses limited high-temperature geothermal resources, but has good potential for using low-temperature geothermal resources for direct heating or cooling applications in several highly populated areas.
- Investigations into using mine water heat from flooded abandoned coal and metal mines have seen an increase in activity in recent years. The Coal Authority is involved in developing heat resource from 16 existing mine water treatment schemes, currently at different stages of development.
- Hydrothermal systems are aquifer-based geothermal schemes that extract heat from groundwater sourced from deep onshore sedimentary basins. These have been noted as having large potential to provide heat in the UK. However, progress in this area has been limited, with only basins in south and north-east England having been drilled for geothermal use to date.
- For petrothermal, or deep, hot geothermal resources, the most significant development has been the completion of the drilling phase of the United Downs Deep Geothermal Project on the site of the previous HDR programme near Redruth in Cornwall. The UK government has provided more than £4.5 million in grants to support the development of other deep EGS projects, for example, the Eden Project near St Austell, Cornwall on the site of the former Rosemanowes EGS site.
- A review of deep geothermal energy in the UK presented at the European Geothermal Congress in 2019 highlighted the possibility of using deep geothermal single well (DGSW) systems to supply heating to district heating networks from low-temperature geothermal energy. This is being trialled in Cornwall, and a number of other projects are under development elsewhere in the UK.

The main potential environmental impacts include:

- Contamination **of nearby ground and surface water bodies and soil** during operation of the system by mobilised and introduced chemicals such as naturally occurring radioactive material (NORM) and trace elements within geothermal brines, or liquid or solid waste from drilling.

Pathways could be geological, including reactivated faults and induced fractures (for EGS), the well or mine infrastructure, and spills, leaks or leaching at the surface from the operations or stored waste.

- **Release of gas (for example, hydrogen sulphide (H_2S)/CO_2) from the subsurface to the atmosphere**: where geothermal systems are open, or leaks can occur in a closed system, gases from the subsurface can be emitted. However, geothermal temperatures in the UK are too low to produce electricity with dry or flash steam plants, which release more gases.
- **Thermal impacts** through heating or cooling of the geothermal reservoir and surrounding rock, potentially causing chemical and mechanical changes and impacting groundwater or surface water bodies.
- **Seismicity and ground motion**: for EGS systems, seismicity can be induced through stimulation and changing pore pressure and temperature at depth. Changing pressures can also cause seismicity if hydrothermal systems are near fault zones. Ground movement could occur at mine water geothermal or EGS sites.

Retrievable energy storage

This technology area comprises compressed air energy storage (CAES), underground hydrogen storage (UHS), underground bio-methanation and underground pumped storage hydropower (UPSH). The main observations relating to the status of the industry and technology environment include the following:

- The technologies have attracted very different levels of research and development interest, and are at different stages of maturity.
- Both CAES and UHS have reached a commercial stage, with one project in the USA and one in Germany, respectively. However, no new projects for CAES or UHS have been commissioned in the last decade due to various commercial, economic and technical reasons.
- Historically, UHS has been limited to residential town gas, which had hydrogen as the main flammable component, prior to the discovery of the North Sea gas fields. There are currently only 4 underground hydrogen (H_2 95% purity) storage projects in salt caverns globally, with the Teeside salt field being one of them. Currently, there is no pure hydrogen storage in porous reservoirs.
- The UK is a leading country for underground gas storage in salt caverns, with a number of projects currently in operation. Theoretical estimations suggest that England (and the UK as a whole) has potential salt cavern capacity to meet future domestic hydrogen gas storage demand.
- UPSH and underground bio-methanation are both at low technology readiness levels, with underground bio-methanation still at the concept stage.

With respect to environmental impacts, the main potential impacts include the following:

- **Reservoir instability** is a recurring risk for all 4 technologies due to alternating pressure and temperature during operational cycles. For CAES and UPSH, the operational cycles will be more frequent, therefore the potential risk is likely to be more significant. For adiabatic compressed air energy storage (A-CAES)/advanced adiabatic compressed air energy storage (AA-CAES) systems, it is important to identify and keep storage reservoir pressures and pressure rate changes within reservoir specific operational envelopes (for example, such as remaining below the reservoir fracture pressure) to avoid reservoir fracturing or potential for collapse.
- **Water resources**: salt caverns, a preferred reservoir type for both CAES and UHS, require large volumes of fresh water during the construction stage when solution mining is used to excavate caverns. The use of freshwater, and the subsequent brine disposal, is an important environmental issue which will require detailed site-specific studies and planning management.
- **GHG emissions**: conventional CAES requires fossil fuels for turbine combustion, making it a less attractive technology option from an environmental perspective unless fossil fuels can be substituted.
- **Explosion risk**: repurposing depleted hydrocarbon reservoirs for CAES carries a risk of explosion depending on the hydrocarbon and air composition and the presence of an ignition source, whether from the process plant or from heat generated during operation. Similarly, rupture of the riser pipe in UHS can potentially lead to explosions of a vapour cloud.
- **Hydrogen leakage** from UHS, either by slow diffusion or via un-controlled leakage pathways, is a potential environmental impact. Hydrogen may damage underground infrastructure made from steel, and may also have effects on soil and groundwater microbial communities and associated nutrient cycles.
- **Increased microbial activity** from hydrogen leakage causing an imbalance in ecology and subsurface biological systems, including those in groundwater.
- **Geochemical and geomechanical** impacts in adjacent geological structures (potentially including mineral resources) from hydrogen leakage, which may change the structural integrity of the subsurface (especially if already compromised through mining) and/or mineral resource quality and value.

Permanent underground storage of carbon dioxide

This technology relates to the geological storage of injected carbon dioxide (CO_2) underground in either saline aquifers or depleted oil and gas fields:

- Injection of CO_2 in international projects has continued successfully for over 4 decades without significant incident. A large amount of experience internationally in onshore environments is derived from the CO_2 enhanced oil recovery (CO2EOR) industry in North America where over 18,000 CO_2 injection wells have been successfully drilled and operated.
- While the business model for CO_2 capture has changed from one of single point source emissions projects (for example, coal-fired power stations) to integrated industrial CO_2 capture clusters, the focus on CO_2 storage potential for the UK has remained, and is likely to remain, offshore.
- With over 25 years of offshore CO_2 injection experience and a similar oil and gas operating profile to that of the UK, Norway is seen as an important technology partner. This is confirmed by a memorandum of understanding (MOU) between the respective governments, suggesting that there will be significant cross-border working, collaboration and learning as CCS develops in both countries.
- CCS, and by extension CO_2 storage, is seen as an important enabler for blue hydrogen. This changes the business model from CCS providing an alternative disposal option for CO_2 to CCS being an integrated part of the blue hydrogen business model.
- Global standards and regulations (particularly in Norway, Europe and North America) for CO_2 injection projects are well matured and defined, with operators having a very clear understanding of the design requirements needed to ensure safe and permanent storage of CO_2.

With respect to environmental impacts, the main observations include the following:

- **Climate change due to atmospheric CO_2 release during construction**: research studies suggest that the most significant environmental impacts are likely to occur during the site preparation and drilling phase of a CO_2 injection well. Impacts are centred around the operation of fossil fuel-powered drilling platforms and ancillaries and release of associated chemicals and drilling muds into the environment. Such emissions could be expected for well and site preparations for energy extraction & production and retrievable energy storage also.
- **Adverse changes in soil and groundwater chemistry** through acidification caused by formation of carbonic acid from CO_2 and water (either present as saline brine or fresh groundwater). This can result in localised pH changes that can impact flora and fauna such as dieback of

agricultural crops and forests. Chemical interactions with adjacent geology can cause reduced mechanical strength through increased porosity due to mineral dissolution. This can potentially result in seismic activity or deformation of geological structures above the storage formation, impacting the surface and subsurface.

- **Deformation of geological structures** through over pressurisation of the storage formation. Caused by expansion of the formation and adjacent geologies, resulting in surface deformation (uniform or not) that can affect surface water movement, infrastructure and potentially reduce land use options.
- **Increased ground water mineral and trace element concentrations** resulting from the mobilisation of storage formation brines due to caprock failure or CO_2 injection well integrity issues. Brines can be supersaturated with various chemical species, some with known toxicity that can cause imbalances in soil and ground water ecology. Brines are often chemically reactive with elevated pH that can cause the mobilisation of chemicals like lead, arsenic and BTEX (benzene, toluene, ethylbenzene and xylene) from sediments, and undisturbed industrial wastes. These can then leach into the surrounding environment causing significant impact. Brines can also change the redox (oxidation state of atoms) conditions of soil and groundwater, further impacting ecosystems that are sensitive to change in oxidation conditions – especially with respect to free iron (Fe).

1. Introduction

The UK government's ambition for a 68% reduction in greenhouse gas (GHG) emissions of 1990 levels by 2030 is likely to result in changes to the energy mix in the near future. The commitment to move to more sustainable energy sources is clear, and many new 'low carbon' technologies that use the subsurface for green energy extraction, storage and CO_2 abatement are likely to be demonstrated and potentially commercialised in the UK in the coming years.

The Environment Agency needs to understand and effectively manage environmental risks associated with these technologies, including their subsurface use, to prevent environmental harm and/or unintended barriers to their development. This report examines 3 low carbon technology areas that could potentially be developed in England in the coming years:

- Energy extraction and production, including:
    - mine water geothermal heating and cooling
    - hydrothermal
    - petrothermal
- Retrievable energy storage, including:
    - compressed air energy storage
    - underground hydrogen storage
    - underground bio-methanation
    - underground hydropower storage
- Permanent underground storage of carbon dioxide – namely CO_2 storage associated with carbon capture and storage (CCS)

The different low carbon subsurface technologies are illustrated in Figure 1 below. Note, that that not all technologies would necessarily be located in the same place.

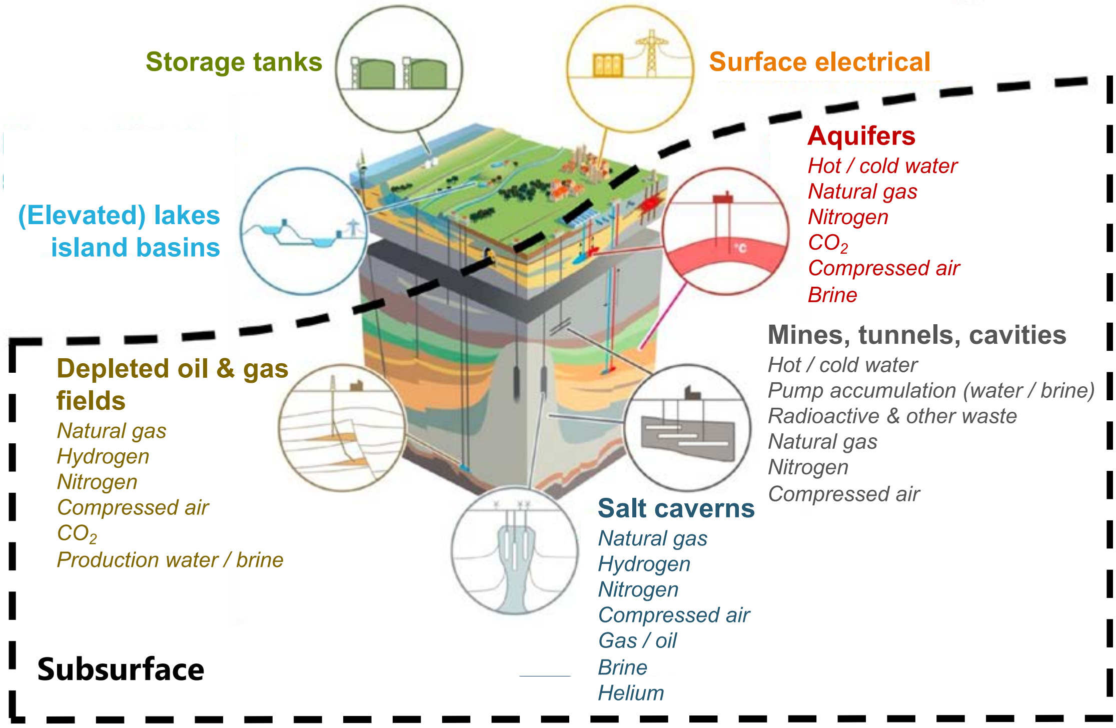


Figure 1: Subsurface energy storage options (adapted from (The Ministry of Economic Affairs and Climate Policy, 2019))

The aim of this project was to better understand the potential environmental impacts of low carbon subsurface technologies. WSS Energy has carried out the project on behalf of the Environment Agency.

WSS Energy identified a comprehensive list of low carbon subsurface technologies that could be used onshore in England to contribute to its net zero emissions goals. The following characteristics of these technologies have been briefly summarised:

- technology characteristics, processes and readiness levels
- likely geological settings
- possible scale of application

Section 3 'Low carbon subsurface technology overview' describes the technology characteristics and appropriate geological settings for each of the low carbon subsurface technologies identified.

Section 4 'Status of low carbon subsurface industries' quantitatively describes the scale of the technology applications, with a review of factors such as commercial viability and the current number of applications (commercial or demonstration).

For each technology area, WSS Energy assessed possible environmental impacts. It also assessed unintended consequences such as impacts from thermal, hydraulic, mechanical and chemical changes and interaction with other subsurface uses in England.

Section 5 ‘Potential environmental impacts of low carbon subsurface technologies’ summarises the potential environmental impacts, and includes simple illustrated conceptual SPR models.

The potential environmental impacts were identified through a quick scoping review (QSR) of available literature. This included international published and grey literature from 2016 to 2021, with a focus on review papers and reports. The aim was to identify potential environmental impacts and unintended consequences associated with deep subsurface use of onshore low carbon technologies in England. Where information was lacking from the QSR, comparisons have been drawn with SPR conceptual models of hydrocarbon extraction or other technologies.

The SPR models were complemented with an assessment of the scale of potential environmental impacts from literature or, where there were gaps in the academic record, WSS Energy’s interpretation of impact potential.

Knowledge gaps and research priorities that need to be addressed in order for the Environment Agency to effectively regulate and otherwise manage subsurface environmental risks from low carbon subsurface energy technologies have also been identified.

2. Method

This project was initiated in January 2021 and completed in March of the same year by WSS Energy on behalf of the Environment Agency. WSS Energy conducted an evidence review based on the QSR method outlined in the Joint Water Evidence Group QSR guidance document (Department for Environment, Food and Rural Affairs, 2015). This method was supplemented with reviews of peripheral grey literature that were:

- suggested as reading, or formed the basis of a recent literature review, of an article identified in the QSR method
- recommended or considered as an important document by the respective industry, especially the case for government policy and publications by industry groups and associations
- outside of the parameters of the QSR screening method but provided critical understanding of the industry or technology, and were suitably cross-referenced by industry, government or qualified associations

Besides corporate statements, referenced as such, all efforts were made to avoid the use of company marketing, unqualified performance statements and forecasts, or articles lacking a robust peer review method. Articles where academic results are likely or known to have been superseded were not included in this review.

Throughout the project WSS Energy ensured that the basis for research was driven by the QSR method and complemented using grey literature. This was to ensure the integrity of the search and to remain unbiased. Where possible, a variety of publications were used to qualify a statement to ensure reliability.

ScienceDirect draws on a range of credible and numerously cited scientific publications. Therefore, without requiring further verification, though many aspects have been crosschecked, the authors consider the QSR literature to be verifiable and developed in accordance with global scientific best practice.

Grey literature was taken from either peer reviewed sources or publishers with a qualified reputation, for example, government publications, other peer reviewed literature or material produced by industry research associations and groups.

The QSR method used follows a 5-step process:

- Step 1. Establish a steering group with representation from the Environment Agency. This took place prior to the formal project kick-off meeting.
- Step 2. Review and refine the research questions with the steering group both during and immediately after the kick-off meeting.

- Step 3. Review and confirm the scope, method, boundaries and main assumptions of the search for evidence, an activity involving both the Environment Agency steering group and the project team.
- Step 4. A search for available evidence, including both literature and referred works that are directly applicable or directly relevant to England, an expert synthesis of the evidence and the creation of a series of SPR models for each identified potential environmental impact from the QSR.
- Step 5. Results communication (including this report), which includes a report review feedback loop between the project team and the Environment Agency steering group, final report delivery and a project presentation and workshop to share and discuss the main findings of the study.

Specifically, the QSR for this study was limited to the following search parameters:

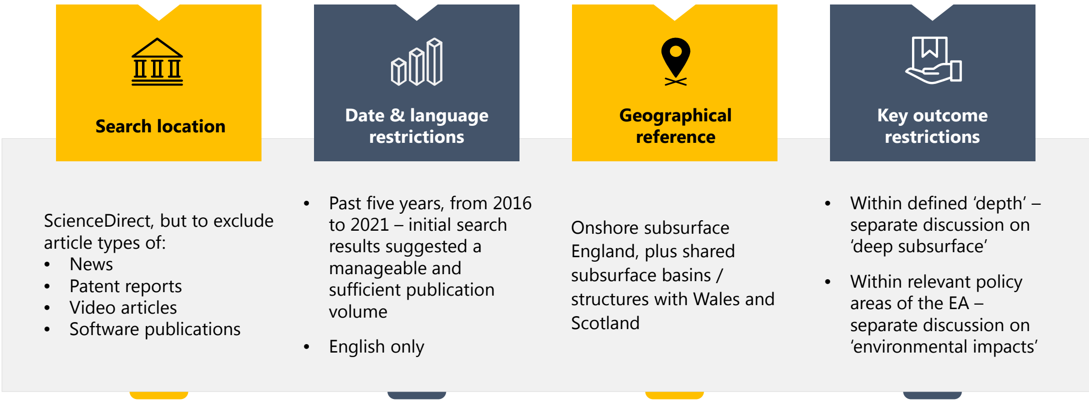


Figure 2: QSR search parameters used in this study

It should be noted that some milestone developments for certain technologies, and their associated publication record, sit outside of the date range specified (2016 to 2021). Including this material was decided on a case-by-case basis according to the perceived significance of the publication by the report authors.

WSS Energy proposed technologies and technology themes at the outset during the proposal stage. Besides the technologies described in this review, which are considered an exhaustive account of the low carbon subsurface technologies, 2 technologies were screened out at the kick-off meeting for the following reasons:

- **Shallow geothermal.** These projects are seen as being relatively cheap to develop and therefore the prevalence of the technology is expected to be greater than for other larger geothermal applications. The shallower nature of these projects requires different environmental considerations than the other technologies considered here and consequently, the potential environmental impacts were considered to be too broad to be contained within this scope and are better placed to be examined in a separate focused review.

- **Radioactive waste storage.** Since the nuclear industry is separately regulated, removing this topic from the review was justified. This theme was respecified to ‘permanent underground storage of carbon dioxide.’

Unique to the project was the coverage of a range of diverse subsurface technologies at various ‘technology readiness levels’. This means that they all have a diverse publication record that varies with industry participation and sponsorship, government policy and industry incentive, and perceptions of commercial viability that may or may not have changed over time. Some of the technologies reviewed are conceptual and therefore the publication record, especially publications strictly adhering to the QSR method, is limited.

The following observations with respect to the publication record for each technology area provide some insight into how the literature searches were carried out for each section and what constraints the researchers observed during the project:

- **Energy extraction and production**. This is an area that has been in development for many years, with the first geothermal plant constructed in Tuscany in 1904. In the UK, the first exploratory drilling was carried out by a programme funded by the UK government from 1977 until 1994. For this reason, there is an extremely large body of evidence and literature on to this topic. While this review was designed to focus on the most recent literature, as specified in the QSR method, several examples of literature are included from outside of this range, as the evidence within them was relevant and without any recent improvement. Examples have also been referenced from outside England and the UK, as considerable work has been carried out in other countries that was felt to be relevant to environmental impacts in England.
- **Retrievable energy storage.** Compressed air energy storage (CAES), underground hydrogen storage (UHS), underground bio-methanation and underground pumped-storage hydropower (UPSH) are all relatively new technologies, although CAES has reached an early commercial stage with 2 existing plants. The ongoing research effort is largely focusing on technology advancement, for example, operational efficiency, system reliability, and variance in configurations, with limited emphasis on environmental impacts, especially systematic environmental impact assessments. Due to this, the number of relevant papers as a result of the QSR search is insufficient for this study. To ensure the review comprehensively covered all the known environmental impacts from a wider industry perspective, a large amount of grey literature was included.
- **Permanent underground storage of carbon dioxide.** CCS has been through a number of interest cycles, with increased levels of research between 2000 and 2010 and, more recently, from 2017 onwards. Many government positions regarding CCS, including the UK, were established over a decade ago and are presently undergoing a revision as the industry retools for modern day CCS which is underpinned by different commercial models. Much of the research for CCS environmental impacts, especially those relating to the subsurface, was carried out early

in the last decade (and outside this QSR's date range and geographical focus). Consequently, research from that decade is often cited in more recent literature. Several tables in this review look to combine this knowledge. There are many publications used in his review that reference the environmental impacts of CO_2 storage and these have largely been sourced using the QSR method. The exception to this are recent updates of government positions which fell outside of the QSR search parameters and recently cited research articles published in the 2010s.

Using the QSR method outlined here, the literature search of ScienceDirect yielded the following publication breakdown. Grey literature from other relevant sources, including journals, project websites and government strategy documents, standards and regulations were used to enrich the dataset and are referenced accordingly.

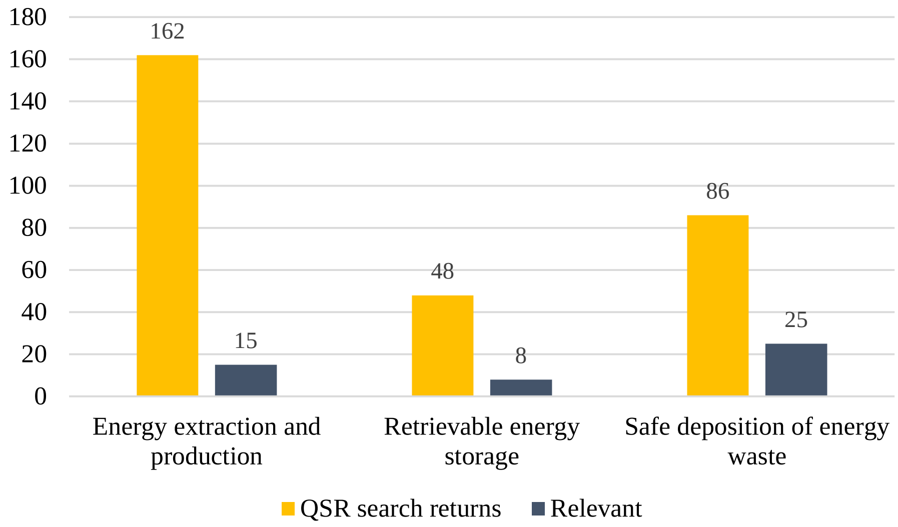


Figure 3: Returned publications and relevance based on the QSR search method used

3. Low carbon subsurface technology overview

3.1 Energy extraction and production

3.1.1 Mine water geothermal

In recent years, there has been a growing interest in using warm water from disused flooded coal mines in the UK for district heating applications (Bailey and others, 2013; Farr and others, 2016). In the UK, the last coal mine was closed in the 1990s. After the closure of the mines, dewatering activities generally ceased, and water recharged into the network of interconnected mining voids. Today, flooded mine workings consist of highly permeable man-made aquifers in which a large volume of water can be stored and abstracted at relatively high rates (Banks and others, 2004). Using heat pump systems, heat can be harnessed from the ~12 to 20°C mine water and used as a low temperature and low carbon source of energy for heating/cooling applications.

There are 4 main categories of mine geothermal systems:

1. **Open-loop systems with disposal of thermally spent water**. Mine water is abstracted from a flooded mine via a shaft or boreholes and passes directly through a heat exchanger coupled to a heat pump. After heat exchange, the mine water is discharged into surface water after treatment. Examples of such schemes include the Barredo coal mine shaft at Mieres, Asturias, northern Spain (Covadonga Loredo, 2016) and the Caphouse Colliery in Yorkshire, UK (Burnside and others, 2016). This setup has also been sanctioned for use in the UK Geoenergy Observatories (UKGEOS) due to the good quality water recorded (Environment Agency, pers. comm.).
2. **Open-loop systems with reinjection of thermally spent water**. Re-injection of the water back into the mine workings or to another aquifer unit following heat exchange (Banks and others, 2019). Examples of this type of scheme include Shettleston, Glasgow and Lumphinnans, Fife, Scotland (Banks and others, 2009) and Heerlen, The Netherlands (Ferket and others, 2011). The largest mine water heat pump schemes in the UK (Egremont, Cumbria pilot scheme of 103 kW) and in the world, are open-loop schemes (Banks and others, 2019).
3. **Closed-loop systems**. A heat exchanger is submerged in the mine water, in flooded mine shafts, for example Folldal mine in Norway (Banks and others, 2004) or within a mine water treatment lagoon after the mine water has been pumped to the surface, for example Caphouse, Yorkshire. A heat transfer fluid is circulated through the heat exchanger in a heat pump and used to provide space heating or cooling.
4. **‘Standing column’ systems**. Water is abstracted from a specific depth in a mine shaft. After passing through a heat exchanger, the water is

partly or entirely returned to the same shaft at a different depth and different temperature. The remaining water can be disposed of at the surface. The reinjected water flows along the shaft towards the pump, absorbing heat from the walls of the shaft though conduction. Heat replenishment to the borehole can be enhanced by the natural water advection along the shaft, which might also prevent the accumulation of thermally spent water near the pump.

The 4 types of mine geothermal systems discussed above, plus 2 variations on closed-loop and standing column, are displayed in Figure 4.

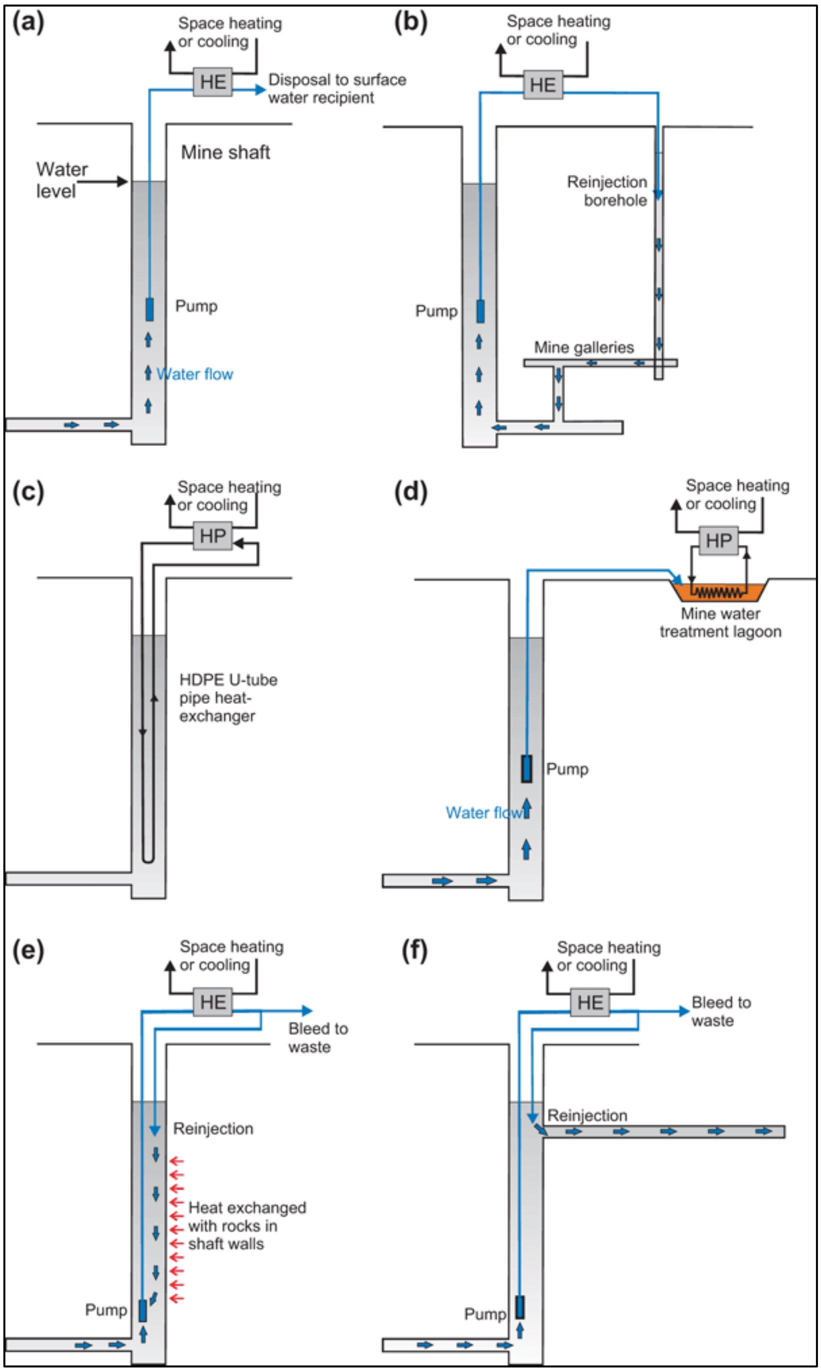


Figure 4: Different modes of heat extraction from, and rejection to, abandoned and flooded mines: a) open loop with disposal of water to surface recipient, b) open loop with reinjection, c) closed loop in flooded shaft, d) closed loop in surface mine water treatment pond, e) standing column with bleed (during peak temperature periods, some water 'bleeds' from the system to induce groundwater flow and recirculation in shaft, f) standing column configuration, with large natural flow up shaft. HE: heat exchanger, HP: heat pump where HE is differentiated from HE by using a closed-loop system typically with a tailored working fluid (Banks and others, 2019)

Each of the 4 main systems has its own advantages and disadvantages:

Type	Advantages	Disadvantages
Open-loop systems with disposal of thermally spent water	Possibility to upgrade system by adding heat exchange capacity. Reinjection facilities not required, providing fluid quality is high enough for disposal.	Cost of fluid treatment if fluid is not reinjected. Risk of chemical precipitation in pumps, heat exchanger (iron oxyhydroxides, manganese oxides). Difficulties in disposing of thermally spent water.
Open-loop systems with reinjection of thermally spent water	Water resources are conserved. Reinjection avoids the costs of treatment and discharge to surface waters.	Reinjection requires the drilling and maintenance of reinjection boreholes. Risk of thermal ‘feedback’ if the connection between the abstraction and injection points is too direct.
Closed loop	Does not depend on mine water pumping. No issues related to mine water quality (that is, chemistry and treatment) provided system is kept free of leaks and air ingress.	Limited heat replenishment. Less efficient than open-loop systems. Less readily scalable.
Standing column	May avoid licensing issues. No need for treatment.	May not be scalable.

Table 1: A review of the advantages and disadvantages of the main types of geothermal mine water arrangements currently in use

3.1.2 Hydrothermal

Hydrothermal energy, typically supplied by underground aquifers, is a source of thermal energy used in electricity generation. Geothermal electricity generation requires high temperature water (> 90°C) or steam.

In the UK, the temperature of the resources is too low for use in dry steam plants. Dry steam is not saturated and has added energy due to it being superheated (commonly referred to as degrees of superheat). In dry steam setups, the steam produced in the hydrothermal reservoir exceeds 150°C and is used to indirectly generate electricity. Typically, a heat-exchanger is used to ensure minerals in geothermal loops do not come into direct contact with the internals of steam turbines. Excess steam can be released. In flash steam plants, hydrothermal fluids are pumped under pressure to a low pressure tank where it can rapidly vapourise. It derives work from latent heat released during condensation. The temperature resource is also too low for use in flash steam plants where electricity is generated from lower quality or lower temperature geothermal energy sources.

Binary plants (Figure 5) have been developed to generate combined heat and power via an organic Rankin or Kalina cycle (closed-loop systems) using low to medium temperature resources and therefore are much better suited for the UK. Binary plants consist of a closed-loop system where heat from geothermal hot water is transferred to another working fluid circulating in a separate circuit. A heat exchanger transfers heat from the water to the working fluid, causing it to 'flash' to steam, which then powers the turbine/generator to produce electricity.

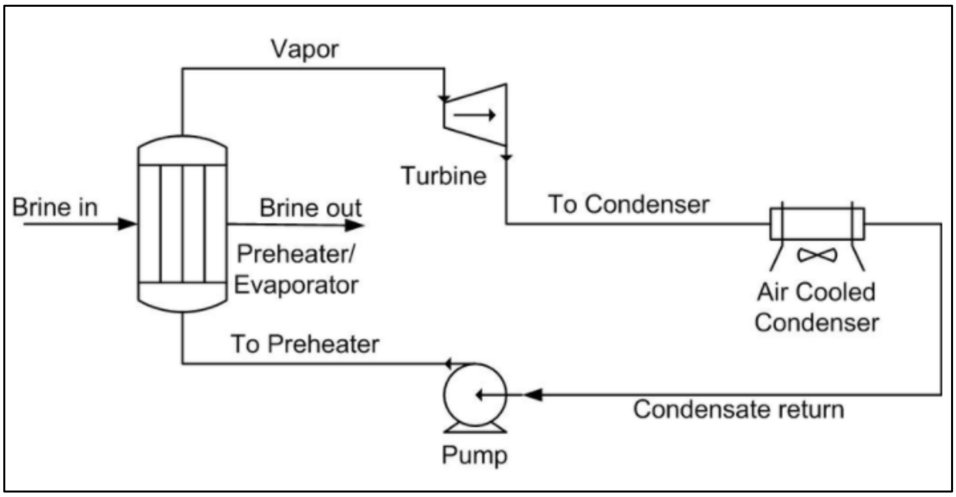


Figure 5: Basic schematic diagram of a binary plant (Ashwood & Bharathan, 2011).

The organic Rankine cycle (ORC) is a technology used in thermal or power plants to provide district heating or electricity from low to medium temperature resources. It is a binary cycle process where the primary fluid is extracted from the production well, carrying the heat to a working fluid which boils at a much lower temperature compared to water, producing vapour pressure to drive a turbine. The principle of the ORC is described as follows:

- Low pressure liquid (isobutane) is pumped from the condenser to increase the pressure of the fluid.
- High pressure isobutane is preheated in the regenerator (here shown as the preheater) where it undergoes a phase change and vaporises.
- Heating and vaporisation of isobutane in the evaporator using geothermal heat.
- High pressure isobutane vapour rotates the turbine to generate power.

- Exhaust low pressure vapour isobutane flows through the regenerator where it heats the high pressure liquid isobutane
- Low pressure vapour isobutane is condensed in the air condenser.

This technology is used in the enhanced geothermal systems (EGS) power plant in the Rhine (electricity generation at Soultz-Sous-Forêt or heat production at Rittershoffen) and in district heating plants in the Dammarie-les-Lys in the Paris Basin. Co-generation of electricity and heating for domestic hot water and direct heating also uses this technology at Chevilly Larue and l'Hay les Roses, Paris Basin.

In the UK, binary plants are being developed in EGS plants, for example, the United Downs Project in Cornwall, but also have potential use in hydrothermal.

In conventional hydrothermal systems, the heat is transported by natural groundwater, circulating within deep aquifers. Such a system uses naturally high permeability occurring within the geological formation. Depending on the temperature of the fluid, it can be used for district heating via direct use of the heat (space and water heating, space cooling, agriculture, industry) and/or for producing electricity.

Geothermal heat from deep sedimentary aquifers is exploited via a 'doublet system', which consists of a production well, a surface heat exchanger and a reinjection well. Both wells are drilled in the same aquifer or reservoir down to depths of 5km, allowing the target fluids to circulate in a closed surface system. A number of configurations exist where the wells can be vertical, deviated or a combination of both. A famous example of a doublet system is the Dogger Aquifer in the Paris Basin in France, where heat is used for district heating (Figure 6) (Lopez and others, 2010).

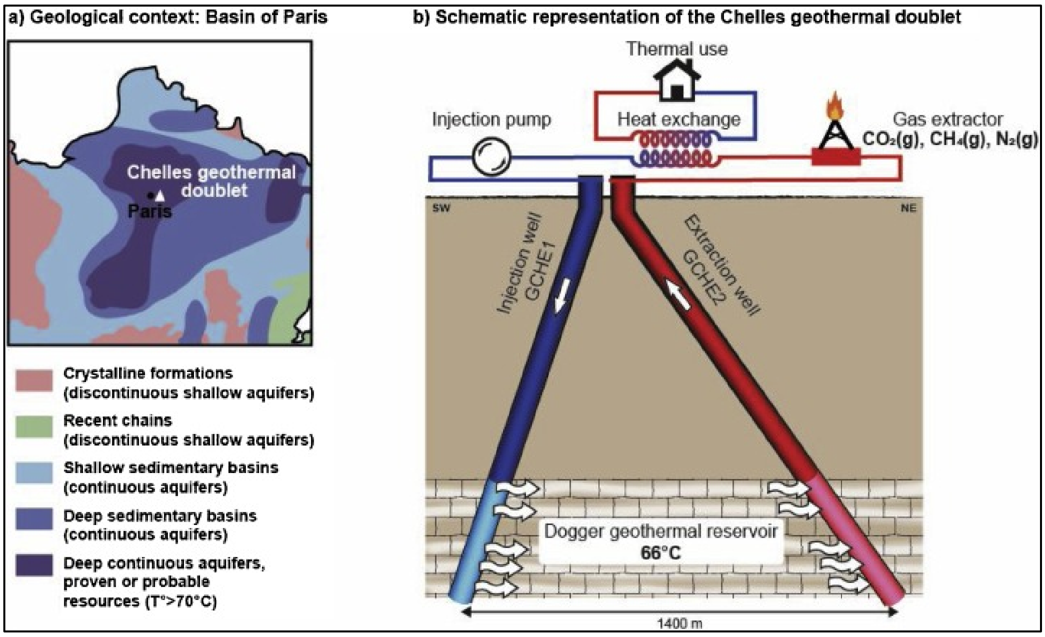


Figure 6: Schematic of the setup in the Dogger carbonate aquifer in the Paris Basin (Marty and others, 2020)

There are various regions within the UK onshore where such hydrothermal systems could provide a geothermal resource. These include the areas of the sedimentary basins in north-east England, southern England (the Wessex basin), north-west England (Cheshire basin), and Northern Ireland. These often coincide with areas of high heat demand. For many areas of the UK, it would be technically feasible to exploit geothermal resources for space heating using district energy schemes.

3.1.3 Petrothermal

Petrothermal systems are also known as engineered geothermal systems (EGS) or hot dry rock (HDR). Doublet systems can also be used to harness energy from this type of system. These systems consist of low-permeability rocks, for example, granite or granodiorite that have high radiogenic heat production but no natural heat transfer through the movement of groundwater due to extremely low permeabilities. In conventional EGS systems, rock is fractured to increase the permeability of the rock.

Petrothermal systems are most common in rocks with naturally high heat flow, such as granite, which may be generated from high concentrations of radiogenic elements found within the rocks. The natural decay of radioactive isotopes of uranium (238U), thorium (232Th) and potassium (40K) is assumed to contribute 45% of the Earth's heat flow (Turcotte & Schubert, 2002). Radioactive elements such as radon (Rn) and radium (Ra) dissolve from the rocks into geothermal fluids and can be transferred to the surfaces as naturally occurring radioactive material (NORM). The concentration of radioactive elements in groundwater will mostly depend on the rock type and on the physical-chemical properties of the water, including salinity and pH. NORM can also be found in metamorphic (for example, gneiss) and clastic sedimentary rocks.

Through the EGS procedure, a large amount of water is injected in the system and circulated within the induced fractures to extract the heat from the rock before being pumped back to the surface at the production well. Once at the surface, the fluid is produced as a brine or steam (temperature ranging from 100 to 200°C) that is used to generate heat for district heating systems or electricity.

To overcome the permeability and low fluid flow issues of conventional EGS, pilot demonstration projects and research studies are testing the possibility of using deep borehole heat exchanger systems (DBHE). These closed ‘U-Loop’ systems do not need subsurface permeability in the rocks, as a working fluid is continuously circulated within an engineered sealed pipe well system through the hot rock and up to the surface for power generation.

In DBHE systems, no fluid is injected into or extracted from the rocks. Typically, environmental permits are substantially less involved and time-consuming to obtain. Although heating effectiveness of this type of closed-loop plant is much lower than conventional plants due to pure conductive heat extraction, such a system can operate in a broader range of temperatures and rock composition. It can also offer some potential for retrofits to unproductive geothermal oil and gas wells or for repurposing geothermal systems where it is difficult to overcome potential issues from extracted brines (Alimonti and others, 2021).

Although offshore hydrocarbon fields, and the potential repurposing of hydrocarbon wells, offer significant geothermal energy potential (Gluyas and others, 2018; Lefort, 2016; Auld and others, 2014), it is likely that only electricity generation would be appealing in such remote environments and exclusively for in-project utilisation, unless interconnecting export grids become available, for example, from Iceland.

3.2 Retrievable energy storage

3.2.1 Compressed air energy storage (CAES)

Compressed air energy storage (CAES) represents a promising ‘power to power’ energy storage technology where energy is stored in the form of high pressure compressed air and consumed as a different form of energy converted from the compressed air (Wang and others, 2017). It is a mechanical form of energy storage which converts off-peak electricity to mechanical energy in the form of pressurised air. It then stores the compressed air in subsurface geological formations and retrieves it during times of peak electricity demand to produce power using turbines, which use pressure difference to turn their blades and an inline generator (Chen and others, 2020). It is considered a low-cost opportunity for utility scale energy storage, with a suitable power rating, storage capacity and duration, low self-discharge and high efficiency (Bouman and others, 2016). CAES could provide energy storage from small-scale uses up to 360MWh (Chen and others, 2020). However, its large-scale uses may be limited by geographical conditions suitable for constructing the technology (Bo Wang, 2019).

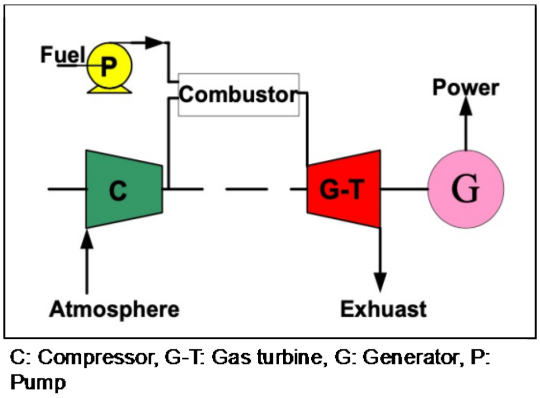
Potential applications and benefits of CAES include (Bo Wang, 2019), (Evans & Carpenter, 2019), (Wang and others, 2017):

- price arbitrage – benefitting from price difference during low and peak demand (in other words, storing compressed air during low power prices and dispatching stored energy during peak times)
- peak shaving and demand-side management - using CAES to manage energy supply by storing energy from periods of excess generation and releasing during peak-demand times
- integration of more renewable power generation plants into the existing power network to provide stable power generation
- applications to smart grids and wind energy networks - playing a role in both supply side and consumption side
- applications in other fields, including in the event of power supply failure - CAES acting in black-start capacity (the capacity for a power generating module to restart from a total shutdown using a dedicated auxiliary power source without any external electrical energy supply), rapidly providing power to important users

The technologies behind current and future CAES systems (as well as underground hydrogen storage (UHS) in the following section) are derived from proven storage technologies developed for underground natural gas storage, dating back as far as 1915 (Evans & Carpenter, 2019).

The motivation for developing CAES technology is to achieve energy sustainability and to reduce emissions, therefore current technology developments aim to avoid using fossil fuels in CAES systems (Wang and others, 2017).

The existing CAES concepts can be categorised into diabatic CAES (D-CAES), adiabatic CAES (A-CAES), and isothermal CAES (I-CAES). Generally speaking, CAES technology is based on the principle of traditional gas turbine plant (Wang and others, 2017). A gas turbine plant uses air and gas as the working medium. A turbine plant consists of 3 main sections: the gas turbine, compressor and combustor (Figure 7 left). A high temperature and high pressure gas is formed by mixing compressed air and fuel (for example, hydrocarbon) in the combustion chamber which drives the turbine. This, in turn, drives a generator to generate electricity. A CAES plant has 2 different stages of operation – compression and expansion (Figure 7, right). Because these 2 stages do not run simultaneously, it can achieve higher system efficiency than in traditional gas turbine systems (Jidai Wang, 2017).



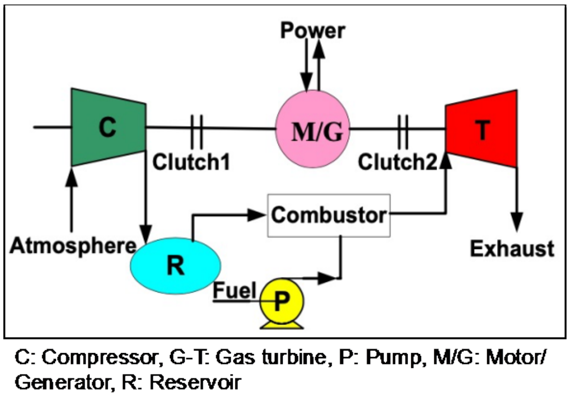


Figure 7: Left: schematic diagram of gas turbine plant; right: schematic diagram of a CAES plant (Wang and others, 2017)

CAES technology uses the elastic potential of air to store it as compressed air. The operating principle can be summarised as: 1) use surplus (electricity) power to compress ambient air, 2) store compressed air in the storage vessel, 3) release and preheat the stored compressed air in the heat exchanger before being directed into the turbine-generator to produce electricity, and 4) transmit the produced electricity back to the grid. The main components of CAES technology are illustrated in Figure 8 below. They include the compressor, thermal energy storage (TES) (only applicable to A-CAES), compressed air storage vessel (subsurface), turbine, and generator (Duhan, 2018). For A-CAES systems the heat is extracted during the compression cycle and stored in TES.

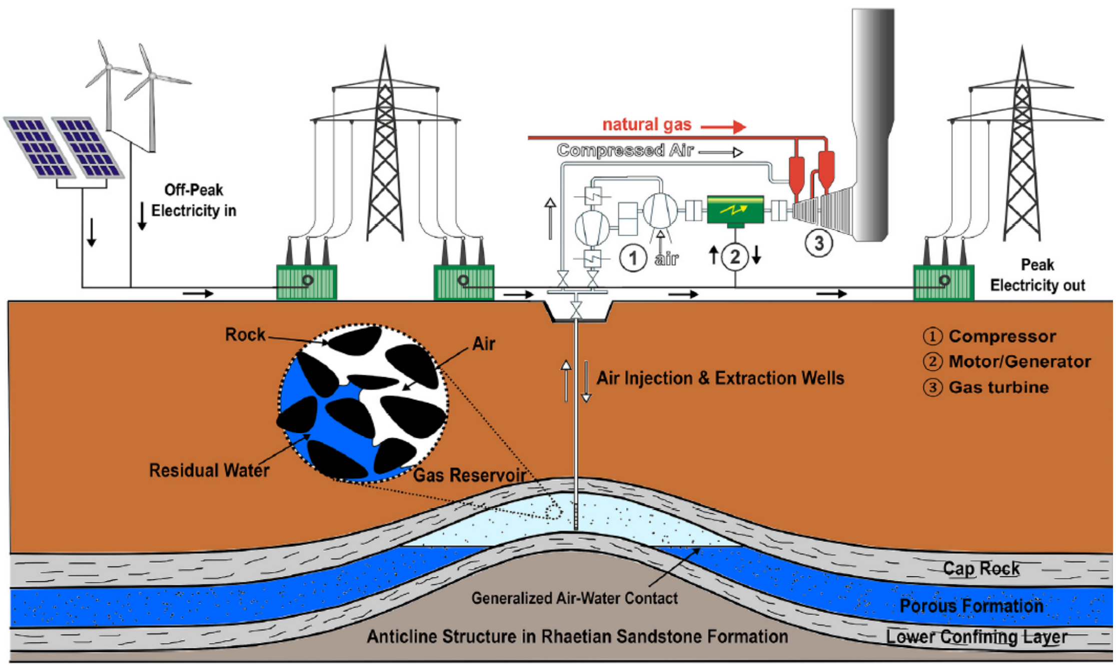


Figure 8: A schematic sketch of a hypothetical conventional CAES facility using a porous formation as the storage reservoir. Diagram not to scale (Bo Wang, 2019).

The TES is designed for the applied internal pressure and is sufficiently insulated to minimise heat energy losses. In the regenerator type TES, hot air passes through ceramic, concrete or natural rock materials, while its heat is transferred to the storage inventory. TES systems based on thermo-oil, molten salt and others can also be used.

As previously mentioned, there are a number of CAES concepts. Generally speaking, the 2 main categories of CAES technologies are conventional CAES also known as D-CAES (fuel-fired) and A-CAES (fuel-free).

Compression of ambient air to high storage pressure generates heat that is either wasted away using a cooler (for D-CAES) or stored in TES (for A-CAES) (Duhan, 2018). During the expansion stage, it is necessary to preheat the compressed air before it enters the turbine for electricity generation. The main difference between D-CAES and A-CAES is the process of preheating the compressed air in the expansion stage. In D-CAES, natural gas is used to reheat the compressed air in the expansion stage. Whereas, in A-CAES, heat extracted during the compression stage is stored as TES and later used to reheat compressed air in the expansion stage. Therefore, not only does A-CAES optimise the energy efficiency of the system energy, but it also eliminates dependence on fossil fuels (Tong and others, 2021). Figure 9 provides an illustrative comparison between D-CAES and A-CAES.

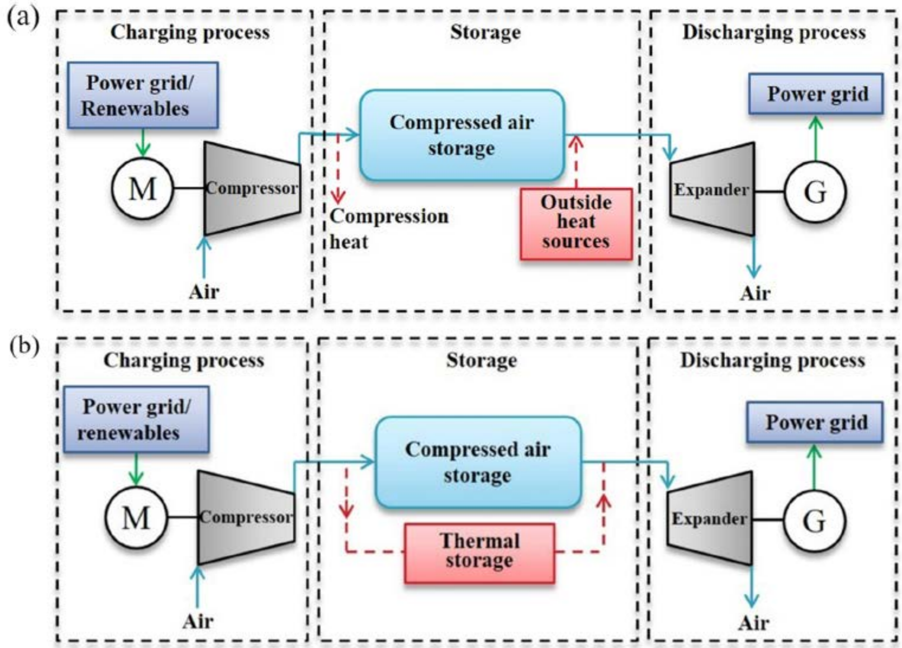


Figure 9: Comparison between (a) D-CAES; and (b) and A-CAES (M – Motor, G – Generator) (Tong and others, 2021)

Reusing the heat in A-CAES systems increases the efficiency of CAES up to 60% to 70% compared to the 40 to 50 % efficiency of D-CAES (Duhan, 2018), (Evans & Carpenter, 2019), (Tong and others, 2013). The RWE AG's 'ADELE' (German acronym for adiabatic compressed air energy storage for electricity supply) advanced A-CAES (AA-CAES) test project reported 70% efficiency (Evans & Carpenter, 2019). Improved overall efficiencies of A-CAES to above 70% are expected, for example, the predicted system efficiencies at the ALACAES SA (a privately held Swiss company) AA-CAES tunnel test facility, commissioned in 2016, are expected to approach 90% (Evans & Carpenter, 2019). Due to its higher efficiencies and being more environmentally friendly because of the elimination of the supplemental gas-firing process, the current focus of research is mainly on the 'second generation' A-CAES or AA-CAES (Evans & Carpenter, 2019).

I-CAES is an emerging technology that also offers the potential for increased efficiency (Evans & Carpenter, 2019). The process requires the continual removal of heat from the air during the compression cycle (interstage cooling) and its continuous addition during expansion to maintain an isothermal process. In terms of I-CAES, the system reduces heat energy loss by cooling air during the process of compression to prevent temperature rise, while using recycled compression heat in the release process to maintain constant temperature expansion. Ideally, the cycle efficiency of an I-CAES system would be 100%, and expected efficiency is over 80% (Tong and others, 2021). To date, technology testing of I-CAES generally involves above ground processes and storage (Evans & Carpenter, 2019).

The operational nature of cavern and porous media storage differs. For salt caverns and mined voids, 2 operational modes are generally considered. The 2 modes present different environmental considerations (see Section 5 - the environmental impact section) (Evans & Carpenter, 2019), (Wang and others, 2017):

- Fixed volume, variable pressure system (isochoric process): the most common mode, with a cavity or cavern of fixed volume operated over an appropriate pressure range, increasing as air is pumped in, and vice versa. Both Huntorf (Germany commissioned 1978) and McIntosh (Alabama, USA, commissioned 1991) facilities operate in this mode.
- Constant pressure but variable volume storage cavity (isobaric process): the underground storage cavity is linked to a water (or brine) reservoir at the surface; as compressed air is pumped in, water is displaced from the cavity (brine compensation mode). The pressure in the cavern remains almost constant, despite the increase in volume of the air, which represents a more efficient system than the constant volume method. Examples of liquid hydrocarbon (propane) salt cavern storages operating by brine displacement are found in Teesside in England.

Figure 10 provides a schematic illustration of the isochoric process and the isobaric process

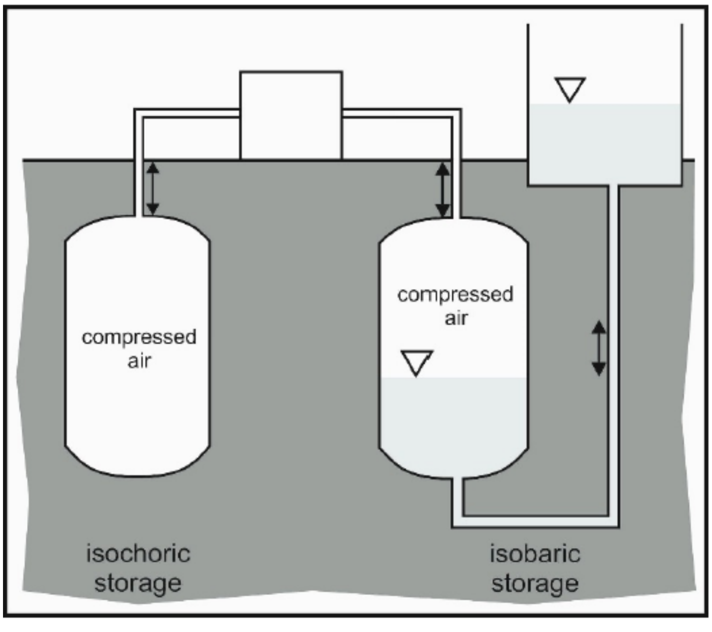


Figure 10: Schematic of operational isochoric (constant volume) and isobaric (constant pressure) pressure modes in underground storage of CAES (Evans & Carpenter, 2019)

In general, there are 5 types of reservoirs that theoretically can be used for CAES underground storage (Evans & Carpenter, 2019), (King and others, 2021):

- salt caverns
- porous reservoir: aquifer
- porous reservoir: depleted oil and gas field
- lined rock caverns
- mined voids: abandoned mines and unlined rock caverns

Figure 11 below illustrates the first 4 types of storage options.

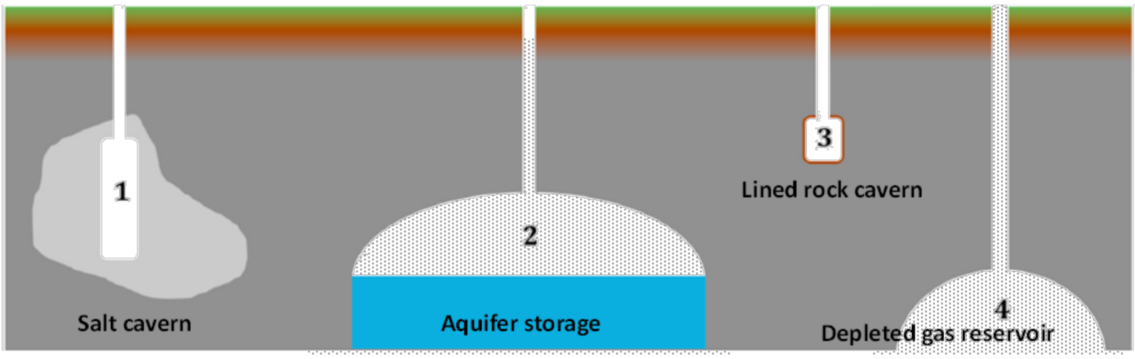


Figure 11: 4 types of CAES underground storage options (adapted from (King and others, 2021)). Mined voids are not shown and grey shading in 2 and 4 indicates porous rock. Diagram not to scale.

Among these options, salt caverns are considered the most feasible option for grid-scale storage due to suitable storage properties of rock salt such as low permeability, tightness, high strength, and ease of creation. The high strength of rock salt enables pressurising and cycling compressed air at desirable rates and on a frequent basis without cavern collapse (Chen and others, 2020).

Salt caverns are in bedded and domal salt deposits (Figure 12) created through solution mining. This is a process where water is injected from the surface in a controlled manner into a well in the salt rock, which dissolves the salt and forms brines that are extracted. However, if the bedded layer is thin (60 to 100m), as it is in some areas in England, horizontal drilling techniques are required (Stone and others, 2015). Depending on the required storage capacity and local geology, salt caverns can be built up to 3,000m below the surface, 1,000,000m^3 in volume, 300 to 500m in height and 50 to 100m in diameter, accommodating pressures of tens or hundreds of bars (Pimm and others, 2019).

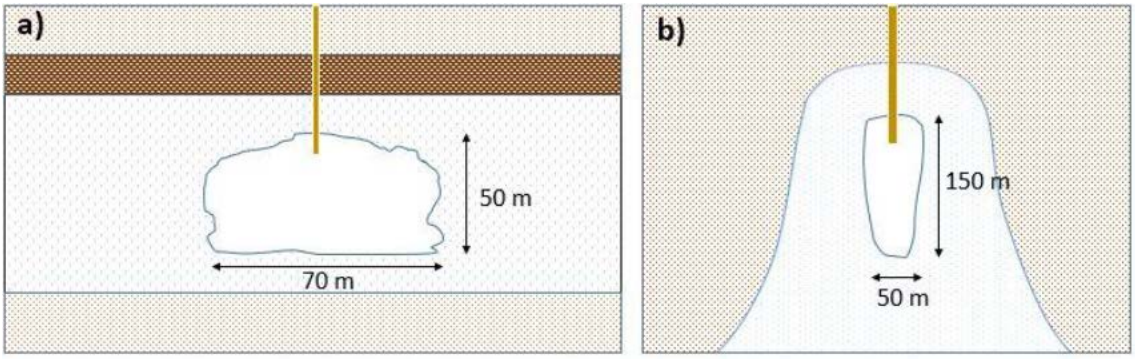


Figure 5: Salt caverns in a) bedded and b) domal salt deposits (Duhan, 2018)

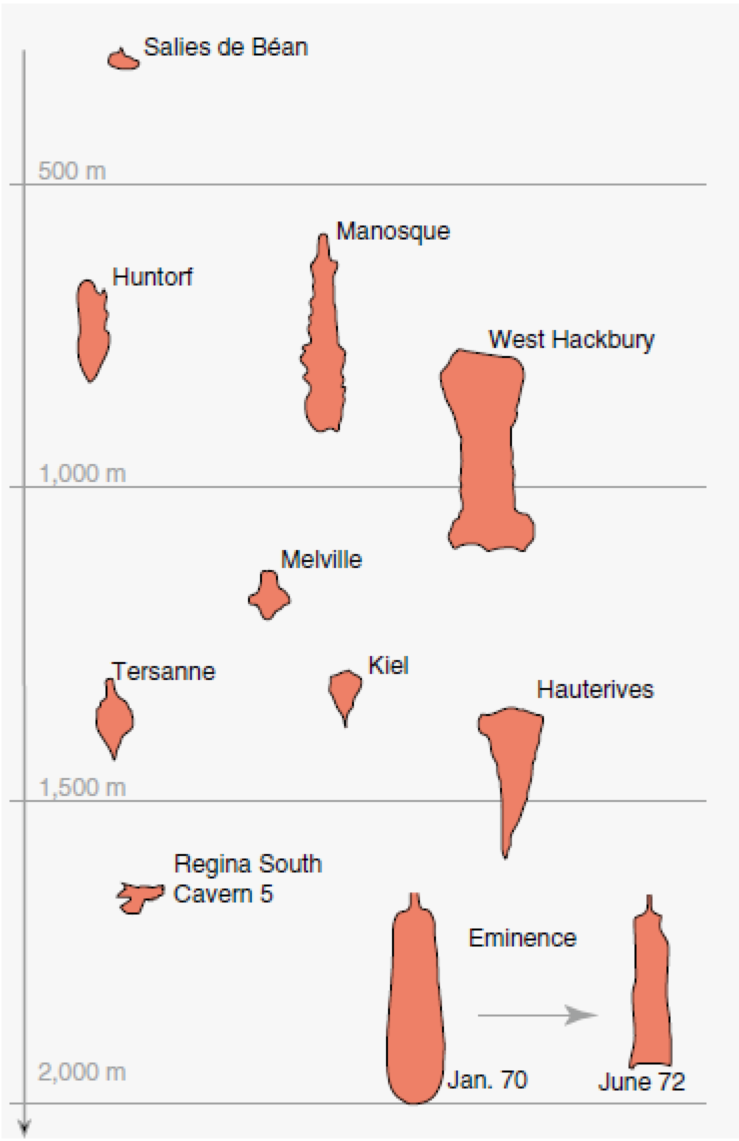


Figure 13: Depth profiles of various salt caverns, all are in salt domes except Regina South and Salies de Bean, which are in bedded salt (Warren, 2016)

Recent publications suggest the operational window for CAES salt caverns lies between 500 to 1,300m below the surface, based on operating pressures being directly dependent on depth and power-plant components (Evans & Carpenter, 2019). However, breakthroughs in compressor and turbine technology could enable CAES deployment to greater depths than previously possible, with 1,500m once considered at Islandmagee in Northern Ireland (Evans & Carpenter, 2019) (Figure 14).

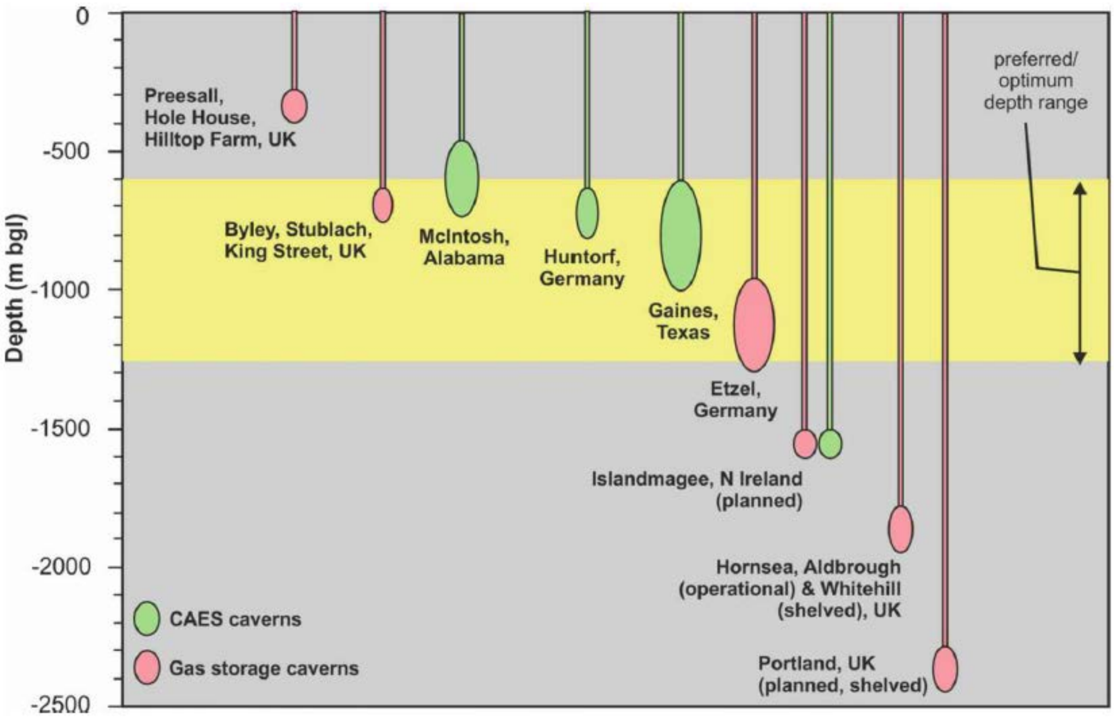


Figure 6: Selected example to illustrate the depths of operational and proposed global gas storage caverns and operational and proposed global CAES caverns (Parkes and others, 2018)

There are geological and geographical limitations on the distribution of these rocks and the ultimate volumes available to support salt cavern CAES (Bo Wang, 2019), (Evans & Carpenter, 2019). It is widely accepted that there is potential to advance CAES technology beyond caverns to use porous formations such as aquifers and depleted hydrocarbon reservoirs for CAES storage - a more promising worldwide option (Bo Wang, 2019), (Evans & Carpenter, 2019). Moreover, porous formations can provide much larger potential storage capacities. Depleted hydrocarbon reservoirs and aquifers could provide 81% and 13% of gas storage volumes respectively (Evans & Carpenter, 2019).

CAES storage in porous formations and depleted hydrocarbon fields requires a suitable structural trap and caprock and adequate porosity and permeability (Evans & Carpenter, 2019). A disadvantage in using aquifers is the slow flow rate that occurs due to the presence of water in the pore space. This limits the efficiency of the CAES system in aquifers when compared to salt caverns. Depleted hydrocarbon reservoirs have additional considerations due to the residual hydrocarbons present in the formation. These considerations are provided in the environmental impacts section of CAES due to the potential risks they pose.

Lined rock caverns (LRC) are a variation on the mined void storage type, with rock caverns constructed and lined with an artificial, gas-tight barrier, generally comprising concrete and a stainless-steel sheet (Evans & Carpenter, 2019). The technology was proved for gas storage at 2 pilot plants in Sweden between 1988 and 1993 and several small CAES test facilities in former mine tunnels in Korea and Japan during the 1980s. Tests were successful, but in general were short in duration and no projects were developed subsequently (Evans & Carpenter, 2019). Investigations into the feasibility and stability of shallow CAES LRCs in cavities and tunnels is ongoing (for example, at the University of Minnesota and ETH Zurich), with studies on the coupled thermodynamic, geomechanical behaviour and stability of lined caverns located at 60 to 120m depth (Evans & Carpenter, 2019). Although smaller volume and higher cost than other storage options, LRCs have greater geological flexibility (Evans & Carpenter, 2019), (Kim and others, 2016). However, one of the main challenges in underground storage of compressed air in LRCs is the risk of air leakage from the storage caverns (Kim and others, 2016).

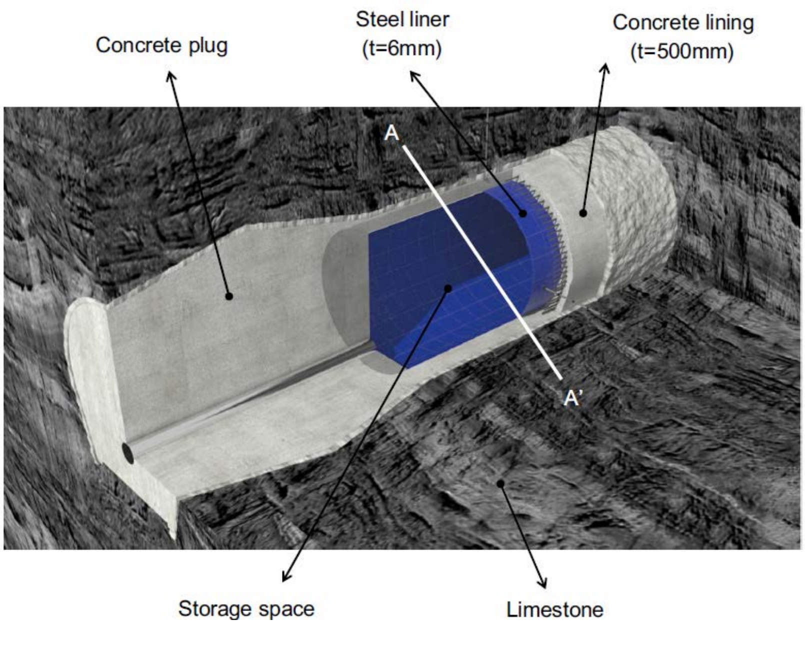


Figure 15: A CAES pilot test cavern located in limestone at a depth of about 100m (Kim and others, 2016).

Abandoned mines and caverns mined specifically for storage have both been used for gas storage. Some rock masses are gas-tight, but generally the host rock, while stable, has fractures and joints, and is not tight with respect to liquids and gases (Evans & Carpenter, 2019). Several past gas storage projects in abandoned coal mines have been closed due to leakage issues (Evans & Carpenter, 2019).

Other options for storage could be underground piping, but this is an unlikely option due to the storage volume needed (Bouman and others, 2016).

D-CAES has reached a commercial stage and is now considered a mature technology. Major improvements in either reduced energy input or efficiency of these systems in the near future are unlikely (Evans & Carpenter, 2019). Use of renewable energy sources such as carbon neutral biomass fuels during generation would lead to significant GHG emission reductions from the D-CAES systems. A-CAES/ AA-CAES are currently in testing and pilot demonstration stages, with a number of projects likely to reach large-scale commercialisation within several years.

3.2.2 Underground hydrogen storage (UHS)

Hydrogen storage in underground structures is not a new concept. Compared to surface tank storage, underground storage is a cheaper alternative for large quantities of gaseous hydrogen.

For hydrogen storage in the subsurface environment, depleted oil or gas reservoirs, man-made salt caverns, deep aquifers, hard rock caverns and abandoned mines are all available. Generally speaking, the 2 preferred options for UHS projects are man-made salt caverns in thick evaporitic formations and deep porous formations such as saline aquifers and depleted oil and gas reservoirs (Sainz-Garcia, et al., 2017), (Zivar and others, 2020).

UHS is a cyclic operation with alternating periods of injection, withdrawal and idle, depending on the energy production and demand. During a typical seasonal operation, the storage will be charged during the summer months and discharged during the winter months when energy demand is higher. The main driving force for hydrogen movement in and out of the formation during the operation will be compression and expansion of the gas (Hagemann, 2017). An efficient withdrawal is important for a successful storage operation. Withdrawal efficiency depends on many parameters such as well patterns, withdrawal scheme, withdrawal rate, deliverability of the well and reservoir, and capacity of surface and subsurface facilities (Zivar and others, 2020). In addition, it is suggested that the location of the extraction wells also has a direct impact on the overall hydrogen (H_2) storage performance and efficiency (Sainz-Garcia, et al., 2017).

Prior to hydrogen injection, cushion gas is preinjected. Cushion gas, normally nitrogen (N_2) or methane (CH_4), is a volume of gas or a gas mix, considered not to be part of the production but a permanent inventory in the reservoir. The cushion gas also undergoes alternate compression and expansion during the hydrogen injection and reproduction cycle.

Although each underground storage type has its own characteristics, there are several important requirements that are common to all types of hydrogen storage sites:

- The structure needs to provide enough volume to store large amounts of hydrogen.
- The structure needs be enclosed to prevent hydrogen losses in the adjacent rocks.
- The structure needs to allow the injection and withdrawal at efficient rates.

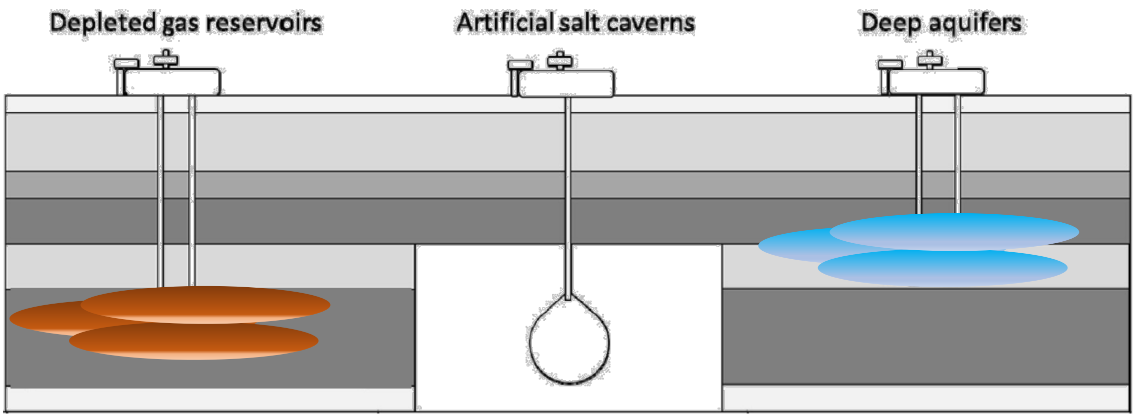


Figure 16**: Schematic depiction of the 3 major types of UHS. Diagram not to scale. Brown & light blue shading indicates porous rock, white box indicates salt deposits (Dopffel and others, 2021)**

Ideal for short and medium-term storage (Heinemann and others, 2021), salt caverns are currently considered to offer the most promising underground storage option. They offer a number of advantages, including large sealing capacity, flexible operation with potentially higher injection rates and withdrawal cycles, low cushion gas requirement and low permeability. The inert nature of salt structure and salinity means that it has fewer issues with bacterial growth (Zivar and others, 2020), (Caglayan and others, 2020), (Pimm and others, 2019). The detailed description and features of salt caverns are provided in the CAES section.

Aquifers are porous and permeable media where pore spaces are filled with either fresh or saline water. The injection of air through a borehole displaces the water, creating an air 'bubble' within the pore space in the near-well region, which creates a 'gas cap' (Evans & Carpenter, 2019). They can be a cost-effective option that offer significant storage capacity. The requirements for hydrogen storage in deep aquifers include good reservoir characteristics of the host rock and the presence of an impermeable layer, or cap rock, to prevent migration of the gas being stored (Sainz-Garcia and others, 2017), (Zivar and others, 2020). Due to the high mobility of hydrogen, the storage must be located in a suitable tectonic trap with a steeply dipping structure, such as domes, to enable the recovery of high-quality hydrogen (Sainz-Garcia and others, 2017). Other aspects to consider include the reactivity of the hydrogen with aquifer components and hydrogen losses due to its high mobility. The assessment of the hydrogen footprint and its recovery ratio are the main challenges in aquifer storage (Sainz-Garcia and others, 2017). The industry's direct experience of hydrogen storage in deep aquifers comes from town gas projects. Due to the fact that deep aquifers never contained naturally occurring hydrocarbons (or air), and therefore present a different fluid storage environment, injected hydrogen may migrate to regions where it becomes stranded or is unable to be retrieved.

Consequently, aquifer storage typically requires significantly more cushion gas than depleted reservoirs: up to 80% of the total gas volume. Therefore, developing an aquifer storage facility for hydrogen or other gas storage can be more time-consuming and expensive than salt caverns and depleted reservoirs (Evans & Carpenter, 2019).

Depleted oil and gas reservoirs are a hydrocarbon-bearing geological trap, capped with an impermeable caprock from which all economically viable hydrocarbons have been produced. Due to their well-identified geological structure, excellent tightness, the integrity of caprock and the existence of necessary surface and subsurface infrastructure, depleted oil and gas reservoirs are often considered to be the most appropriate options for underground gas storage, especially depleted gas reservoirs (Zivar and others, 2020). Remaining gas in a depleted gas reservoir which has not been recovered can potentially be used as cushion gas. On the other hand, using a depleted oil reservoir as a hydrogen storage site will need a comprehensive study as the residual oil in the reservoir could possibly cause chemical reactions and conversion between hydrogen and remaining oil.

Table 2 shows a comparison of the features of salt caverns, deep aquifers and depleted gas reservoirs.

	Salt caverns	Deep aquifers	Depleted gas reservoirs
Tightness - ability to inject and retrieve stored hydrogen	Excellent	Excellent	Excellent
Flexibility – ability to be used for other gas types	Feasible	Medium	Medium
Temperature range	Mostly 20 to 35°C	7 to 174°C	Large range
Salinity	Up to saturation	Up to saturation	Large range
CAPEX – site preparation and construction	Medium	Medium	Low
Experience for hydrogen storage	Medium	Very low	Low

Knowledge on in-situ reactions	Very low	Low	Low

Table 2: High-level comparison of different underground hydrogen storage options (Dopffel and others, 2021), (Zivar and others, 2020)

Despite ongoing industry enthusiasm and the potential offered by UHS, the overall maturity of UHS is low. As mentioned previously (section 3.2.1), there are 4 commercial scale UHS projects in operation worldwide, however none of these store hydrogen with 100% purity. Furthermore, porous reservoir storage is much less mature than salt caverns, with development activities still being limited to laboratory studies and testing, and practical applications restricted to the storage of town gas. Due to the overall low maturity, UHS is associated with several uncertainties and challenges.

3.2.3 Underground bio-methanation

The technical concept of underground bio-methanation is directly related to the technology of underground natural gas storage and based on the fact that a methanogenesis reaction during the storage of hydrogen produces methane (CH_4) (Strobel and others, 2020).

In underground bio-methanation, H_2 and CO_2 are injected together into a deep storage reservoir. Due to the microbial reaction, a portion of the injected mixture is converted into methane and water. Figure 17 illustrates the concept of a doublet system for underground bio-methanation.

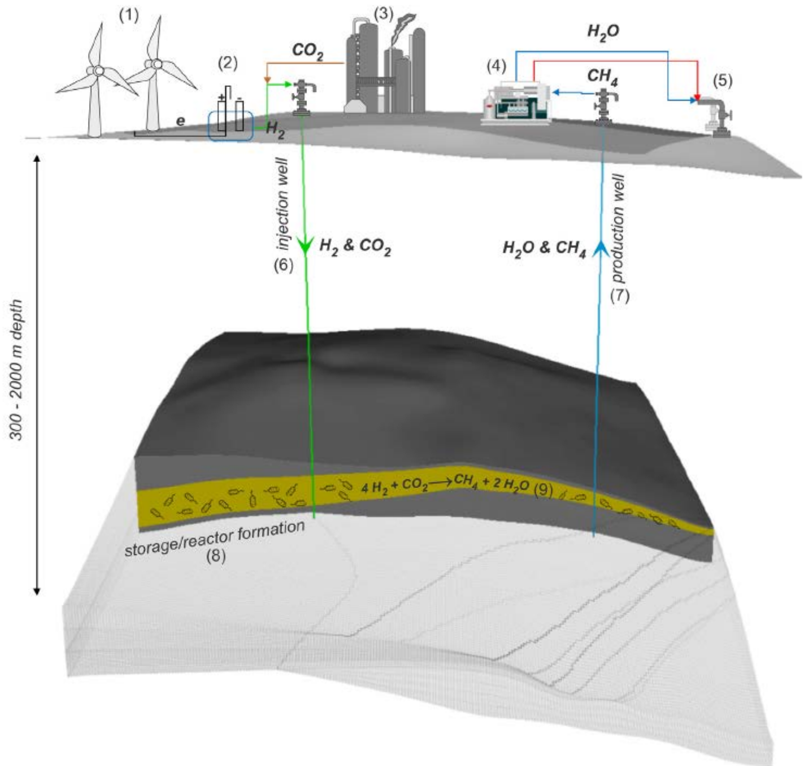


Figure 17: The concept of a doublet system for underground bio-methanation (Strobel and others, 2020)

Underground bio-methanation requires a deep porous reservoir between 300m and 2,000m that acts as a reactor where stored H_2 and CO_2 are converted into methane (Strobel and others, 2020). Both aquifers and depleted oil and gas reservoirs are considered to be feasible if the following geological prerequisites are met (Strobel and others, 2020):

- A porous rock with > 10 % porosity is required as the underground bio-reactor. Siliciclastic rocks, sedimentary rocks comprising predominantly quartz grains, are the preferred rock types due to the limited reactions between minerals and injected gas.

- A geological trap (for example, an anticline or fault) is needed to prohibit vertical and horizontal gas migration.
- An impermeable cap rock, above the reactor formation, should seal the formation. Shales and salts like halite are suitable cap rocks. The sealing capacity of the rock type further depends on its capillary threshold pressure. Exceeding the threshold pressure can cause gas to leak through the upper formation.
- The pores in the rock need to be connected. The permeability influences the movement of the gas, therefore permeability > 5 x 10^{-14} m^2 is preferable.
- A formation water saturation > 10 % is crucial for the microbes to grow.
- Since salt content could be an inhibitor for the growth of microbes, salt content in the formation water should not exceed 150g/l.
- A temperature between 30 to 70°C is preferable.

It is useful to compare the attributes and features of underground bio-methanation with underground hydrogen storage as these technologies share common infrastructure and may potentially be located together to take advantage of topside equipment and supply chains. The table below provides such a comparison.

Criteria	**Technology**	
	Underground bio-methanation	Underground hydrogen storage
Objective	Conversion and storage	Storage
Working gas	CH_4 and 4:1 H_2 / CO_2	H_2 pure or admixed
Storage type	Porous rock	Porous rock or salt cavern
Depth (m)	< 2,000	< 3,000
Favourable temperature (°C)	< 65	-
Water saturation (%)	> 10	< 20
Porosity (%)	> 10	> 10
Permeability (m^2)	> 5 x 10^{-14} m^2	> 5 x 10^{-14} m^2

Salinity (g/l)	< 150	-

Table 3: Comparison of underground bio-methanation and underground hydrogen storage (Strobel and others, 2020)

3.2.4 Underground pumped storage hydropower (UPSH)

UPSH is a large-scale energy storage facility, with typical power varying from 100 to 1,000MW, and energy capacity from 1 to 15GWh depending on the size of the storage reservoirs. It is a variant of pumped storage hydropower, therefore in principle the same technology could be used in UPSH (EERA, 2018).

UPSH plants consist of 2 reservoirs; the upper reservoir and lower reservoir. The upper reservoir is located at the surface or at shallow depth, while the lower reservoir is underground (Pujades and others, 2020), (Pujades and others, 2017). The 2 reservoirs are vertically separated by several hundred metres (EERA, 2018), (Pickard, 2012). The stored water in the upper reservoir contains potential energy, provided as hydrostatic head. The stored energy is proportional to the mass of the water lifted up and the vertical height between the reservoirs. When electricity is needed, the water flows into the underground reservoir and runs a Francis turbine (generation mode) and an alternator which feeds electrical energy into the distribution network (Menéndez and others, 2020). Conversely, the energy from the electrical grid is used by the motor to run the Francis turbine in pumping/consumption mode, which drives the water from the underground reservoir to the surface reservoir.

Caverns can be constructed for the powerhouse and will include excavations for the hydraulic equipment (for example, electrical facilities, supply and transmission lines to the electrical grid) as well as a connected network of tunnels and shafts for the underground water lower reservoir (Menéndez and others, 2019), (EERA, 2018).

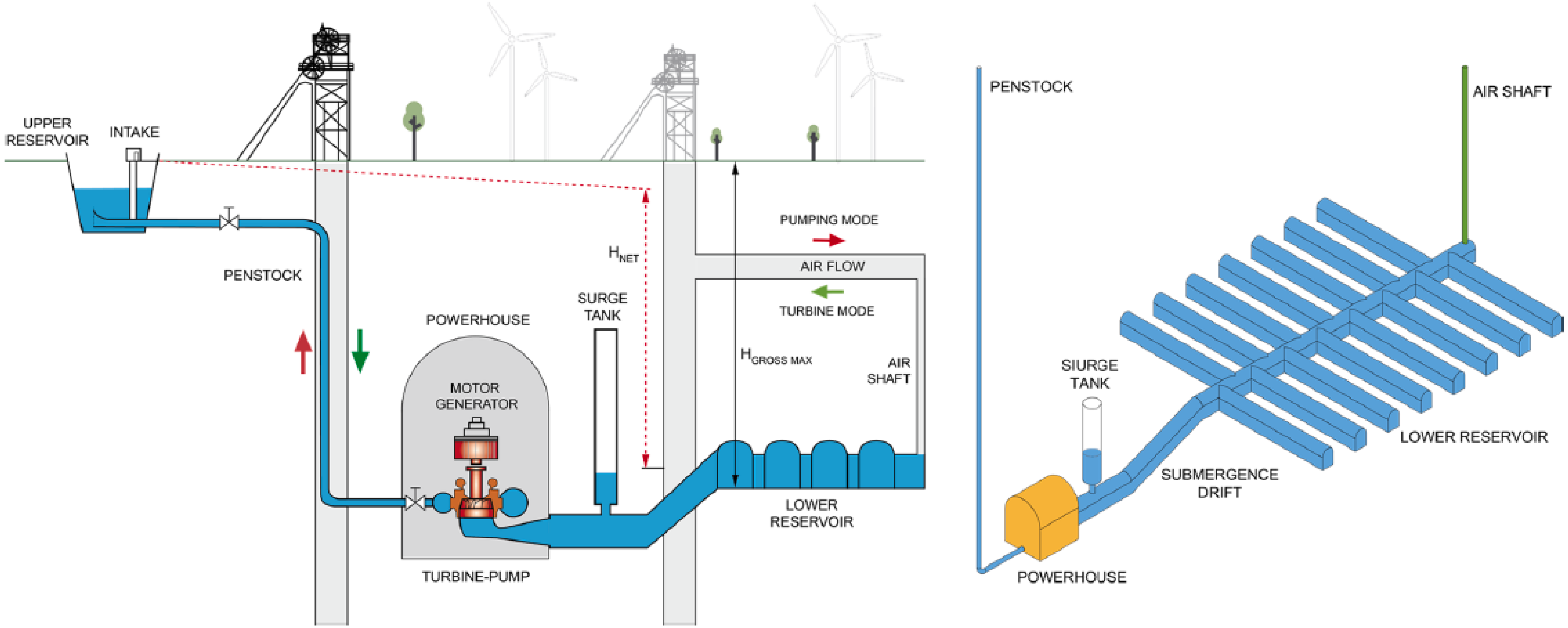


Figure 18: Scheme of UPSH in a closed underground mine: upper and lower reservoir, penstock (for water movement), valve (for flow control), Francis pump-turbine, motor-generator, surge tank and vent shaft (left). 3D detail of the lower reservoir (right) (Menéndez and others, 2019). Gross max head (here $H_{gross\ max}$) shows the maximum potential energy of the system. The larger the maximum head, the more energy can be generated (or consumed to pump to the upper reservoir).

However, unlike conventional PSH plants, the operation of UPSH plants is complex due to the substitution of water and air during energy generation and pumping (Menéndez and others, 2020). The air enters the mine during the pumping mode and leaves the mine, through the ventilation shaft, during the generation mode (Menéndez and others, 2020). The air inside the underground reservoir becomes compressed as the reservoir fills. If the underground system were allowed to pressurise (in other words, no venting of air) the $H_{gross\ max}$ would be artificially reduced, due to back pressure, reducing the efficiency of the system (Menéndez and others, 2019). Flow rate and air pressure depend on the flow rate of the Francis turbine and the diameter of the ventilation shaft (Menéndez and others, 2019). Simulations suggest an efficiency of about 75%, similar to conventional pumped storage hydropower plants, where between 70 and 80 % can be achieved (Menéndez and others, 2019).

It is suggested that the underground reservoir should be vertically separated from the surface reservoir by a few hundred metres to a thousand metres (EERA, 2018), (Pickard, 2012) to provide an optimum hydrostatic head.

Abandoned coal mines, including deep and open-pit mines, have the potential to be used as underground reservoirs for UPSH plants, which is a cheaper option than constructing new caverns (Pujades and others, 2017). Mines likely to flood are not thought to be feasible as maintenance costs will be high (Menéndez and others, 2019).

In reality, mines are very rarely free from water ingress, either from the surface or from surrounding geological formations, and water exchange is expected to occur (Pujades and others, 2020). The consequences of water exchange between the UPSH and the surrounding groundwater is one of the most challenging aspects of UPSH.

The concept of UPSH is not new and several projects have been undertaken over the past 50 years (Pujades and others, 2020), (Pujades and others, 2017), (EERA, 2018). Numerous authors have investigated the suitability of energy storage systems in different countries such as Singapore, the USA, South Africa, The Netherlands, Germany, Belgium or Spain. To date, there are no UPSH plants constructed and the overall technology maturity of UPSH is low.

3.3 Permanent underground storage of carbon dioxide

3.3.1 Underground storage of carbon dioxide

CO_2 storage in deep geological formations is an important part of the carbon capture and storage (CCS) process. CO_2 captured from a stationary emissions source is typically compressed then transported by a surface pipeline to the storage location. In some cases, especially that planned at Norway's Northern Lights CCS Project (Northern Lights CCS, 2021), CO_2 may be transported from a diverse range of sources by ship and temporarily stored at the injection site in surface tanks to mitigate supply fluctuations.

The CO_2 that arrives at the storage location is then injected, typically as a supercritical fluid, into a deep geological formation and stored indefinitely, thereby isolating the CO_2 from the atmosphere and preventing it from contributing to global warming. For a geology to be suitable for CO_2 storage 3 main requirements need to be fulfilled; capacity, injectivity and containment. An overall CCS value chain is described in Figure 19, albeit for an offshore CO_2 storage project. The UK CCS industry bias to offshore storage is further expanded in the following sections of this report.

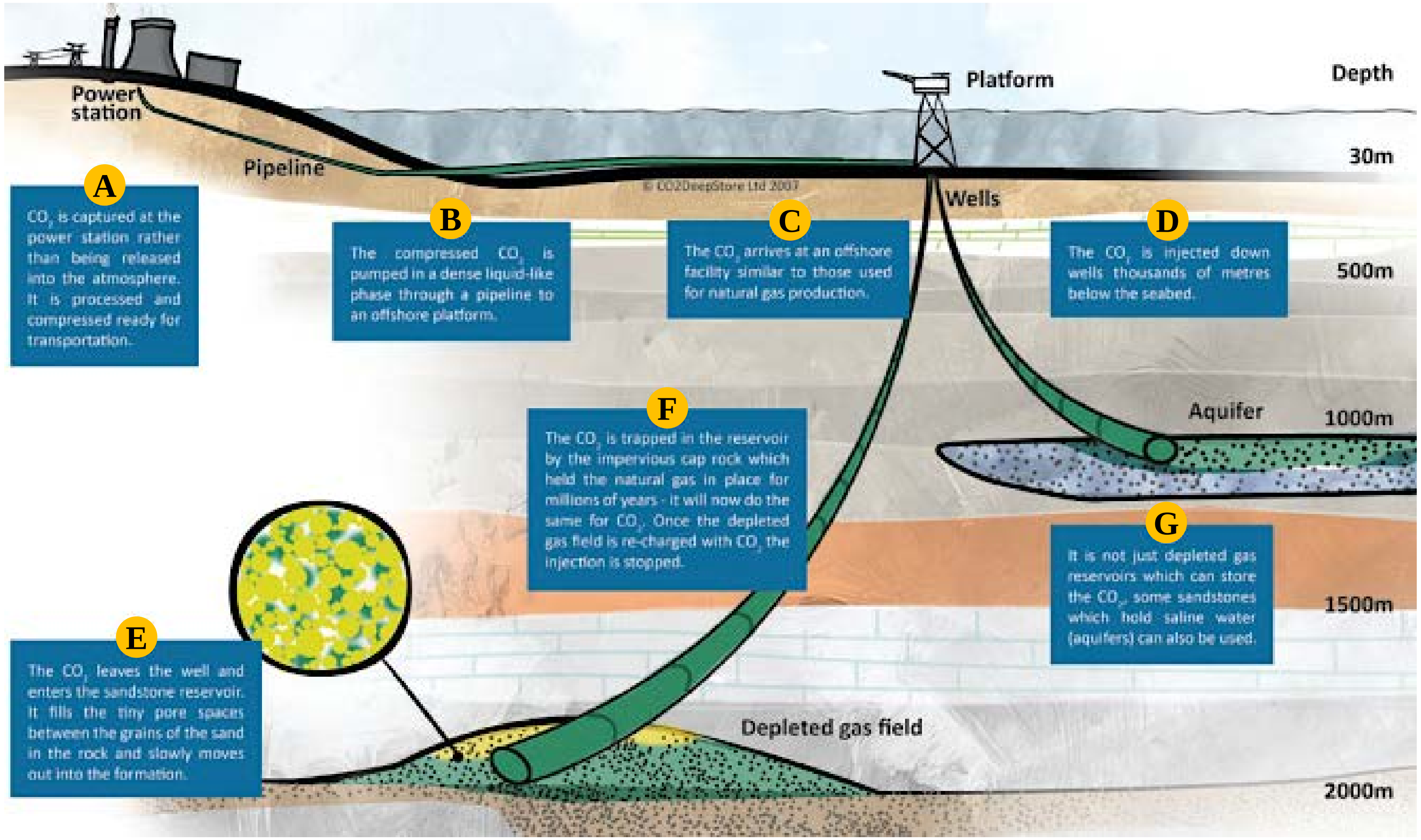


Figure 19: Schematic of the CCS process, including storage within a saline aquifer and depleted natural gas field (Pale Blue Dot, 2016)

The CCS value chain is, broadly speaking, divided into 3 elements: 1) carbon capture, 2) transportation and 3) carbon storage. While this report focuses on aspects of geological storage of CO_2, it is worthwhile understanding the value chain and surface infrastructure contributing to capture and transportation of CO_2 from various sources.

CO_2 can be captured from various industrial processes. This is also known as 'gas separation'. Such facilities include fossil fuel-based power generation, including gas, coal and even oil. Also, a significant source of CO_2 emissions are natural gas processing facilities (natural gas with CO_2 needs to be purified before it can be sold into gas grids) and some industrial processes (for example, production of hydrogen from natural gas produces CO_2) (British Geological Survey, 2020). Carbon dioxide capture falls into 5 broad technology categories:

- Post-combustion carbon capture – CO_2 is removed from the flue gas (mainly containing nitrogen (N) and CO_2) of a fossil fuel combustion process. Examples include the exhaust of a coal-fired power facility. This technique is particularly useful for facilities that need CCS to be retrofitted to existing facilities.
- Pre-combustion carbon capture – this is where the CO_2 is removed from the fuel prior to combustion. The fossil fuel is typically partially burned in a gasifier to form 'syngas' that is made up of CO_2 and hydrogen gas. The CO_2 is captured from this syngas and the remaining hydrogen is then combusted in either a boiler or gas turbine. The exhaust gases are vented to the atmosphere and do not contain any CO_2; only water vapour and some other minor impurities.
- Hydrogen production including CCS – natural gas can be converted into hydrogen and CO_2 through a process called 'steam reformation'. The CO_2 can be removed from the reformer exhaust and the hydrogen used for various industrial and residential applications.
- Oxyfuel combustion – this is a process where combustion progresses in an oxygen only environment. The benefits of this approach are that the exhaust gases from this process contain only CO_2. Therefore, a separation step is not required to get a pure stream of CO_2 – only compression is required for densification for transportation.
- Direct air capture – this is an emerging technology where CO_2 is captured from the air using chemical means. In order for this process to be carbon neutral, energy to run the capture facility must be provided from renewable sources.

Prior to transportation, the CO_2 is compressed to a supercritical state where it shares properties of both liquid (density) and gas (viscosity or flowability). This makes it cheaper to transport and helps the processes of injection and chemical integration of the CO_2 into the storage formation.

CO_2 for CCS is currently transported exclusively by pipeline (British Geological Survey, 2020). The majority of transportation of CO_2 takes place in the United States, where more than 5,800km of dedicated pipelines are used to transport CO_2 between natural CO_2 sources (contained in geological CO_2 accumulations) and CO_2 injection sites for an oil recovery process called CO_2EOR (CO_2 enhanced oil recovery).

For smaller quantities of CO_2, road tankers may be considered a viable option. This is especially the case for locations with limited pipeline access, for industries that produce small quantities of CO_2, or, in the case of carbon capture, utilisation and storage (CCUS), where CO_2 consumers (such as medical industries and beverage manufacturers) only have a relatively limited demand for CO_2. For large scale CCS, the use of road tankers is not considered practical due to the scale of CO_2 production and large distances, often offshore, where CO_2 needs to be transported. An image of a small-scale road tanker is shown in Figure 20.

Figure 20: A road tanker for CO_2 transport used in the fertiliser manufacturing industry in Europe (Van Hool Road Tankers, 2021)

The Northern Lights Project, to be built on the Norwegian West Coast, will be the world's first full-scale CCS project, capturing CO_2 from cement and waste-to-energy industrial sources in the Oslo-fjord region. The project is unique because it will be the first in the world to ship CO_2 from industrial sources to the subsea storage site (Northern Lights CCS, 2021). It is expected that the project will be commissioned in 2024. A schematic of the main elements of the Northern Lights project is shown in Figure 21.

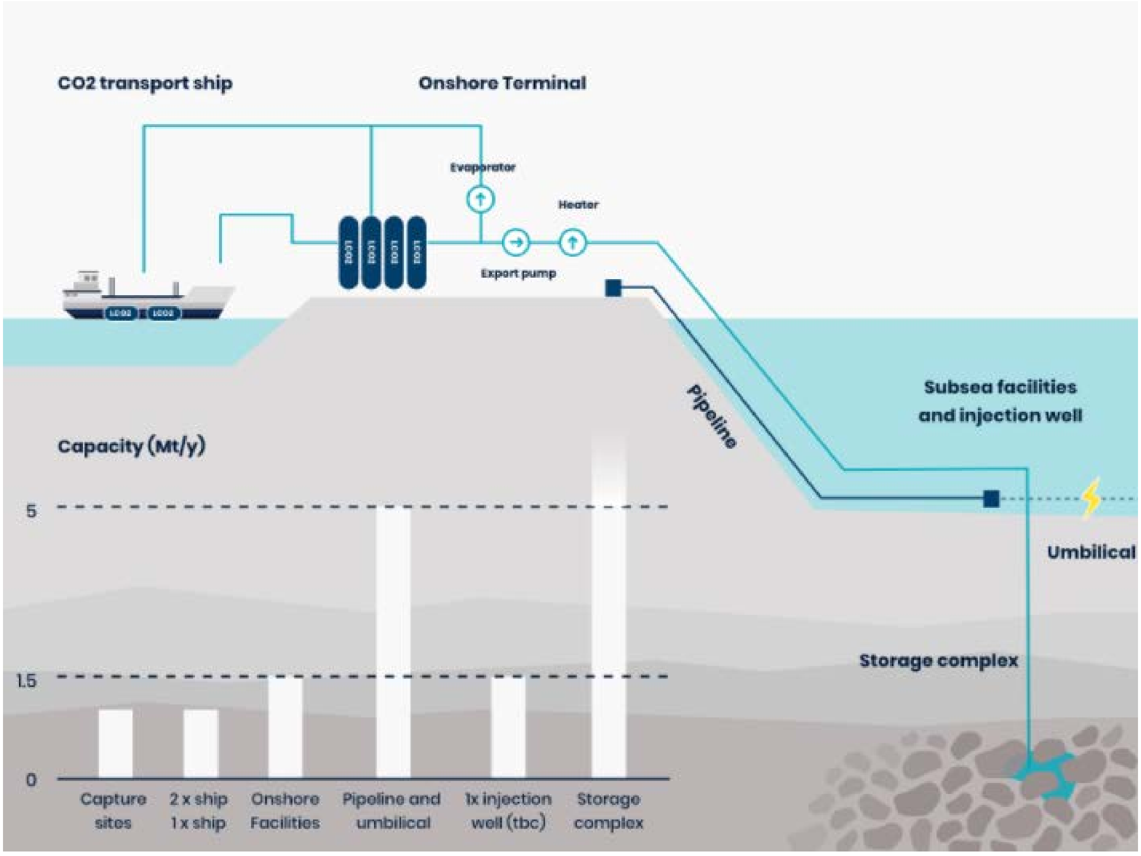


Figure 21: Overview of Northern Lights CCS project, note intermediate CO_2 storage at onshore terminal (Northern Lights CCS, 2021)

The final link in the CCS value chain, and the primary focus of this report, is the geological storage of CO_2 underground. Storage of CO_2 is a relatively straightforward process and can be summarised as injecting the CO_2 into an underground geological structure or structures (for example, saline aquifer or depleted natural gas field) where the CO_2 is permanently stored. Structures are chosen based on some basic geological requirements that include (Pale Blue Dot, 2016):

- capacity: sufficient CO_2 storage capacity for the duration of the project, ideally with contingency storage for future expansion or changes in market requirements
- injectivity: the ease by which CO_2 can be injected into the field. This depends on reservoir properties (for example, permeability or porosity) and the formation's ability to dissipate pressure through various subsurface mechanisms. These can be both chemical (for example, mineralisation) and physical (for example, plume migration or dissolution into formation brines)
- containment: the site must have suitable geological structures, including impermeable caprock and appropriate CO_2 containment or trapping mechanisms to ensure CO_2 remains within the desired geological location

Depending on the storage structure, the CO_2 may mineralise (become chemically integral to the surrounding geology), remain as a trapped plume contained in the pore space of the geological structure or be dissolved within saline brines that may exist in the formation. Significant effort is made to completely understand the formation within which the CO_2 is to be permanently stored. Indeed, as in the case with using depleted oil and gas reservoirs, an in-depth understanding of the storage formation may have been gained from many decades of hydrocarbon production. During injection and after the closure of the storage formation, the stored CO_2 and the decommissioned injection infrastructure (that is, the plugged injection well) continue to be monitored to ensure the following (Furre, 2017):

- conformance monitoring: ensuring the operator of the field understands the movement and migration of CO_2
- containment monitoring: ensuring and monitoring that injected CO_2 remains within the storage formation
- contingency monitoring: monitoring to ensure that the contingency measures designed to stop movement of CO_2 out of the storage formation are still functioning

One of the main components of a CO_2 storage project is the injection well. The injection well is the continuous conduit within which CO_2 is introduced into the subsurface. It is therefore relevant to explain the working principles of a CO_2 injection well and some of the potential leakage pathways for CO_2 in and around the well and its sub-components. A schematic of a typical CO_2 injection well is shown in Figure 22.

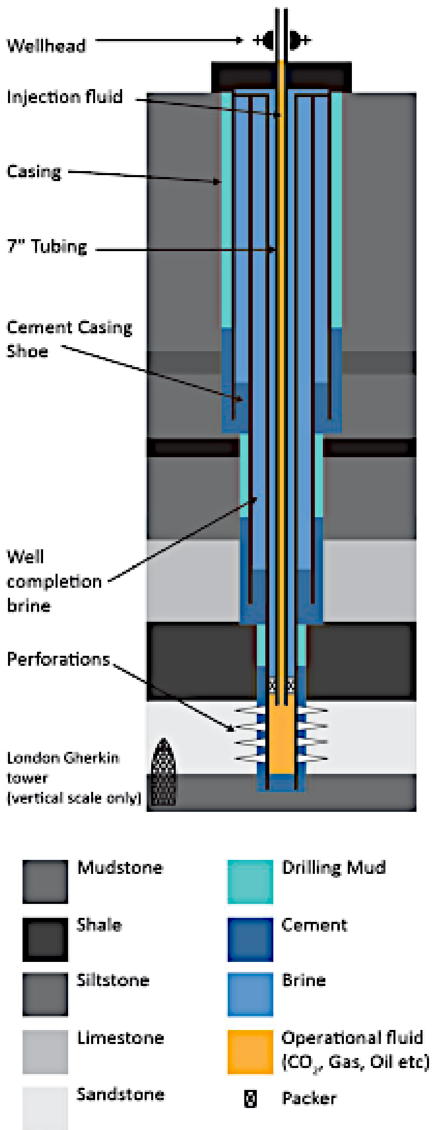


Figure 22: Schematic of a CCS injection well (Pale Blue Dot, 2016)

Wells have been drilled for a variety of purposes for a variety of industries, including geothermal, bore water abstraction, and for oil and gas production. The specific designs described here are taken from the oil and gas industry which largely operates as a surrogate supply chain for CCS. Oil and gas well construction is the closest comparator to CCS wells, with many regulations, standards and procedures for their design and completion conserved between the 2 industries.

In oil and gas production, wells are drilled and completed (the process of preparing a well for production) for a variety of reasons, including for oil and gas exploration, appraisal, production, injection of production fluids (including CO_2 in the case of CO_2EOR), and for monitoring. Wells are designed for their specific purpose and may involve complex downhole technology to benefit operations and monitoring. The complexities of subsurface reservoirs (or CO_2 storage structures) that wells target generally require some wells to be deviated and horizontal. The oil and gas industry has significant experience in completing wells that are nearly horizontal and highly deviated to increase contact with the subsurface storage structure. This is especially the case for Norway's Sleipner CCS project where the well curves up almost vertically to precisely inject the CO_2 into a saline aquifer.

Wells are typically drilled in sections using surface drillings rigs. These drill rigs use powerful motors that turn a 'bit', which impacts or grinds subsurface rock into small 'cuttings' that are lifted to the surface by precisely weighted circulating mud (slurry like material containing combinations of oil and clay or water and clay). The mud serves several purposes: 1) to convey cuttings away from the drill bit, 2) to cool the drill bit and formation, 3) to prevent inflow of well fluids (such as brines, and in the 'production zone', oil or gas), and 4) if installed, mud can be used to power downhole steerable drill bits.

Once a section of the well has been drilled, a steel casing (thick tube or pipe) is set in the wellbore with cement. The cement has several purposes: 1) it bonds the casing to the wellbore geology, making the well 'integral' with the wellbore, 2) it prevents flow of subsurface fluids (such as groundwater, or in the production zone, oil or gas or CO_2) to the surface, 3) it provides corrosion protection for the casing, and 4) if installed, it can contain well monitoring equipment like behind-casing fibre optic sensors. Depending on the design or purpose, the well may contain many sections of casing that progressively decrease in diameter along its length.

A well is taken as being completed once it has been drilled to its total depth (TD). This is typically at the point where the operator wishes (in the case of CCS) to inject the CO_2 into the formation. At TD, the completion is slightly different to the rest of the well. Here, a high velocity perforating 'gun' is used to conduct controlled blasting of both the completion (casing and cement) and the reservoir geology. The purpose of this process is to increase the injectivity of the well by forming fluid paths at right angles to the well and some depth into the formation.

At the end of the CCS project's life the well will be decommissioned and permanently sealed. Practices for decommissioning a CCS well vary depending on many factors, including regulatory jurisdiction, wellbore geology, well history (has it encountered any issues throughout its life) and many other factors. However, a basic method practised routinely in the United States for onshore CCS and CO2EOR wells is to remove all surface equipment, and plug the well with either a cement barrier or a retrievable/removable plugging material, although the former is more common. In some installations, surface equipment (such as well valving structures) may be left so that monitoring equipment can be installed in the future.

The offshore environment is more complicated, and global experience is limited to the Norwegian continental shelf, where only a handful of CO_2 injection wells have been decommissioned. In Norway, the regulator requires that the well is almost completely removed. That is to say, the injection well is firstly plugged with cement, the subsea injection infrastructure is then removed, and the casing is 'pulled' or removed above the plug to the surface (seabed). This leaves the seabed effectively rehabilitated to its original condition and prevents fishing trawler nets from inadvertently colliding with subsea infrastructure. Many oil and gas operators adhere to offshore standards applied in the Norwegian continental shelf due to their proven track record, perceived robustness and specific guidance to operators regarding well designs and completion. Adherence to these standards for offshore well decommissioning, especially in the North Sea, is very common.

Onshore UK decommissioning requirements are similarly defined, though largely untested for CCS due to a lack of onshore CO_2 storage projects. Operators of onshore wells are obliged to seal any permeable layers within the well (production zones for oil and gas, storage zones for CCS) and to fill the well with cement before cutting and removing steel well casing below ground level (Oil and Gas UK, 2018). The well is also required to be examined by an independent well inspector and the Health and Safety Executive before it is reinstated to its pre-operative state.

When a well fails, it is said to have lost its 'integrity.' The definition of well integrity is very specific as issues relating to well construction failures also manifest themselves in the oil and gas industry. Consequently, 'the Norwegian standard' NORSOK D-010 defines well integrity as:

"Application of technical, operational and organisational solutions to reduce risk of uncontrolled release of formation fluids throughout the life cycle of a well" are implemented (Norsk olje & gass, 2019).

Similarly, the International Standards Organisation provides its own definition that states (International Standards Organisation, 2017):

"Containment and the prevention of the escape of fluids (liquids or gases) to subterranean formations or surface."

A well may be considered to have lost integrity if one of the following observations are made:

- Through failure of various mechanical integrity testing techniques conducted downhole or through permanent monitoring such as behind casing fibre optic sensors or sustained casing pressure measurements at the surface.

- Through mechanical failure, whereby the effects of a well failure are realised at any point along the wellbore or at the surface.

Figure 23 below highlights where CO_2 could potentially migrate to the surface due to a well integrity issue from mechanical failure.

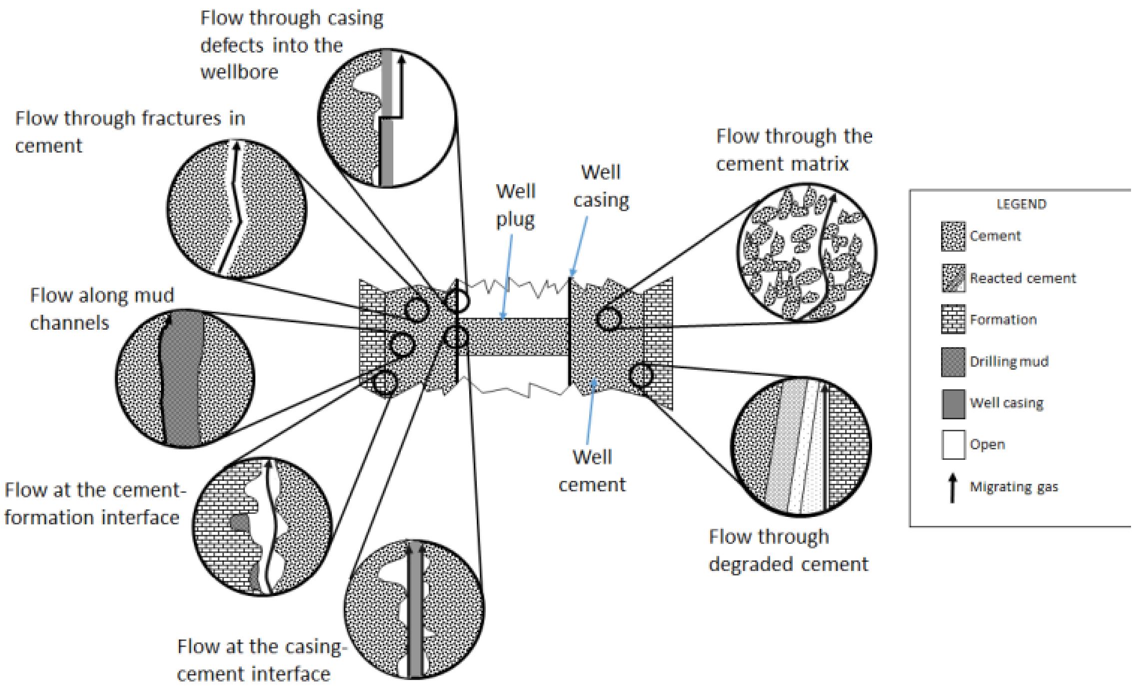


Figure 23: Schematic of potential well integrity issues for CO_2 injection wells (Sminchak, 2018)

Well integrity issues can happen for a variety of reasons. These issues can be due to poor well construction or through inappropriate operation of the well. The steel casing is a barrier between the wellbore fluids and the cemented annulus that bonds the casing to the wellbore geology. In CO_2 storage projects (or indeed in CO_2EOR operations), the casing is exposed to CO_2 and may even be exposed to formation fluids as is typically the case when a well is temporarily taken offline for maintenance. Exposure to wet CO_2 (that is where CO_2 is present with water) and corrosive formation brines (such as chlorides, hydrogen sulphide (H_2S)) can result in pitting of the casing, leaks between casing strings (collars) and other casing issues (Sminchak, 2018). Debonding of the cement and the casing can lead to the development of microannuli, which can form a conduit for well fluids, including CO_2. Casings may fail for a variety of reasons including:

- thermomechanical cycling: cyclical injection of CO_2 can cause the casing and cement to expand and contract and eventually debond, resulting in the formation of a microannuli (flowpath for CO_2)
- wear: tools and logging devices are frequently put into the well. After a well completion, various retrievable sensors and logging devices are put

downhole with a wireline to inspect the quality of the casing and cement. These tools are also run downhole throughout the life of the well. Running of tools downhole, and various other well ‘workover’ (remediation technology) techniques can cause wear to the casing, weakening its structure

- corrosion: when CO_2 comes into contact with water it forms corrosive carbonic acid. This acid can attack the mild steel alloy of the casing and reduce its strength (Figure 24). In many cases, where it is likely that the well environment will be corrosive, such as is the case with saline aquifer CO_2 injection, the last stage of the well in contact with water will be made with corrosion resistance alloys such as 13Cr (pronounced 13 Chromium).

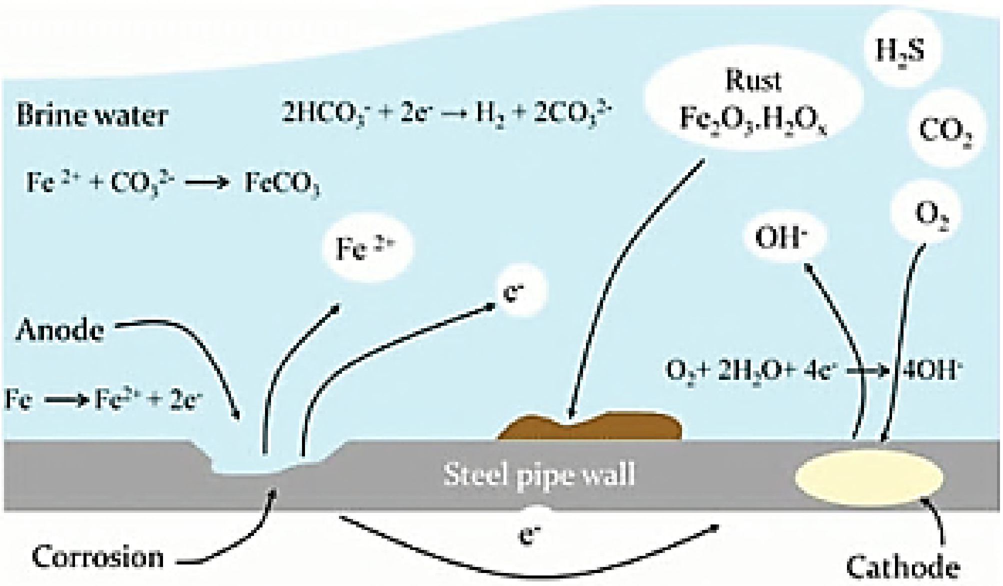


Figure 24: Illustration of corrosion mechanism for casing steel (Moreno, 2019)

The completion cement (typically Portland cement) is also vulnerable to attack by corrosive well fluids that are present downhole. Exposure to carbonate brines, and carbonic acid, results in the lowering of the cement pH. This results in cement carbonation where calcium (Ca), integral to the bond structure of cement, is leached out of the cement in the form of calcium carbonate ($CaCO_3$) (soluble in water). The gradual removal of Ca ions results in the reduction of the cement’s mechanical strength and can increase the matrix porosity even further, promoting increased rates of degradation. Nevertheless, investigations into the SACROC Unit CO_2EOR project, having been exposed to CO_2 and CO_2-saturated brines for over 30 decades, found that little degradation of Portland cements could be seen and steel casings showed similarly low levels of corrosion – all wells were found to have maintained their integrity (Carey, 2007).

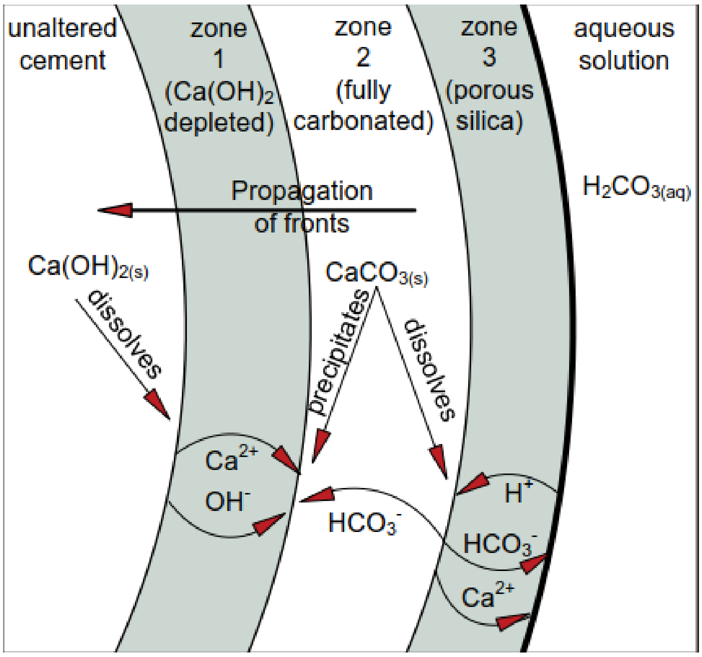


Figure 25: Illustration of cement degradation due to carbonic acid attack (Medimuric, 2010)

The failure of the completion cement can result in several well integrity issues that include:

- microannulus formation: this is where a small gap between the casing and the cement forms. The casing and the cement are considered to have debonded from one and other. Microannuli can be formed at the time of construction or during operation of the well
- cracking: through thermochemical cycling or geological movements the cement may fracture, forming conduits for fluid movement. Mining or construction of dams above the well may increase the lithostatic pressure and change the geomechanical forces on the well
- eccentering: this happens when the casing is not correctly centred within the borehole. Here the steel casing may be in direct contact with the wellbore geology with little or no cement to bond it. This typically leads to poor mud removal (during drilling and completion) and/or poor cement placement
- mud contamination and mud channels: as previously mentioned, during the construction of the well circulating muds are used. If the well is not properly cleaned before the cementing job, then mud may remain on the surface of the wellbore as a mud cake. When the cementing job proceeds, the cement does not correctly bond with the wellbore geology and this can lead to a leakage pathway being formed
- fluid/gas invasion: nearly all formations, saline aquifers or depleted gas fields will have resident well fluids of some nature. To prevent the inflow of wellbore fluids into the well during drilling, muds are used to maintain

pressure on the formation and formation fluids. During cementing of the well the ability for the cement to provide overbalanced hydrostatic head on the reservoir is diminished, and this could lead to potential ingress of fluids that could impact the integrity of the well through penetration or thinning of the cement job

Through many decades of experience, the drilling and wells completion industry, largely via knowledge gained in the oil and gas industry, has developed best practices, testing and remediation methods to ensure well integrity at all stages of the well's life.

A summary of the oil and gas industry's understanding of well integrity, including CO_2 injection wells, issues and how and why they occur is shown in the table below.

Well component	Integrity issue	Description	Causes	When	Leakage pathway
Casing	Thermo-mechanical cycling	Contraction and expansion of well casing	Differences between properties of materials	Construction, operation, workover, abandonment	Debonding along cement interfaces (microannulus)
	Wear	Wear to the casing	Casing interactions with wellbore and tools	After drilling, during workovers	Burst, collapse, holes in casing
	Corrosion	Corrosion of casing	Contact with corrosive fluids saturated with CO_2	Construction, operation, workover, abandonment	Pores in cement or along degraded cement at interfaces
Cement	Degradation	Dissolution or alteration of cement	Contact with corrosive fluids saturated with CO_2	Construction, operation, workover, abandonment	Pores in cement or along degraded cement at interfaces
	Microannulus and cracking	A small gap between casing and	Casing and cement debond, or	Construction, operation,	Along casing-cement interface

		cement and cracks in the cement	bond was never established or was broken	workover, abandonment	
	Mud contamination	Poor mud removal before cementing	Poor cement job design, poor hole cleanout	During construction	Along interfaces or through the bulk cement
	Eccentering	Casing is not centred in the borehole	Poor centralisation	During construction	Along casing cement, or mud interfaces
	Muds channels	Cement slurry fingers through the mud in the annulus	Poor cementing job design	During construction	Along mud channel interface or through flowing mud
	Fluid invasion	Invasion of fluids into cement	Poor cement slurry design and loss of hydrostatic pressure	During construction	Poor zonal isolation
Borehole wall (geological processes)	Formation lithology	Borehole breakout and drilling induced fractures	Induced stresses greater than maximum of the formation stress	During drilling	Poor cement bond to borehole wall
	Geomecha-nical stresses	Changes in stress field	Pressure gradient changes and creep	Construction, operation, workover, abandonment	Cement and casing damage or failure

Table 4: Known well integrity issues, their causes and CO_2 leakage pathways (Sminchak, 2018)

Sedimentary basins for CO_2 storage in the UK typically consist of one of two rock types, calcium carbonate limestones and sandstones. An appropriate storage formation consisting of either of these materials needs to have sufficient pore structure within which the CO_2 can be stored. Formations that are too 'tight', that is to say have very low porosity and/or permeability, are not likely to be successful candidates for an injection location.

While the formation might be seen as the 'sponge' in which the CO_2 is stored, the 'container' or containment vessel which keeps the CO_2 within the formation is the caprock. Caprock consists mainly of dense impermeable shales or mudstones or may be formed of precipitated salt layers. CO_2 is commonly injected as a supercritical fluid, which means sharing the density of a liquid and the viscosity or flowability of a gas. One of the critical factors for CO_2 storage in the UK being focused on the offshore environment is because these storage formation characteristics are also crucial to the containment of hydrocarbons like oil and gas.

Depleted oil and gas fields often provide excellent conditions for CO_2 storage. The rock properties are often well understood through years of hydrocarbon production. Storage is largely assured because of the presence of hydrocarbons and their successful containment over many millions of years. These types of reservoirs are also very well characterised through various seismic surveys (a way of understanding the subsurface) and downhole logging. These fields present themselves as ideal candidates in that very few unknowns need to be understood before designs for CO_2 injection can proceed. The storage mechanisms in depleted oil and gas fields are variable and depend on the condition of the field after production has ceased and what formation fluids (for example, oil, gas and brines) remain in place. Depleted oil and gas fields in the UK are typically located at depths of more than 2,000m (Pale Blue Dot, 2016).

The description of the CO_2 storage field refers to the initial state of the geological structure. A depleted hydrocarbon field has been subjected to intense subsurface activity over its lifetime. That is to say, once a field has ceased production it may be filled with all manner of fluids, including gases, brines, muds (from drilling operations) and intervention chemicals (corrosion inhibitors). The filling mechanism may be passive (in other words, the ingress of co-located reservoir brines moving to fill the voids made by gas and/or oil production) or active (whereby the operator has intentionally injected fluids into the reservoir as might be the case for produced water and treated seawater for reservoir pressure maintenance). A depleted oil or gas field may contain saline brines which interact in the same way as saline aquifers. Consequently, from the perspective of stored CO_2, differentiating storage formations without understanding the fluids occupying the pore volume may lead to inaccurate characterisation of the field. Operators developing CO_2 storage projects typically take both the geomechanics (nature of the rock and rock stress) and petrophysics (understanding of fluid interactions in the pore space) into account when designing a CO_2 injection project. The diagram below illustrates typical geological characteristics for a depleted gas field with potential for CO_2 storage.

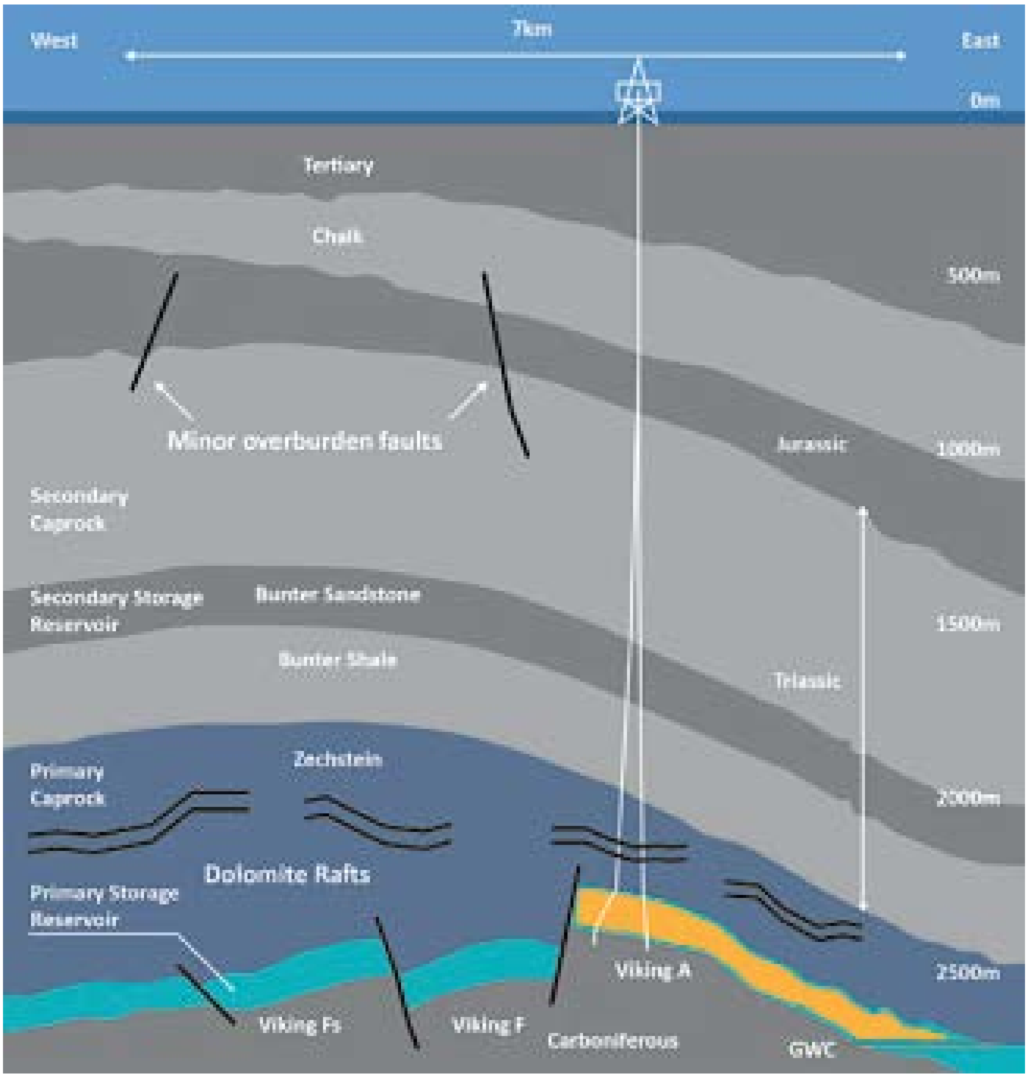


Figure 26: Viking depleted gas field in the Southern North Sea. Yellow indicates the potential storage formation. Rig not to scale (Pale Blue Dot, 2016)

The second type of CO_2 storage formation are saline aquifers. Unlike depleted oil and gas fields, saline aquifers have typically never seen production of their fluids. Contained in the pore structure of the aquifer are saline brines into which CO_2 dissolves. As the CO_2 dissolves into the saline brine, it gradually migrates away from the injection zone. Over time, saline brines may become saturated with CO_2 and/or CO_2 may interact with the surrounding geology and/or mineralise in situ.

Norway's offshore Sleipner CCS Project (Rose, 2018) is an example of a saline aquifer injection project. Saline aquifers have been less extensively drilled in the UK, but several have been surveyed and are well understood. Such is the size of the opportunity with saline CO_2 storage that this type of reservoir is expected to play an important part in the future UK CO_2 storage industry (Pale Blue Dot, 2016)(Figure 27). Saline aquifer depth can vary, and in the UK, they are present at a variety of depths, from relatively shallow formations 1,200m deep (some onshore aquifers are as shallow as 700m), to significantly deeper, 3,000m, formations seen in the Forties sandstone. Characterisation of the appropriateness of UK onshore saline aquifers for CO_2 storage is very limited. Again, the focus of the industry indicates offshore opportunities might be preferred.

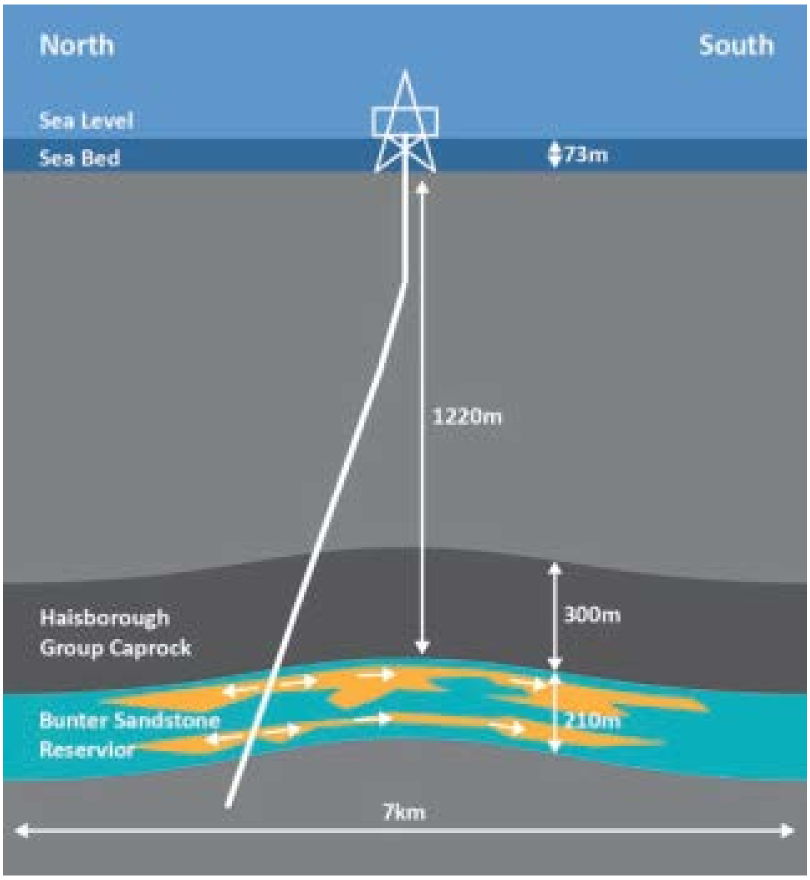


Figure 27: Bunter Closure 36 saline aquifer dome in the Southern North Sea. Yellow indicates the potential storage formation. Blue indicates saline fluids. Rig not to scale (Pale Blue Dot, 2016)

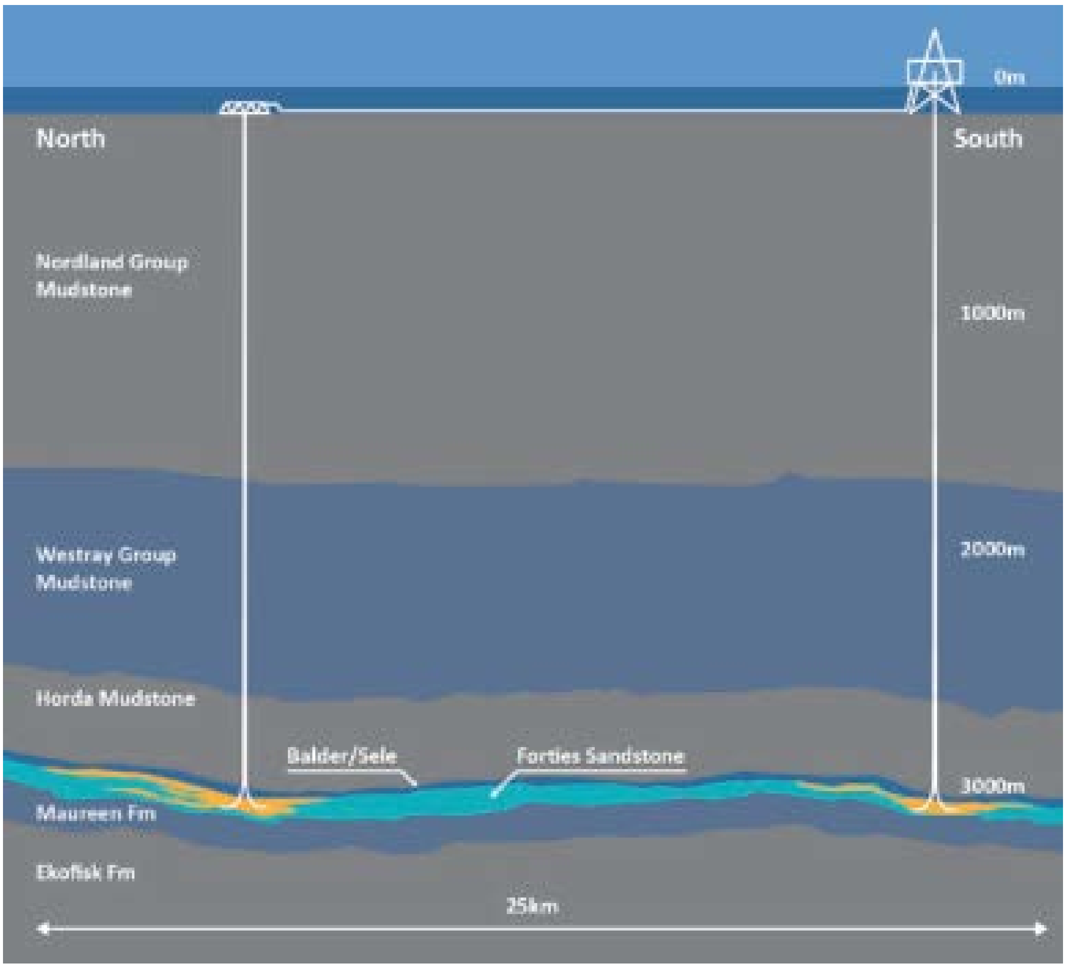


Figure 28: Forties 5 sandstone aquifer covers over 20,000km^2. Yellow indicates the potential storage formation. Blue indicates saline fluids. Rig and subsea topsides not to scale (Pale Blue Dot, 2016)

Successful storage of CO_2 in a storage formation involves several mechanisms that combined or, in some geological settings acting separately, ensure the CO_2 is contained. Some of these mechanisms are seen immediately after the CO_2 is injected, others may occur over longer timeframes. The 5 mechanisms that retain injected CO_2 in the storage formation include (Pale Blue Dot, 2016):

- low velocity trapping: as CO_2 moves within the pores of the formation, small volumes of residual CO_2 are left in the pore space. Continuous deposition of CO_2 in the pores reduces the size of the mobile CO_2 plume front, thereby reducing the velocity of the plume to less than 10m a year – a point at which the CO_2 is considered to be trapped in terms of emissions
- residual trapping: is where residual CO_2 left in the pore structure of the storage formation becomes a gaseous bubble that is stranded in the formation. Over time, the gaseous CO_2 can then dissolve into formation brines

- buoyant trapping: occurs when the CO_2 migrates to the top of the storage formation and is trapped by the caprock under pressure from the formation brine or aquifer below. If correctly designed, the storage formation will not have an alternative flow path for the CO_2 and it is considered trapped
- solution trapping: is particularly relevant for UK storage projects and results in the stranding of small CO_2 bubbles within the formation brines (present in depleted hydrocarbon fields or saline aquifers). Over time, the CO_2 gradually dissolves into the brine to the point where the brine becomes saturated. The saturated brine has a higher density and sinks to the bottom of the storage formation. In this form, the CO_2 is considered trapped from the perspective of atmospheric emissions
- mineral trapping: saturated brines with dissolved CO_2 have a low pH and consequently are able to react with the formation. In many cases, this causes the CO_2 to come out of solution as precipitate, effectively making the CO_2 integral to the formation geology. This process may take place over many thousands, if not millions, of years

There are many final storage mechanisms for CO_2 injected into a depleted hydrocarbon field or a saline aquifer. The interplay of these mechanisms and the progression of mechanisms over a large geological timeframe is likely to mean that potential environmental impacts through well or caprock failure could be quite diverse and may vary in scale. Such factors are further described in the environmental impacts section (Section 5). In the later stages of CO_2 demobilisation where solution brines react with the surrounding geology, the need for containment and caprock integrity becomes less important. The reverse is true for early stage injection projects or those that rely on buoyant trapping or low velocity trapping mechanisms.

Onshore CO_2 storage seems unlikely in a UK context. The UK's oil and gas production has been dominated by over 5 decades of offshore exploration and development activity. There are a small number of onshore sites in England, predominantly in the south and in the Midlands (Krevor, 2016), where CO_2 injection might be considered. However, there has been no meaningful analysis of these sites or suggestion that they may be developed in the future.

4. Status of low carbon subsurface industries

4.1 Energy extraction and production

In the UK, ‘deep geothermal energy’ refers to resources derived from depths greater than 500m (British Geological Survey, 2021). The UK possesses relatively limited high temperature geothermal resources. However, there is good potential for using low temperature geothermal resources for direct heating/cooling applications in several high population density areas. These areas have high demand, and geothermal development has the potential to contribute significantly to the decarbonisation of the energy mix. The experience from other European countries shows that the success of geothermal development is closely linked to the government’s commitment to support the development of technologies through policies and incentives (Abesser and others, 2020).

The use of ground source heat pump (GSHP) technology has been expanding rapidly in the UK in recent years (Banks and others, 2019). However, the geothermal resources in the UK are still underused (Batchelor and others, 2020). With the increasing need to decarbonise the UK's heating sources, more direct use applications for space heating/cooling are expected through the development of district heating schemes (Figure 29).

The UK has set ambitious targets in order to harness its geothermal resources. For example, the Department for Business Energy and Industrial Strategy (BEIS) has allocated £25 million in funding to the Heat Networks Investment Project to support a variety of research projects into geothermal heating of homes (Triple Point Heat Networks, 2020). Third-party companies are currently employed to carry out feasibility studies, reviews on costs and returns, technological development and innovation on methods of extraction. The economic viability of these projects largely depends on being able to sell the heat. However, combined heat and power systems are being considered to provide a viable business case (Batchelor and others, 2020).

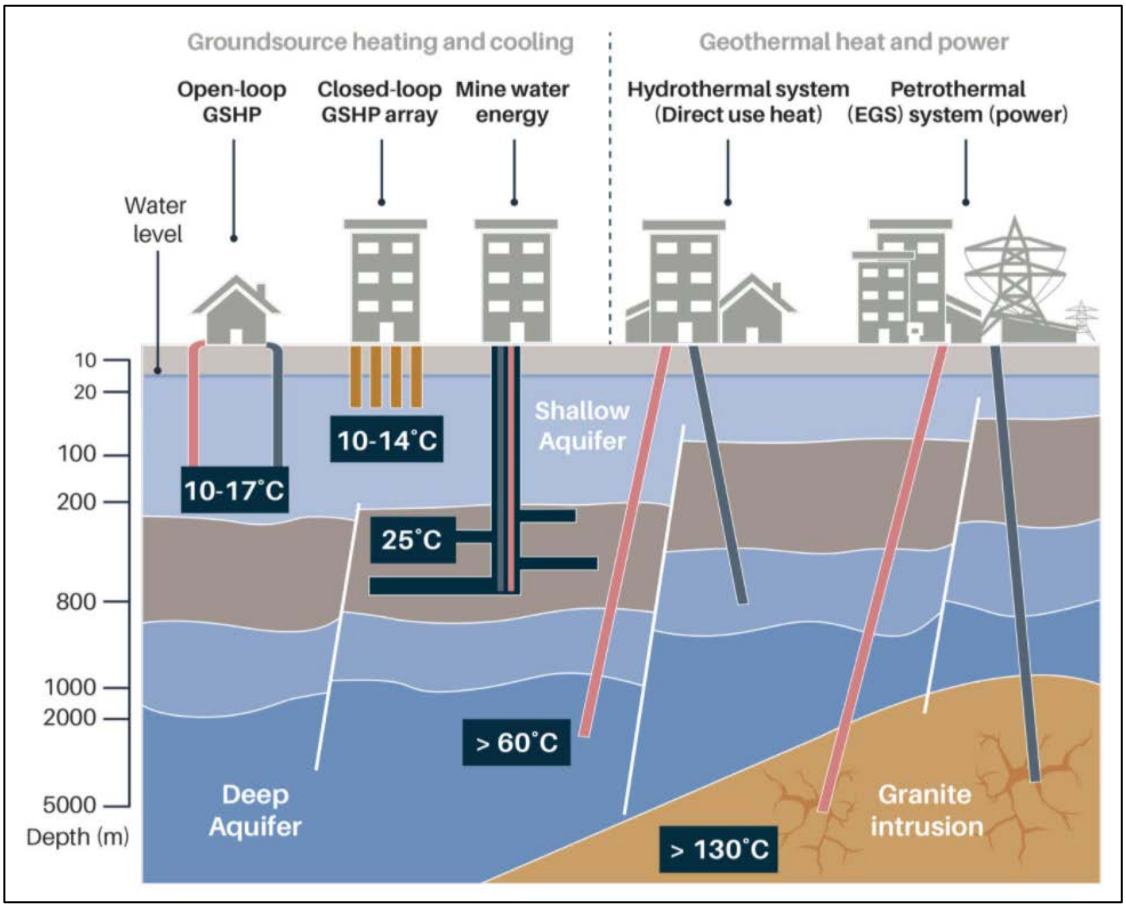


Figure 29: The various options regarding geothermal energy extraction (Abesser et al., 2020)

At present within the UK, there are several deep aquifer, mine water, deep borehole heat exchanger systems (DBHE) and enhanced geothermal systems (EGS) projects, at various stages of testing and development (Batchelor and others, 2020). The current research in the UK is largely concentrated on developing the potential of less conventional resources as deep hot sedimentary aquifers are only found in a few regions and often not in regions of high heat demand (Batchelor and others, 2015).

The following sections provide an overview of the status of the geothermal industry, with a focus on the UK and some examples from outside the UK as appropriate.

4.1.1 Mine water resources

Mine water heat schemes have been operational since the 1980s in Nova Scotia, Canada (Jessop, 1995). The first trials for operational schemes in Scotland were carried out in the early 1990s in Shettleston (Glasgow), shown in Figure 30, and Cowdenbath (Fife). Although the first project was successful, the second project failed as a result of chemical clogging in the heat exchangers (Banks and others, 2009). More recently, feasibility studies into the potential of abandoned coal mine workings have been funded in Scotland and Wales (Harnmeijer and others, 2017). One of the two UK Geoenergy Observatories (GEOS) located in Glasgow specifically aims to research the viability and impact of mine water heat technology (Monaghan and others, 2018).

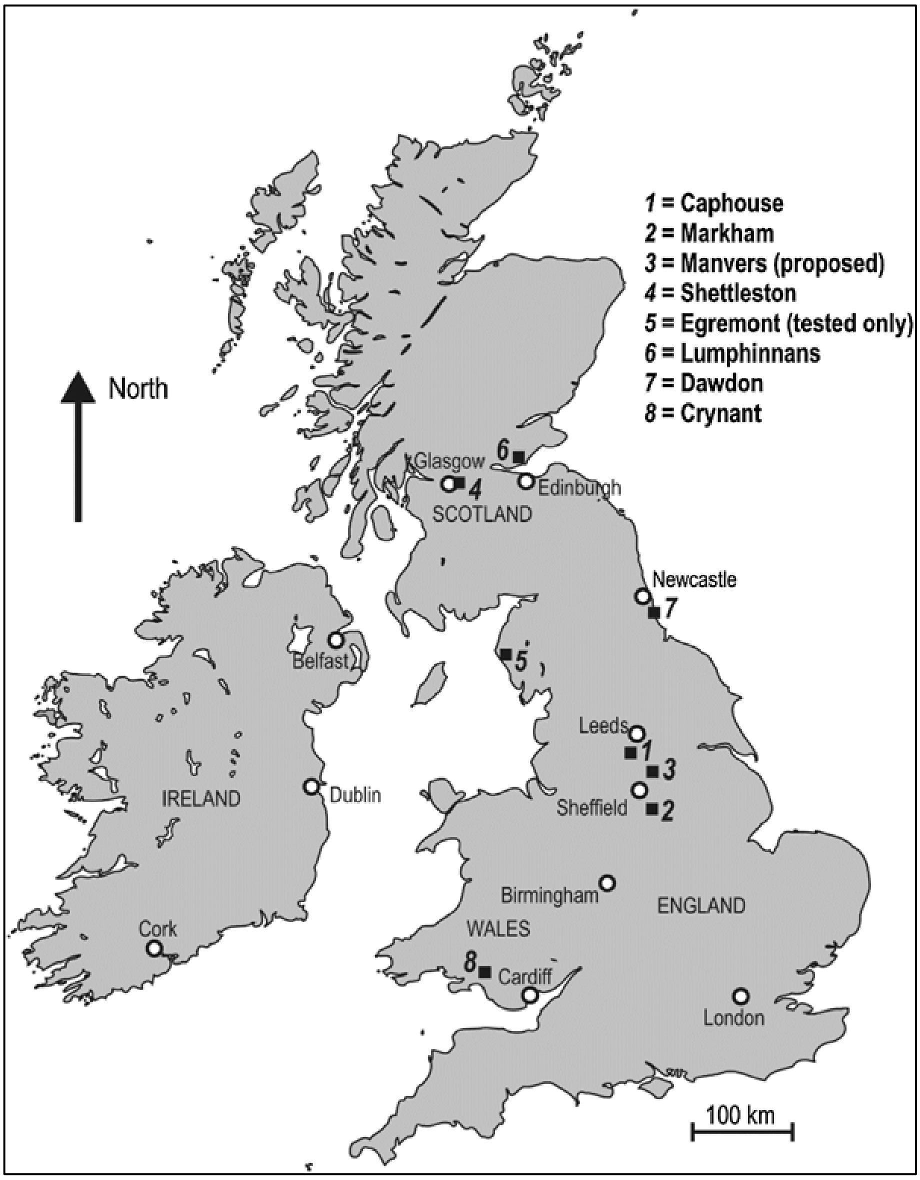


Figure 30: Overview map of Britain and Ireland, showing mine water heat pump schemes. The Egremont setup is based on an ironstone (haematite) mine, while the rest are coal mines (Banks and others, 2019)

Pilot heat pump schemes have been installed at 2 former collieries in England (Banks and others, 2019). The Caphouse Colliery site, Yorkshire includes an open-loop mine water system with disposal to a treatment lagoon and a closed-loop system installed in a mine water treatment pond. In the open-loop system, mine water is pumped through a heat exchanger coupled to a 10.5kW heat pump used to provide space heating to a museum, and then discharged to waste. The closed-loop heat exchanger submerged in an aeration pond also provides energy to the heat pump at any time of the day.

At Markham Colliery, near Bolsover, Derbyshire, a standing column arrangement is used to pump a small volume of the 14°C mine water from depth in the flooded Markham No. 3 shaft (Figure 31) (Burnside and others, 2016). In the Markham open-loop GSHP system, the water circulates through a heat exchanger coupled to a heat pump and is then returned to the same mine shaft at a slightly different depth (Banks and others, 2019). In general, shallow wells with resource temperatures significantly below 150°C can be used directly for domestic hot water or for district heating systems. If the ground temperature is less than 25°C, an electric heater or heat pump is required to raise the temperature (Al-Habaibeh and others, 2018).

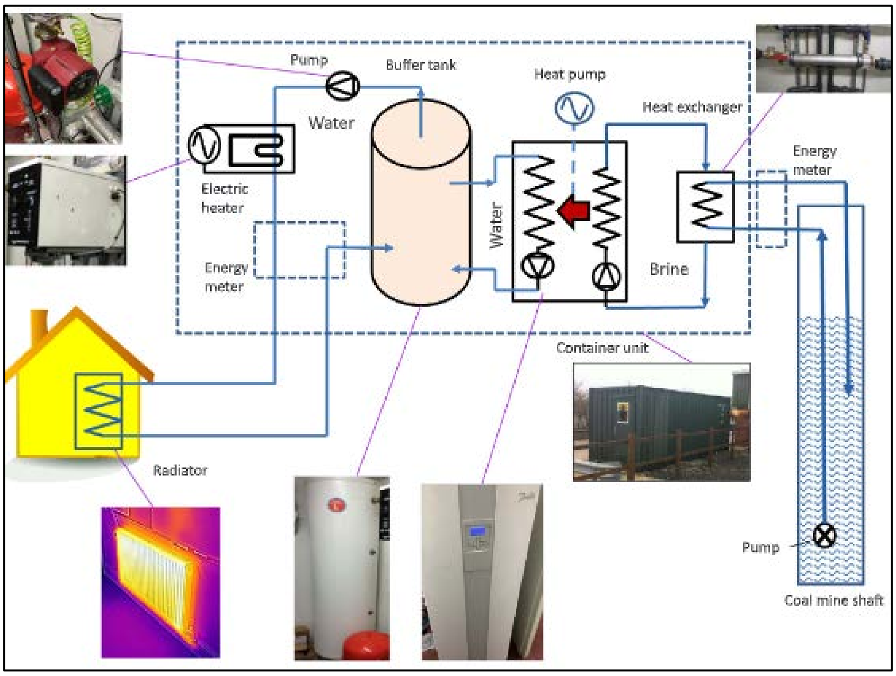


Figure 31: Schematic of the considered open-loop GSHP system for heating applications from flooded-mine shafts in Markham, UK (Al-Habaibeh and others, 2018)

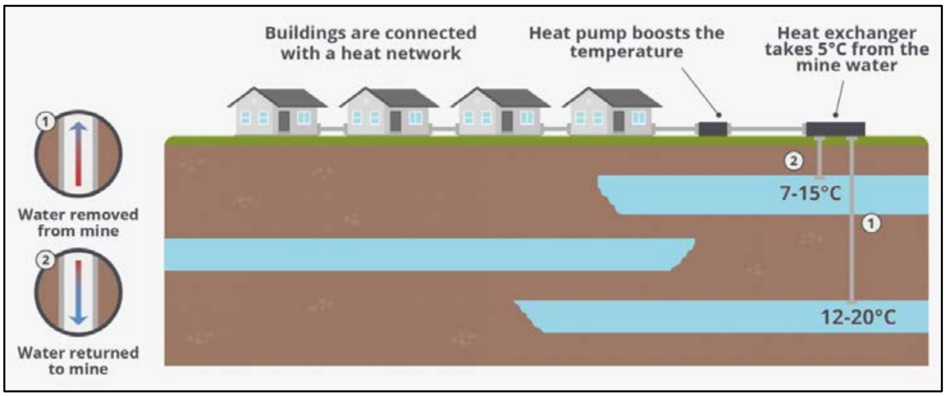


Figure 32: Infographic demonstrating the potential use of mine water to heat buildings and homes (BGS Press, 2020)

The possibility of using mine water heat from flooded abandoned coal and metal mines has seen an increase in interest in recent years in the UK and forms an important part of the work into the UK's geothermal resource. One mine water-based district heating network, at Shettleston in Scotland, has been operating since 1999 (Banks and others, 2009). This project serves 16 two storey houses and 2 three storey flats and is based on mine water from flooded coal mine workings in the Glasgow Ell Seam beneath the site. This is abstracted via a borehole approximately 100m deep, where mine water at 12°C is circulated through a water-to-water heat pump. This heats water to 55°C which is output to an insulated thermal storage tank, with heating supplemented by a side loop of solar collector panels. Wastewater from the system is discharged below the water table via a shallower reinjection borehole, at 3°C (Banks and others, 2009; Energy and Climate Change Directorate, 2013).

Currently, the Coal Authority is developing the heat resource from 16 existing mine water treatment schemes, and these are at various stages of development. In 2020, the Seaham Garden village in East Durham was established, with the aim of using the 20°C mine water pumped at the nearby Dawdon Mine Water Treatment Plant as a low carbon energy source for the first large-scale mine energy district heating network in the UK (Rattle and others, 2020). This water is currently abstracted at a rate of 100 to 150 l/s, cleaned and discharged into the sea, but has the potential for 6MW of low-cost energy available for space heating and domestic hot water throughout the year (RPS, 2021).

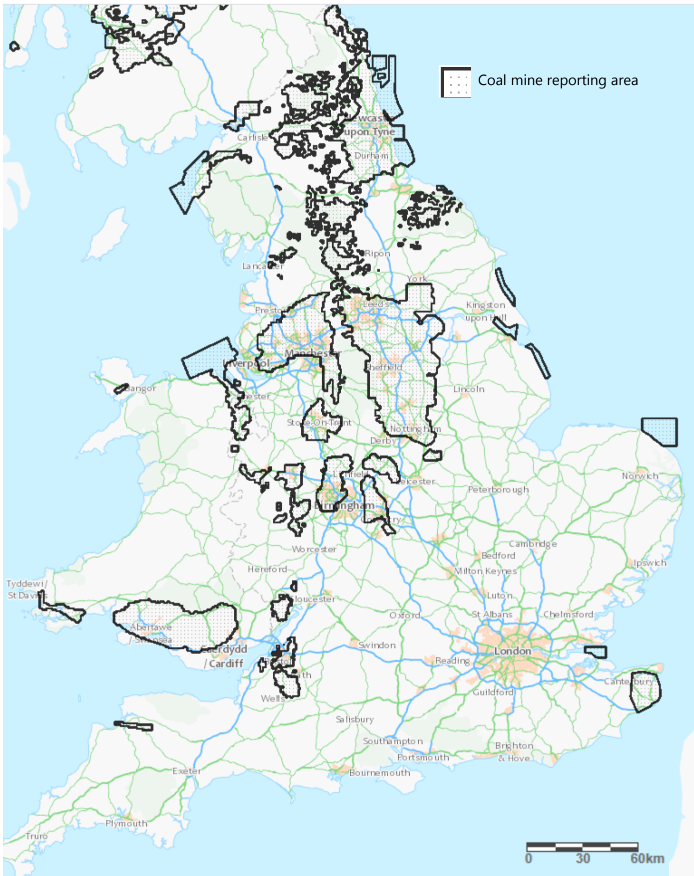


Figure 33: Map of coal mines in England (adapted from (The Coal Authority, 2020))

In South Wales, Bridgend Council has started drilling into inactive coal mines in the Llynfi Valley, with the intention of heating more than 200 homes. The British Geological Survey (BGS) is also developing a new geothermal research facility over former coal workings in Glasgow (UKGEOS). As part of the D2GRIDS European project launched in 2019, 2 pilot mine water-based sites will be installed in the UK, in Glasgow and Nottingham, based on the successful mine water development at Heerlen in the Netherlands (Batchelor and others, 2020).

4.1.2 Hydrothermal resources

Aquifer-based hydrothermal schemes extract heat from groundwater sourced from deep onshore sedimentary basins. In the UK, Permo-Triassic sandstone aquifers (for example, Sherwood Sandstone) located in Mezosoic basins (the Wessex and Worcester basins in southern England; Cheshire Basin in north-west England; eastern England; Larne and Lough Neagh Basins in Northern Ireland) between 1 and 3km depth have been shown to have geothermal potential. These aquifers typically have a resource temperature of 40 to 60°C. The main Mesozoic basins are shown in Figure 34, with a summary of the calculated resources from each in Table 5.

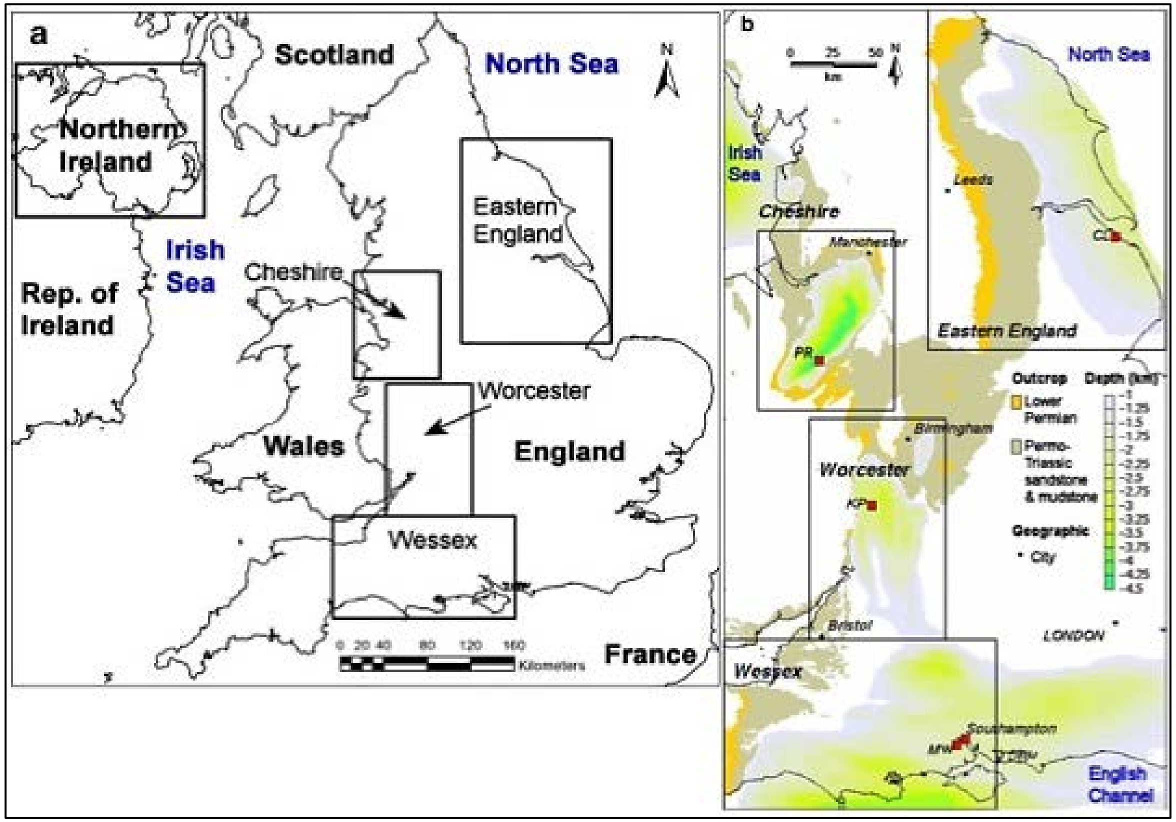


Figure 34: Main Mesozoic basins within the UK- (a) general location map of the eastern England, Wessex, Worcester and Cheshire Basins in England (and partly Wales) shown with depth to base of the Permo-Triassic sandstones. Red squares are deep boreholes referred to in the text: CL Cleethorpes; KP Kempsey; LA Larne No. 2; MW Marchwood; PR Prees; and Southampton) (Busby, 2014)

Basin	Aquifer	Area (km^2)	Geothermal resource (at >40°C, EJ)	Identified resource (EJ) reject temperature 25°C, recovery factor 33%	Maximum temperature (°C)	Maximum thermal store (GJ/m^2)
Eastern England	Triassic Sherwood Sandstone	4,827	122	24.6	65	60
Wessex	Triassic Sherwood Sandstone	4,188	27	6.5	95	18
Worcester	Triassic Sherwood Sandstone	500	8	1.5	55	35
Worcester	Permian Collyhurst Sandstone	1,173	60	11.8	65	110
Cheshire	Triassic Sherwood Sandstone	677	36	7.6	80	75
Cheshire	Permian Collyhurst Sandstone	1,266	38	9.1	100	60
Northern Ireland	Triassic Sherwood Sandstone	1,618	35	4.7	60	25
Total			**326**	**65.8**		

Table 5: Summary of the UK's low temperature hydrothermal resources exceeding 40°C (Gluyas and others, 2018). EJ is exajoule (10^{18} joules).

In deeper Upper-Paleozoic basins, rocks are generally of lower permeability and groundwater flow is fracture-dominated (Busby, 2014). The presence of warm springs at Bath, Bristol and south Wales (Darling, 2019) and in the Peak District around Buxton (Brassington, 2007) indicate the presence of deep fracture flow in the Carboniferous limestone aquifer. In the Eastern England Basin (see Figure 34(a) above), the presence of a pronounced thermal anomaly also demonstrates the existence of groundwater flow at depth, below the shallow productive sandstone aquifer (Busby, 2014). The main lateral equivalent of the Carboniferous limestone in northern England is the Fell sandstone, found at a depth of 1.7km north of Newcastle-upon-Tyne. Within fractured limestone intervals over parts of southern England, south Wales and northern England, measured temperatures reach 80°C, with temperatures expected to reach 140°C around Manchester (Busby, 2010; Busby, 2014).

To date, only basins in the south and north-east England have been drilled for geothermal utilisation. Temperatures observed across the UK are below the economic threshold for conventional (steam turbine) power generation of 160°C. However, as long as rock permeability is sufficient to allow groundwater flow, a doublet system down to depths of 5km or deeper could be used to provide heat for direct-use space heating as well as for a variety of heat-intensive industrial processes and agricultural applications. The organic Rankine cycle technology may play an important role in enabling electricity production in these low temperature basins (section 3.1.3).

Projects for the direct use of heat in the UK include the following:

- The Southampton District Heating Scheme: This was the first geothermal power scheme and has been in operation since 1986. It remains the only significant exploitation of low temperature geothermal energy (Batchelor and others, 2015). The scheme draws water of 76°C from the Wessex Basin aquifer (Triassic sandstone) at a depth of 1,800m. This is then used together with conventional boilers in a large-scale combined heat and power plant to provide heating for 3,000 homes, 10 schools and several commercial buildings, including the city hall, supermarkets, a leisure centre and Southampton port.
- Bath hot springs: Recent refurbishment of the Bath hot springs tourist attraction consists of a cascaded flow from the hot springs into the thermal spa waters, and also provides space heating for a new underfloor installation near Bath Abbey (Batchelor and others, 2020).
- North-east England exploration drilling: In 2004, an exploration borehole was drilled at Eastgate in Weardale, County Durham, down to a depth of 998m (see Table 6) (Watson and others, 2019b). This well encountered the naturally fractured Weardale granite, with a bottom hole temperature of 46°C, indicating a heat flow of $115mW/m^2$. This initial well produced saline water at a temperature of 27°C from a depth of 411m at a rate of $140m^3/h$ (39 l/s) per metre of drawdown.
    - This was followed by the drilling of an appraisal well in 2010 that proved the granite to be impermeable, with fractures limited to the vicinity of a major fracture in the granite, known as the Slitt Vein (Watson and others, 2019b).
    - The 1,800m 'Newcastle Science Central' deep geothermal exploration well was subsequently drilled in the city centre of Newcastle-upon-Tyne in 2011, down to the Lower Carboniferous

Fell Sandstone Formation (Watson and others, 2019b). It aimed to use geothermal energy from 2,000m below the city to supply hot water to the city at a temperature of 80°C (Curtis and others, 2005). Although this well confirmed the high regional geothermal gradient and demonstrated the geothermal potential across the region, it also proved the low porosity and permeability of the Fell Sandstone in this locality, meaning that water could not be extracted at viable rates (Younger and others, 2016).

- Manchester residential heating: Set up initially by GT Energy, the Manchester scheme aims to supply heat to an equivalent of 8,000 homes by harnessing heat from the Carboniferous limestone of the Cheshire Basin (Busby & Terrinton, 2017). In December 2012, the Manchester project received its ground investigation consent (GIC) from the Environment Agency, which was followed by the granting of a 24-year water abstraction licence. In 2020, it was announced that IGas had purchased GT Energy UK. While there is little public information on the current plans that IGas has for the geothermal project, the news release concerning the acquisition does refer to an ongoing ambition to set up the UK's first-ever low carbon heat network system on this large, city-wide, scale.
- Funding for a £52 million district heat network (DHN) was granted to Stoke-on-Trent City Council, which secured part funding of £19.75 million of government sponsorship in 2014 (Corrigan, 2017). The DHN, initially due to provide green heating to thousands of homes and business in 2018 has been delayed, partly due to the uncertainty over the location of existing underground utilities (Corrigan, 2020). Once the initial scheme is operational, buildings will be connected to a network linked to a geothermal plant that aims to produce 45GWh a year of sustainable heat energy (Corrigan, 2017; Clark & Clegg, 2014). The 14MW power plant will be operated by GT Energy, who is investing £18 million for the retrofit of the Stoke-on-Trent district heating network (Townsend and others, 2020). Under the current timetable (early 2021), it is anticipated that drilling and testing could commence by the end of 2021, with the installation operational by March 2022 (Richter, 2020).

Hydrothermal research projects include:

- exploiting the permeability of deep fracture systems as viable geothermal resources (Glasgow University)
- exploring the extent of palaeo-karst within the buried Carboniferous limestone and its geothermal potential (Durham University)

The table below highlights some significant hydrothermal and petrothermal projects mentioned above.

Location	Completion	Well depth (m)	Bottomhole temperature (°C)	Main aquifer depth (m)	Aquifer temperature (°C)

Rosemanowes RH11	December 1981	2,175	90	2,100	55 – 70
Rosemanowes RH12	October 1981	2,143	90	Not identified	N/A
Rosemanowes RH15	January 1985	2,652	100	Not identified	N/A
Marchwood	February 1980	2,609	88	1,672 – 1,686	74
Larne	July 1981	2,873	91	960 – 1,247	40
Southampton	November 1981	1,823	77	1,725 – 1,749	76
Cleethorpes	June 1984	2,092	69	1,093 – 1,490	44 – 55
Eastgate-1	December 2004	995	46	411	27
Eastgate-2	July 2010	420	-	Not present	No flow
Science Central	July 2011	1,821	73	1,418.5 – 1,795	No flow
United Downs	Drilling	2,500 / 4,500	190 (est.)	4,500	190 (est.)
Jubilee Pool, Cornwall	2018	400	35	400	35

Table 6: Summary table of deep hydrothermal and petrothermal boreholes drilled in the UK for geothermal exploration purposes (Watson and others, 2019b)

4.1.3 Petrothermal resources

Medium to high-temperature resources in the UK are limited to areas where the presence of radiogenic granites has resulted in increased heat flows, for example, in Cornwall, the Lake District region, Weardale and the East Grampians of Scotland (Figure 35). In the Lake District, for example, heat production averages 3.06μW/m^3 at 5,000m and, in Cornwall, heat production from the rock averages 4.6μW/m^3. In these areas, the temperatures at economically drillable depths (around 5,000m) are high enough for power generation with binary cycle power plants or for industrial and residential (direct-use) heating.

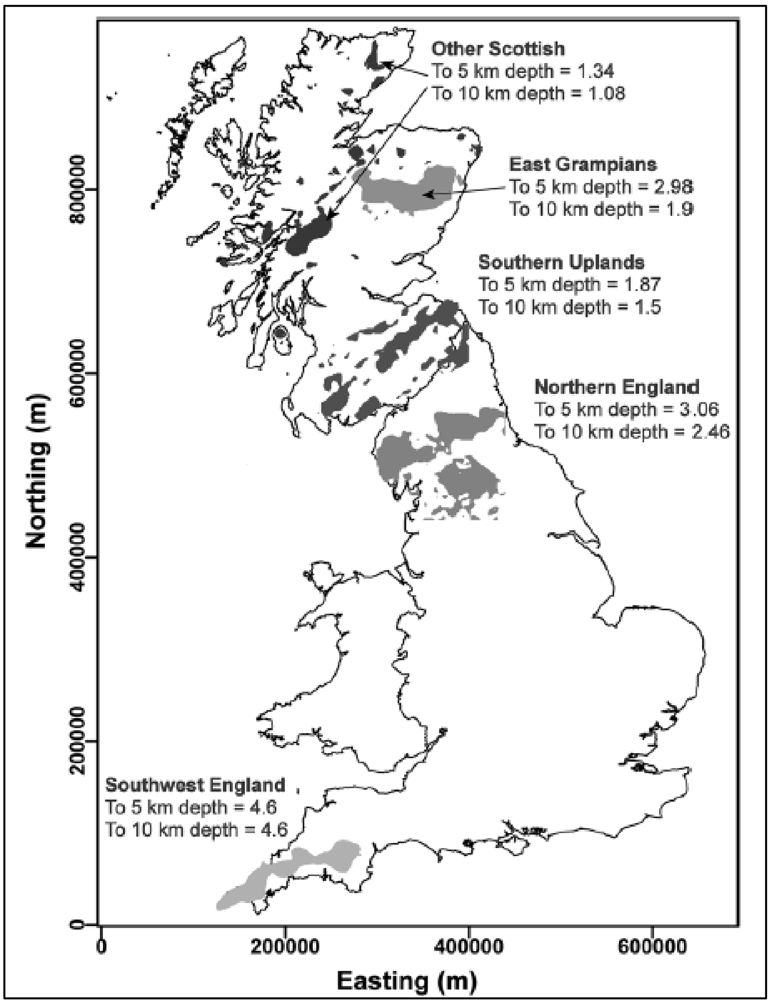


Figure 35: Locations in the UK where significant quantities of heat producing granites exist within the upper crust. Quantitative figures of average heat production in μW/m^3 are given for 5,000 and 10,000m depths respectively (Busby & Terrington, 2017)

To date, the most significant petrothermal development has been the completion of the drilling phase of the United Downs Deep Geothermal Power project (UDDGP) run from 2009 to the present day on the site of the previous hot dry rock (HDR) programme near Redruth in Cornwall (1977 to 1991). The UDDGP project is the first commercial geothermal power plant in the UK, partly funded by the European Regional Development Fund (£1.475 million in 2009) and Cornwall Council (Ledingham and others, 2019), and is run by Geothermal Engineering Ltd (Batchelor and others, 2020). Drilling and completion of the 5,200m deep production borehole UD-1 and the 2,500m (measured depth) injection borehole UD-2 were carried out between 2018 and 2020 and are currently being hydraulically tested (Environment Agency pers. comm.). The project aims to supply 3MW of renewable electricity and heat via a binary power plant.

In addition to the United Downs project, the Deep Geothermal Challenge Fund, established by the Department for Business, Energy and Industrial Strategy (BEIS) has provided more than £4.5 million in grants to support the development of other deep enhanced geothermal systems (EGS) projects (Lu, 2018). This includes the Eden Project near St Austell, Cornwall (£2.01 million in 2009), located on the former Rosemanowes EGS site.

The Rosemanowes project initially ran between 1977 and 1991 but failed due to an unsuccessful attempt at performing hydraulic stimulation (Lu, 2018). In December 2010, the follow-on Eden Project was given permission to build a petrothermal geothermal plant that aims to produce 3 to 4MW of electricity for use by the Eden Project, with a surplus going into the National Grid. The initial project comprises 2 wells drilled down to 4,500m in granite, to obtain a downhole temperature of at least 175°C (Curtis and others, 2013). As of May 2021, the Eden Geothermal project stated that the drilling of various wells has commenced, with a total depth (TD) of over 800m already drilled (Eden Geothermal, 2021).

In 2017, Busby and Terrington published a new assessment of the resource base for EGS systems in the UK (Figures 35 and 36). The authors estimated that within the current technical limitations, the technical potential power that could be utilised by EGS technology in the UK to a depth of 6,500m is 222,393 MWe.

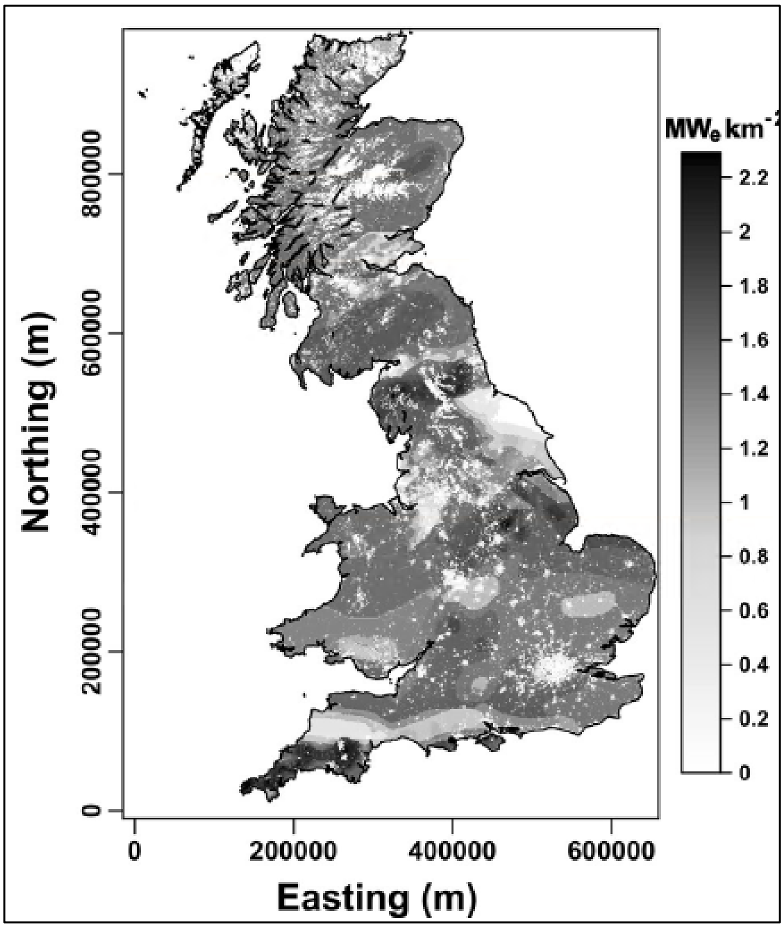


Figure 36 Technical potential power density across the UK for the depth range of 3,500 to 6,500m. Areas with zero potential are mainly excluded as a result of land cover comprising urban settings and mountains (Busby & Terrington, 2017)

Feasibility studies to consider the potential for further suitable EGS sites in Cornwall are already underway. The Natural Environment Research Council funded GWatt (Geothermal Power Generated from UK Granites) project has been established to explore the potential for deep EGS systems based on fracture networks in the UK granites (Rochelle and others, 2020).

A review of deep geothermal energy in the UK, focusing on the potential for heat production, was presented at the European Geothermal Congress in 2019 (Watson and others, 2019a). This review highlights the possibility of using deep geothermal single well (DGSW) systems to supply heating to district heating networks from low temperature geothermal energy. Geothermal Engineering Ltd and Arup in an attempt to overcome barriers linked to conventional geothermal systems in the UK (i.e., exploration risk, capital project cost, geographical reach, induced seismicity risk, proximity of heat demand).

DSWG field tests were performed in an existing deep well near Rosemanowes in Cornwall in 2014 (Collins & Law, 2017) using a deep co-axial heat exchanger (Watson, et al., 2019b). The co-axial system is formed of a single wellbore structured to form a centred outlet and an annular inlet as shown in Figure 37 and Figure 38. The DGSW was installed in an existing 2,600m deep well, which penetrates the granitic rock in Cornwall, drilled in the 1980s as part of the HDR project (Collins & Law, 2017).

Heat can be provided by a monovalent system where the DGSW is the sole source of heat or a bivalent system where gas-fired boilers provide supplementary heat. Based on a delivery temperature of 69°C, the field trial in Cornwall proved that the monovalent system could deliver a peak heat load of 363kW, with a very high co-efficient of performance (COP) equal to 52. The COP (dimensionless value) corresponds to the ratio of the heating produced over the electrical input required by the compressor. The greater the COP value, the less electricity is required to operate and the more efficient the system (Khosravy, 2021).

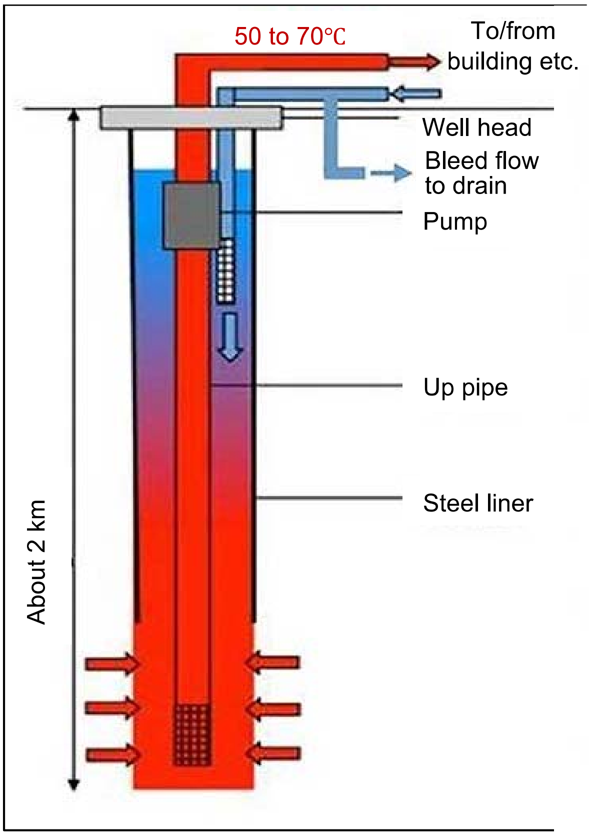


Figure 37: Schematics of the DGSW technology tested in Rosemanowes, Cornwall (Collins & Law, 2017)

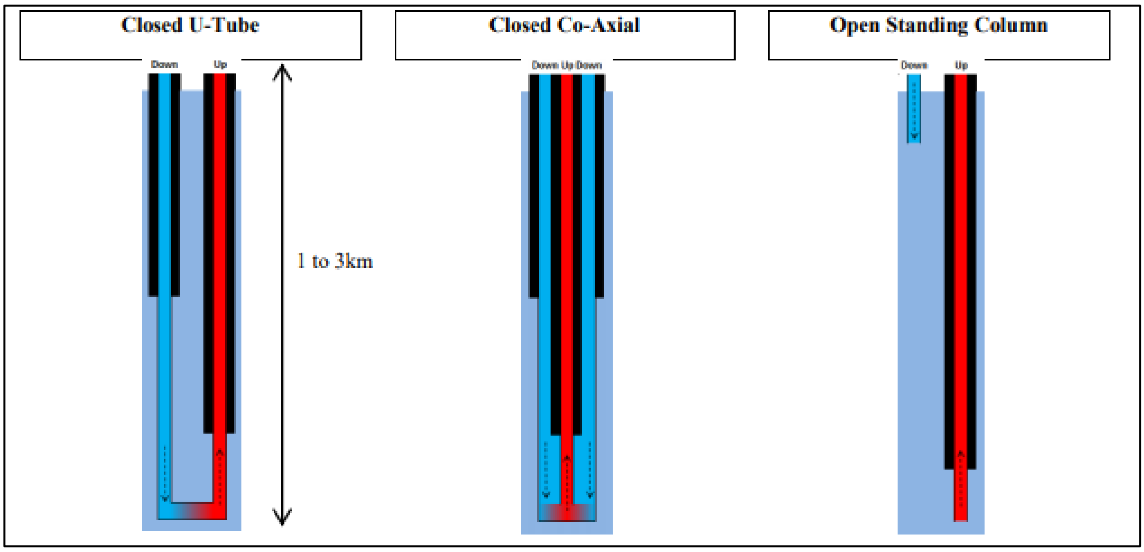


Figure 38: Configurations considered for a DGSW configuration (Law and others, 2016).

In addition to closed-loop co-axial systems, other potential configurations for DGSW systems include a closed-loop U-tube system or an open loop standing column system (Figure 38) (Law and others, 2016).

- Closed-loop U-tube: Traditional shallow geothermal system configuration, where heat transfer occurs by conduction only.
- Closed co-axial: Transfers heat from the rock to the well by conduction only, but as the central 'up' pipe is encased by the larger 'down' pipe, there is greater heat transfer through the outer wall, and greater insulation as the heated water travels to the surface.
- Open-loop: If groundwater is available, this system draws water up from the base of the well, the heat is dissipated to the building and the cooler water returned to the top of the well to maintain the water level.

Following the Cornwall field trial, a joint venture company, Geon Energy Ltd was formed between the 2 companies to roll out the DGSW technology in the United Kingdom (Collins & Law, 2017). Several proposals have been developed for similar DGSW projects in England and Scotland and are at various stages of development.

The projects include:

- Aberdeen Exhibition and Conference Centre (AECC): Geothermal Engineering Ltd, Arup and the University of Plymouth carried out a feasibility study in 2016 on using DGSW to provide decarbonised heat at the AECC. The demonstration project consists of a single, vertical well drilled to a depth of approximately 2km within the granite beneath the site (GEL, 2016). The project is still ongoing.
- The Science Central Borehole (Newcastle University): Results in the target interval of the Fell Sandstone formation indicated a low permeability, which prevented its development as either a demonstration or operational abstracting geothermal well (Younger and others, 2016).

This project is currently being re-initiated by various projects at Newcastle University.

- Jubilee Pool, Penzance: The initial project, funded in 2018 by the European Regional Development Fund (ERDF), aimed to install a 1,700m deep geothermal borehole to help attract more visitors to the lido pool in Penzance, and to help the wider redevelopment of the area. The initial plan to provide direct use of heat (pumped directly to the lido pool) was modified to an open-loop water source heat pump system due to drilling issues and seawater ingress (Batchelor and others, 2020). The pool was opened to the public in September 2020 (Jubilee Pool, 2021).
- Low temperature district heat network project in East Ayrshire in Scotland with the School of Geosciences, University of Edinburgh.

As well as reducing the dependence on the geothermal site location and exploration costs, this type of technology gives the opportunity to repurpose abandoned hydrocarbon wells for geothermal heat production and seasonal heat storage (Watson and others, 2019b).

4.2 Retrievable energy storage

4.2.1 Compressed air energy storage (CAES) industry

Currently, 2 grid-scale CAES facilities are in operation, in Huntorf, Germany and in McIntosh, US. Both projects use subsurface salt caverns to store the compressed air.

The Huntorf plant has been running since 1978. It is the world's first CAES plant and has a peak generating capacity of 290MW for 3 hours. Currently operated by E.ON (He and others, 2017), the facility uses 2 underground salt caverns, at a depth of 600m, with volumes of 140,000m^3 and 170,000m^3, resulting in a total volume of 310,000m^3. The caverns are typically operated between 4.3MPa and 7.0MPa and have a maximum extraction rate of 1.5MPa/hr (Duhan, 2018), (He and others, 2017). The Huntorf CAES plant has been reliably operated with a 99% starting reliability (He and others, 2017).

The McIntosh plant was commissioned in 1991 and has a peak generating capacity of 110MW for 26 hours. The facility uses a single 460m deep cavern, with a volume of approximately 560,670m^3; the cavern has a maximum height and diameter of 230m and 72m, respectively. The facility typically operates between 4.5MPa and 7.6MPa (Duhan, 2018), (He and others, 2017). The McIntosh CAES plant has maintained an average starting reliability between 91.2% and 92.1%, and an average running reliability of 96.8% and 99.5% for the discharge and charge periods, respectively (He and others, 2017).

Although currently no CAES facilities are operating in porous formations, the concept has been shown to be feasible, and was first studied in the 1980s at a field test site in Pittsfield, Illinois, USA (Bo Wang, 2019).

Apart from the 2 large-scale conventional CAES plants, there are a number of recent CAES projects that are either operating at small scale (for demonstration) or are in the development stage for larger commercial scale applications. Table 7 below provides a summary of those projects.

Name	Location	CAES technology	Project purpose	Power delivered (MW)	Efficiency (%)	Storage type	Status
Gotthard base tunnel pilot AA-CAES	Biasca, Switzerland	Adiabatic	Demonstration	0.7	63 – 74	Excavated unlined rock cavern	Active
Goderich A-CAES facility	Ontario, Canada	Adiabatic	Demonstration	2.2 (charge) 1.75 (discharge)	>60	Specifically mined cavern	Active
Zhongyan Jintan CAES	Jintan, China	Adiabatic	Commercial	50 – 60	-	Solution mined salt cavern	Construction
Apex CAES Bethel Energy Centre	Texas, USA	Conventional diabatic	Commercial	324 – 487	-	Solution mined salt cavern	Construction
Feicheng A-CAES	Feicheng, China	Adiabatic	Commercial	1,250 (expected)	67	Repurposed salt and coal mine caverns	Construction
PGE Corporation Advanced Underground CAES	California, USA	Conventional diabatic	Commercial	300 (expected)	-	Depleted natural gas store	Construction
Angas A-CAES facility	Strathalbyn, Australia	Adiabatic	Commercial	5	>60	Repurposed zinc mine	Construction

Table 7: Major CAES demonstration projects and commercial projects that are to be commissioned (Wang and others, 2017), (Tong and others, 2021), (King and others, 2021)

In recent years, a number of different CAES concepts have been developed to improve the technical and economic performance of the system and to accommodate the energy storage needs of different application scenarios. These include liquid air energy storage, underwater compressed air energy storage, and steam injection compressed air energy storage (Tong and others, 2021). Figure 39 provides an overview of the main classification of CAES technologies and a number of emerging new concepts. In addition, a few other innovative concepts, such as supercritical CAES (Wang and others, 2017), (Tong and others, 2021), low-temperature adiabatic CAES (Chen and others, 2020) are also being discussed in various literature.

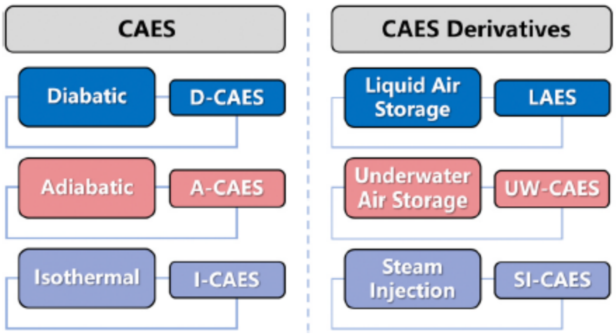
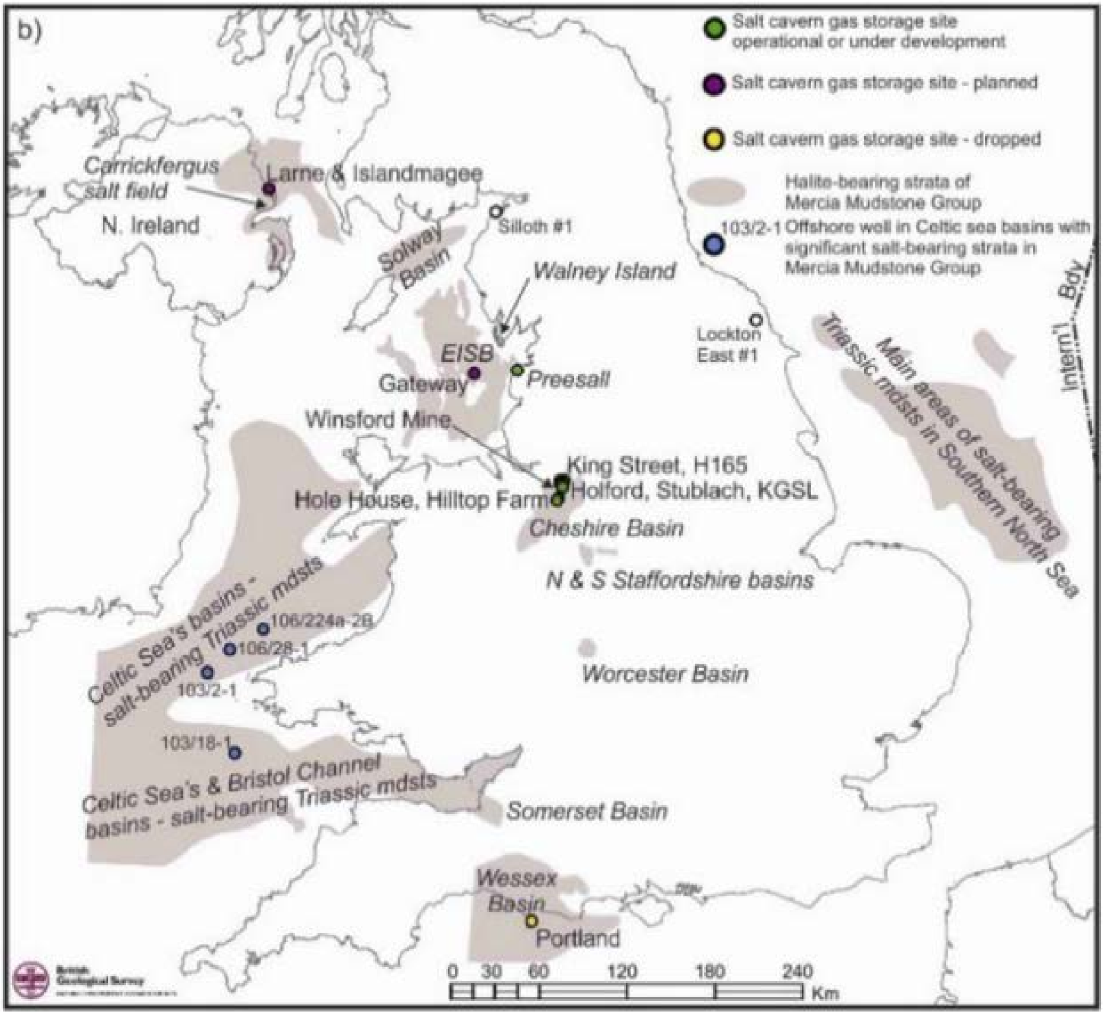


Figure 39: Classification of main CAES technologies and a number of new concepts (Tong an others, 2021)

At present, salt caverns seem the most likely storage sites for a CAES facility in the UK (Evans & Carpenter, 2019), (King and others, 2021), (Parkes and others, 2018), although porous reservoirs have also been suggested and investigated. To date, no planning applications for CAES have been submitted in England, with the only one in the UK being for the Gaelectric project CAES Larne, Northern Ireland, submitted in 2015. This was subsequently withdrawn due to the developer Gaelectric entering administration in 2017 (Crampsie, 2019).

Currently, the salt caverns used for underground gas storage (natural gas, hydrogen, nitrogen) in England are located onshore in Cheshire, Stafford, Yorkshire and Teeside (Stone and others, 2015). The development of onshore facilities is partly because they are technologically simpler and therefore cheaper, but also because the storage sites are closer to the required energy markets.

In terms of the salt basins in England, as shown in Figure 40(a), the European Permian Basin, reaching from the eastern United Kingdom up to the North Sea, contains a considerable amount of bedded salt deposits and diapiric salt structures. It fulfils the geological prerequisites such as depth and thickness for salt cavern storage (Caglayan and others, 2020). Outside of the European Permian Basin, Mesozoic salt, which formed during the early Triassic period, can be found in north-west and south-west England (Wessex Basin), see Figure 40(b). The Cheshire Basin, with its thick massively bedded Triassic halite deposits, is a major region of interest for CAES studies (Parkes and others, 2018). The region has historically been worked by dry mining for rock salt and brine production from both the area of wet rockhead and also from solution-mined caverns. Apart from the Cheshire Basin, salt beds of the Triassic Preesall Halite in the East Irish Sea were also a target for the Gateway gas storage project and the previously mentioned Gaelectric CAES facility in Permian salt beds onshore in the Islandmagee area of Northern Ireland (Parkes and others, 2018).



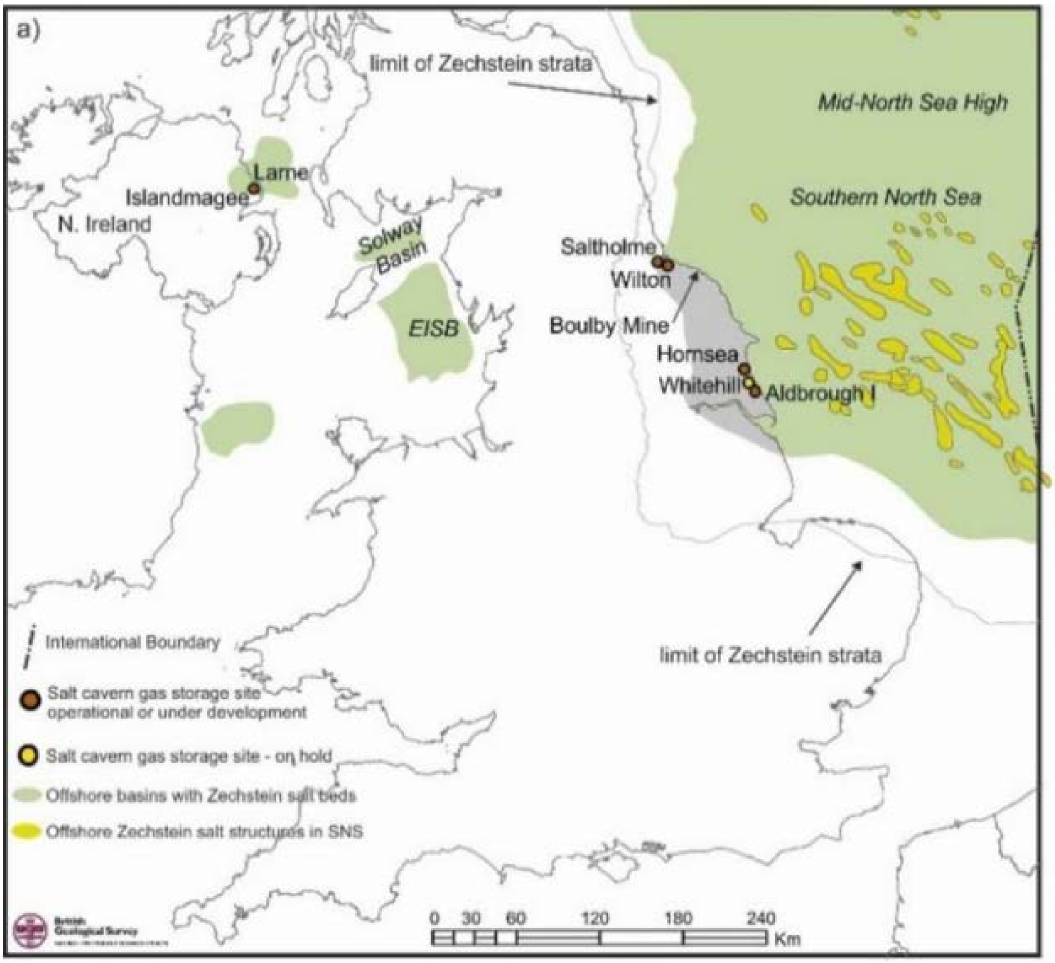


Figure 40: Map of UK Permian and Triassic basins: (a) principal Permian salt basins; (b) principal Triassic salt basins. EISB is East Irish Sea Basin, Intern'l Bdy is international boundary (image originals from the BGS and adapted by (Parkes and others, 2018)

No salt reserves exist in the south-central and south-east regions of the UK (Bo Wang, 2019).

In addition to using salt caverns, there is great potential for the UK's saline aquifer resources to be used for CAES. There is estimated to be sufficient storage capacity for 96TWh in saline aquifers, although these will prove more difficult to harness and their use relies upon less established technologies than salt deposit storage (King and others, 2021).

Parkes and others (2018) suggested that the alternative geological storage options to salt caverns are not likely to be developed in the near future due to potential problems of storage integrity and deliverability and/or development costs, which are considerably higher than for salt caverns (Parkes and others, 2018). Marcus King and others (2021) further recommended that going forward, the salt deposits should be targeted for the development of CAES in the UK, prioritising existing infrastructure from previous gas stores (King and others, 2021). Table 8 shows operational and non-operational gas stores in the UK.

Status	Facility/operator	No. of caverns	Cavern depth: top/base (m)	Pressure range: min. / max. (bar)	Volume (m^3)
Operational	Hornsea (Scottish and Southern Energy)	9	~1,780 – 1,830/ 1,880 – 1,930	Min=120 Max=270	~220,000
	Aldbrough I (Equinor, Scottish & Southern Energy)	9	~1,780 – 1,830/ 1,880 – 1,930	Min=120 Max=270	~270,000
	Holford H165 (Ineos Enterprises)	1	350/420	Min=~70 Max=85	175,000
	Hole House (EDF Trading)	4	300/400	Not known	Not known
	Hilltop Farm/Hole House ext. (EDF Trading)	10	~240/380	Min=29 Max=45	600,000 – 650,000
	Holford (E.ON Gas Storage UK)	8	570 – 610/670 - 700	Min=40 Max=105	~370,000
	Stublach (Storengy)	20	~500/600	Min=30 Max=101	~330,000
Non-operational (under-construction or discontinued)	Gateway (Gateway Gas Storage Ltd)	20	~624	Min=36 Max=120	1,000,000
	Islandmagee (Islandmagee Storage,Limited)	7	~1,500	Min=120 Max=250	480,000
	Whitehill (E.ON Gas Storage UK)	10	~ 1,730 – 1,830	Min=100 Max=345	250,000
	King Street Energy (King Street Energy Ltd)	11 (+7)?	~320 – 420	Min=not known Max=66	500,000 – 850,000
	Preesall (Halite Energy Ltd)	19	340 – 456/413 – 618	Min=33 Max=92	58,000 – 860,000
	Keuper Gas Storage (Keuper Gas Storage Ltd)	19	~650 – 750	Min=43.8 Max=123	314,000
	Portland (Portland Gas)	8	~ 2,400/2,500	Min=brine hydrostatic pressure Max=440	~250,000

Total numbers of caverns (as of 2018): 155

Total cavern volume (physical) (as of 2018): 5,159,000m^3

Table 8: Summary of UK salt cavern gas storage facility design and operational parameters by 2018 (Parkes and others, 2018)

The figure below (Figure 41) further illustrates the locations of the project mentioned above, together with locations of town gas exploration storage wells (early 1960s) in England.

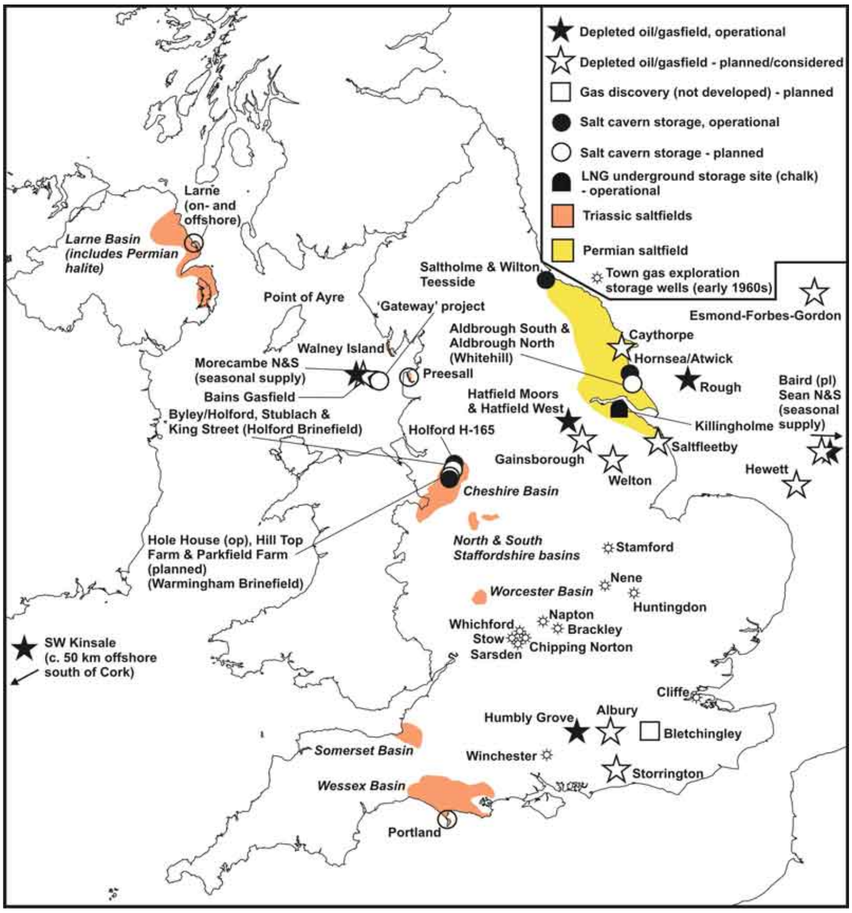


Figure 41: Distribution of the main halite-bearing basins in England (and Northern Ireland) and the location of operational and proposed underground gas storage sites, including depleting oil and gas fields and mined chalk facilities (Evans & Holloway, 2009)

A modelling study performed by Parkes (2018) produced an initial estimate of possible salt storage cavern locations and physical cavern volumes of the Cheshire Basin. The results suggested that the largest individual cavern volume of 1.050 million m^3 was found at the depth interval 250 to 1,300m. The depth range 250 to 1,500m had the largest total volume (7,930 million m^3) and cavern number (16,607 caverns). If the cavern height is restricted to 100m to align with Huntorf and active gas storage caverns in the Cheshire Basin, then for the 500 to 1,500m (when considering infrastructure buffering) range, there is a potential for approximately 1,600 caverns in the Cheshire Basin (Parkes and others, 2018). For the Cheshire Basin, just 1 % of the current available salt could support a viable (100m cavern height) storage facility and, ignoring cavern distribution, there is the potential for upward of 100 new, ~16 cavern, storage facilities within the basin (Parkes and others, 2018).

4.2.2 Underground hydrogen storage (UHS)

To date, no pure (100%) hydrogen underground storage exists (Sainz-Garcia, et al., 2017). At the moment, located in the UK and USA, there are 4 operating UHS projects with 95% hydrogen, worldwide. All 4 projects are used to supply hydrogen to the chemical industry (DBI Gas and Umwelttechnik GmbH, 2017). In addition to these 4 UHS projects, there are also a number of underground town gas (with a composition of around 50% of H_2 and 50% CH_4) storage projects such as Engelbostel and Bad Lauchstadt in Germany, Lobodice in the Czech Republic and Beynes in France. Table 9 below provides an overview of the UHS projects and town gas projects, including their current operational status.

Field/project name	Storage type	Since (year)	H_2 purity (%)	Working condition	Depth (m)	Volume (m^3)	Status
Teeside (UK)	Bedded salt	1972	95	45 bar	365	3 x 71,000	Operating
Clemens (USA)	Salt dome	1983	95	70 - 137 bar	1,000	580,000	Operating
Moss Bluff (USA)	Salt dome	2007	-	55 - 152 bar	1,200	566,000	Operating
Spindletop (USA)	Salt dome	-	95	68 - 202 bar	1,340	906,000	Operating
Kiel (Germany)	Salt cavern	1971	60 (town gas)	80 - 100 bar	430	32,000	Closed
Ketzin (Germany)	Aquifer	1964 - 2000	62 (town gas)	-	200 - 250	1.30 x 108	Operating with natural gas
Beynes (France)	Aquifer	1956 - 1972	50 (town gas)	-	430	3.3 x 108	Operating with natural gas

Lobodice (Czech Republic)	Aquifer	1989	50 (town gas)	90 bar/ 34°C	400	-	Operating
Diadema (Argentina)	Depleted gas reservoir	2010 -2018	10 (town gas)	10 bar/ 50°C	600	750,000	-
Underground Sun Storage (Austria)	Depleted gas reservoir	2017	10 (town gas)	78 bar/ 40°C	1,000	115,444	Operating

Table 9: Operating UHS and town gas storage sites worldwide (Dopffel and others, 2021), (Zivar and others, 2020)

Currently, only salt caverns are in continuous operation for hydrogen storage, whereas storage in porous reservoirs such as aquifers and depleted oil and gas fields are still on a field test scale (Dopffel and others, 2021). In recent years, multiple numerical studies have investigated the dynamics of hydrogen in porous media. However, the influence of different well configurations on storage performance has not been yet investigated (Sainz-Garcia, et al., 2017). In addition, a number of well-known projects such as Roads2HyCOM (monitoring project across multiple EU countries, 2005), Hychico (Argentina, 2006), H2STORE (Australia, 2012), Underground Sun Storage - phase I (Austria, 2012), HyUnder (Spain, 2012), ANGUS+ (Denmark, 2013), CEN-CENELEC (multiple EU countries, 2014) and HyINTEGER (Germany, 2016), and HyStorPor (Scotland, 2020) have been launched to investigate the feasibility in terms of production, transportation, storage and utilisation of hydrogen in the last decade.

As mentioned in the CAES section, major salt depositions in England are Paleozoic (Permian) salt deposits in the east coast, and Mesozoic (Triassic) salt deposits in the north-west and southern England. It has been estimated that the UK has the third largest salt cavern storage capacity (onshore and offshore) in Europe (Caglayan and others, 2020).

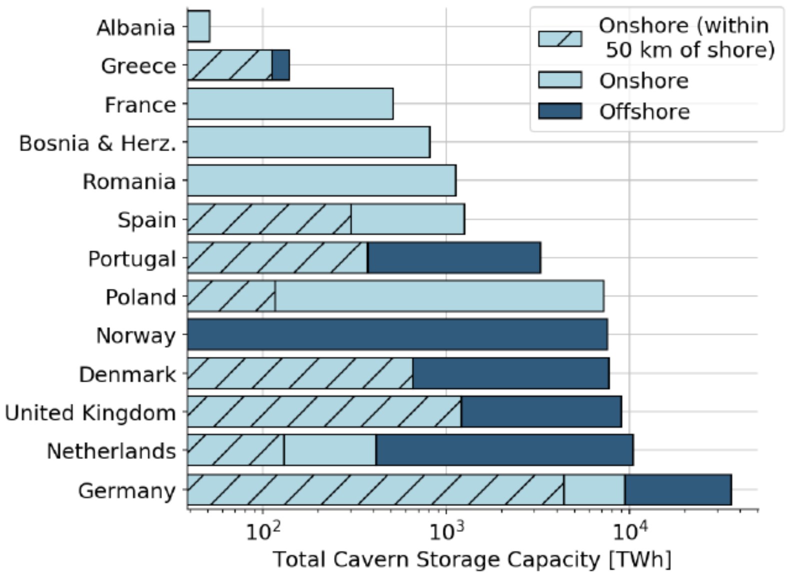


Figure 42: Total cavern storage potential in the UK and other major EU countries classified as onshore and offshore (Caglayan and others, 2020)

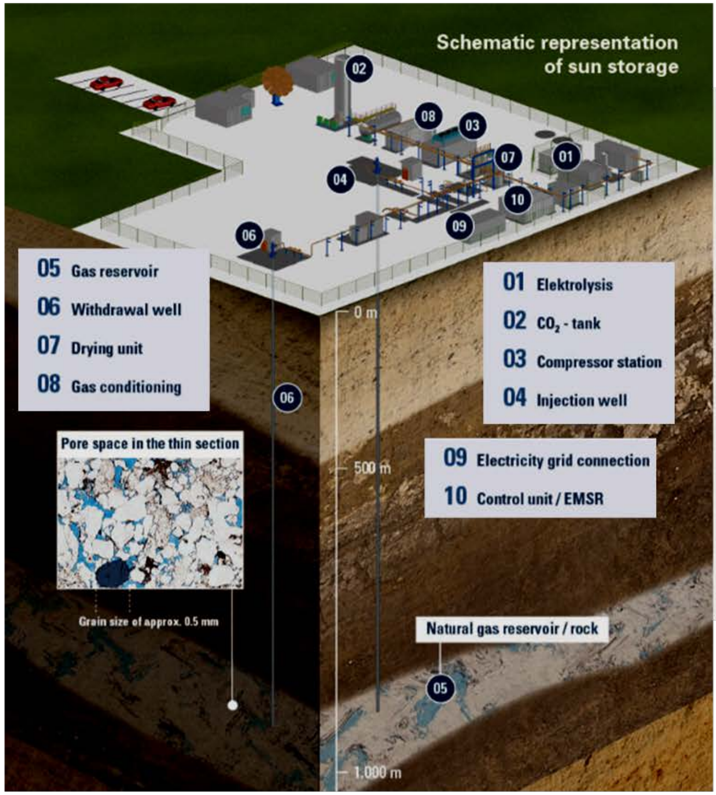
4.2.3 Underground bio-methanation

At the moment, there is only one planned bio-methanation project globally, (Nikolaev, 2020), the Underground Sun Conversion project - phase II (2017 to 2021), in Austria. This project is still in its infancy, and pilot and commercial-scale facilities appear to be a long way in the future (Figure 43).

The Underground Sun Conversion project is conducted by RAG Austria AG and the project partners. The current research project has 2 explicit goals (Bauer, 2017):

- demonstration of storability of renewable gases in gas storage facilities
- research into the effects of 10% hydrogen admixtures in existing gas storage facilities

Future research themes look to understand microbial methanation in underground natural gas reservoirs and to expand industry understanding of chemical reactions that occur in the subsurface.



Reservoir	
Max. pressure	107 bar
Temperature	40°C
Depth	1,027 m
Working gas volume	1.7 mn cu m
Reservoir volume	6.2 mn cu m
Elektrolysis	
Installed power	500 kW 100 cu m H2/h

Figure 43: Overview of the Underground Sun Conversion project (adapted from (RAG Austria AG, n.d.))

Laboratory research of the Bio-UGS project, led by the Friedrich Schiller University of Jena in Germany, is currently ongoing. The main aim of the project is to quantify the potential of converting hydrogen to methane in the potential porous reservoirs of Germany (Nikolaev, 2020).

4.2.4 Underground pumped-storage hydropower (UPSH)

UPSH is a potential alternative for storing and managing electricity supply in regions where a flat topography does not allow the use of conventional pumped-storage hydropower (PSH) (Pujades and others, 2020), (Pujades and others, 2018). Although there have been some UPSH projects and a number of studies, there are no known plants operating worldwide (Menéndez and others, 2020), (Menéndez and others, 2019).

There are several publications on planned UPSH projects using abandoned mines, however little information on their progress is available, and the development status of these projects is largely unclear. These projects include (Chaves, 2020):

- Elmhurst Quarry Pumped Storage Project in Chicago, USA (50-250 MW)
- Riverbank Wisacasset Energy Center in Maine, USA (1,000 MW)
- Prosper-Haniel coal mine in Germany (200 MW)
- Kidston Pumped Storage Hydro Project in Queensland, Australia (250 MW)
- Bendigo Mines Pumped Hydro Project in Victoria, Australia (30 MW)

Little research has been carried out into the UK's potential for UPSH. However, site selection for UPSH can be very challenging as the upper reservoir ideally needs to be remote from urban areas and vertically separated by several hundred metres from the lower reservoir. Finding former mining sites that meet these criteria is difficult.

The latest map of coal mines of the UK, released in December 2020, from the British Geological Survey and the Coal Authority, contains the locations of mines in England, together with temperature and depth profiles (Figure 33).

4.3 Permanent underground storage of carbon dioxide

4.3.1 Carbon capture and storage (CCS) industry

In March 2020, UK government support for CCS was bolstered by recent spending commitments to establish and encourage the development of CCS clusters at 2 sites by 2030 (Duckett, 2020). This brings UK government commitments to support research and development in CCS to £18 billion (Doyle, 2019). The UK government is looking to support the establishment of domestic CCS capabilities and is hoping that such skills can be a viable UK export to other countries as global use of CCS increases.

The principles of CCS and the methods for managing CO_2 are well documented globally. The nature of CCS and its geographic specificity, especially with regard to storage, mean that global experience in CCS technology, storage geology, carbon markets, project economics and project operations are not consistent. In the context of a state-of-the-industry understanding of CO_2 storage, it is important to subdivide CCS experience into the following 4 examples:

- Onshore CO_2 management: translatable experience from onshore CO_2EOR and early CCS in North America.
- Offshore CO_2 management: permanent storage of CO_2 in the European offshore environment.
- Broadening the CCS portfolio: planned expansion of CCS for industrial capture of CO_2 in Europe and the United Kingdom.
- Onshore CCS in the UK: offshore competition likely to occupy the CCS industry in the longer-term.

Onshore management of CO_2

The United States and Canada have produced onshore oil using the method of CO2EOR for over 4 decades (Jacobs, 2020). In this process, CO_2, from industrial sources or from naturally occurring CO_2 reservoirs, is injected into a depleted oilfield, whereby the CO_2 causes the oil to expand and flow more readily. The process of CO_2EOR is typically used at the stage of the reservoir's life when the natural flow mechanism of the field is diminished or the original oil in place is stranded and needs applied recovery techniques to produce it. Such is the size and scale of the North American CO_2EOR industry (Figure 44) that between 2011 and 2035 the industry is expected to produce 4 billion additional barrels of oil and potentially drive over US$10 trillion in economic development (Campopiano & Hendersen, 2013).

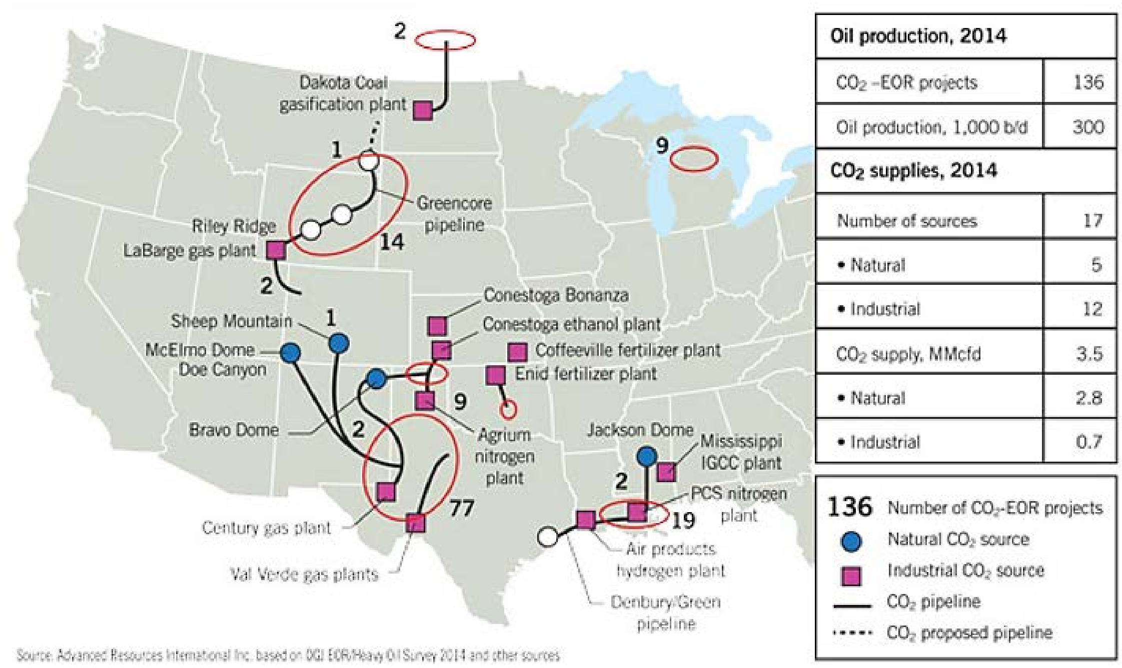


Figure 44: United States (Weyburn storage project in Canada is connected with a North Dakota CO_2 source) CO_2EOR infrastructure and operational projects (Oil & Gas Journal, 2014)

CO_2EOR has been important in understanding CO_2 storage on many fronts. Besides the topside handling (for example, separation, transport and compression) of CO_2, CO_2EOR has benefitted CCS in several ways:

- Monitoring and reservoir understanding: CO_2EOR requires a very detailed understanding of the reservoir and flow paths for both oil and CO_2. Consequently, many monitoring technologies (for example, micro seismic, gravity, fibre optics) have been able to be transferred into the CCS industry. Furthermore, the CO_2EOR industry, with its detailed understanding of many of North America's oilfields, is well positioned to advise on appropriate CO_2 storage sites. In some cases, project boundaries between CO_2EOR and CCS in North America are blurred as the industries are becoming interdependent.

- Supply chains and expertise: the CO_2EOR industry, along with the domestic oil and gas industry, has been a large employer of geologists, geophysicist and reservoir engineers with specific understanding of CO_2EOR, CO_2 injection and reservoir-CO_2 interactions. Similarly, supply chains in North America are very advanced, with specialist CO_2 well design and completion service providers, reservoir monitoring and analysis service providers, and even a distinct operatorship (for example, Occidental, Denbury Resources & Kinder Morgan) to support the growth of both CO_2EOR and CCS in both North America and Canada.
- Regulation and industry standards: both operators and regulators in North America (EPA in the United States and State Agencies in Canada) have a long relationship defining and redefining subsurface legislation to benefit the environment and the industry. Nearly 40 years of regulator experience has resulted in some of the world's more robust standards surrounding the injection of CO_2, and the design, completion and maintenance of injection infrastructure. Notable is the extension of Class II well specification for CO_2EOR to Class VI well specification for CCS. These relationships between the industry in aspects of regulation, technology and best practice are well developed.
- Monetisation of CO_2: in the US states there are fiscal incentives for domestically produced oil production. CO_2EOR is seen as an enabler technology and this has spurred the building of many capture facilities across the country. The business environment in North America appreciates CO_2 as a commodity, and the economic incentives to develop CCS projects associated with CO_2EOR (Weyburn and Midale projects (Plains CO2 Reduction Partnership (PCOR), 2019) support the commercial viability of CCS in North America.

While the USA has a long way to go before onshore CCS becomes distinguished from its more established sister industry, CO_2EOR, the frameworks for technology, subsurface understanding, regulation and the supply chain for onshore CO_2 storage appear to be well matured. For some time, the CO_2EOR industry has been experiencing a shortage of CO_2 supply from both naturally occurring and industrial CO_2 sources. Consequently, new CO_2 supply is quickly absorbed by CO_2EOR projects with a commercial and tax incentive to produce domestic oil. This has led to US onshore CCS failing to progress beyond pilot scale projects.

The United States' recent withdrawal, then readoption, of the COP21 Paris Agreement has left US industry in an emissions policy 'limbo'. Costly investment in CO_2 capture technology, in retrofittable and greenfield projects, otherwise mandated by Federal Government environmental commitments, have been delayed until more clarity surrounding CO_2 emissions and a roadmap for their reduction is committed to in law.

Offshore management of CO_2

Offshore CCS originate from a very different place to North America's CO_2EOR industry. Considered the better comparison for a UK CCS industry, but predominantly an offshore business model, Norway has led the way in the development of technology, standards and regulations for the permanent storage of CO_2 offshore. The Norwegian experience began in the early 1990s with Statoil (now Equinor) starting to investigate the decarbonisation of European industry, including chemicals, coal-fired power and the production of natural gas and oil.

Norway, with its well-established offshore oil and gas industry, associated supply chains and uniquely innovative R&D ecosystem, spearheaded the development and deployment of offshore CCS from a very limited experience in CCS. The first industrial project of its size, Sleipner CCS project (in operation since 1996) has a proven track record and has provided the global CCS industry with a range of operational and subsurface research directly translatable to other projects; already built or currently in planning (Rose, 2018). Subsequent experience with the Snohvit CCS project (in operation since 2008) has given Norway accumulated injection experience of over 22 million tonnes of CO_2, specifically saline aquifer injection.

The collective experience of these 2 projects, and that gained through associated research, gives Norway a unique leadership position in offshore CCS development.

Norway, through its oil and gas industry, realised early in its offshore industrialisation, that Europe would be a significant export destination for its hydrocarbon products. Similarly, aspirations to become a centre of excellence for CCS enabled Norway to act as an importer of the European continent's industrial CO_2. While Norway still positions itself as a leader in CCS, the business drivers have shifted. Europe has subsequently made pledges to decommission coal, and renewables have become commercially viable as alternatives to hydrocarbon generation. Norway has repositioned its CCS capabilities to complement the blue hydrogen industry (that is, hydrogen produced from natural gas with CCS to store the CO_2). There are several benefits of this shift in thinking:

- CO_2 emissions reductions form natural gas use: blue hydrogen allows for natural gas to be converted into hydrogen, which can then be exported and combusted in power stations or for residential use without CO_2 emissions into the environment.

- Monetisation of national resources: Norway is able to decarbonise its natural gas for international sale, providing consumers with a reliable and alternative supply of hydrogen. Alternative fuels include brown hydrogen (produced from natural gas without CCS) and green hydrogen (produced using renewable electricity).
- Securing Norwegian industry: while the original motivation for CCS was to reduce emissions from local industry (for example, such as fertiliser production in Porsgrunn), being able to supply end-users with a zero-carbon feedstock/fuel is an equally valid way to ensure longevity of industries reliant on hydrocarbon chemistry without the need for capture facility retrofits.

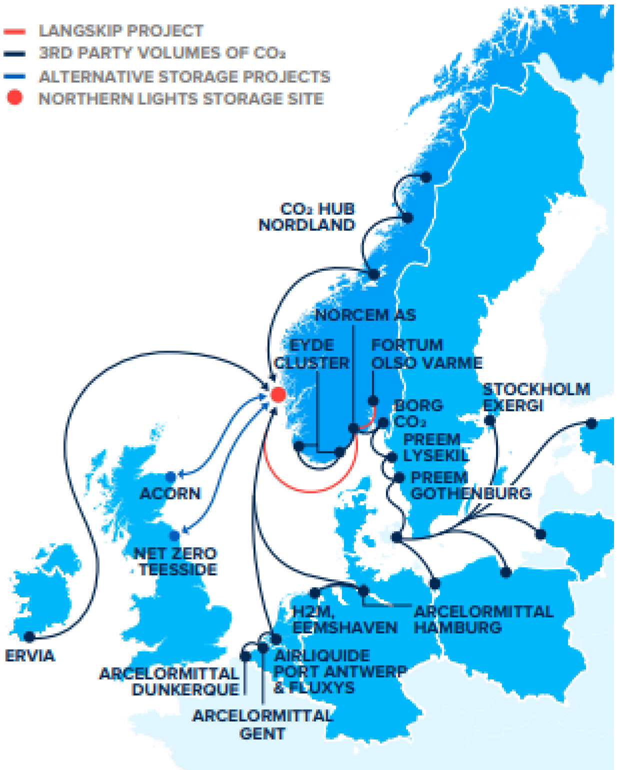


Figure 45: Northern Lights CCS Project and potential CO_2 sources (Global CCS Institute, 2020)

With the announcement of the Northern Lights CCS Project (Northern Lights CCS, 2021) and investment in the blue hydrogen project H2H Saltend in the UK (Equinor, 2020) that will combine hydrogen production with offshore CO_2 storage, the Norwegian CCS industry (through Equinor's UK involvement) is expected to remain at the cutting edge of CCS value chain development and the integration of CCS with other industries like hydrogen. Recent discussions between the UK and Norway, and the signing of a memorandum of understanding (MOU) for greater cooperation between the 2 countries with respect to CCS, is likely to result in beneficial transfer of Norway's CCS experience to the UK, albeit focused on the offshore business environment (The Ministry of Petroleum and Energy of the Government of Norway, 2018).

With the majority of Norwegian experience very closely associated with domestic offshore oil and gas, outside of capture facilities, it is unlikely that CCS (particularly CO_2 storage) will find itself in an onshore environment, and society's acceptance of onshore CO_2 storage in Norway is untested.

Broadening the CCS portfolio

Enthusiasm for CCS as a technology has gone through various cycles, with changes in policy, market forces and economic circumstances. Consequently, the growth of CCS as a technology has languished in recent years, with strong investment support at the start of the millennium followed by a marked investment downturn in the late 2010s. In recent years, realignment of energy markets around the hydrogen economy (especially in Europe, Japan, South Korea and Australia) and the United States pushing forward with CO2EOR developments, and to a lesser extent CCS projects, has meant that CCS is gaining further investment support. The figure below shows the changes in investment over the last decade, with operational CCS projects expected to continue to grow year-on-year.

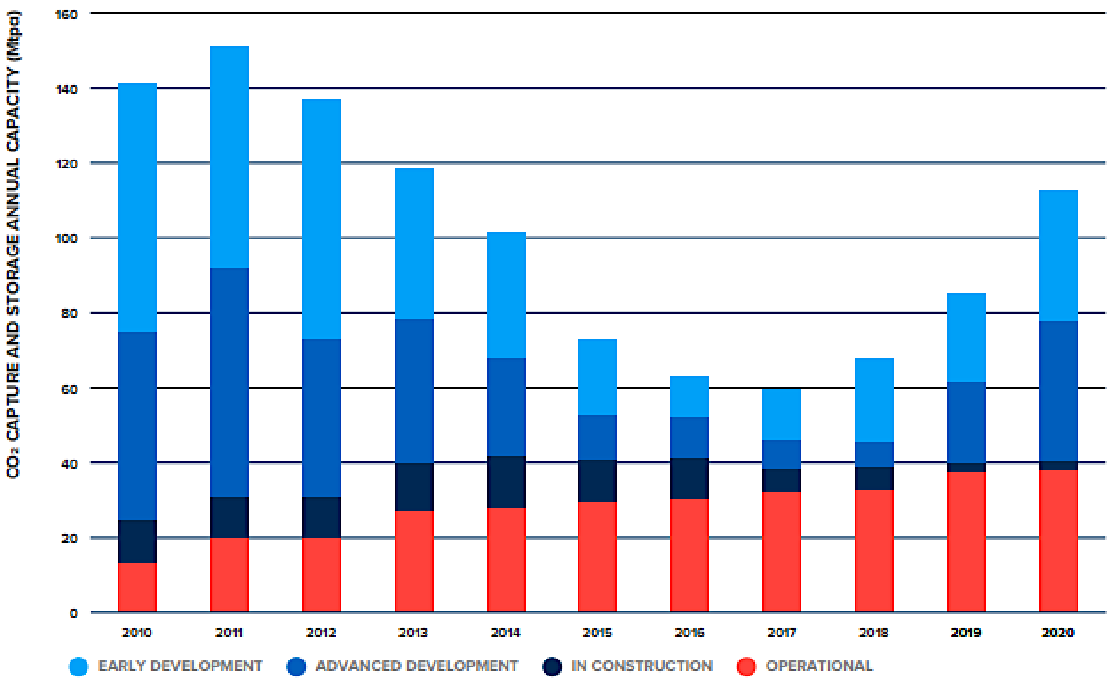


Figure 46: Pipeline of large-scale global CCS and CCUS investments (Global CCS Institute, 2020)

Internationally, there are broadly 2 classes of CCS projects; commissioned and planned (industrial scale and demonstration), with centres of excellence in capture, transport and storage distributed globally. The map below highlights the 2 major centres of excellence (onshore North America and offshore

Europe), along with projects in Latin America, Australia, the Middle East and Asia, both operational and planned.

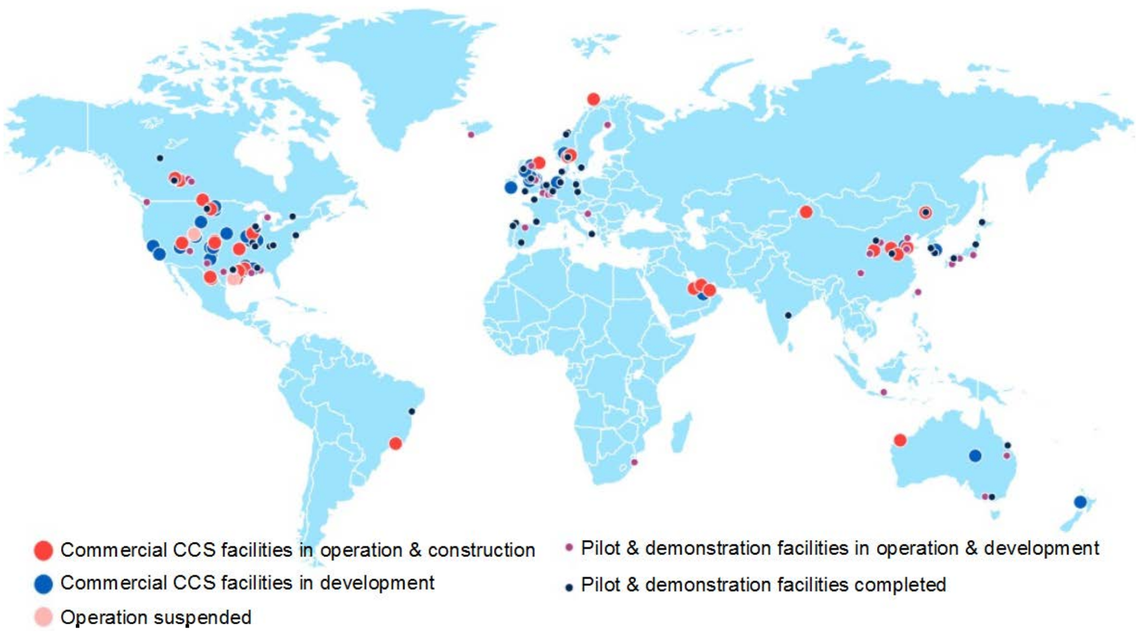


Figure 47: World map of CCS projects at various stages of development (Global CCS Institute, 2020)

In summary, CCS globally is a growth sector. North America, with its established CO_2EOR business and integrated national network of CO_2 infrastructure will likely lead the way with respect to onshore technology, regulations and industry best practice. Europe, faced with the task of revitalising (or repurposing) its declining oil and gas industry, and carbon intensive chemical and industrial sectors, will likely look to tackle both challenges with offshore CCS. The track record of European developments, now almost 25 years of injecting CO_2, and the portfolio of proposed projects, is a clear indication that focus will continue to be on offshore CCS for the foreseeable future.

Onshore UK CCS

It is useful to take the Norwegian perspective when looking at the UK CCS industry. Indeed, the similarities extend beyond just business decisions regarding CCS; both share North Sea geology and over 60 years of offshore oil and gas experience. This factors greatly into UK thinking with respect to CCS and where CO_2 is to be stored for future UK projects. By and large, the UK's CCS story going forward will be one of an offshore business. The Department for Business, Energy and Industrial Strategy (BEIS) made statements in its 2012 CCS Roadmap that the UK was in a unique position regarding CCS for the following reasons (Department of Energy & Climate Change, 2012). The UK has:

- extensive storage capacity under the seabed, particularly under the North Sea
- existing clusters of power and industrial plants with the potential for CCS infrastructure
- expertise in the offshore oil and gas industry which can be transferred to the business of CO_2 storage
- academic excellence in CCS research (especially in CO_2 storage)

At the time of publication, the CCS Roadmap nearly exclusively looked at storage options in the North Sea and East Irish Sea as options for CCS. The map below highlights storage sites and CO_2 sources listed as appropriate for CCS in the UK. Figure 48 highlights the Roadmap's offshore focus regarding CO_2 storage options for the UK.

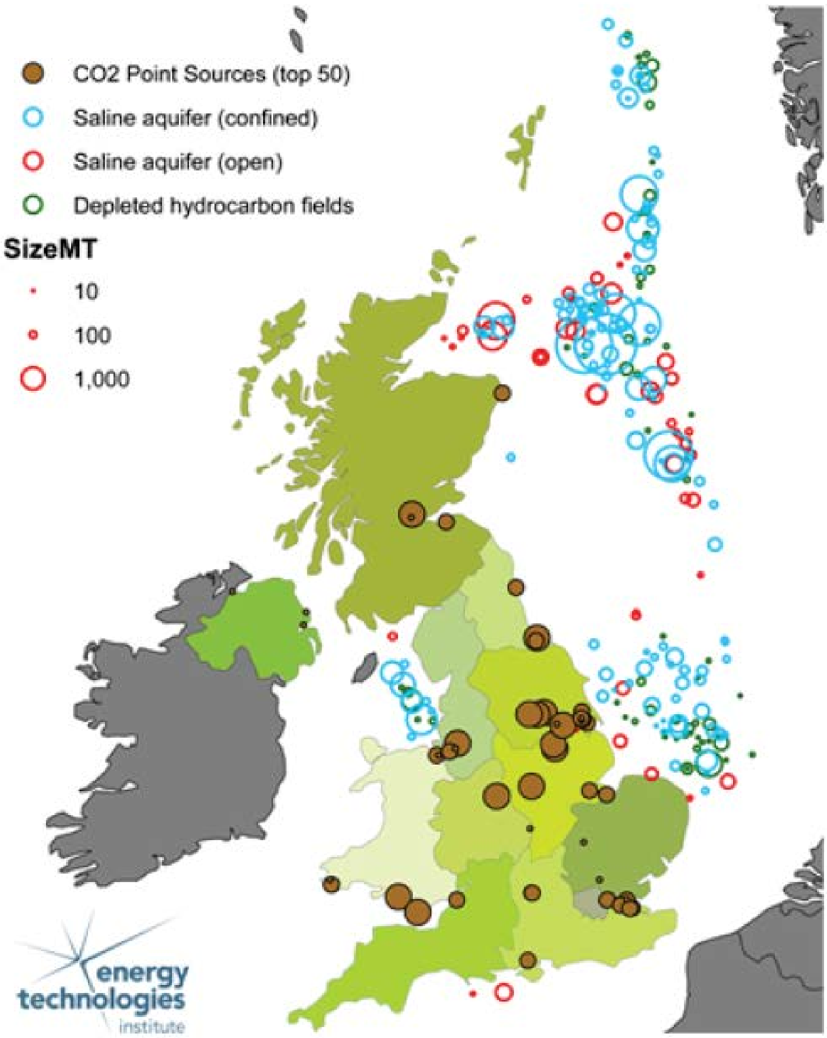


Figure 48: Prospective UK CO_2 sources and storage sites mentioned in the UK government CCS Roadmap (Department of Energy and Climate Change, 2012)

There have been many developments in the UK energy sector since the CCS Roadmap was established in 2012. While fundamentally changing the business model for CCS in the UK, these sectoral changes have not changed the underlying motivations for establishing an offshore CCS industry. They have also not established a convincing business case for exploring an onshore CCS equivalent.

The closure of all but 4 coal-fired power stations by 2021 (Drax, Kilroot, Ratcliffe-on-Soar and West Burton) and planned decommissioning of those remaining by 2025, has led to partial decarbonisation of power without CCS, with renewables, biomass and gas power (reduced emissions compared to coal) filling the supply gap. Indeed, in April 2017, for the first time in 135 years, the UK saw a period of 24 hours where coal-fired power was not used (Power Stations UK, 2021). While the electricity sector has successfully set itself on a path to net zero without CCS, industries, including manufacturing, chemicals and the oil and gas sector have looked to take advantage of CCS' new momentum.

The UK CCS industry has moved from that of large point source emissions, whereby a whole CO_2 storage project might use the exhaust of a single emitter, such as a coal-fired power station, to one of net-zero industrial clusters. In these clusters, carbon intensive industries benefit from the use of common infrastructure, including CO_2 transportation and storage. BEIS established a strategy document outlining how the UK should orchestrate its CCS industry to centre around the establishment of net-zero industrial clusters. A list of the largest industrial clusters with CCS investment potential are shown in Table 10.

Industrial cluster	Emission (million tonnes CO_2)
Humber	12.4
South Wales	8.2
Grangemouth	4.3
Teeside	3.1
Merseyside	2.6
Southampton	2.6

Table 10: Largest industrial clusters by emissions identified by BEIS (Department for Business, Energy & Industry Strategy, 2020)

In this report only offshore storage sites were considered as viable options for CCS in the UK – all sites considered are more than 3 miles from the UK coast. The use of offshore storage sites is not entirely unsurprising given the UK's previous roadmap for the direction of the CCS industry. Furthermore, the previously mentioned MOU with Norway regarding the establishment and sharing of offshore CCS capabilities appears to consolidate UK CO_2 storage into an offshore geography only. Figure 49 highlights the 3 offshore CO_2 storage sites considered by the UK government in its most recent review of the CCS industry.

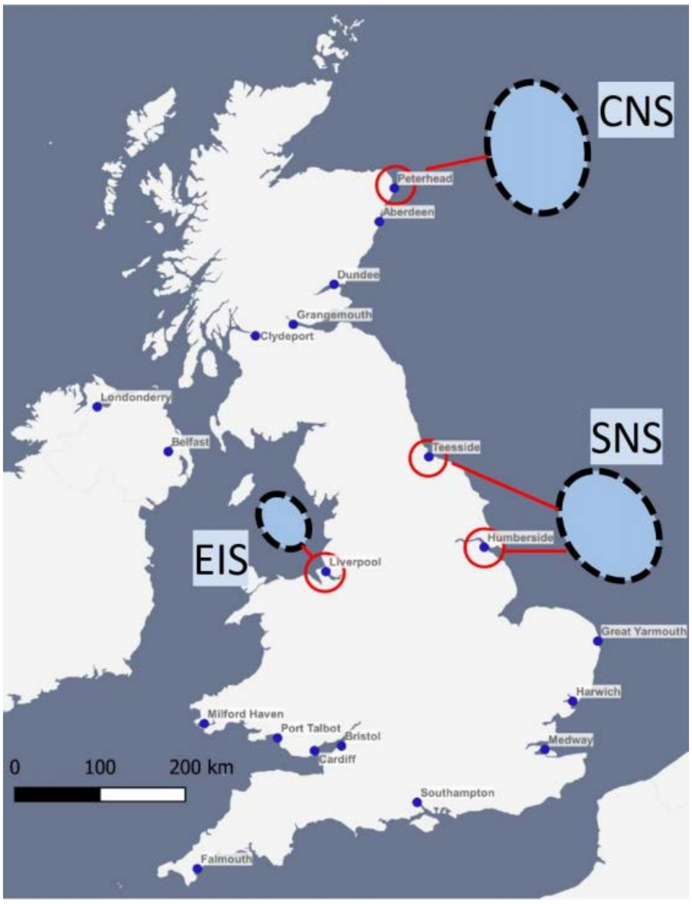


Figure 49: CO_2 storage sites selected for analysis by BEIS with respect to industrial CO_2 clusters. CNS is Central North Sea, SNS is Southern North Sea and EIS is East Irish Sea (Department for Business, Energy & Industry Strategy, 2020)

Looking to the immediate future for UK CCS, the focus on offshore storage remains a consistent theme. Three projects, all likely to be sanctioned relatively soon, provide some guidance on the direction and scope of the UK CCS industry:

- Teeside Cluster Carbon Capture, Usage and Storage (CCUS) Project: presently a design concept, the project looks to gather CO_2 from onshore industrial sources located in or near the River Tees in the north of

England. The project will then use an integrated CO_2 compression station and pipeline to transport the CO_2 to offshore storage sites in the southern North Sea. It is expected that by 2030 the project will capture over 10 million tonnes of CO_2 each year, or the equivalent of 3 million UK homes (Oil and Gas Climate Investment, 2019). Partners in the project (Net Zero Teeside (NZT) Consortium) include BP, Eni, Shell, Total, Equinor and National Grid. Apart from National Grid, the partners all have interests and a wealth of experience in offshore oil and gas operations, including reservoir management and CO_2 storage.

- Zero Carbon Humber (ZCH): In 2019, the ZCH partnership was established, with the hope of transforming the Humber region into the world's first net-zero carbon industrial cluster by 2040. In contrast to Net Zero Teeside, Zero Carbon Humber will look to establish a UK industrial cluster around the blue hydrogen economy. CO_2 from the natural gas reformation process (previously described) will be piped to offshore storage in the southern North Sea. Similarly, a biomass power plant operated by Drax will capture its CO_2 (a net negative CO_2 project) for storage at the same location. Presently plans are for the hydrogen demonstration test facility to be commissioned by 2025, with CCUS installed on the biomass power plant in 2027. Full commercial operations are expected for 2028 to 2035 (Zero Carbon Humber, 2020). An overview of the project plan can be seen in Figure 50 below.
- Acorn Project: Looks to capture 200,000 tonnes of CO_2 from the St Fergus Gas Terminal near Peterhead. The CO_2 will then be transported to depleted gas fields in the North Sea via the Atlantic pipeline. The project looks to repurpose existing oil and gas infrastructure for use in the CCS value chain. The first phase of the project is expected to deliver CO_2 for injection by 2024, with phase II bringing online further CO_2 with the commissioning of a blue hydrogen plant using North Sea natural gas with CO_2 captured for storage.

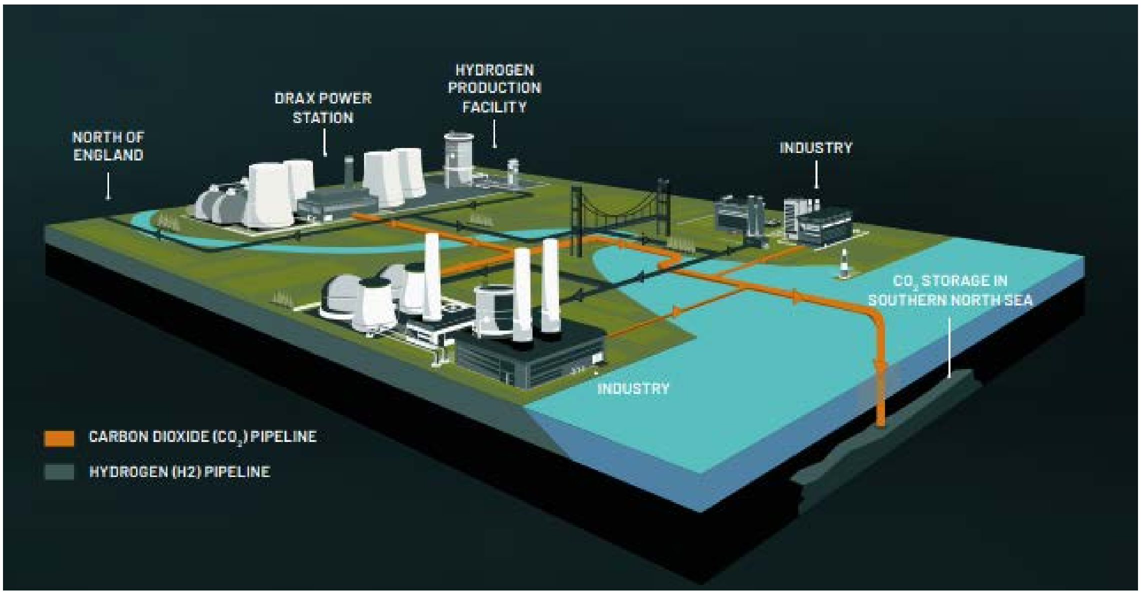


Figure 50: Schematic illustration of the Zero Carbon Humber project, including hydrogen reformation (Zero Carbon Humber, 2020)

Further reinforcing industry attitudes for CO_2 storage potential in the UK, and the fact that the majority of development interest is centred around offshore developments, the CO_2 Storage Evaluation Database was set up. Nominated as the UK's database of over 500 potential storage units and developed by the British Geological Survey (BGS) and The Crown Estate, the database provides detailed accounts of geological storage options in the north, central and southern North Sea regions and the east Irish Sea. The purpose of the database is to help operators and developers fast track their search for appropriate storage sites. Data compiled by the project included theoretical field capacity, pore volume and injectivity as well as storage risks (for example, from reservoir fracture) and evaluations of development economics (Bentham and others, 2014). The figure below provides an overview of the fields considered for the database – none are onshore.

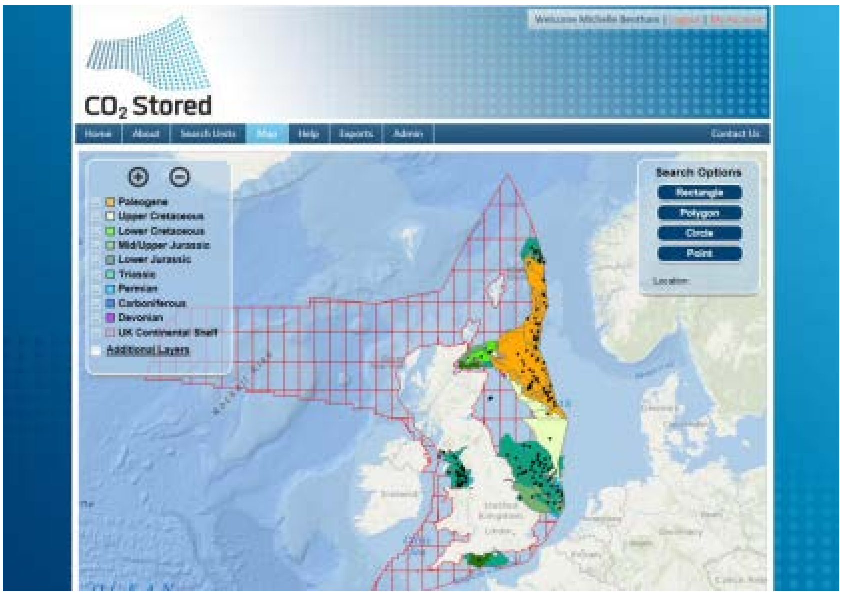


Figure 51: CO_2 stored online interface show focus on offshore CO_2 storage (Bentham and others, 2014)

There remains a technical possibility that CCS could occur onshore and therefore within the jurisdiction of the Environment Agency. The UKCCS Research Centre, in collaboration with Imperial College and the BGS, conducted a study on the feasibility of various CO_2 storage sites in the UK. This study did not have the commercial biases towards offshore storage (based on the sources of surface emissions and existing supply chains) and purely examined the geological potential for storage of CO_2 in the UK. Although focusing its attention on wells located offshore, the analysis shows there is potential for onshore storage in the UK (Figure 52).

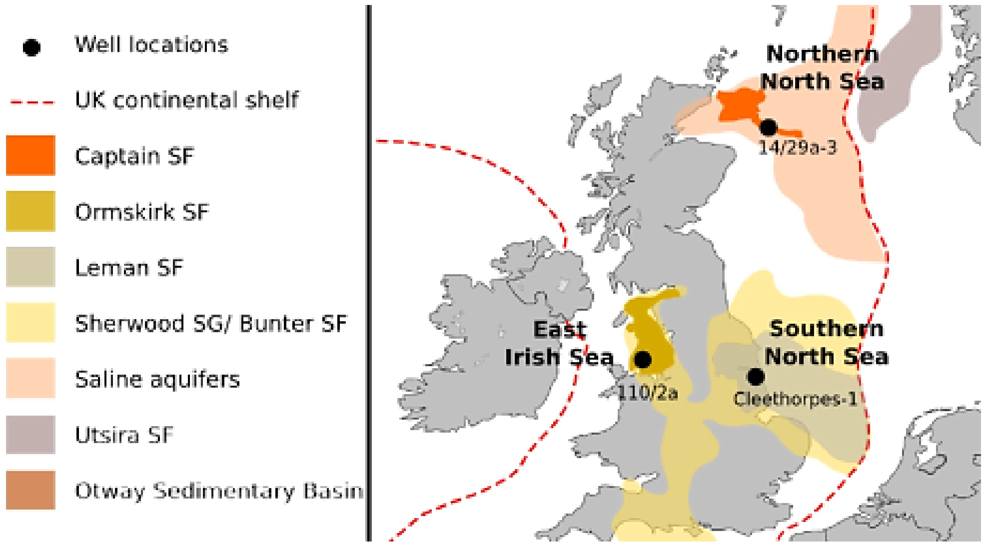


Figure 52: Map of sites characterised for multiscale CO_2 storage by the BGS (Krevor, 2016)

In summary, the focus of research and investigation in the UK with respect to CO_2 storage potential has been in the offshore environment. Government sponsorship and support for CCS storage projects is almost entirely focused on offshore locations, with a view to extending the life and leveraging decades of experience of offshore oil and gas supply chains and infrastructure. Many founding organisations of storage projects still planned to go ahead are oil and gas operators with significant experience in the North Sea and in CCS projects abroad.

While global experience with CCS is well described, and there are several notable commercial facilities routinely injecting CO_2 into subsurface formations in both offshore and onshore environments, the technology is yet to be demonstrated at scale in the UK. The UK has a distinct lack of onshore CCS projects to date – reasons being described in the status of the industry section. Projects that are described later in this report, if approved, will likely be designed and operated by companies with global experience.

5. Potential environmental impacts of low carbon subsurface technologies

5.1 Energy extraction and production

5.1.1 Mine water geothermal

Potential environmental impacts

The main concern about mine water geothermal expressed in the reviewed literature is the wider impact on the environment due to changes in the hydrogeological regime. Due to the nature of mine water geothermal, hydrological impacts are likely, bringing about changes to surface landforms, ground water and surface water flow rates, paths and chemical composition.

Depression of the water table around the pumping zone is a major impact that can occur for systems where there is no reinjection of the fluids. Lowering the water table can impact flow in nearby streams, wetlands and lakes water levels if the groundwater is in continuity with these settings (Younger and others, 2004). During the extraction of coal bed methane, water tables are lowered to desorb methane from the coal surface, which is held in place by the hydrostatic pressure of the formation water residing naturally within the coal seam (Environment Agency, 2014). Therefore, consideration should be given to the impact of any methane release due to the lowering of the water tables during geothermal operations.

Mine water geothermal could pose a risk of contaminating the surface environment and surrounding or overlying groundwater aquifers and water bodies if mine water is directly discharged to water bodies. This contamination can also occur from leaks in the well casing during drilling or later during the operation phase, or from the surface infrastructure. The risk to the natural environment of these leakages is due to the high concentrations of calcium carbonate ($CaCO_3$), iron (Fe), sodium (Na), potassium (K), sulphate (SO_4), zinc (Zn), arsenic (As), cadmium (Cd), copper (Cu) and lead (Pb) commonly found in mine water. Where the mines contain large amounts of pyrite (FeS_2), there is an elevated risk from high Fe and sulphur (S) contents in the fluids due to pyrite oxidation (Younger and others, 2004).

Where mine water does flow into local soils and aquatic systems, iron ochre can form. Iron ochre is formed by iron particles being transferred in the water, which forms a slurry of iron hydroxide ($Fe(OH)_2$) upon contact with the atmosphere.

Alternatively, where Fe bacteria are present within the water table, the bacteria can produce a gel-like mass due to oxidation of the Fe. As a result of this, reddish deposits and staining in watercourses and on the surface of the soil are observed. These deposits can also produce an odour which may be unpleasant (Younger and others, 2016).

Ochre deposited by iron-rich waters can have a devastating effect on the freshwater ecology as the ochre smothers the riverbed. Natural fish populations including salmon, sea trout and freshwater trout are especially susceptible to such pollution as they require open, well-aerated gravels to lay their eggs in. The low-pH water extracted from the mine can also be directly toxic to the local environment. Of note is the damage this causes to fish gills. The acidic conditions are noted to increase the solubility, and therefore mobility, of metals such as aluminium (Al), Cu, Pb, Zn and Cd. These metals can accumulate in aquatic organisms and affect the food chain (Younger and others, 2004).

Any solid waste prevalent in the mine water, including sediment and other subsurface components, can cause accumulations of foreign particles where the fluid is discharged onto the surface. Such accumulations include carbonate (CO_3) or sulphate (SO_4) salts, silica (Si), and silicate (SiO) salts, which precipitate upon temperature drop and accumulate as solid waste (Sayed and others, 2021). Any excavation of the mine required to set up and operate the geothermal plant, results in additional solid waste that needs to be disposed of at the surface.

The fluids abstracted from the geothermal fields usually contain gases (such as hydrogen sulphide (H_2S)) and volatile material (those including and derived from boron (B), carbon (C) and S) (Sayed and others, 2021). H_2S is a toxic gas naturally produced in coal mines and is mainly responsible for offensive odours, but can also impact health with repeated or prolonged exposure.

Another important effect discussed is the impact on land subsidence in the local vicinity of the mine water geothermal operations (Younger and others, 2004). Subsidence related to mine workings can be caused by 4 main processes:

- The extraction of water can cause fine-grained sediments to compact.
- In former pillar-and-stall mine workings, where pillars of coal were used to support the roof of the mine, pillars may rupture due to cycles of injection and production of water from and back to the mine galleries (known as cyclic cooling-warming thermal effects) (Todd and others, 2019).
- In longwall mining, where a long wall of coal is mined in a single slice, there is a risk of delayed compaction and in the goaf layer (waste left in old mine workings), which can cause the collapse of mine workings and delayed subsidence (Donnelly and others, 2008).
- In some mine settings with active, shallow faulting regimes, the faults can be reactivated due to an increase in pore pressure during operational phases (Younger and others, 2016). This can result in instabilities of the

ground (such as subsidence, collapse) and therefore surface or subsurface infrastructures. The reactivation of faults can result in the introduction of new pathways for fluids to move both within, and to be released from, the subsurface (Atkins, 2013).

As with any drilling operations, additional wells constructed into the mine to extract and reinject the fluids, present a risk of noise pollution and wildlife disturbances in the local area. Local disturbance of the natural habitats and biodiversity can occur due to the change in land use (Sayed and others, 2021).

Source-pathway-receptor model

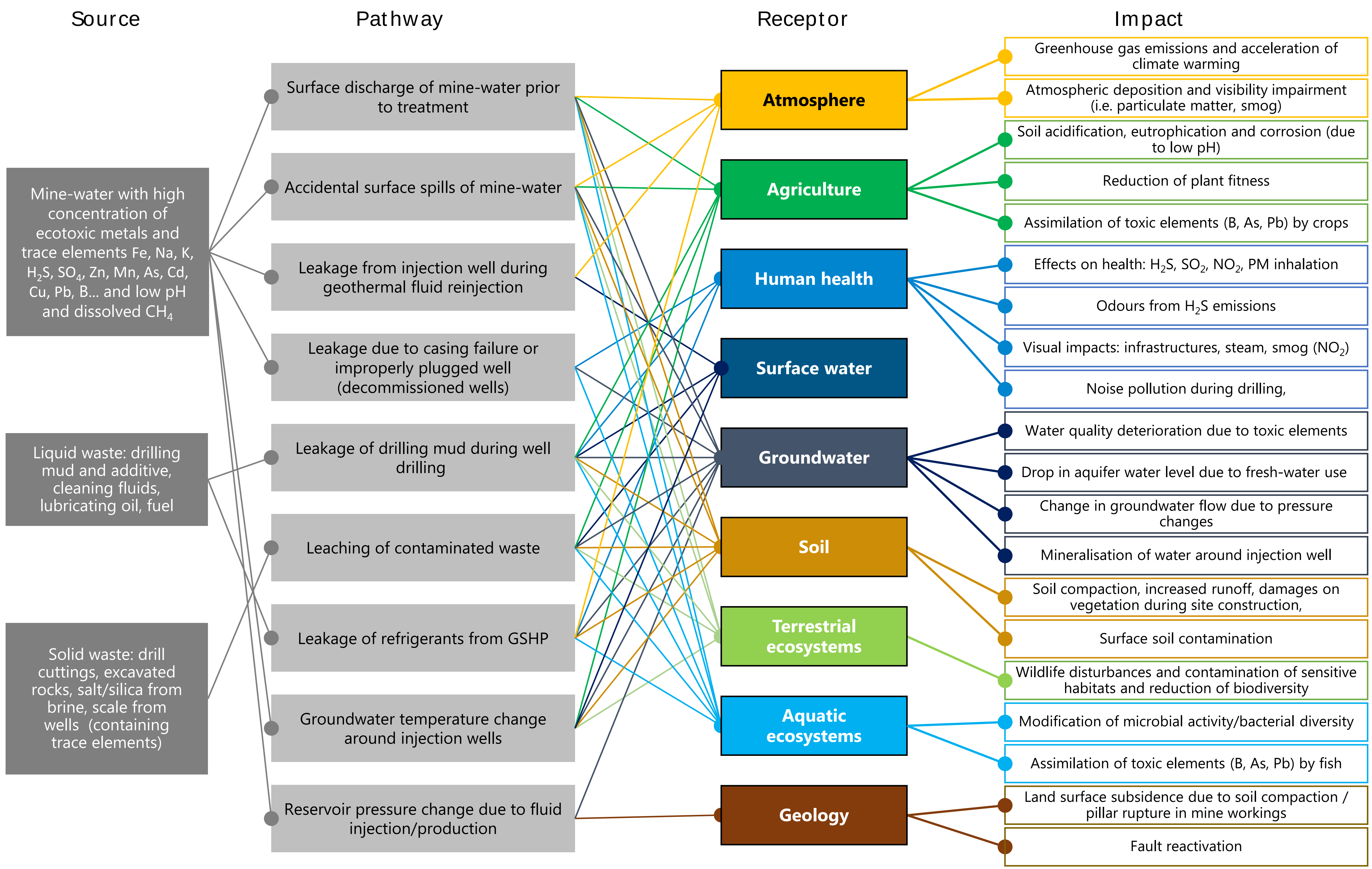


Figure 53: SPR diagram for mine water geothermal heating and cooling

Observations and knowledge gaps

There are 2 main environmental concerns related to using mines for geothermal. The first impact is on water quality and quantity. The discharge of fluids and soil waste from the mine, which commonly contain large amounts of metals and trace elements, have been shown to have detrimental effects on the natural environment. Changes to the hydrogeology could occur at both the local and wider scale. This is an area of ongoing concern, and one that needs understanding better. The impacts of the changes to the water levels are even more important if the extracted fluid is not reinjected, as it is more likely that ground water depletion may occur. The resulting impacts on surrounding water bodies (ground/surface) in the process need considering fully at each development (Younger and others, 2004).

The second impact is on soil and rock compaction and ground movement due to subsidence and collapse of the mines because of water movement. A review by (Andrews and others, 2020) looking at the internal structure of collapsed pillar and stall mine workings near Whitley Bay in England concluded that when working with these mines, the products and outcomes of mine collapse should be understood. This would help to predict the hydrogeological effects in advance of any drilling or site preparations. There is currently a lack of understanding about this, across most locations, and therefore further detailed research into mine collapses and their outcomes is needed. Researchers highlight that it is important to understand how well connected the fault and fracture network overlying the workings is. It is fundamentally important to the success of the project, and to mitigate against potential environmental impacts, as faults can either increase or degrade flow pathways.

It is recommended that the scale of the potential impact of a mine collapse or related ground subsidence is considered. This will help to fully understand the potential environmental impacts that mine redevelopment poses. This could be achieved by using numerical modelling and monitoring of ground subsidence, for example, using GPS or InSAR or monitoring ground fractures though field investigations.

The environmental impacts on flora and fauna of leaked, or released, mine water are well covered in the literature, as mine water has been studied for a considerable length of time in the UK, especially in areas of rejuvenation of existing mine workings. However, the impacts of mine water on the local environment will be site specific (Díaz-Noriega and others, 2020). Consequently, establishing sound assessment protocols (including baseline studies), that apply to a variety of projects, is likely to be of more use to the industry than site-specific research that cannot readily be applied to other locations. Areas that require further understanding may include approaches to geochemical investigation into the water extracted from the mine and effects on the natural environment, including critical concentration modelling. Standards and processes surrounding regular chemical (water and gas) sampling, temperature and water level measurements at boreholes located at different locations across a mine water geothermal site could provide clear benefits with respect to system understanding, designs and monitoring during operation. This would enable better insights into the interconnectivity of the mine proposed for development. Standardisation of modelling approaches to better characterise the internal state of the system must be used together with all available data from the mine, with care taken to include archived material from old, abandoned mines (Díaz-Noriega and others, 2020).

5.1.2 Petrothermal

Potential environmental impacts

In high-temperature geothermal systems (temperature exceeds 160°C), steam is generated and used to drive the turbines within the plant and, in turn, generate power. In a dry steam power plant, steam is produced and non-condensable gas can be released as those systems are generally 'open'. Similarly, flash steam power plants generate steam from high-temperature geothermal fluids. Although thermally spent geothermal brine can be reinjected, it is sometimes discharged on the surface in geothermal ponds (for example, the Blue Lagoon, Svartsengi, Iceland). Flash steam power plants have a higher risk life cycle. This means that the running of the plant has potentially more impacts than other geothermal operations, where dry steam is used and condensation and steam volume change are better controlled. Most of the life cycle environmental impacts of a flash power plant are contributed by the surface activities (Liua & Ramireza, 2017).

The sources of contamination at a geothermal power site will vary depending on the setting, but may include some or all of the following (Manzella and others, 2018):

1) Gases can be contained in variable quantities in high temperature fluids, including non-condensable gases (such as CO_2, H_2S, CH_4, H_2, He, mercury (Hg), argon (Ar), O_2, nitrogen (N), trace elements (As, B, radon (Rn), antimony (Sb)) and aerosols.

Although abatement systems exist to reduce emissions of CO_2, H_2S and Hg from the plant, there is the potential for varying amounts of CO_2 and other non-condensable gases to be emitted from dry and flash steam geothermal plants during their operation. While geothermal steam is condensed after passing through the turbine, some CO_2 within the fluid might not condense, and instead passes through the turbine to the exhaust system, where it is released into the atmosphere through the cooling towers. Non-condensable gases are generally emitted downstream of the condenser and at the outlet of the cooling towers, and can also be emitted during well drilling (by degassing from discharged waters) and during plant shutdown (free steam discharge). CO_2 is primarily sourced from the reservoir rock and the emissions vary over the production time (Dhar and others, 2020). H_2S is formed in anaerobic environments and is unstable in oxidising environments, enabling it to readily react with other materials, especially steel. Hg is a trace element that can be found in the mineral form (cinnabar) or as small droplets and can be emitted as a non-condensable gas or as a salt, dissolved in the drift of released steam or process vapour. In the atmosphere, Hg can form a toxic methylmercury that has potential for contaminating water, fish and other animal organisms and therefore the human food chain.

Arsenic (As) is naturally found in organic and inorganic compounds in different oxidation states. In geothermal fluids, it remains in the aqueous phase and can be easily reinjected with the geothermal fluid, but small amounts can be emitted by the drift in cooling towers. Boron (B) is toxic when ingested, but necessary for plant growth. It is found in evaporitic deposits from hydrothermal water as salt and forms boric acid (H_3BO_3) in the drift. It can also combine with ammonia (NH_3) and form ammonium borate ($H_{12}BN_3O_3$) which can cause irritation.

Aerosol particles (solid particles or water-soluble gas) can mix with drift emitted from cooling towers and be released into the environment. Primary particulate matter, NOx and sulphur dioxide (SO_2) is not directly emitted by geothermal plant. However, secondary particulate matter may form from the oxidation of H_2S (produces SO_2) and from NH_3 (that produces ammonium hydroxide (NH_4OH) when combined with water). Water-soluble gases (NH_3, H_3BO_3) can be transported into the atmosphere through air stripping, and drift from the cooling towers can be deposited on soil and washed out by rain. The products of H_2S and NH_3 oxidation contribute to soil acidification.

2) Hazardous liquid and solid waste can be produced from drilling activities, during the plant operation and plant shutdown.

- During drilling, liquid waste includes the drilling mud (bentonite, can also contain barium sulphate ($BaSO_4$) and synthetic polymers), drilling mud additives, cleaning fluid waste and geothermal brine. Solid waste includes the drill cuttings, excavated earth and rocks, salts and Si contained in geothermal brine.
- During plant construction, excavated earth and rocks, unused materials from building access roads and pipe laying, plastics from packaging, metallic waste, waste timber, rubbery materials, filters and materials contaminated with lubricating oil and urban waste are potential sources of contamination.
- During plant operation, there is the potential for contamination from liquid waste, including the waste produced from H_2S abatement waste or cooling chemicals (Dhar and others, 2020), spent geothermal fluids and petroleum products such as fuels, together with lubricating oils and other chemical agents. Waste can also include scale from cleaning wells or pipelines and filter materials (Kagel and others, 2007), and parts of old machines (such as ferrous and plastic scrap) and urban waste (Manzella and others, 2018).

3) Noise can be a source of environmental pollution in high temperature geothermal power plants. Noise can occur during the construction phase of drilling due to site traffic, drilling operations and during the well testing. During plant operations, most of the noise is generated from the cooling towers (~90 dBA) and in the pipelines. The average noise is about 71 to 83dB, exceeding

World Health Organisation community noise standards of 55dB for outdoor spaces and 70dB for industrial districts (Chen and others, 2020).

The pathways to the environment depend on the nature of the contaminants, and can occur at all stages of the power plant life cycle. Drilling accidents, well-casing failure, pipeline leakage, discharge of fluids to open water, accidental spills of mud and geothermal fluids stored in tanks prior to reinjection and other surface spills of contaminated or wastewater can be possible pathways for the contamination of surface and groundwater (Tester and others, 2006). Leaching of contaminated solid waste or of the drift from cooling towers, once deposited in the soil near the power plant, can contaminate soil, water and sediments. All non-condensable gases emitted from the cooling tower can be directly emitted in the atmosphere. The formation of aerosols or other particles when gas and water are combined can lead to the deposition of toxic elements away from the power plant. This can contaminate the soil and surface or groundwater, but also threaten the food chain through ingestion by animals or absorption by plants.

Pathways may be created in the subsurface to overlying aquifers or surface waters, by fractures induced by the geothermal operations, including aquifer stimulation and associated micro seismicity (Atkins, 2013). When fluid is injected during fracture stimulation, or during operation of the field, it may migrate along these pathways, resulting in potential contamination of water bodies. The size and impact of these fractures and resultant pathways will be site specific and, as such, each area should be evaluated appropriately. This would likely include understanding the regional rock physics, stress fields, mapping of the subsurface region for existing faults and fractures, collating topographical information, and gaining an overview of the regional hydraulic gradient (Environment Agency, 2020).

Naturally occurring radioactive material (NORM) can be brought to the surface when water is pumped for geothermal utilisation and be released at the surface in case of discharge of geothermal water (open-loop plant), or form scaling/deposits in the plants (Vasile and others, 2017). As NORM is transported in the system fluids, it follows the same pathways as previously discussed, including through induced fractures.

In EGS systems, this is especially important as hydraulic stimulation requires a large amount of water to be used which, depending on its source, can increase the effects on the changing hydrogeology. Areas of consideration include water quantity, ground subsidence, soil desertification and groundwater or surface water pollution. Reinjection of fluid is the preferred option to avoid ground subsidence and prevent surface water or soil contamination. However, if the water from a geothermal reservoir is not to be reinjected into the system, the treatment and discharge of water at the surface needs to be considered (Dhar and others, 2020).

Regarding the impact of NORM from deep hot geothermal, the main receptors are humans, animals and plants, where the carcinogen elements are received through the pollution of the surface water/soils (that is, assimilation by plants). Rn gas is an example of a human carcinogen element that is formed from the radioactive decay of 238U. This can be found in high concentrations in high-temperature geothermal fields. One study that evaluated 34 locations around the main geothermal exploration and exploitation area of Turkey, showed soil radon reached concentrations of 3,700Bq/m^3, with the highest levels being associated with either tectonic faults or drilling wells (Ayadar & Diker, 2021). Regulations exist in England (Health and Safety Executive, 2021) to ensure that the levels of radioactive substances, including NORM, stay below the acceptable levels.

Receptors include the soil, surface water, groundwater and wildlife, and can also directly or indirectly impact agriculture and fishery activities and human health. Example of impacts include:

- reactivation of faults, creating pathways for the movement of fluids (Atkins, 2013)

- gaseous and volatile emissions: CO_2, H_2S and solid particles affecting workers/social impacts (for example, toxic emissions with potential health effects, visual impact of steam and smog). This includes the offensive odours caused by gas such as H_2S emitted from fluids abstracted from geothermal fields
- solid waste: the fluid (brine) from the geothermal fields is usually saturated with rock formation constituents, including $CaCO_3$/SO_4 salts, Si, and SiO salts, which precipitate upon temperature drop and accumulate as solid waste. Leaching of solid waste deposited at the surface can lead to soil and surface water contamination
- alteration and contamination of soil, surface water and groundwater by geothermal brine, discharged at the surface or due to leakage from the injection and production wells
- wastewater: during drilling or during the plant operation, water can contain foreign materials (such as chemicals, additives) and/or salts from soil/ rock formation, which can be hazardous to the environment upon discharge to water bodies
- water consumption: large volumes of water are required during the drilling operations. The operation of the power plant may also require a source of fresh water in order to condense steam in the cooling towers
- thermal pollution: the release waste heat to the environment with wastewater or into the air. Reinjection of the thermally spent geothermal brine into the geothermal reservoir can also lead to cooling of the subsurface
- disruption of natural habitat and impacts on biodiversity: due to the land use and change in the local site of the geothermal plant

- noise pollution and wildlife disturbances linked to drilling operations

Most papers about the environmental impacts of conventional EGS focus on the injection-induced seismicity during operation (Rathnaweera and others, 2020) and can depend on the system set-up. For example, fluid can be injected into fractured rock far away from a fault system, into fractured rock close to a fault system, and directly into a fault system (Zhang and others, 2019).

Injection-induced seismicity in a geothermal reservoir can be associated with both thermal and poro-elastic stresses, as the working fluid cools down the reservoir rock and increases the pore pressure (Johnson & R, 2017; Yu and others, 2018; Norbeck and others, 2018). These effects are mainly caused by pore pressure diffusion due to differences in fluid pressure or by the interaction between the hot reservoir rock and cold injected fluid which causes rock contraction (Kim and others, 2018).

During the construction and operation of an EGS facility, there are 4 main stages where fault instability can be triggered (Okamoto and others, 2018). These are during:

- the initial injection of geothermal working fluid, including at the stimulation stage
- the withdrawal of working fluid from the geothermal reservoir
- reinjection of working fluid after heat extraction
- the shut-in stage

The presence of pre-existing faults near the geothermal field tends to control the occurrence and magnitude of induced seismicity (Kim and others, 2018). Studies show that long-term injection operations are more likely to generate larger magnitude seismic events than short-term injection operations (Zhang and others, 2019). After the shutdown of the well, post-injection induced seismicity can occur because of poro-elastic effects (a change in pore pressure distribution along the faults) or thermo-mechanic process (slow cooling by conduction).

As with all drilling procedures, there are risks associated with the borehole integrity (Manzella and others, 2018). The drilling mud, which can contain bentonite and barium (Ba) and synthetic polymers, can have adverse effects on the local flora and fauna if leakage occurs at the surface. If the wells are improperly plugged, connection paths for contaminants might be created between separated water-bearing zones along the well casing, leading to cross-contamination of groundwater aquifers (meaning that contaminants can move between aquifers along the well casings) (Chen and others, 2020). To limit the impact on the surface environment, drill cuttings and excavated earth and rocks need to be disposed of in a suitable way.

During construction of the plant, noise from site traffic and drilling operations can be a risk to the local environment. During the operation phase of the geothermal plant, the main source of noise is from the cooling towers (potentially as high as ~90dBA) and in the pipelines. Though it should be recognised that cooling towers may not be required for hydrothermal facilities in the UK given the lower geothermal temperatures. The plant construction can also lead to a change in local natural habitat and biodiversity because of the change in land use at the local site of the geothermal plant. Increasing soil compaction can modify the physical properties of soil and increase the surface run-off, preventing plant growth.

As previously discussed, offensive odours can potentially be created by the geothermal facility, as fluid extracted from the geothermal fields usually has some gases (such as H_2S) and volatile material (Sayed and others, 2021).

Source-pathway-receptor models

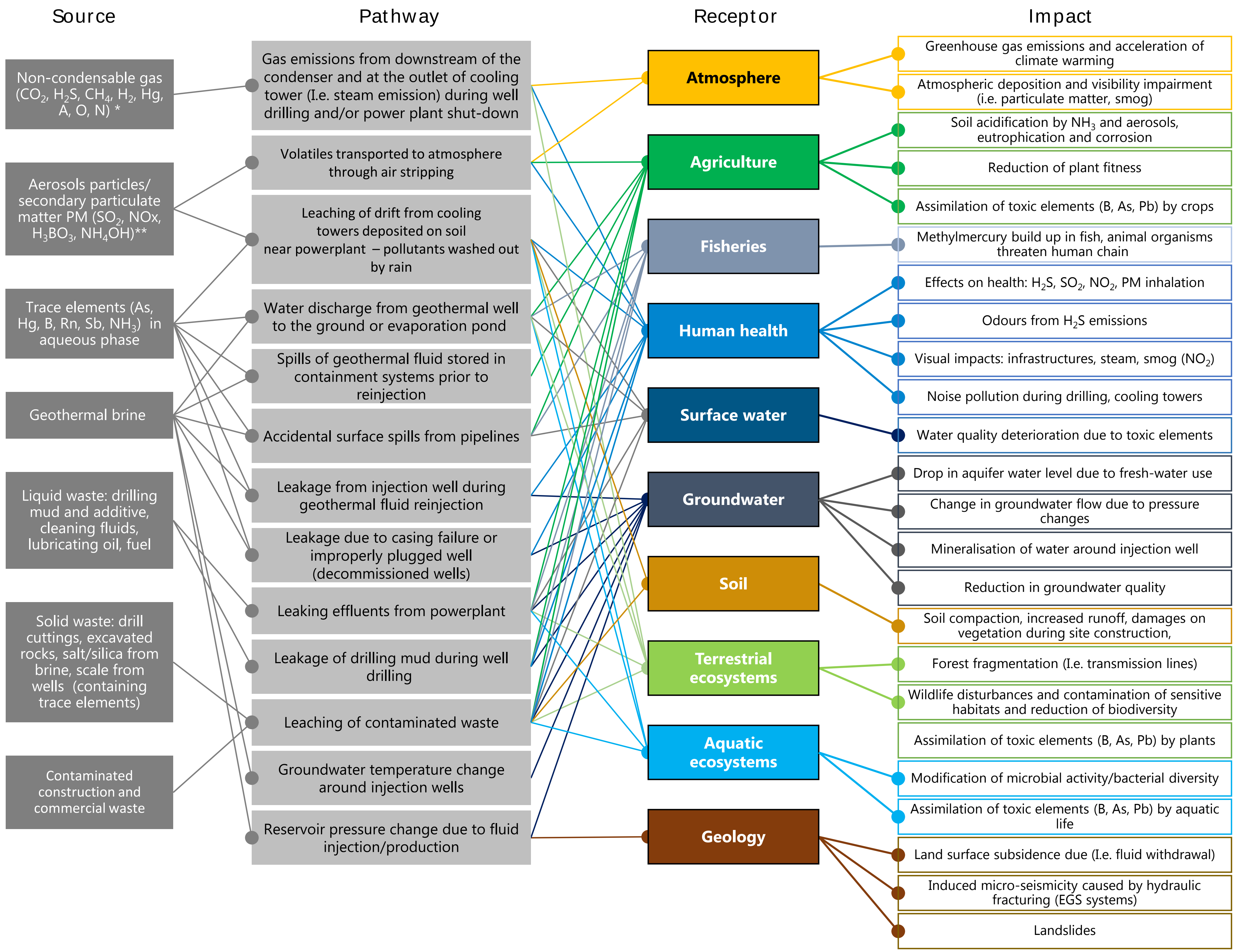


Figure 54: SPR diagram for petrothermal geothermal systems

Observations and knowledge gaps

There appears to be several areas where there is a lack of compelling research regarding the impact of petrothermal systems. As dry or flash steam plants are not expected to be used in the UK, binary plants are likely to be the predominant type of geothermal plant. Therefore, there is little concern over non-condensable gases (NCGs) released through the cooling mechanism. The main gaps in knowledge about petrothermal systems include:

- impact of metals released, the resultant fluid (brine) composition and hydrogen sulphite emission control
- detailed understanding of thermal–hydrologic–mechanical–chemical related processes and their impacts on the reservoir (Gan & Lei, 2020)
- impacts of fluid spill into soil, surface and subsurface ecosystems, including microbiology (Hyun and others, 2020)
- for EGS, modelling around the high-water demand, and the amount of loss due to leakage in the subsurface
- emissions of non-condensable gases, trace elements and aerosol particles into the atmosphere, although the importance of this is limited for the UK
- transport of NORM from the deep hot rocks to the surface through fluid related pathways
- liquid and hazardous solid waste discharged during drilling and plant operation
- water consumption and the effects on the local aquifers/surface water
- soil, surface water and groundwater contamination by geothermal brines
- induced seismicity. Regarding the induced seismicity risk for these deep extraction methods, there is no earthquake prediction approach that is currently reliable. There is much work to be done to improve this, with the aim of providing insight into the impact of injection-induced seismicity and the damage level. Assessment can be based on predicting the maximum magnitude, using statistical, physics-based, and hybrid forecasting approaches (Rathnaweera and others, 2020). Statistical forecasting approaches require analysis of the catalogues of recorded seismic events before and during reservoir stimulations, including occurrence, time, magnitude, and event locations. Physics-based forecasting simulates the physical change of the reservoirs induced by fluid injection and indirectly uses the recorded catalogues for model calibration. When these 2 methods are combined, a hybrid forecast is produced (Rathnaweera and others, 2020)

In addition, understanding the composition of brines in the working fluids and their impact is an area that is not commonly discussed in the literature within the UK. Groundwater flow pathways and their connectivity with aquifers and deep faults would need to be assessed and explored on a site-by-site basis to gain full insights into the potential for environmental impacts.

5.1.3 Hydrothermal

Potential environmental impacts

Despite differences related to their technology, the environmental impacts of petrothermal and hydrothermal energy systems are very similar.

One of the main concerns about the extraction of heat from deep systems is related to the chemistry of the geothermal fluid, or brine. Deep hot water can contain dissolved CO_2 in the form of bicarbonate (HCO_3) ions (Manzella and others, 2018; Dhar and others, 2020). As this fluid is brought to the surface, it undergoes a drop in pressure, which causes a precipitation and deposition of $CaCO_3$ and other salts contained in the geothermal brine, as well as a release of the CO_2 gas. However, where binary plants with air cooling are set up to function as a closed-loop system, no CO_2 should be emitted as the geothermal fluids are never exposed to the atmosphere. These are proposed as the main type of operation for hydrothermal plants in the UK, and therefore the release of $CO_{2,}$ and other non-condensable gases on the atmosphere should be negligible.

Although binary power plants are closed systems, potential surface environment contamination during the plant operation can result from working fluid or chemical waste leaking from the power plant or from geothermal fluids leaking from pipelines or the storage tank prior to reinjection. Although they are generally found in lower concentration than in high-temperature geothermal fluids, toxic trace elements such as Hg, Pb, As and B can have adverse effects on the surface environment. They can be ingested by animals or can reduce plant health. Pollution can also result from leaching of solid waste such as filter materials (Kagel and others, 2007) or industrial waste (Manzella and others, 2018).

As discussed in the petrothermal section, NORM can be brought to the surface in fluids that have originated from deep rocks, including sedimentary rocks with decaying organic material (including hot shales). One study based at Balmatt, Flanders in Belgium measured the natural radioactivity levels of 238U (uranium), 234U, 226Ra, 228Ra, 210Pb, and 210Po (polonium) in formation water resulting from the operation of a geothermal doublet drilled into a limestone reservoir at a depth of about 3km (Vasile and others, 2017). The geological layer above the reservoir was found to be rich in U and Th, while the layer of the reservoir was particularly rich in 226Ra. Despite this, results showed low values for the concentration of U, thorium (Th), 210Pb and 210Po in the formation water and in the precipitate.

As a result of dropping water levels, together with the different soil responses to any injected fluid, the ground can be subject to cracking and subsidence (Sayed and others, 2021). This is typically restricted to the area directly above the point of extraction, but can radiate out depending on the geology and direction of the watercourses. Additional ground movement can be caused by fluid circulating in the geothermal field, creating a variation in the fluid pressure in the ground formation, which can lead to rock fracture (Sayed and others, 2021).

A rise in groundwater temperature can modify the soil pH and mobilise previously immobile contaminants to flow into the adjacent aquifer. For deep geothermal systems, the effects on groundwater are not expected to be significant. This process tends to increase the toxicity of any stored pollutants in the soil. It occurs through the combined effect of an increase in the solubility of the contaminants within the fluid and a reduction in their adsorption capacity, therefore releasing the components into the water (Knauss and others, 2000; Noyes and others, 2009).

Hot water extraction and cooler fluid injection can also alter the groundwater temperature, which may have an effect on the local microbial and bacterial diversity. Thermal plumes in the subsurface will tend to propagate according to the direction of the groundwater flow, potentially leading to thermal disturbances of groundwater downstream and rivers, should suitable pathways be available for fluid movement.

Source-pathway receptor models

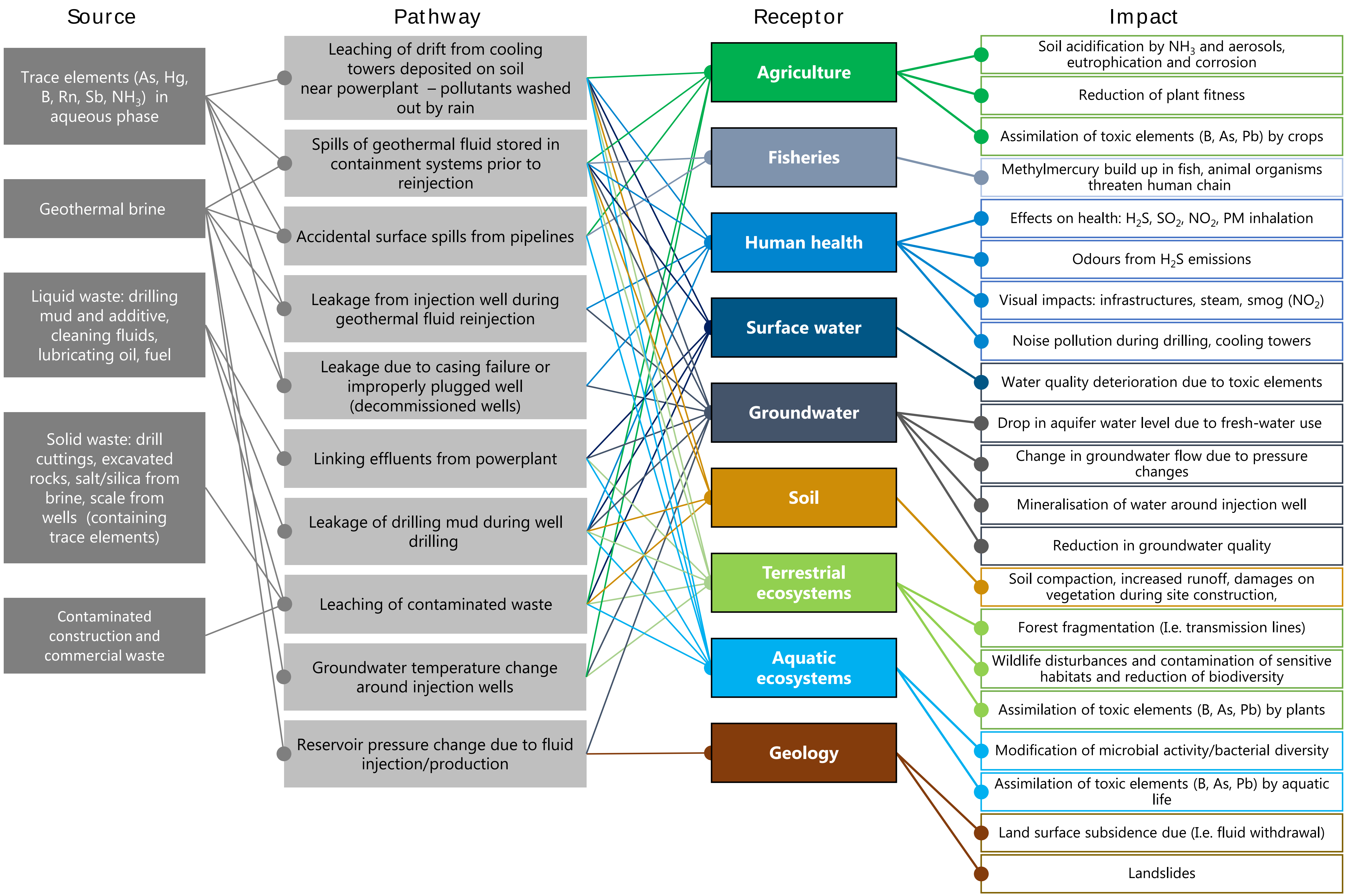


Figure 55: SPR diagram for hydrothermal systems

Observations and knowledge gaps

Important knowledge gaps for hydrothermal systems include the release of trace elements and NORM in aqueous phase, effects on the hydrogeology, spills of geothermal brine and effects from the drilling of the wells to operate the plant.

Induced seismicity introduces a site-specific risk and it is recommended that there are comprehensive investigations of site stress fields, with detailed geological and seismotectonic studies to identify faults capable of generating damaging earthquakes that could create contamination pathways. There do not appear to be full investigations into the use of technologies that maintain a balance between produced and reinjected fluids (and therefore minimise the pore pressure changes at depth) in the reviewed literature.

There should be consideration of soil properties and contamination levels surrounding geothermal resource sites, together with vegetation and wildlife habitat responses. Environmental monitoring should be conducted in surrounding groundwater aquifers, soils and/or rivers (water level, chemistry, temperature) to detect any impact from geothermal reservoir utilisation.

Waste should be carefully managed during drilling, plant operation and at the end of life. Waste needs to be stored safely in special locations and any fluids need to be stored in sealed tanks before being recycled or disposed of.

5.2 Retrievable energy storage

5.2.1 Compressed air energy storage (CAES)

Potential environmental impacts

The following environmental impacts related to subsurface CAES storage have been identified through this study (Evans & Carpenter, 2019) (Beckwith & Associates, 1983):

- air quality and climate, pollutant emissions
- water quality and consumption, wastewater discharge and hydrological impacts
- thermal alteration of subsurface energy storage zone (rock and groundwater)
- geological structure and seismicity, including rock cavity closure by altering stress fields, rock strengths, and/or removal or redistribution of material, which may lead to surface subsidence
- subsurface erosion and weathering, which may lead to cavity failure and subsequent surface subsidence, increases of porosity/permeability, carryover of subsurface materials in the air stream, and geochemical reactions that could change the physical character of aquifers

D-CAES requires fossil fuels (natural gas) for combustion in the turbine during the generation phase. The production, combustion and transportation of natural gas to the CAES site will result in direct GHG emissions, including CH_4, SO_2, nitrogen oxides (NO_x), particulates and carbon monoxide (CO) (Duhan, 2018), (Evans & Carpenter, 2019) (Beckwith & Associates, 1983), each of which has a potential environmental impact on air quality and particulate matter, human health, soil acidification, photochemical oxidant formation, climate impacts, as well as leading to eutrophication potential and fresh water aquatic ecotoxicity potential (Duhan, 2018), (Bouman and others, 2016), (Evans & Carpenter, 2019).

Additional potential environmental impacts associated with CAES are mostly reservoir-specific and they are summarised in the following subsections.

Salt cavern construction and operation

During the solution mining process, significant volumes of fresh or low salinity (relative to cavern brine) water are required, abstracted from local rivers or from the sea. Abstractions from a local river can adversely impact the river system and the associated flora and fauna (Evans & Carpenter, 2019). The solution mining process used for salt caverns can produce a large volume of brine, often 8 times the final storage volume (Stone and others, 2015), (Pimm and others, 2019), and therefore can pose significant challenges when it comes to brine disposal.

There are 3 common ways to dispose of brine: discharge to surface waters, disposal into surface ponds, and deep well disposal. However, because of environmental issues such as soil and groundwater contamination, discharge to surface waters and disposal into surface ponds are largely discouraged or prohibited by regulations (Duhan, 2018) unless treated. Deep well disposal requires a suitable aquifer that can be shown to provide containment and is also subject to the regulatory process (Duhan, 2018) and would not be adversely impacted. Brine disposal through injection into the faulted strata typically associated with salt domes might induce seismic activity (Beckwith & Associates, 1983) and may also cause aquifer contamination.

In England, apart from the Portland gas storage project, where storage of some brine was considered in a deep saline aquifer, there have been no plans to inject brine from solution-mining into porous rocks (Evans & Carpenter, 2019). For projects such as Hornsea and Aldbrough in East Yorkshire, brines from construction of gas storage caverns at sites close to the shore were disposed of offshore (Evans & Carpenter, 2019). The environmental impact assessment required modelling of the brine plume and dispersion, in addition to modelling of the impacts on the local seabed and communities (Evans & Carpenter, 2019). For the proposed King Street energy facility in Cheshire, there was no local water supply or brine available, so a 58km twin pipeline parallel to the Cheshire Basin was constructed to an outflow point in the Mersey Estuary to bring in seawater as well as to take away brine from the solution-mining of the caverns. There were a number of environmental concerns regarding the pipeline route such as its impact on protected species and habitats (ActonBridge.Org, 2013). Cavern storage operations using brine compensated mode may also pose environmental risk as a large surface shuttle pond/reservoir is required for the brine, which must be secure from leakage and or failure.

In addition, similar to the situation in the oil and gas industry, the drilling of boreholes may lead to a series of pollution issues.

The injection of air to form a bubble within the aquifer may affect local aquifer pressures, water production and adjacent groundwater (Evans & Carpenter, 2019). Water levels in existing wells may fluctuate due to long-term formation pressurisation that can occur several years after operations begin. This could limit the use of aquifers due to sensitivities of the operation to drawdown (Evans & Carpenter, 2019).

Similar to other underground gas storage technologies, cyclic loading is experienced with compressed air storage in salt caverns. It is expected that the effect of cyclic loading on cavern stability is more severe in CAES as the frequency of the loading cycles is high (Duhan, 2018). In order to maintain the geo-mechanical stability of reservoirs to avoid over-pressuring and fracturing, or under-pressuring and collapse (Duhan, 2018), (Evans & Carpenter, 2019), it is important to keep the operation between maximum and minimum pressures and set pressure rate changes.

Major cavern stability issues include cavern closure, roof collapse, interbed slip, and tensile fracturing (Duhan, 2018).

Cavern closure is a major issue for salt cavern storage, due to the tendency for rock salt to creep in (Duhan, 2018). To generate maximum electricity, cavern operators would wish to extract the maximum amount of air out of the cavern. However, this situation might expose the cavern to extremely low air pressures that can increase the strain rate. In addition to low pressure, high temperatures also result in an increase in creep.

Roof collapse is possible due to one or a combination of the following reasons: low height/diameter ratio, low minimum air pressure within the cavern, inadequate roof shape, thin salt roof, and thin and incompetent non-salt roof (Duhan, 2018), (Donadei & Schneider, 2017). Movement in the cavern due to creep or roof collapse can be transferred to the ground surface and form a subsidence bowl (Duhan, 2018), (Beckwith & Associates, 1983), (Donadei & Schneider, 2017). In addition, cavern collapse or major damage around the cavern may cause micro-seismic events (Duhan, 2018).

Interbed slip is the result of differential deformation between non-salt interbeds and salt (Duhan, 2018). Non-salt interbeds do not creep, and during low pressure periods in the cavern, the stress difference between non-salt interbeds and salt increases, resulting in slip. In terms of consequences, the location of interbed determines the type of damage the slip will cause. The worst-case scenario is when the interbed slip occurs near the roof of the cavern, roof stability issues can arise and the casing can be damaged (Figure 56) (Duhan, 2018). When interbed slip happens in the cavern centre or top, interbeds will fall to the bottom of the cavern and potentially reduce the storage capacity of the cavern (Duhan, 2018).

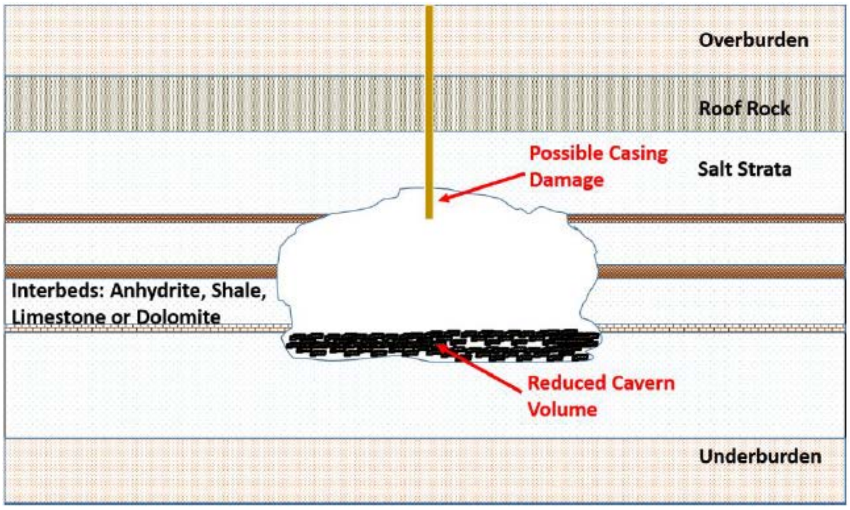


Figure 56: Consequences of interbed slip: casing damage and reduction in volume (Duhan, 2018)

Injecting compressed air at very high pressure is desired so that more air can be stored at a given time. However, high cavern pressures can lead to fractures in the cavern roof and walls (Duhan, 2018). Tensile fractures can even extend up to non-salt roof rock if the salt roof is thin and cavern pressure exceeds the fracture pressure of the non-salt roof. In this scenario, the efficiency of the CAES plant will decrease as compressed air will leak out of the cavern (Duhan, 2018).

Multiple caverns might be required in a large-scale CAES facility due to operational reasons and limited salt strata thickness reasons. In this case, it is important to ensure the distance between caverns is sufficient to avoid cavern stability issues (Duhan, 2018). The salt rock mass between caverns is called the 'pillar', and the distance between caverns is the 'pillar width'. During CAES cyclic loading, induced stresses on the cavern boundaries are transferred to the pillars. Pillar width should be 4 times the cavern diameter to avoid large deformations or failure of the pillar (Duhan, 2018).

For the isobaric operating mode mentioned previously, an additional risk is associated with the failure of the surface compensating reservoir which may create flooding, causing significant damage to life and property immediately downstream of the reservoir (Beckwith & Associates, 1983). The water in the onsite compensating reservoir is likely to become highly mineralised and contaminated with pollutants during construction and operation. Therefore, failure of reservoir containment could also cause downstream degradation of water quality (Beckwith & Associates, 1983).

Porous reservoirs

The operation of CAES using porous reservoirs for storage presents a complex series of problems and environmental concerns (Evans & Carpenter, 2019) and it is governed by thermal, hydraulic, mechanical and chemical processes (Bo Wang, 2019), (Evans & Carpenter, 2019).

For the aquifer reservoirs, the elevated temperatures and pressures during short CAES operation cycles will have some impact on the physical and chemical conditions within the aquifer system and may degrade groundwater quality (Beckwith & Associates, 1983). Possible impacts include hydrolytic and oxidation reactions, mineral solutioning transport and reprecipitation, degradation of cement bonds, transport of fine grains, swelling of clay minerals, alteration of packing geometry and general reduction in elastic moduli and compressive strength (Beckwith & Associates, 1983).

Caprock integrity and possible damage will require assessment (Evans & Carpenter, 2019). During production, the reservoir pressure declines, which may lead to settling of the caprock and overburden, causing fracturing. Upon re-pressuring of the reservoir, the opening of fractures may result in gas/air leakage eventually to surface.

A cyclic operation may introduce cyclic stresses in the formation rock (Bo Wang, 2019), (Beckwith & Associates, 1983). Thermal-mechanical and thermal-chemical stresses may affect the integrity of the caprock and subsurface equipment (Beckwith & Associates, 1983). Increased pore pressures across a fault zone as a result of air injection can decrease the effective normal stress and, in some cases, cause an increase in seismicity along the fault zone (Beckwith & Associates, 1983).

Water and air cycling through the energy storage reservoir system will be at different temperatures to the surrounding rock and groundwater, causing thermal alterations. As a result, subsurface ‘weathering’ and erosion may occur (Beckwith & Associates, 1983). Erosion and weathering of subsurface rock would likely include: 1) grain and cement disintegration and micro-fracturing, 2) solutioning and redistribution of mineral components, 3) reduction in elastic moduli and compressive strength, and 4) thermal and cyclic fatigue of reservoir rock (Beckwith & Associates, 1983). SiO and CO_3 hydrolysis are among the most common mineral weathering reactions that may take place. Effects of such reactions include pH increases, production of potentially swellable clay minerals and residual solids, and cations and silicic acid in solution. Other important potential reactions are SiO, CO_3, and sulphide (S^{2-}) oxidations. Typical effects include precipitation of insoluble oxides and hydroxides; production of weak silicic, carbonic, and/or sulfuric acid; and additional pH decrease from subsequent hydrolysis of metal ions (Beckwith & Associates, 1983).

The potentially induced chemical impacts by CAES in a porous formation differ significantly from those of other gas storage, as air containing oxygen is introduced into porous geological formations that are long-free of oxygen (Bo Wang, 2019). Oxidation can take place in redox-sensitive conditions or rocks containing Fe minerals such as pyrite (FeS_2), which can partly or completely consume the oxygen (Bo Wang, 2019), (Beckwith & Associates, 1983). Gypsum ($CaSO_4$) scale could be precipitated during oxidation, occluding porosity and impairing CAES performance (Evans & Carpenter, 2019). Studies on acid mine drainage indicate that pyrite oxidation with ongoing supply of oxygen, for example, near gas wells for CAES operation, can lower the pH to very acidic conditions, which increases the risk of wellbore corrosion and degrades groundwater quality (Bo Wang, 2019), (Beckwith & Associates, 1983). Meanwhile, mineral precipitation induced by geochemical reactions may clog pore space, therefore reducing porosity and permeability of the storage formation, which would again lower the well deliverability and power output. During air extraction (especially because of inappropriate reservoir operation), some of the residual low pH formation fluid near the extraction well may be produced together with the air. The acidified formation fluid is therefore in contact with the subsurface materials and equipment and increases the risk of corrosion (Bo Wang, 2019), (Beckwith & Associates, 1983).

The injection of hot air may affect in situ subsurface conditions, both mechanically, geochemically and also biologically. Local aquifer flows might be perturbed during the injection, and in the presence of fluids, geochemical changes leading to hydrolytic and oxidation reactions, mineral dissolution and transport, which could all lead to permeability changes, weakening and increased reservoir integrity issues and impact on the groundwater quality (Evans & Carpenter, 2019), (Beckwith & Associates, 1983).

For depleted hydrocarbon reservoirs, in addition to potential formation and caprock integrity damage during production mentioned previously, injection into depleted hydrocarbon reservoirs will carry additional health, safety and environmental risks (Evans & Carpenter, 2019). Depleted natural gas or oil reservoirs present a possible safety issue as a result of residual hydrocarbons remaining in the depleted formation (Grubelich and others, 2011). Explosions are possible as the compressed air provides oxygen and the fuel is available from residual hydrocarbons and possibly CO_2 and H_2S in the formation, and heat or ignition sources could be provided via a variety of mechanisms (Evans & Carpenter, 2019), (Grubelich and others, 2011). Possible ignition sources include; the heat of compression energy generated as the air is compressed prior to injection, friction during compressed air charging or discharge, piezoelectric discharge from material within the formation, static electricity discharge or by a surface lightning strike (Grubelich and others, 2011). Furthermore, during the withdrawal phase, the air will contain some native gases from the reservoir, which will require separation and subsequent disposal. This can pose a real danger of explosion, while H_2S poses major health risks (Evans & Carpenter, 2019).

Mined voids: lined or unlined

The main impacts of this form of storage relate to the production of waste rock and its use or disposal, either on site (waste piles) or elsewhere (Evans & Carpenter, 2019). If on site, then leaching of the waste piles can lead to contamination of surface water bodies (Evans & Carpenter, 2019). Dust emissions may be significant if transport is required (Evans & Carpenter, 2019). If water enters the storage void during normal operations, as is the case in some fuel storages facilities, where containment is partly provided by hydrostatic pressure, then produced waters may represent a risk in terms of pollution. This could be due to having dissolved material on its way to the storage, but also within the storage, with the potential for picking up gases from mineral breakdown, bacterial growth or contaminants from former coal mines.

For lined rock caverns (LRCs), one of the essential issues facing underground CAES implementation is the risk of air leakage from the storage caverns (Kim and others, 2016). Compressed air may leak through an initial defect in the inner containment liner, such as imperfect welds and construction joints, or through structurally damaged points of the liner during CAES operation for repeated compression and decompression cycles (Kim and others, 2016). Unlined rock caverns storing compressed air as air cushion surge chambers attached to hydropower plants in Norway have suffered leakages. Problems of containment have also occurred in hydraulic compressed air storages in Finland (Evans & Carpenter, 2019).

Existing studies suggested that for the abandoned coal mines, the surrounding rock with a permeability of 10^{-16} to $10^{-19} m^2$ could impact leakage and efficiency of CAES (Tong and others, 2021).

In addition, the construction of rock caverns is associated with a higher level of risk and accident compared to salt caverns and porous storages due to excavation of the caverns by mining techniques that involve drilling, blasting and clearing the fallen rocks (Evans & Carpenter, 2019).

Source-pathway-receptor models

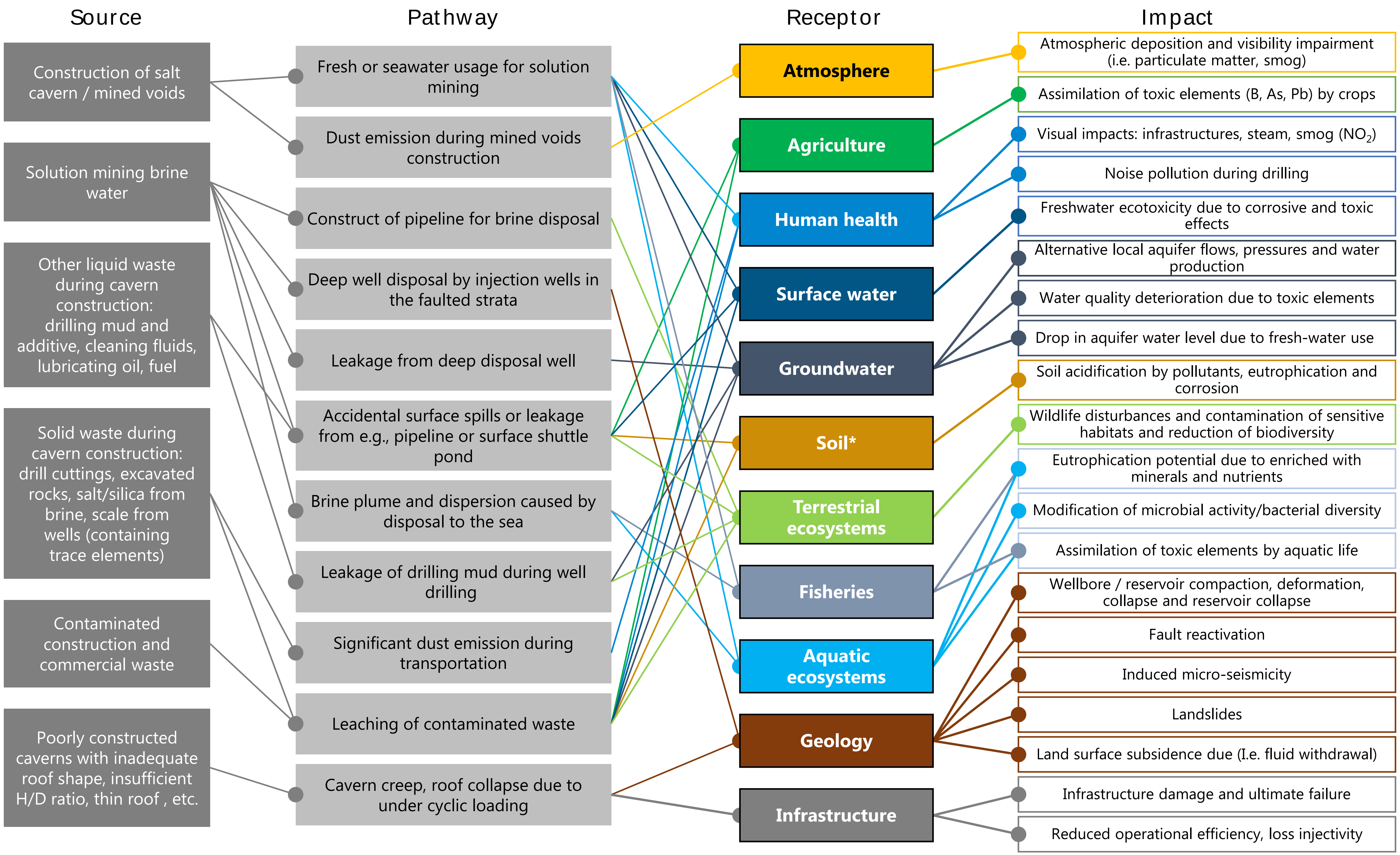


Figure 57: SPR diagram for salt cavern/mined voids for the mining and preparation phase

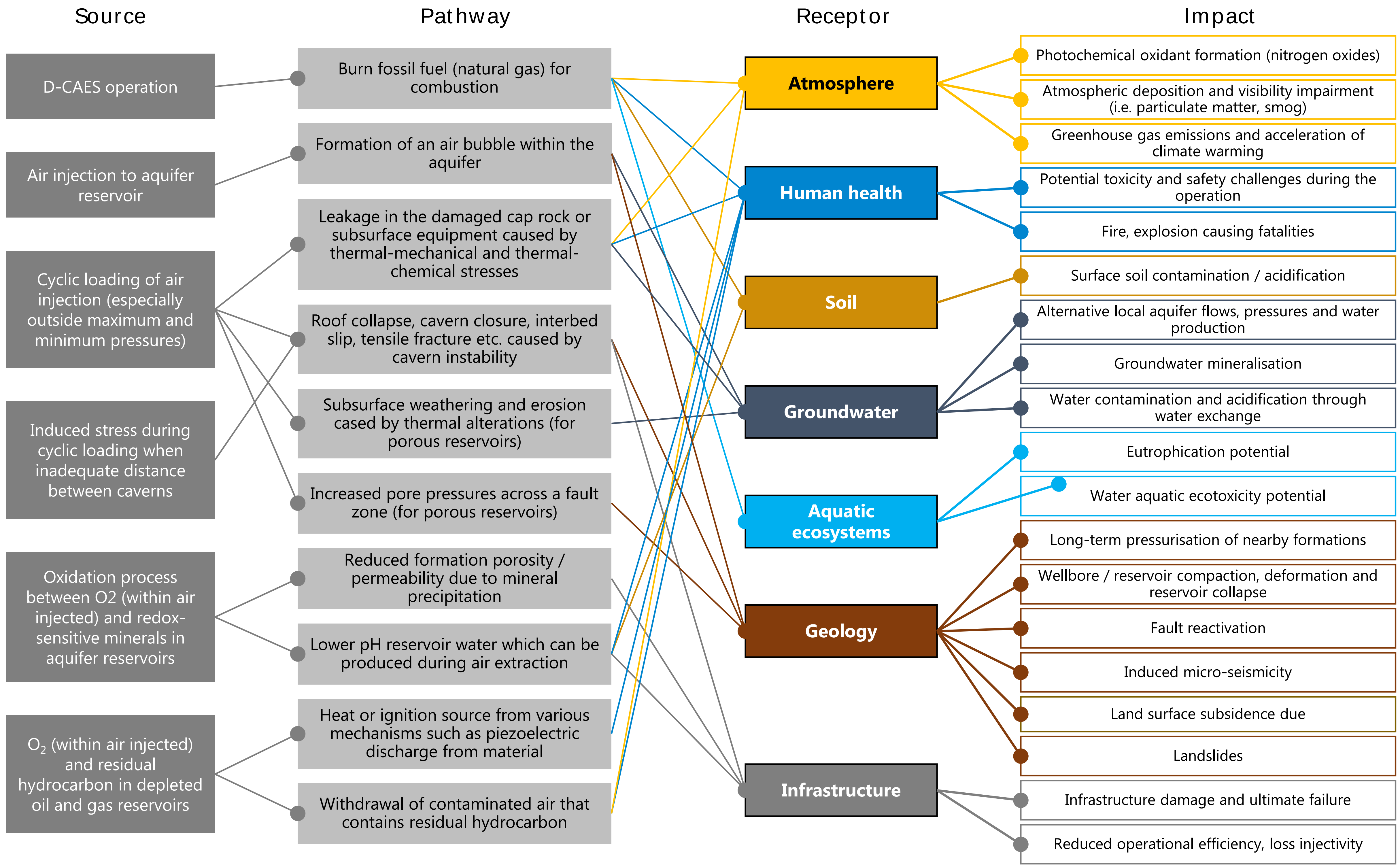


Figure 58: SPR diagram for CAES operations (excluding site preparation)

Observations and knowledge gaps

For underground CAES storage, the most significant potential environmental impacts are in the following 2 areas:

- Reservoir stability and suitability of the storage for frequent, rapid operation cycles, and high injection and withdrawal rates, due to the fact that CAES power plants are typically operated in an extremely fluctuating mode.
- The high reactivity of oxygen in compressed air, for example, forming compounds with the mineral constituents of the storage rock.

Although CAES is generally considered a mature technology, there are knowledge gaps, including the following.

Most of the existing reports tend to focus on global warming potential, with limited assessment of other environmental impacts; little information on the environmental risks of soil contamination has been reported. This is partially due to the lack of sufficient and transparent data and information on the subsurface activities such as drilling, and surface activities such as topside constructions (Liu & Ramirez, 2017).

Only a few reports have highlighted the potential environmental impact on local aquifers and groundwater quality caused by CAES cyclic operations. However, there appears to be a gap in knowledge about the exact mechanisms by which impact can occur and their scale.

For reservoir stability, more quantitative numerical simulations will be needed to better understand minimum and maximum operating pressures for different depths, and to further confirm the optimised cycling frequency.

As highlighted previously, because suitable salt formations are highly localised and might be preferred for other usage, further research on environmental impacts is needed to look at other options for the geological storage of CAES.

Although deep brine disposal has been carried out by the oil and gas industry worldwide, there is a lack of a comprehensive investigation of site suitability for deep brine disposal (Duhan, 2018), especially for petrophysical properties, such as porosity and permeability, that are important factors that influence a site’s brine disposal potential.

5.2.2 Underground hydrogen storage (UHS)

Potential environmental impacts

The potential environmental impacts of UHS are:

- hydrogen leakage due to diffusion and loss of containment
- hydrogen loss, hydrogen contamination and corrosion caused by microbial activities
- reservoir integrity issues, seismicity, fault (re-activation), subsidence caused by microbial and geomechanical reactions
- equipment failure and operational efficiency reduction caused by microbial and geomechanical reactions

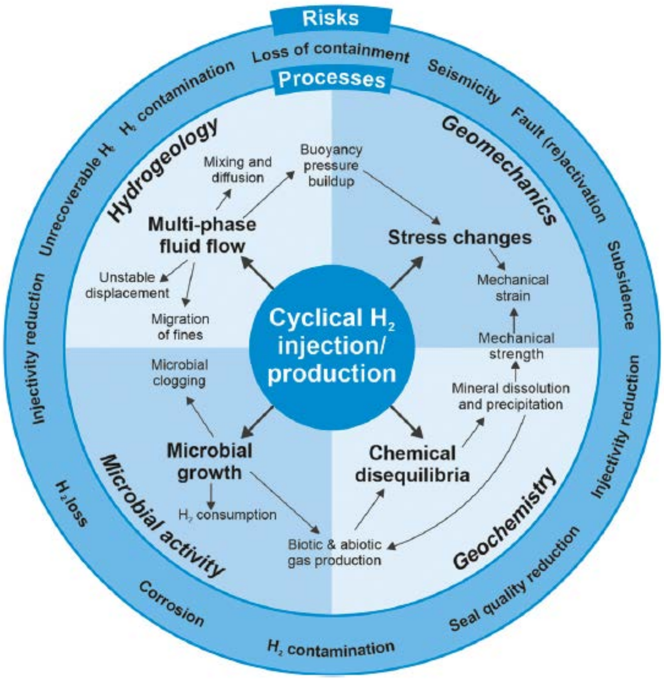


Figure 59: Processes and risks for UHS (Heinemann and others, 2021)

Hydrogen leakage

The high diffusivity, low viscosity and low density of hydrogen leads to a high mobility and therefore the hydrogen leak should be considered in UHS (Hemme & Berk, 2018). Hydrogen can penetrate through any permeable pathways or fissures in cap rocks and may leak from storage as a result of diffusion and dissolution (Zivar and others, 2020), (Hemme & Berk, 2018). Hydrogen diffusion is a slow and long-term process which may cause embrittlement of the subsurface steel components, leading to leakage pathways and equipment failure (Caglayan and others, 2020). One possible unintended and unpredictable leakage of hydrogen is through faults in porous reservoirs where the faults act as ‘fluid conduits’ (Hemme & Berk, 2018). Besides the explosion risk of hydrogen release, it can also have effects on soil and groundwater microbial communities and associated nutrient-cycles (Dopffel and others, 2021). If hydrogen reaches the surface, it would inhibit the growth of trees, understorey and grass (Hemme & Berk, 2018).

High-pressure storage of hydrogen presents a risk for riser pipeline failure that could potentially lead to unconfined vapour cloud explosions (UVCE) (Portarapillo & Benedetto, 2021). The combination of a low ignition temperature and wide flammability range increase the tendency for hydrogen to catch fire or explode, especially when it accumulates in confined spaces.

Accidental leaking of hydrogen into shallow aquifers may result in conditions where an enlarged hydrogen partial pressure will cause a highly-dissolved hydrogen concentration in the shallow groundwater, probably initiating typical redox reactions associated with hydrogen oxidation – see section below for more details (Berta and others, 2018).

Microbial activity

Hydrogen-driven redox reactions are predominantly microbiologically catalysed and are well known from aquatic geosystems (Berta and others, 2018). The hydrogen is an electron donor which makes it a source of energy for microorganisms. It must be assumed that porous natural gas storage sites are not sterile (DBI Gas and Umwelttechnik GmbH, 2017) and a number of different microorganisms can cause several anaerobic metabolic processes (Figure 60):

Reaction 1: Sulphate reduction: $4H_2 + \mathrm{SO}_4^{2-} + 2H^+ \rightarrow H_2S + 4H_2O$ (1)

Limited by the amount of available SO_4 in the reservoir. SO_4 is present either in form of dissolved SO_4 in the water or by the presence of sulphidic minerals (for example, gypsum, anhydride).

Reaction 2: Methanogenesis: $4H_2 + CO_2 \rightarrow CH_4 + H_2O$ (2)

Limited by the amount of co-injected CO_2 or CO_2 sources in the residual gas and CO_3-bearing minerals in the porous reservoirs and high reactivity when pH < 7.

Reaction 3: Acid-forming prokaryotes (acetogenesis): $4H_2 + 2CO_2 \rightarrow CH_3COOH + 2H_2O$ (3)

Limited by the amount of co-injected CO_2 or CO_2 sources in the residual gas and CO_3-bearing minerals in the porous reservoirs and higher activity when pH < 7.

Reaction 4: Iron-reducing bacteria: $3Fe_2O_3 + H_2 \rightarrow Fe_3O_4 + H_2O$ (4)

The iron-reduction process will result in hydrogen consumption as well as reaction with the rock's minerals.

In addition to the above, other microbial hydrogen-consuming processes include denitrification, sulphur reduction and aerobic H_2 oxidation (Dopffel and others, 2021), (Berta and others, 2018). The variety of microbial processes can result in different side effects of underground hydrogen storage.

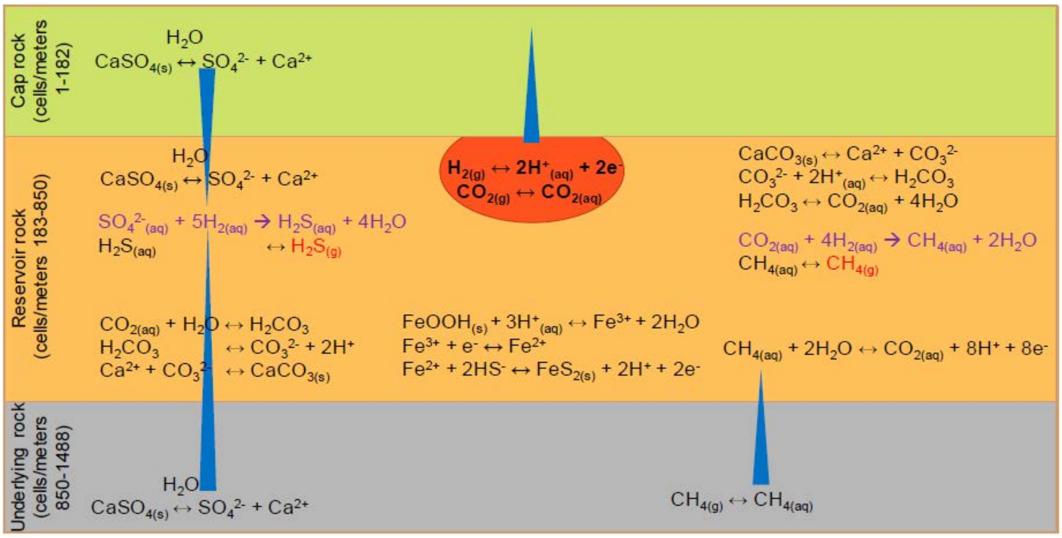


Figure 60: Selected reactions and processes associated with bacterial sulphate reduction and methanogenesis (purple). Single arrow = kinetic-controlled reactions; double arrow = equilibrium reactions; blue triangles = time-dependent diffusive transport of aqueous components; bold = injected gas for storage (Hemme & Berk, 2018)

All the reactions above can generate a considerable amount of water, which may increase the system pressure and intensify the diffusion (Hemme & Berk, 2018). Management of huge amounts of produced water that might be contaminated with toxic chemicals as a result of water coning during the H_2 reproduction period is a serious environmental issue (Zivar and others, 2020). Furthermore, these redox reactions may produce NO_2^-, N_2O, N_2, NH_4^+, Mn-II, Fe-II, H_2S, CH_3COOH, or CH_4, which might be released into the pore water or precipitated into various mineral phases (Berta and others, 2018). Reaction products such as NO_2^- , H_2S or CH_4 may have a negative effect on the composition of the groundwater in terms of its usability for other applications, such as drinking water (Berta and others, 2018).

The use of H_2 by microbes can lead to a decrease of H_2 content and an increase of other gases. This could have a direct effect on the usability of the re-produced H_2 (Dopffel and others, 2021). For example, microbial sulphate reduction, Reaction (1) above, can lead to the formation of the toxic and corrosive H_2S gas. Even a small amount of H_2S can negatively influence various aspects of gas quality, including material integrity and safety and health condensations, and therefore would require additional gas treatment. Sulphate reduction is a very efficient process, and low amounts of sulphate can already lead to a significant amount of H_2S (Dopffel and others, 2021).

Microbial-influenced corrosion is a well-known problem for steel infrastructure in various industries. The complex interplay between abiotic and biotic corrosion reactions by sulphate-reducing micro-organisms, methanogens and acid-producing microbes can lead to localised corrosion of steel infrastructure and subsequent equipment failure (Dopffel and others, 2021). In addition, microbially formed H_2S can enhance corrosion rates and lead to H_2S-induced stress-cracking (Dopffel and others, 2021).

Microbial-induced plugging or clogging of the pore space in the rock will lead to reduced permeability and a subsequent declining injectivity. Sulphate reduction that produces H_2S can react with dissolved ferrous iron (if present in the minerals) and precipitate as FeS. In the presence of dissolved iron in combination with either nitrate or low concentrations of oxygen, iron-oxidising microbes will cause ferric iron minerals precipitation (Dopffel and others, 2021). Another plugging potential is microbial-induced carbonate precipitation due to chemical changes triggered by a variety of different metabolisms. All plugging events will be noticeable by a decrease in injectivity or an increase in injection pressure.

Geomechanical side effects

During hydrogen storage, there are risks to geo-chemical reactions being triggered with rock minerals and reservoir fluids (DBI Gas and Umwelttechnik GmbH, 2017), (Heinemann and others, 2021). Cyclical hydrogen injection and reproduction have a direct impact on the storage integrity (Heinemann and others, 2021).

The introduction of hydrogen into the subsurface reservoir will lead to pressure and therefore stress change, potentially causing reservoir deformation beyond the area of pressure change (Heinemann and others, 2021). The rate of reservoir deformation is controlled by the rate of stress change, therefore the duration of the hydrogen injection-reproduction cycle.

Secondly, the injection-reproduction cycle will also cause cyclical pore pressure changes and further lead to cyclical changes in the effective state of stress in the storage complex. Cyclic stress fluctuations in the wellbore area, within the reservoir and nearby faults (in porous reservoir), might cause reservoir compaction, leading to porosity reduction and therefore reduced fluid flow, subsidence, and/or fault reactivation and potentially micro-seismicity (Heinemann and others, 2021). In addition, reservoir compaction may also lead to caprock flexure, creation of fractures and therefore leakage pathways within the caprock (Heinemann and others, 2021).

Another environmental risk of UHS is the potential chemical reaction between H_2 and minerals of reservoir rocks and caprock, leading to precipitation-dissolution of minerals (Zivar and others, 2020), (Hemme & Berk, 2018), (Heinemann and others, 2021). This process can lead to removal of load-bearing minerals and cements, which may further result in increased elastic and inelastic (permanent) deformation of the reservoir (Heinemann and others, 2021). Mineral precipitation-dissolution are possible in both caprock and reservoir rocks. In the case of the precipitation rate being less than the dissolution rate, the seal capacity and integrity of the caprock can be damaged, leading to hydrogen leakage (Zivar and others, 2020), (Hemme & Berk, 2018). If these processes occur within faults, it may affect their stability and fractional behaviour. On the other hand, the change in chemical environment will also drive other fluid-assisted, grain-scale processes that could lead to permanent deformation (Heinemann and others, 2021).

Sorption process will have an impact on long-term stability and safety of the store. Sorption of hydrogen to swelling clay minerals in clay-bearing reservoirs, caprock and faults can lead to associated swell-induced stress changes. Over the lifetime of a hydrogen storage complex, this could lead to mechanical fatigue of the reservoir and increase permanent deformation (Heinemann and others, 2021). It should be noted that clay swelling is directly correlated to the water content of the clay minerals. While clay swelling can lead to fracture closure, the repetitive H_2 injection and reproduction cycles of dry hydrogen and various microbial reactions that produce water may introduce a repetitive drying and shrinking of clays. This may reverse swell-induced sealing of fractures and lead to the re-opening of leakage pathways (Heinemann, et al., 2021). In addition, clay swelling can lead to fracture closure. Swelling-induced critical stressing of faults may lead to slip, potentially enhanced by any lubrication effect of hydrogen, which could result in induced seismicity and the creation of leakage pathways.

Lastly, a small amount of compaction at the reservoir level can lead to significant impacts at the surface, as evidenced in the oil and gas industry. Potential impacts on the surface include surface subsidence and induced seismicity (Heinemann and others, 2021).

In addition to hydrogen loss, those reactions with rock minerals can lead to damage in the rock and mineral structure, resulting in alteration of crucial reservoir properties such as pore volume and permeability.

Source-pathway receptor models

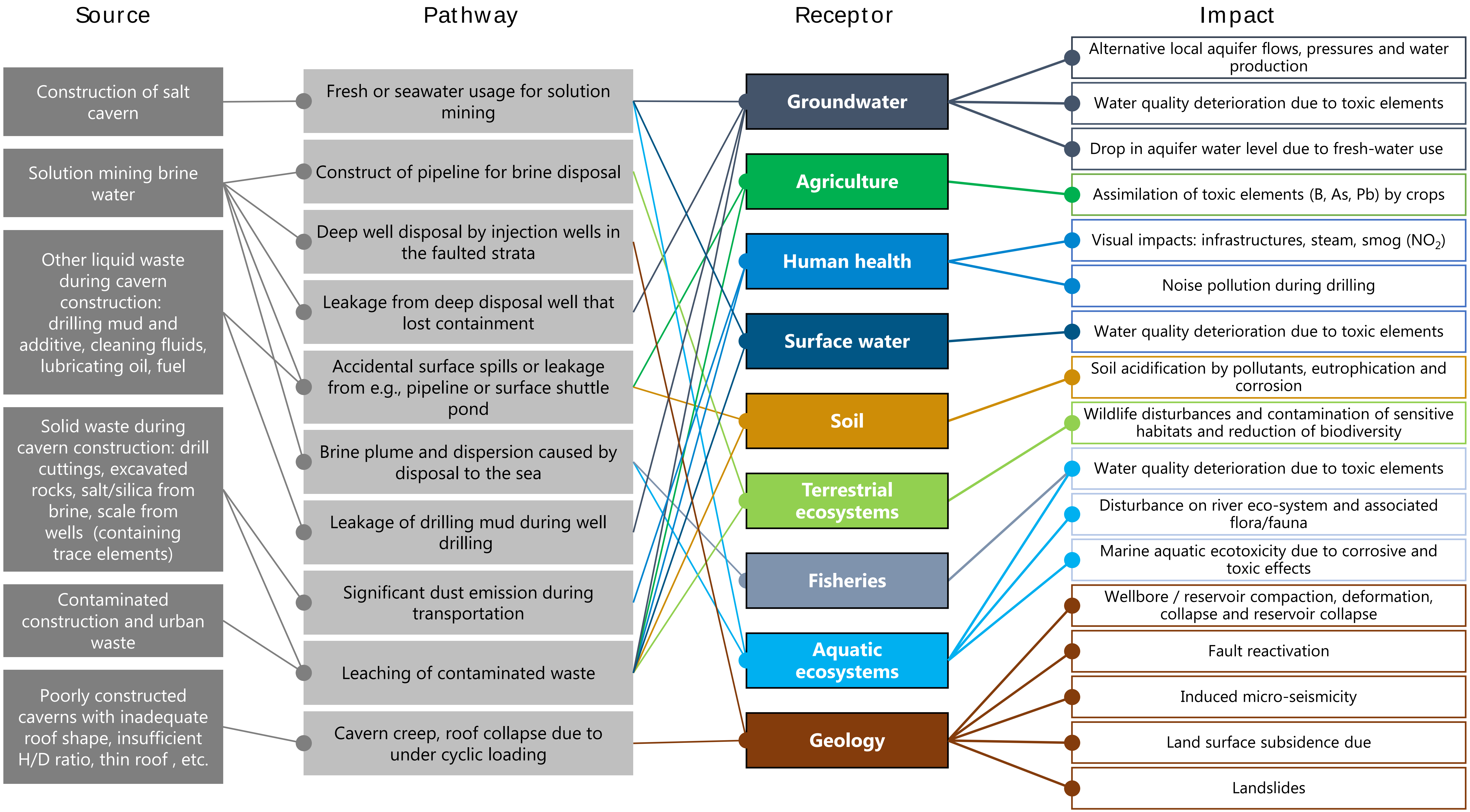


Figure 61: SPR diagram for cavern mining and preparation

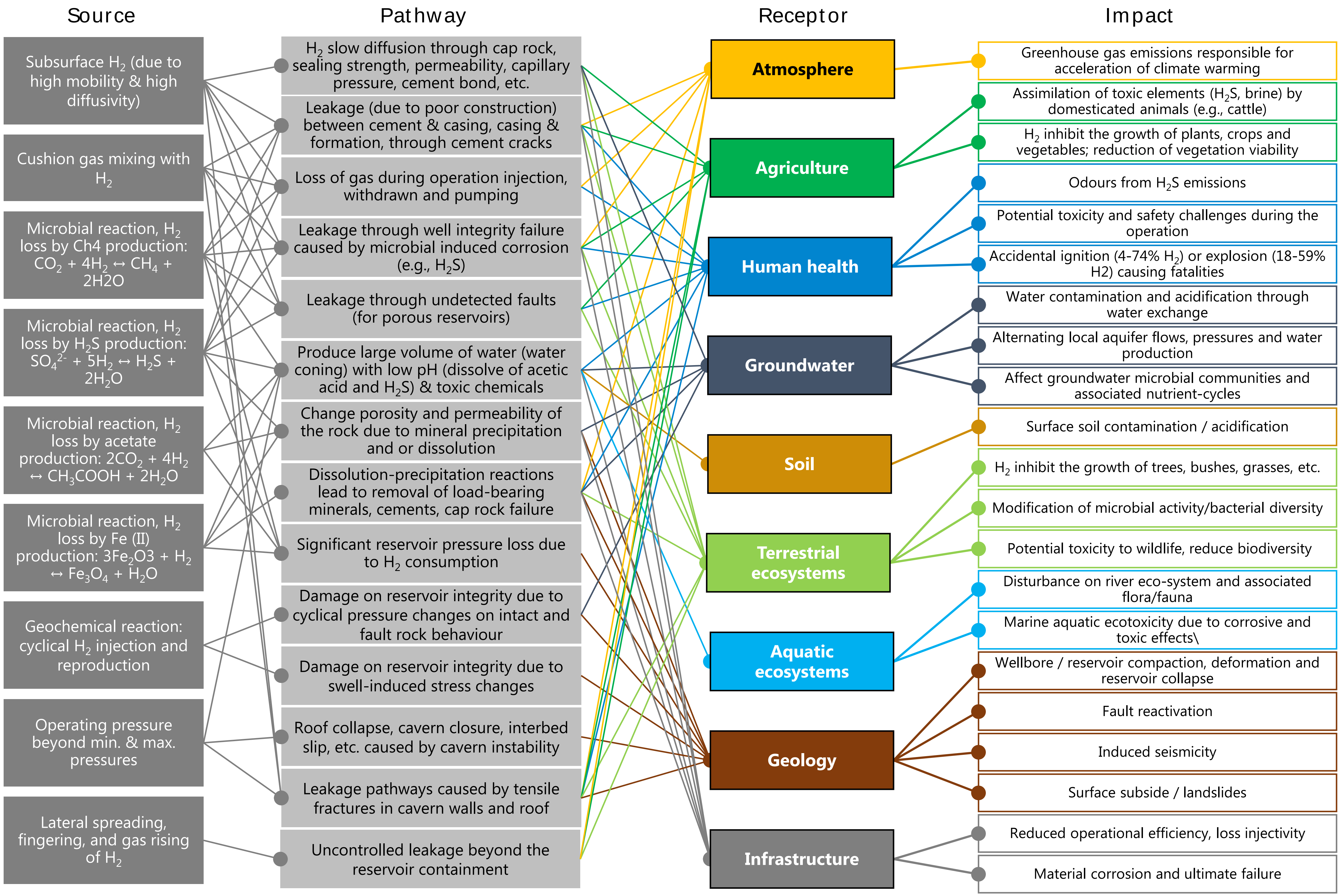


Figure 62: SPR diagram for UHS operation (excluding site preparation)

Observations and knowledge gaps

H_2 leakage and the underground microbial reactions are the biggest environmental issues for UHS storage. However, both are complex issues as a result of a complex interplay between microbiology, geochemistry and physics, which is site-specific and largely unknown.

To overcome the current knowledge gap, more data should be gained through laboratory, field and modelling research, using a cross-disciplinary approach involving microbiologists, physicists, chemists and engineers (Dopffel and others, 2021). Comprehensive and site-specific studies of the reactions between injected gas and pre-existing minerals, gases, ions and bacteria are needed for safe (to minimise any leakage risk) and successful (to avoid conversion of hydrogen to other gases or reduction in its purity) storage operations (Zivar and others, 2020).

Regarding the hydrogen leakage, one gap in knowledge is the possible effects of H_2 leaks on groundwater chemistry and microbiology. It should be investigated, including different groundwater types, if a potential H_2 contamination plume is a topic of concern.

Some of these microbial reactions have already been reported in field and laboratory experiments, but more experience from more field sites is needed to be able to make better predictions on microbial risks. One important point is the need for more microbiological data from field tests. Although microbiology is often stated as one of the main risks in H_2 UGS, microbiological work packages within projects are often small if they exist at all (Dopffel and others, 2021). Furthermore, it may be necessary to further study microbial mitigation methods, for example, addition of broad-range biocides or metabolic inhibitors, specifically for H_2 underground storage sites and their potential environmental impacts.

The effects of high concentrations and partial pressures of hydrogen on the microbial communities in the storage sites are also largely unknown (Dopffel and others, 2021). The continuous seasonal cycle within a storage site of high H_2 during storage to low H_2 during withdrawal to high H_2 will additionally challenge the current understanding of microbial conditions. The long-term effect of these cycles and implications for specific H_2-storage communities is an area for future research.

Another knowledge gap is the relationship between microbiological activity and geochemical parameters. To be able to fully predict biogeochemical reactions, a better understanding of both biological and geochemical processes, separately and together, is necessary. It has been suggested that modelling-based approaches using input data from fields and lab experiments could be productive (Dopffel and others, 2021).

Injection of hydrogen into porous storage reservoirs displaces the formation fluids, leading to complex multiphase displacement patterns, controlled by the rock-fluid properties and the functional relationships between fluid saturation and relative permeability. Rock-fluid interactions are important to be able to simulate and develop a model to predict hydrogen storage performance and flow behaviour. However, currently there is a lack of data and understanding of the rock-fluid properties for the water hydrogen systems (that is, multi-phase properties in porous media for hydrogen subsurface storage) (Zivar and others, 2020). Similarly, such lack of data is also an issue for oil-hydrogen systems in the case of hydrogen storage in depleted oil reservoirs (Zivar and others, 2020).

The influence of hydrogen on the properties of steel alloys has been analysed by several researchers. The exact influence of hydrogen on steel alloys under wet conditions and the salinity of reservoir fluids is not fully explored by existing studies.

Comprehensive monitoring techniques for hydrogen injection and storage in underground formations are not reported in detail. Most of the monitoring techniques have been adopted and applied based on the experience of other geological storage techniques such as CCS and natural gas storage.

5.2.3 Underground bio-methanation

Potential environmental impacts

During this study, no reports have been encountered which address the potential environmental impacts of the underground bio-methanation concept. However, considering its similarity to hydrogen/town gas storage in terms of chemical reactions, some of the theoretical environmental impacts can be derived. Laboratory experiments and field tests are needed to verify these. For this reason, the SPR models for underground bio-methanation are not included in this report.

Observations and knowledge gaps

Up until now, underground bio-methanation was only observed as a side effect during hydrogen-rich gas storage operations. Currently, the industry has insufficient understanding of the behaviour and population kinetics of methanogens in a porous structure, therefore the methane production rate or the system efficiency cannot be concluded (Stone and others, 2015). Further information about potential environmental impacts should be considered when improving understanding of microbial conversion rates, and performance of underground bio-methanation.

5.2.4 Underground pumped-storage hydropower (UPSH)

Potential environmental impacts

UPSH is an emerging technology with no actual projects, therefore, few environmental impacts have been reported to date. During the review, only numerical modelling for predicting the potential environmental impacts of UPSH was found.

Construction of upper and lower reservoirs

There are potential environmental impacts from the construction of the upper reservoir and lower reservoirs, including the requirement to relocate large volumes of fresh water and spoil disposal. Dike failure associated with the upper reservoir could lead to flooding and hazardous waste spills (Pickard, 2012). All of these will have direct impacts on land use, vegetation and wildlife (Pujades and others, 2020), (Pujades and others, 2017).

Tunnelling in abandoned coal mines could cause severe geo-environment problems that are related to mine water, residual voids, infillings and gases (Menéndez and others, 2019), (Tong and others, 2013). Tunnel floor, roof and wall instability may occur during tunnel excavation (Tong and others, 2013). Secondary filling deposits (for example, rock blocks mine debris, flowstone, silt-clayey sediments) are often of poor quality from a geotechnical standpoint and can lead to structural failure (Tong and others, 2013). Crossing ancient or old mine voids currently filled by secondary deposits (for example, goaf) may be hazardous.

Groundwater control during both construction and operation of the tunnel is one of the most challenging issues (Tong and others, 2013). Long-term operation of coal mines can cause fractures and increase the permeability of the surrounding rock. During tunnelling, construction and operation, massive and abrupt water inflows can occur. This poses a serious hazard as well as potentially causing residual subsidence, fault activation, reducing the stability of slopes and cuttings, and potentially influencing the geotechnical properties of the surrounding rocks (Tong and others, 2013). In addition, a drop in mine water levels can also affect the surrounding hydrogeological conditions, including availability of groundwater, and increase the risk of instability (Tong and others, 2013).

Mine gases may be explosive (CH_4), toxic (CO and H_2S) or an asphyxiant (oxygen depleted air). Permeable rock formations, faults, joints, fractures (enhanced by mining subsidence), shafts, wells, boreholes and man-made cuttings and excavations, all act as gas migration pathways. Mine gas emissions may be a significant health, safety and environmental risk during construction (Tong and others, 2013).

The operation of UPSH

As the underground reservoir is filled, the residual air will become compressed and flow through the ventilation shaft. The direction of the air flow will vary depending on the operational mode of the hydroelectric power plant (see Figure 18). The flow rate and pressure of the air will depend on the water flow rate of the Francis turbine and the diameter of the ventilation shaft (Menéndez and others, 2019). This variability in air pressure during the filling and depletion processes may have an impact on the stability of tunnels, ventilation shafts and powerhouse caverns (Tong and others, 2013), causing long-term fatigue damage and deformation (Menéndez and others, 2019).

Mines cannot be considered as impervious reservoirs, and groundwater exchange with the surrounding porous medium during operation is likely. As a consequence, pumping or injecting large volumes of water in a mine, especially within short time intervals, will inevitably impact the surrounding groundwater table (Poulain and others, 2018) and may also impact the amplitude of water level fluctuations in the lower reservoir (Poulain and others, 2018).

Ground stability problems, related to the subsidence or collapse of weathered rocks in the vicinity of the quarry, may be caused or exacerbated by the induced fluctuations of the groundwater table (Poulain and others, 2018).

Mine water chemistry has been recognised as an important challenge for the application of UPSH (Pujades and others, 2018). Under natural conditions, water in the underground reservoir and groundwater in the surrounding porous medium reaches chemical equilibrium with the porous materials. During UPSH operation, water from the underground reservoir is pumped, discharged and stored in the surface reservoir, which aerates the water, and its chemical composition evolves to a new chemical equilibrium with the atmosphere. This is directly related to a variation in the dissolved O_2 and CO_2 concentrations (Pujades and others, 2018). When this water is subsequently discharged from the surface to the underground reservoir, it evolves again towards another chemical equilibrium with the surrounding porous medium. This continuous evolution of the water chemistry may lead to the precipitation and dissolution of minerals, and their associated impacts such as variations in pH (Pujades and others, 2018).

In coal deposits, the oxidation of sulphide minerals is common and may have important consequences for water chemistry. Pyrite is the most common sulphide mineral in coal-mined environments:

Reaction 5: pyrite reduction $\mathrm{FeS_2} + 15/4\mathrm{O_2}\ (\mathrm{aq}) + 7/2H_2\mathrm{O} \rightarrow \mathrm{Fe(OH)_3}\ (\mathrm{s}) + 2SO_4^{2-} + 4H^+$ (5)

Where pyrite is oxidised ferrihydrite may precipitate. Other minerals, such as schwertmannite (an iron-oxyhydroxysulfate mineral), can precipitate because of oxidation of pyrite at low pH (Pujades and others, 2018). These reactions will impact the lower reservoir and the surrounding formation and groundwater. Porosity in the surrounding rocks can also change as a result of mineral dissolution and/or precipitation (Pujades and others, 2018). In addition to the above, O_2 depletion due to oxidation may also happen (Pujades and others, 2018).

Furthermore, when the water is cycled back in the subsurface reservoir, water level oscillations could mobilise contaminants contained in the remaining unsaturated zone within the mine. In addition, ferrihydrite, goethite or schwertmannite may precipitate in the surface reservoir, causing hydrochemical modifications of water quality in the surface reservoir. This pH altered water may accelerate the corrosion of equipment, while minerals precipitation may alter their mechanical efficiency, requiring maintenance and cleaning (Pujades and others, 2018).

Source-pathway receptor-models

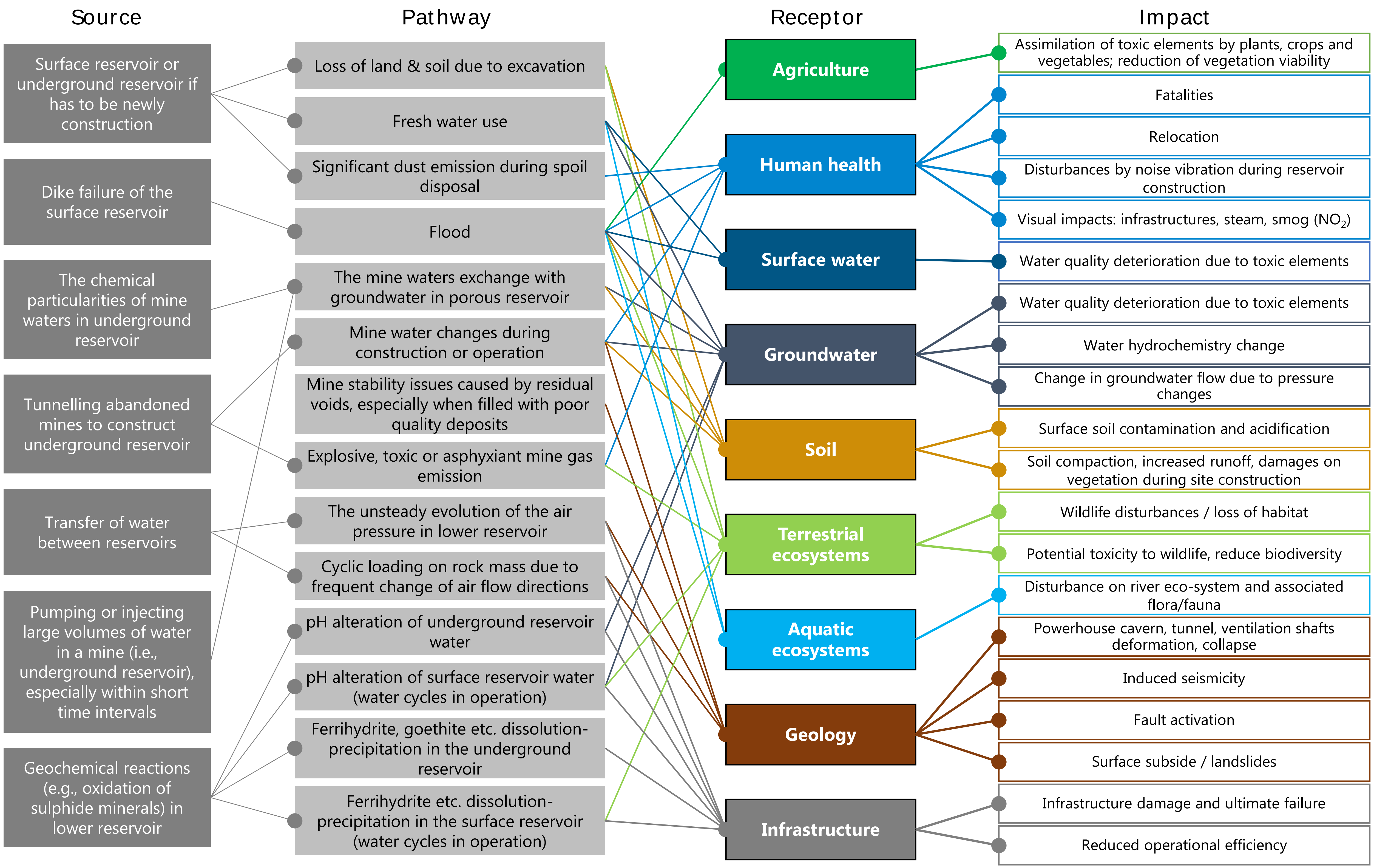


Figure 63: SPR diagram for UPSH operation

Observations and knowledge gaps

During the review, few studies that discuss potential environmental impacts of UPSH have been identified. This is largely because UPSH is an emerging technology, therefore various environmental impacts have yet to identified (Pujades and others, 2018).

In addition to the environmental impacts associated with the reservoir construction, water exchanges between the underground reservoir and the surrounding medium and their associated consequences are an identified area of concern.

The uncertainties associated with using abandoned mines for the lower reservoir for UPSH plants will require further study. In particular, this should focus on the range of possible reservoir configurations and the water exchange mechanisms and their potential impact. This should include water exchange in lower reservoirs as well as water exchange between the lower reservoir and upper reservoir.

The main technical challenge that UPSH faces is the dynamic stress behaviour of rock masses, as well as fluid-mechanical and chemical properties of mine waters (EERA, 2018). Therefore, it will be essential to analyse the reservoir pressure to understand the behaviour of UPSH plants during the operational life cycle (Menéndez and others, 2020). Underground test facilities allowing studies of effects under real conditions would be advantageous.

It was highlighted that there will be a gradual increase in the temperature of cycled water due to absorbing the turnaround losses of the energy storage and retrieval processes (Pickard, 2012). However, no additional information on the potential impact of the elevated water temperature has yet been researched.

5.3 Permanent underground storage of carbon dioxide

Potential environmental impacts

CO_2 storage is the last stage in the overall CCS process. At all levels, macro, meso and micro, CO_2 storage is considered to be a minor environmental risk compared to the other value chain elements – capture and transportation (Liu & Ramirez, 2017). Indeed, the drilling of CO_2 injection wells is one of the highest impact stages of a CO_2 injection project, primarily because the energy, water and materials consumed is proportional to the depth of the well drilled (Wildbolz, 2007). Irrespective of the type or depth of well drilled, emissions from drilling operations are almost guaranteed – emissions relating to CO_2 leakage are much less of risk. Calculations made by Wildbolz (2007) suggest that the global warming potential of drilling a CO_2 injection well in a depleted oil or gas field can be as much as 3 times higher than that of a saline aquifer because of the large differences in drilled depth.

The most recognised and discussed issues with underground storage of CO_2 is the prospect of a CO_2 leak from the storage formation. As previously mentioned, there are 2 main pathways for CO_2 to leak from the reservoir – either through the caprock via a fault or undetected porous zone, or through the well, which is the main penetration point of the reservoir. In its 2007 report (US DOE, 2007), the United States Department of Energy reported on 4 possible leakage scenarios for onshore CO_2 storage. It concluded that the likelihood of migration of CO_2 to the surface was very small. It was also found that correctly located CO_2 storage projects, away from regions of geological activity, were very unlikely to experience events resulting in the failure of the caprock and the seal integrity of the storage formation. It was concluded that it was more likely for a leak to occur via the well through mechanisms previously examined. A study by Zheng (Zheng and others, 2010) concluded that the probability for CO_2 leakage to the surface through an existing fault was as low as 0.01%. Some studies (Oladyshkin, 2011) show that the risk of CO_2 leakage in wells increases during injection to 0.07%, and after 40 days stabilises for the lifetime of the project.

At the meso level, the leakage of CO_2 can cause negative impacts on the quality of groundwater, soil and surface water. There are many impacts of CO_2 migration in the environment above and around the storage formation. Most are related to the fact that in the presence of fresh water or subsurface brines, CO_2 forms corrosive (acidic) carbonic acid. Consequently, CO_2 leakage can promote the following chemical phenomena:

- pH change – the pH or acidity of water or moist soil in contact with the CO_2 can decrease (increase in acidity) by an order of magnitude of 1 to 2

- release of trace elements – the increase in the acidity (decrease in pH) of the environment can result in the leaching of trace elements such as Pb or As. If the CO_2 is accompanied by storage formation brines (that is, CO_2 and brines co-migrate through a fracture or other system conduit), the increased volume of fluid can also help with mobilisation of trace elements. The concentration of these elements may rise and exceed advisable limits within the environment and poison flora and fauna
- release of bulk concentration elements – the increased acidity of the environment can result in the increase in the concentration of ions like Fe and Ca. If such chemical species are present in the biological environment, in situ or through migration, they can have a detrimental impact
- release of BTEX chemicals (for example, benzene) – mobilisation of certain aromatic hydrocarbons at low pHs caused by the presence of CO_2

CO_2 and formation brines, which nearly always contain dissolved CO_2, can co-migrate out of the storage formation into the surrounding environment (Shao and others, 2020). Brines can introduce chemical species into neighbouring geological structures. This results in contamination through dissolved species or precipitates that come out of solution through pH or temperature change. These species can exist as trace elements or as bulk ionic species in solution. The effects of acidic brines are similar to the effects of dissolved CO_2 within native geological waters. In each case, the dissolved CO_2 forms carbonic acid, resulting in a drop in the system pH.

In agriculture and surrounding flora the effects of CO_2 can negatively impact vegetation, resulting in visible signs of vegetation stress (Chen and others, 2019). Typically, anoxia (displacement of oxygen) in plant roots can result in the death of the plant or tree, and is a visible sign that soil concentrations of CO_2 are elevated. Authors Ma, Zhang and Tiang (Ma and others, 2020) report on similar impacts to farm crops in the presence of high levels of subsurface CO_2. Many of the elemental species released or mobilised by CO_2 in the environment can be used as early indicators of CO_2 leakage. For this to be useful, baseline measurements need to be taken before injection occurs (Kharaka and others, 2010).

At a micro level, it is estimated (Liu & Ramirez, 2017) that health effects are very unlikely to occur in a scenario in which CO_2 rapidly leaks through the caprock failure or injection well integrity failure. The authors also consider induced seismicity, due to the pressurisation of the storage formation through increased gas volumes, or expansion of well fluids due to dissolved gases, to be environmental issues. The table below summarises the macro, meso and micro environmental impact noted by Lui and others, (2017) and other referenced authors.

Environmental hazard	Source of hazard/ pathway	Receptor	Environmental Impact	Reference
CO_2 leakage	• Through existing or induced fault or fracture • Through spill point • Caprock failure or permeability increase • Failure of wellhead injection • Through inadequately constructed wells or decommissioned wells	Atmosphere	• CO_2 concentration increase • Climate change acceleration	(Oladyshkin, 2011), (Gerstenberger and others, 2015), (US DOE, 2007)
CO_2 leakage	• Through existing or induced fault or fracture • Through spill point • Caprock failure or permeability increase • Failure of wellhead injection • Through inadequately constructed wells or decommissioned wells	Groundwater	• pH modified (lowered, acid) • Mineral dissolution • Trace element mobilisation (for example, Pb and As)	(Gerstenberger and others, 2015) (Zheng and others, 2010) (US DOE, 2007)
Brine displacement	Pressure build-up beyond the boundary of the CO_2 plume	Groundwater	• Salinisation of groundwater • Exposure to toxic compounds carried by brine migration	(Birkholzer and others, 2009)
CO_2 leakage	• Failure of wellhead injection • Through inadequately constructed wells or decommissioned wells	Human beings	Negative health impact due to acute exposure	(Oladyshkin, 2011) (US DOE, 2007)

Induced seismicity	Pressure change and reactivation of fault and fracture	Human beings	Large seismic event causing infrastructure damage	(Gerstenberger and others, 2015)

Table 11: Environmental hazards and risks of CO_2 storage at the macro, meso and micro (Liu & Ramirez, 2017)

It is worth noting at this stage that the impacts of CO_2 leakage are dependent on both the time of remedial intervention and leakage volume. Small, low flowrate leakages of CO_2 from the storage formation will have a different environmental impact, especially for impacts where the atmosphere or groundwater act as a diluent (that is, they dissipate the CO_2 into the environment), than large-scale releases, with the latter having both meso and macro level environmental impacts. Similarly, the atmosphere may not be affected by a small leak through a microannulus of a well that has lost integrity for a short time before the operator carries out remedial work. A leakage into one aspect of the environment does not necessarily assure a leakage into another. The diagram below shows some of the many leakage pathways and subsurface interactions possible in a CO_2 storage project.

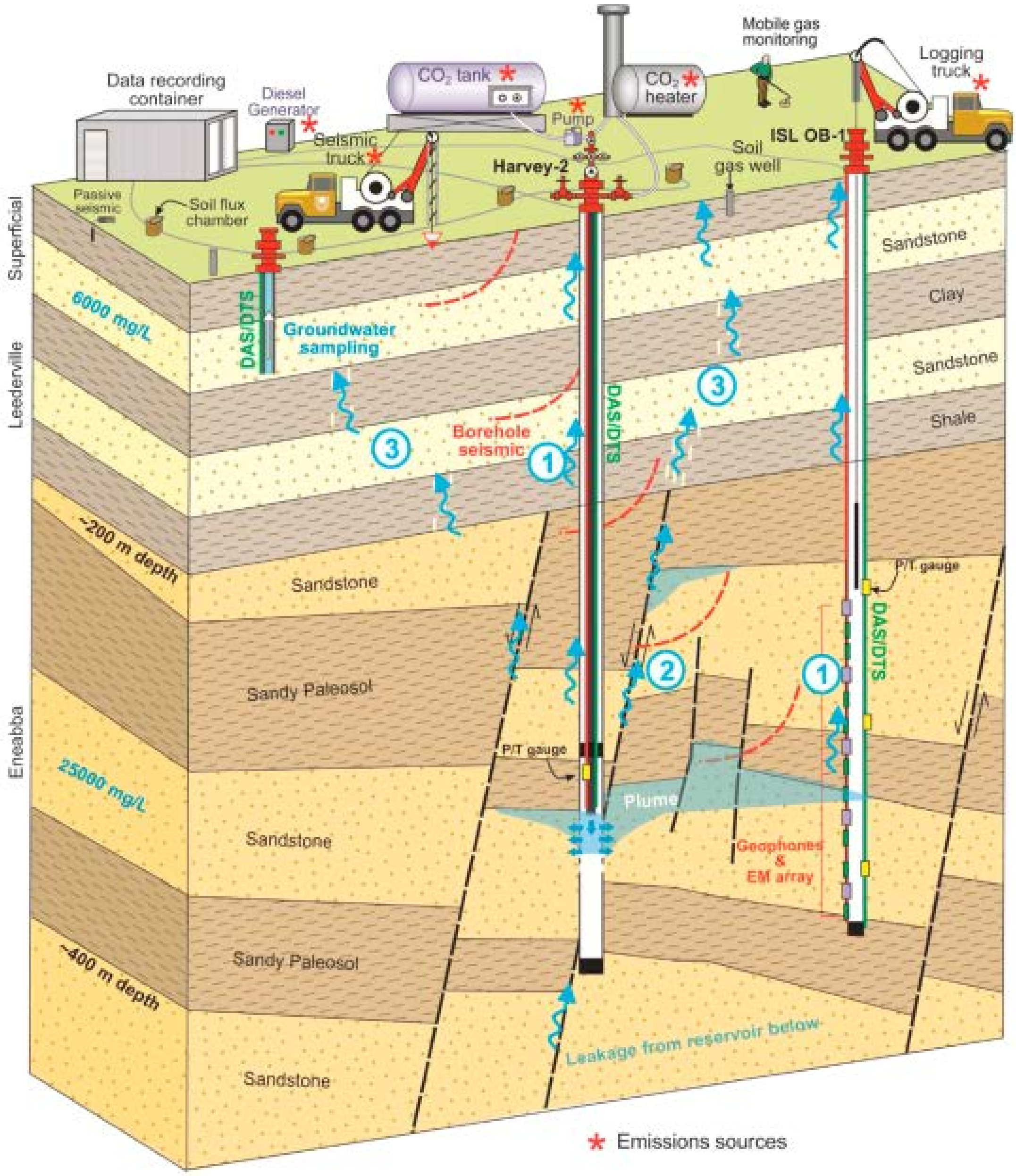


Figure 64: Potential leakage pathways to the ground surface 1) leakage along the well due to inadequate cementing 2) leakage along faults and 3) leakage along zones of increased permeability (Mayers, et al., 2020)

There is a comprehensive body of work behind understanding the range of environmental effects of a CO_2 leak and the scope of each environmental effect. Again, this knowledge has been drawn from a variety of countries and legal jurisdictions. The majority of this experience is in Europe (Roberts & Stalker, 2017) with 10 projects, including: ASGARD (Artificial Soil Gassing and Response Detection), QICS, CO2 Field Lab, Grimsrud Farm, Vrogum, CO2-Vadose/DEMO, CIPRES, SIMEx, Brandenburg, PISCO2. Other experience is in Australia (Ginninderra), South America (Ressacada Farm) and the USA (Zero Emissions Research and Technology Collaborative and Brackeridge). All except one, QICS, have been carried out onshore. The purpose of these projects was to evaluate:

- ecosystem response to injected CO_2
- the movement of CO_2 and the fate of CO_2 as it migrates from the point of injection
- geochemical interactions between CO_2 and groundwater
- the calibration of models for CO_2 flow and ultimate fate
- a broad suite of monitoring technologies and techniques

The figure below highlights global projects to improve understanding of the environmental impacts of CO_2 leakage from CCS projects. Two projects, QICS and ASGARD, were carried out in the UK.

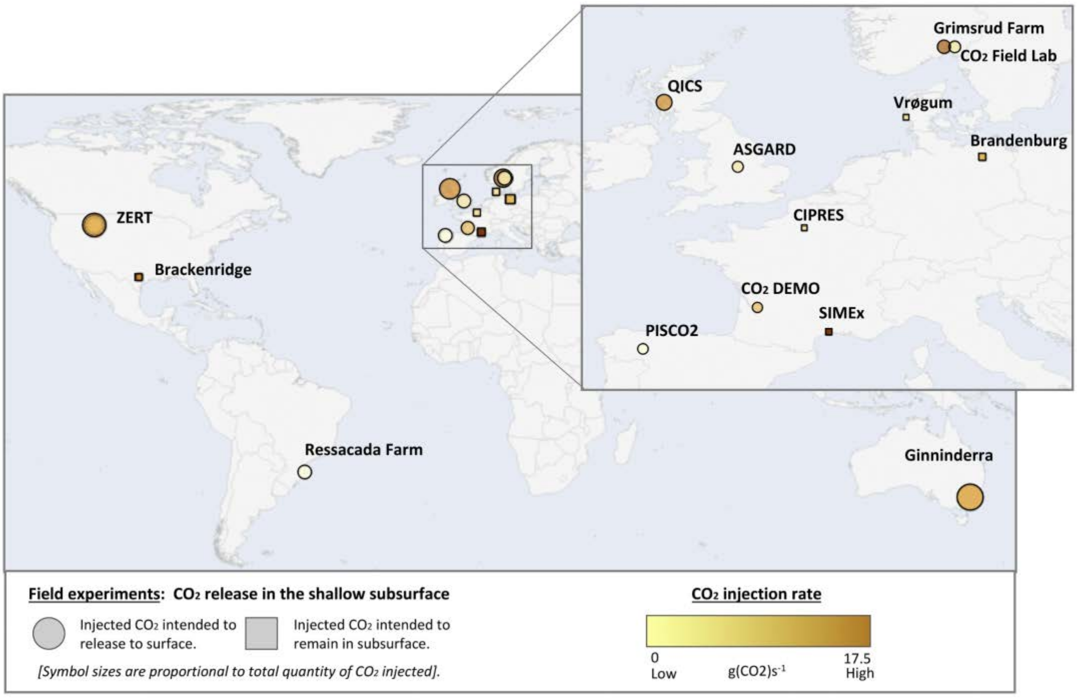


Figure 65: Overview of projects to determine the environmental impact of CO_2 releases in the subsurface (Roberts & Stalker, 2020)

The projects above, and the experiments to understand the environmental impacts of CO_2 released into the environment, provide a valuable backdrop to understanding CO_2 release into the environment in a UK setting – indeed the QICS (offshore) and ASGARD (onshore) projects are very literal in their interpretation.

In the UK, the Research into Impacts and Safety in Carbon Storage (RISCS) project looked into the impacts of a CO_2 leakage from a CO_2 storage formation. At the ASGARD facility (see Figure 66 below), experiments were carried out to determine the effects of elevated CO_2 on crops, soil microbiology, soil flux and soil CO_2 concentration (Smith and others, 2013). They concluded that CO_2

introduced into the soil had a clear and damaging effect on vegetation and the soil microbiology, and the effects were dependent on species, CO_2 concentration and a range of other environmental factors.

Figure 66: Image of the ASGARD facility in 2006 (Smith and others, 2013).

The combined knowledge of the CO_2 injection industry in understanding the movement of CO_2 within the subsurface highlights that there are many factors which contribute to the distribution and extent of a CO_2 leakage and the fate of the CO_2 in the environment. These factors include:

- hydrogeological factors – the depth of the water table, ground water flow, recharge rate and soil properties
- geomorphological factors – pertaining to subsurface geological structures and lithography
- human disturbance – such as the digging of mines, foundation, subsurface infrastructure and LULUCF (Land Use, Land-Use Change and Forestry)

Furthermore, the impact of leaked CO_2 is a function of the rate of the CO_2 released into the environment and residence times for that leak in different aspects of the environment. Large amounts of CO_2 have the potential to build into ‘hot spots’ that can cause irreversible damage, while smaller or slower leaks may dissipate laterally into the subsurface, never reaching critical concentration that might result in a receptor being affected.

Source-pathway-receptor models

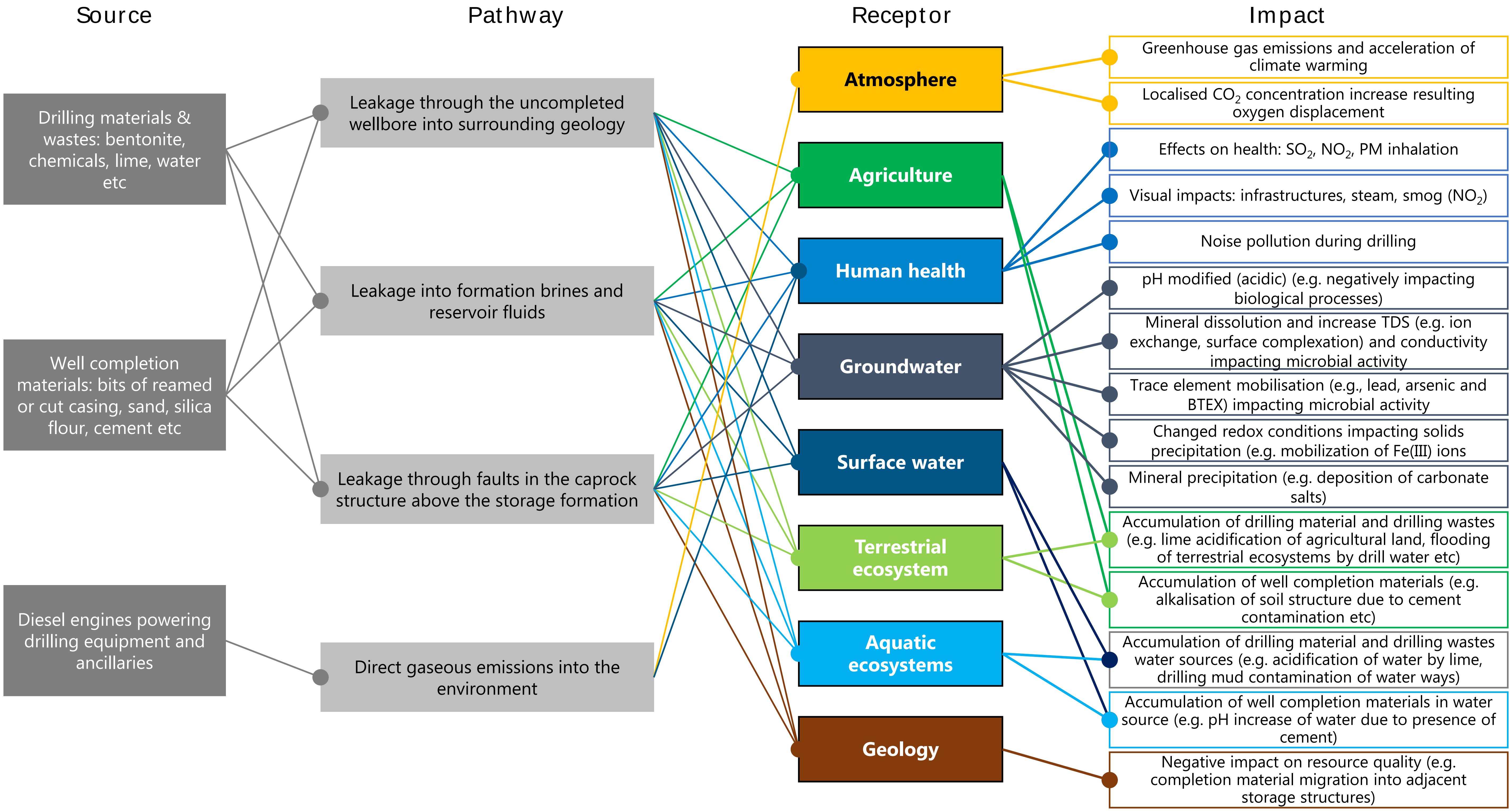


Figure 67: SPR diagram for CO_2 injection well drilling and preparation

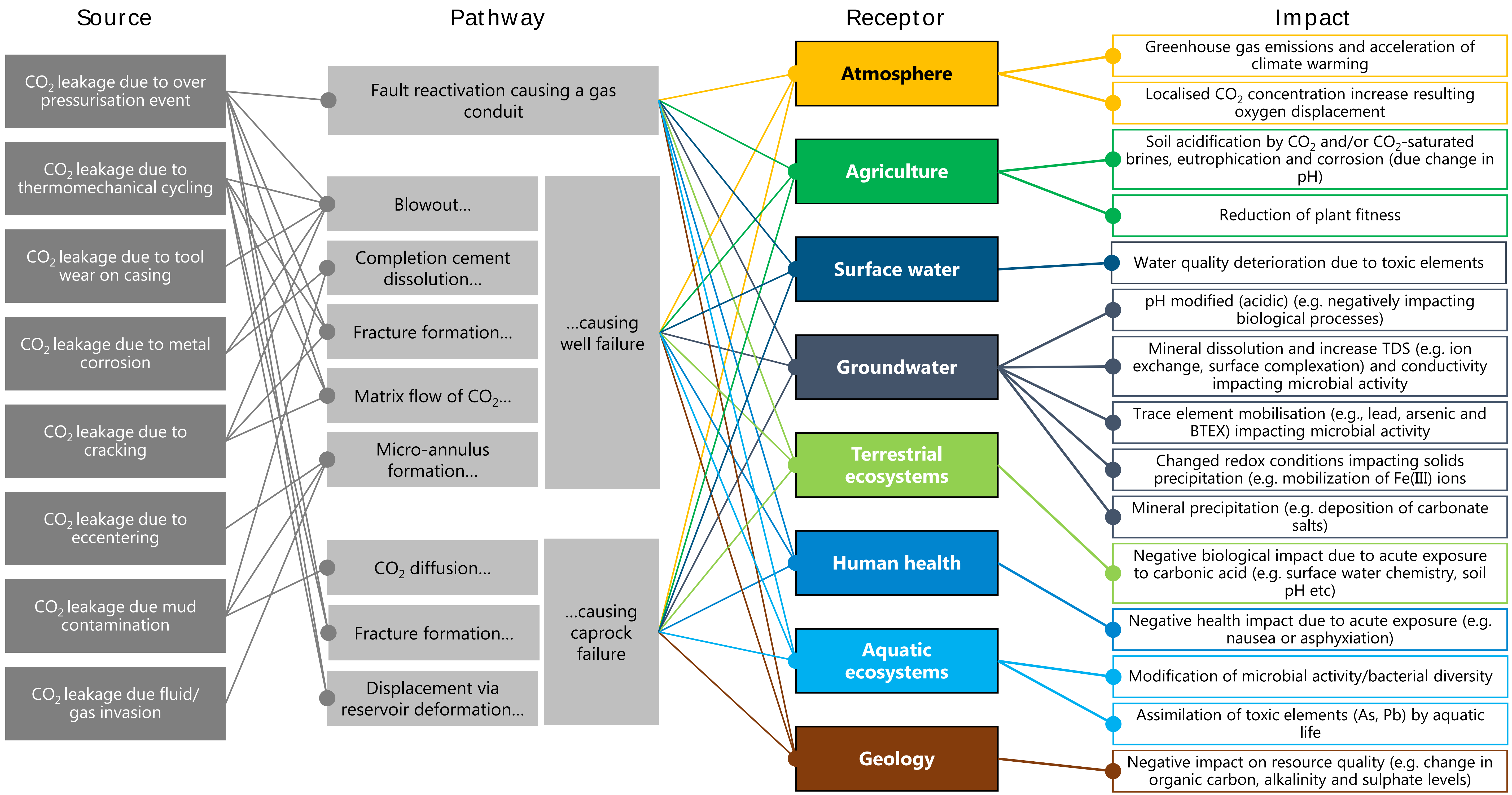


Figure 68: SPR diagram for CO_2 leakage from storage formation

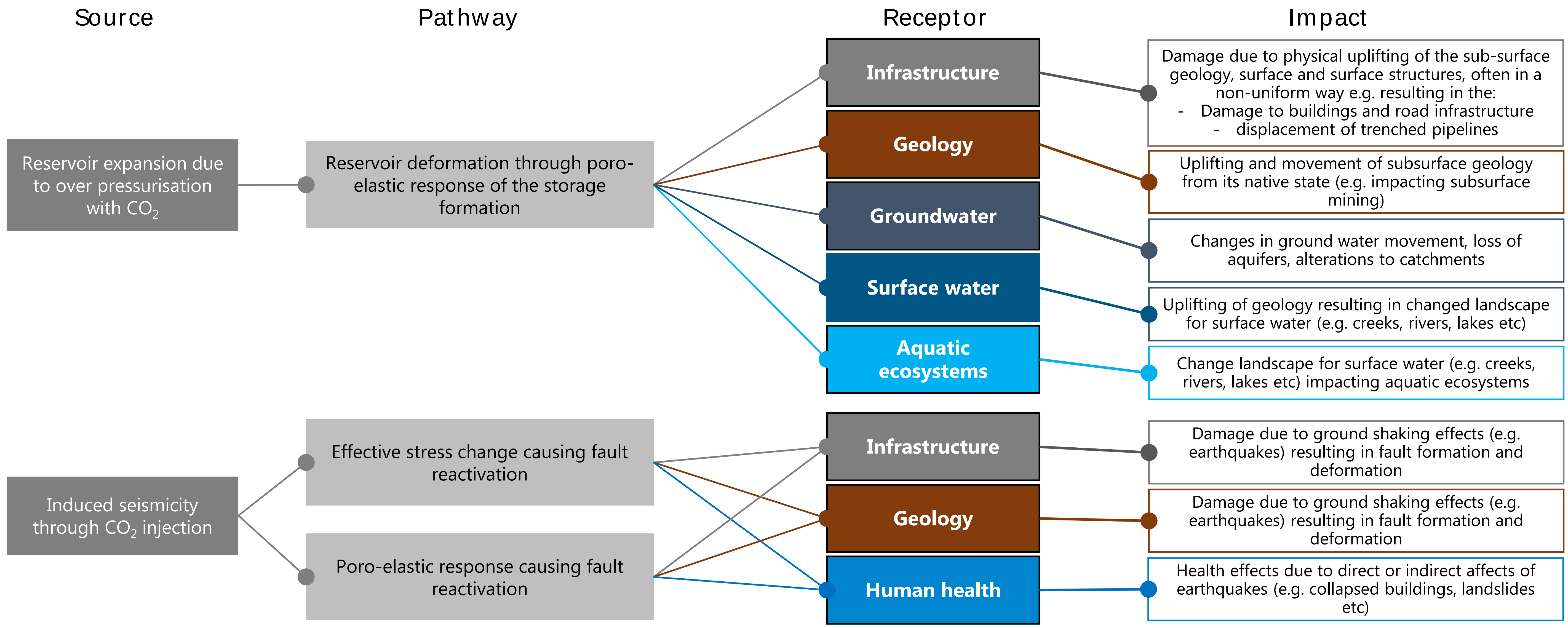


Figure 69: SPR diagram for physical impacts from CO_2 injection

Observations and knowledge gaps

Of all the subsurface technologies reviewed, CO_2 injection has received some of the closest attention with respect to the range and severity of environmental impacts possible. In both onshore and offshore operating environments many site-specific studies are ongoing or have been concluded to understand how CO_2 and CO_2-saturated brines react with the environment and to what extent. Furthermore, in many cases, these studies have identified and proved the very many detection and monitoring systems being developed to understand CO_2 movement, concentration and impact on the environment.

The challenge for authorities working in the CO_2 storage regulation space is maintaining a landscape view of the science looking to understand the impacts of CO_2, its movement and its ultimate fate in the environment, amidst a very quickly moving body of work. Indeed, reviews of the CO_2 storage environmental effects landscape take place almost every year and attempt to keep pace with scientific developments. Roberts and others (Roberts & Stalker, 2020) have published widely in this space, with their most recent review concluding that there are several large gaps in the scientific community's understanding of CO_2 release experiments. Many of these have practical implications regarding specification of regulations relating to monitoring of CO_2 storage formations and surrounding environment. Their conclusions are outlined in Table 12 below:

Variable	Suggestions for future experiments/scientific development
Experiment set-up and site information	• Environment: more experiments need to be established for offshore locations. To date, only one project has examined this environment. The EU H2020-funded programme looks to conduct an offshore CO_2 release experiment to understand the impact of CO_2 on marine ecosystems. • Subsurface properties: there needs to be experiments that look at the release of CO_2 into consolidated rock, or heterogeneous subsurface structures or carbonate units.
CO_2 injection (for each experiment)	• Injection depth: inject CO_2 deeper to understand CO_2 migration in more consolidated and heterogeneous units. • Injection period: inject CO_2 for longer period (months). • Properties: record carbon-13 of all CO_2 injected (each vessel/ cylinder delivered to site).
CO_2 fate	• Aim: to quantify CO_2 leakage. Quantify the total flux and total leak rate of free phase CO_2. This has proven to be a challenge in the field. CO_2 leakage into aqueous/marine environments will likely result in CO_2 leakage into the seabed/sea water column. • Investigate how one of more of the following impact the migration of CO_2 and its ultimate fate: topography, rock type, water table depth (seasonality).
Monitoring	• Baseline surveys need to be expanded on to increase the level of detail and over a longer period than has been studied previously. • Testing of cost-effective detection and quantification techniques like remote detection or chemical tracers to understand CO_2 migration from the leakage source. • Post-release monitoring should occur for longer periods to understand the longer-term environmental effects and the overall impact on an ecosystem.

Table 12: Gaps in scientific understanding of CO_2 leakage and suggested programmes for future research (Roberts & Stalker, 2020)

Further to the above development areas, there are still many unknowns regarding the serviceability of injection infrastructure in site-specific contexts. Just as there are many variables that factor into the extent of an environmental impact associated with a CO_2 leak, there are just as many site-specific variables that need to be accounted for when designing a CO_2 injection facility. Hazards associated with well infrastructure, including lack of understanding of the underlying causes for well failure, fluid migration, caprock failure, reservoir compaction and fault reactivation, are just a few examples of where further understanding is required to reduce operational risks (Schimmel and others, 2019).

References

ABESSER, C., BUSBY, J.P., PHAROAH, T.C., BLOODWORTH, A.J., WARD, R., 2020. Unlocking the potential of geothermal energy in the UK. Nottingham: British Geological Survey.

ACTONBRIDGE.ORG, 2013. Energy in Cheshire - Pipeline Page. [Online]
Available at: http://www.pardoe.net/abo/pipeline.htm
[Accessed 24 February 2021]. [Accessed 05 August 2021]

AL-HABAIBEH, A., ATHRESH, A.P. AND PARKER, K., 2018. Performance analysis of using mine water from an abandoned coal mine for heating of buildings using an open loop based single shaft GSHP system. Applied Energy, Volume 211, pp. 393-402.

ALIMONTI, C., CONTI, P. AND SOLDO, E., 2021. Producing geothermal energy with a deep borehole heat exchanger: Exergy optimization of different applications and preliminary design criteria. Energy, Volume 220.

ANDREWS, B., CUMBERPATCH, Z., SHIPTON, Z. AND LORD, R., 2020. Collapse processes in abandoned pillar and stall coal mines: Implications for shallow mine geothermal energy. Geothermics, Volume 88.

ASHWOOD, A. AND BHARATHAN, D., 2011. Hybrid Cooling Systems for Low-Temperature Geothermal Power Production.: NREL.

ATKINS, 2013. Deep Geothermal Review Study: Department of Energy & Climate Change (DECC).

AULD, A., HOGG, S., BERSON, A. AND GLUYAS, J., 2014. Power production via North Sea Hot Brines. Energy, Volume 78, pp. 674-684.

AYADAR, E. AND DIKER, C., 2021. Carcinogen soil radon enrichment in a geothermal area: Case of Güzelçamlı-Davutlar district of Aydın city, western Turkey. Ecotoxicology and Environmental Safety, Volume 208.

BAILEY, M., MOORHOUSE, A. AND WATSON, I., 2013. Heat extraction from hypersaline mine water at the Dawdon mine water treatment site. In: TIBETT, M., FOURIE, A., AND DIGBY, C. eds. Proceedings of the Eighth International Seminar on Mine Closure. s.l.:Australian Centre for Geomechanics.

BANKS, D., ATHRESH, A., AL-HABAIBEH, A. AND BURNSIDE, N., 2019. Water from abandoned mines as a heat source: practical experiences of open- and closed-loop strategies, United Kingdom. Sustainable Water Resources Management, 5(1).

BANKS, D., PUMAR, A.F. AND WATSON, I., 2009. The operational performance of Scottish minewater-based ground source heat pump systems. Quarterly Journal of Engineering Geology and Hydrogeology, 42(3), pp. 347-357.

BANKS, D., SKARPHAGEN, H., WILTSHIRE, R. AND JESSOP, C., 2004. Heat pumps as a tool for energy recovery from mining wastes. In: GIERÉ, R AND STILLE, P. eds. Energy, waste and the environment: a geochemical perspective. Bath: Geological Society Publishing House, pp. 499-513.

BATCHELOR, A., CURTIS, R., LEDINGHAM, P. AND LAW, R., 2015. Country Update for the United Kingdom. Melbourne, s.n.

BATCHELOR, T., CURTIS, R. AND BUSBY, J., 2020. Geothermal Energy Use, Country Update for United Kingdom. Reykjavik, s.n.

BAUER, S., 2017. Underground Sun Storage - Seasonal Storage of Renewable Energy in Depleted Gas Reservoirs, Results of an in-situ Field Experiment and Outlook, Aachen, Germany: RAG.

BEAMISH, D. AND BUSBY, J., 2020. The Cornubian geothermal province: heat production and flow in south west England: estimates from boreholes and airborne gamma-ray measurements. Geothermal Energy, Volume 4.

BECKWITH AND ASSOCIATES, 1983. Review of Environmental Studies and Issues on Compressed Air Energy Storage, Springfield, Virginia: Battelle Memorial Institute.

BENTHAM, M., MALLOWS, T., LOWNDES, J. AND GREEN, A., 2014. CO2STorage Evalution Database (CO2STORED) The UK's online storage atlas. GHGT-12, Volume 63, pp. 5103-5113.

BERTA, M., DETHLEFSEN, F. AND EBERT, M., 2018. Geochemical effects of millimolar hydrogen concentrations in groundwater - an experimental study in the context of subsurface hydrogen storage. Environmental Science & Technology, 52(8).

BGS PRESS, 2020. New maps reveal heat stored in Britain’s abandoned coal mines. [Online]
Available at: https://www.bgs.ac.uk/news/new-maps-reveal-heat-stored-in-britains-abandoned-coal-mines/ [Accessed 05 August 2021].

BIRKHOLZER, J., ZHOU, Q. AND TSANG, C., 2009. Large-scale impact of CO2 storage in deep saline aquifers: a sensitivity study on pressure response in stratified systems. International Journal of Greenhouse Gas Technology, Volume 181-94, p. 3.

BO WANG, S.B., 2019. Induced geochemical reactions by compressed air energy storage in a porous formation in the North German Basin. Applied Geochemistry, 04 February, pp. 171-185.

BOAIT, P.J. AND FAN, D.S.A., 2011. Performance and control of domestic ground-source heat pumps in retrofit installations. Energy and Buildings, August, 43(8), pp. 1968-1976.

BONTE, M., STUYFZAND, P., HULSMANN, A. AND VAN BEELEN, P., 2011. Underground Thermal Energy Storage: Environmental Risks and Policy Developments in the Netherlands and European Union. Ecology and Society, 16(1).

BOUMAN, E.A., ØBERG, M.M. AND HERTWICH, E.G., 2016. Environmental impacts of balancing offshore wind power with compressed air energy storage (CAES). Energy, Volume 95.

BRASSINGTON, F.C., 2007. A Proposed Conceptual Model for the Genesis of the Derbyshire Thermal Waters. Quarterly Journal of Engineering Geology and Hydrogeology, 40(1), pp. 35-46.

BRITISH GEOLOGICAL SURVEY, 2020. Understanding carbon capture and storage (CCS). [Online]
Available at: https://www.bgs.ac.uk/discovering-geology/climate-change/carbon-capture-and-storage/
[Accessed 2021].

BRITISH GEOLOGICAL SURVEY, 2021. Geothermal Energy. [Online]
Available at: https://www.bgs.ac.uk/geology-projects/geothermal-energy/
[Accessed 2021].

BURNSIDE, N., BANKS, D. AND BOYCE, A., 2016. Sustainability of thermal energy production at the flooded mine workings of the former Caphouse Colliery, Yorkshire, United Kingdom. International Journal of Coal Geology, Volume 164, pp. 85-91.

BUSBY, J., 2010. Geothermal Prospects in the United Kingdom. Bali, Proceedings World Geothermal Congress 2010.

BUSBY, J., 2014. Geothermal energy in sedimentary basins in the UK. Hydrogeology Journal, Volume 22, pp. 129-141.

BUSBY, J., 2015. How hot are the Cairngorms?. Scottish Journal of Geology, Volume 51, pp. 105-115.

BUSBY, J. AND TERRINGTON, R., 2017. Assessment of the resource base for engineered geothermal systems in Great Britain. Geothermal Energy, Volume 5.

BUSBY, J. AND TERRINGTON, R., 2017. Assessment of the resource base for engineered geothermal systems in Great Britain. Geothermal Energy, Volume 5.

CAGLAYAN, D.G., WEBER, N. AND HEINRICHS, H., 2020. Technical Potential of Salt Caverns for Hydrogen Storage in Europe. International Journal of Hydrogen Energy, Issue doi:10.20944/preprints201910.0187.v1.

CAMPOPIANO, M. AND HENDERSEN, T., 2013. Carbon capture and sequestration projects benefit from EOR, Washington: Environmental Law Institute.

CAREY, J., 2007. Analysis and performance of oilwell cement with 30 years of CO2 exposure from SACROC Unit. International Journal of Greenhouse Gas Control, 1(1), pp. 75-85.

CHAVES, E., 2020. Underground Pumped Hydroelectric Storage: A Feasibility Study, s.l.: s.n.

CHEN, S., RAHBARI, H.R. AND ARABKOOHSAR, A., 2020. Impacts of partial-load service on energy, exergy, environmental and economic performances of low-temperature compressed air energy storage system. Journal of Energy Storage, 15 September.

CHEN, S., ZHANG, Q., ANDREWS-SPEED, P. AND MCLELLAN, B., 2020. Quantitative assessment of the environmental risks of geothermal energy: A review. Journal of Environmental Management, Volume 276.

CHEN, Y., JUAN GUERSCHMANN, Z.C. AND CHAO, L., 2019. Remote sensing for vegetation monitoring in carbon capture and storage regions: a review. Applied Energy, Volume 240, pp. 312-326.

CLARK, G. AND CLEGG, N., 2014. City Deal to bring UK's first ever large-scale, low-carbon heat network system to Stoke-on-Trent, UK Government Press Release, Deputy Prime Minister's Office, The Rt Hon Greg Clark MP, and The Rt Hon Nick Clegg. [Online] Available at: https://www.gov.uk/government

COLLINS, M.A. AND LAW, R., 2017. The Development and Deployment of Deep Geothermal Single Well (DGSW) Technology in the United Kingdom. European Federation of Geologists, Volume 43, pp. 63-68.

CORRIGAN, P., 2017. Work starts on city's £52 million district heat network. [Online] Available at: https://www.stokesentinel.co.uk/news/stoke-on-trent-news/work-starts-citys-52-million-549277
[Accessed 22 February 2021]. [Accessed 05 August 2021].

CORRIGAN, P., 2020. This £54.5m council scheme has been beset by delays - and now underground cables are to blame. [Online]
Available at: https://www.stokesentinel.co.uk/news/stoke-on-trent-news/district-heat-network-delays-caused-3794715
[Accessed 22 February 2021]. [Accessed 05 August 2021].

CRAMPSIE, S., 2019. Larne CAES plans withdrawn. [Online]
Available at: https://www.modernpowersystems.com/news/newslarne-caes-plans-withdrawn-7376728
[Accessed 15 February 2021]. [Accessed 05 August 2021].

CURTIS, R., LEDINGHAM, P., LAW, R. AND BENNETT, T., 2013. 2013 Geothermal Energy Use, Country Update for United Kingdom. Pisa, s.n.

CURTIS, R., LUND., J., SANNER, B., RYBACH, L., HELLSTRÖM, G., 2005. Ground Source Heat Pumps - Geothermal Energy for Anyone, Anywhere: Current Worldwide Activity. Antalya, s.n.

DARLING, G., 2019. Thermal groundwaters of the UK: geochemical indications of flow, vulnerability and possible threat to the shallow hydrosphere. Quarterly Journal of Engineering Geology and Hydrogeology, 52(4).

EVANS, DAVID, J., G. C. e. a., 2019. Mechanical Systems for Energy Storage – Scale and Environmental Issues. Pumped Hydroelectric and Compressed Air Energy Storage. In: Energy Storage Options and Their Environmental Impact. s.l.:s.n.

DBI GAS AND UMWELTTECHNIK GMBH, 2017. The effects of hydrogen injection in natural gas networks for the Dutch underground storages - Final Report, Den Haag: Netherlands Enterprise Agency.

DEPARTMENT FOR BUSINESS, ENERGY AND INDUSTRY STRATEGY, 2020. CCS deployment at dispersed industrial sites, London: BEIS.

DEPARTMENT FOR ENVIRONMENT, FOOD AND RURAL AFFAIRS, 2015. The production of Quick Scoping Reviews and Rapid Evidence Assessments, London: Department for Environment, Food and Rural Affairs - Joint Water Evidence Group.

DEPARTMENT OF ENERGY AND CLIMATE CHANGE, 2012. CCS Roadmap - Supporting deployment of Carbon Capture and Storage in the UK. London: s.n.

DEPARTMENT OF ENERGY AND CLIMATE CHANGE, 2012. CCS Roadmap, London: DECC.

DHAR, A., NAETH, M., JENNINGS, P. AND EL-DIN, M., 2020. Geothermal energy resources: potential environmental impact and land reclamation. Environmental Reviews, 28(4), pp. 415-427.

DÍAZ-NORIEGA, R., ÁLVAREZ, L. AND FERNÁNDEZ, P., 2020. The Challenges of Sustainable Use of Abandoned Underground Flooded Mines as Geothermal Resources. s.l., s.n.

DONADEI, S. AND SCHNEIDER, G.-S., 2017. Compressed Air Energy Storage in Underground Formations, Hannover, Germany: KBB Underground Technologies GmbH.

DONNELLY, L., CULSHAW, M. AND BELL, F., 2008. Longwall mining-induced fault reactivation and delayed subsidence ground movement in British coalfields. Quarterly Journal of Engineering Geology and Hydrogeology, 41(3), pp. 301-314.

DOPFFEL, N., JANSEN, S. AND GERRITSE, J., 2021. Microbial side effects of underground hydrogen storage - Knowledge gaps, risks and opportunities for successful implementation. International Journal of Hydrogen Energy, Volume 46, pp. 8594 - 8606.

DOST, B., EDWARDS, B. AND BOMMER, J., 2018. The Relationship between M and ML: A Review and Application to Induced Seismicity in the Groningen Gas Field, The Netherlands. Seismological Research Letters, 89(3), pp. 1062-1074.

DOYLE, A., 2019. UK Prime Minister promises funding for CCS and R&D. The Chemical Engineer.

DUCKETT, A., 2020. UK confirms £800m for carbon capture clusters. The Chemical Engineer.

DUHAN, J., 2018. Compressed Air Energy Storage in Salt Caverns: Geomechanical Design Workflow, CAES Siting Study from a Geomechanics Perspective, and Deep Brine Disposal, Waterloo, Ontario, Canada: University of Waterloo.

EDEN GEOTHERMAL, 2021. Eden Geothermal. [Online]
Available at: https://www.edengeothermal.com/news/
[Accessed May 2021]. [Accessed 05 August 2021].

EERA, 2018. Joint Program SP4 - Mechanical Storage - Underground Pumped Hydro Storage, s.l.: EERA (European Energy Research Alliance).

ENERGY AND CLIMATE CHANGE DIRECTORATE, 2013. Potential for deep geothermal energy in Scotland: study volume 2. [Online]
Available at: https://www.gov.scot/publications/study-potential-deep-geothermal-energy-scotland-volume-2/pages/13/. [Accessed 05 August 2021].

ENVIRONMENT AGENCY, 2014. An environmental risk assessment for coal bed, coal mine and abandoned mine methane operations in England - report – SC130029/R, Bristol: Environment Agency, Horizon house, Deanery Road.

ENVIRONMENT AGENCY, 2020. Mapping brackish aquifers and deepsourced spring.

EQUINOR, n.d. H2H Saltend. [Online]
Available at: https://www.equinor.com/en/what-we-do/h2hsaltend.html
[Accessed 2021].

ERBS POULSON, S., ALBERDI-PAGOLA, M., WOLDRUM TORDRUP, K. AND CERRA, D., 2020. Sustainable, building-integrated heating and cooling for future resilient cities.

EVANS, D. J. AND HOLLOWAY, S., 2009. A review of onshore UK salt deposits and their potential for underground gas storage, London: The Geological Society.

FARR, G. AND OTHERS, 2016. Low enthalpy heat recovery potential from coal mine discharges in the South Wales Coalfield. International Journal of Coal Geology, Volume 164.

FERKET, H., LAENEN, B. AND VAN TONGEREN, P., 2011. Transforming flooded coal mines to large-scale geothermal and heat storage reservoirs: what can we expect? Aachen, s.n., pp. 171-175.

FREEDMAN, V., WAICHLER, S., MACKLEY, R. AND HORNER, J., 2012. Assessing the thermal environmental impacts of a groundwater heat pump in southeastern Washington State. Geothermics, Volume 42, pp. 65-77.

FURRE, A.-K., 2017. 20 years of monitoring CO2-injection at Sleipner. Energy Procedia, Volume 114.

GAN, Q. AND LEI, Q., 2020. Induced fault reactivation by thermal perturbation in enhanced geothermal systems. Geothermics.

GEL, 2016. Geothermal Engineering Ltd, Arup & St Andrews University Deep Geothermal Single Well (DGSW) Aberdeen Exhibition & Conference Centre Feasibility Report for the Low Carbon Infrastructure Transition Programme (LCITP). [Online]
Available at: http://www.gov.scot/Publications/ [Accessed 05 August 2021].

GERSTENBERGER, M., CHRISTOPHERSEN, A. AND BUXTON, R., 2015. Bi-directional risk assessment in carbon capture and storage with Bayesian Networks. International Journal of Greenhouse Gas Technology, Volume 35, pp. 150-159.

GLOBAL CCS INSTITUTE, 2020. Global Status of CCS 2020, s.l.: Global CCS Institute.

GLUYAS, J., ADAMS, C.A., BUSBY, J.P., CRAIG, J., HIRST, C., MANNING, D.A.C., MACCAY, A., NARAYAT, N.S., ROBINSON, H.L., WATSON, S.M.M WESTAWAY, R., AND YOUNGER, P., 2018. Keeping warm: a review of deep geothermal potential of the UK. Proceedings of the Institution of Mechanical Engineers, Part A: Journal of Power and Energy, 232(1), pp. 115-126.

GOVERNMENT OF THE UK, 2020. Press release: PM outlines his Ten Point Plan for a Green Industrial Revolution for 250,000 jobs. [Online]
Available at: https://www.gov.uk/government/news/pm-outlines-his-ten-point-plan-for-a-green-industrial-revolution-for-250000-jobs
[Accessed 2021].

RPS GROUP, 2021. Seaham Garden Village [Online]
Available at: https://www.rpsgroup.com/projects/seaham-garden-village/

GRUBELICH, M.C., BAUER, S.J. AND COOPER, P.W., 2011. Potential Hazards of Compressed Air Energy Storage in Depleted Natural Gas Reservoirs, Albuquerque, New Mexico: Sandia National Laboratories.

HAGEMANN, B., 2017. Numerical and Analytical Modeling of Gas Mixing and Bio-Reactive Transport during Underground Hydrogen Storage, Göttingen, Germany: Clausthal University of Technology.

HARNMEIJER, J. SCHLICKE, A., BARRON, H., BANKS, D., TONSEND, D., STEEN, P., NIKOLAKIPOULOU, LU, H., ZHENGAO, C., 2017. Fortissat minewater geothermal district heating project: case study. Engineering & Technology Reference, Volume 1, pp. 1-8.

HEALTH AND SAFETY EXECUTIVE, 2021. Naturally occurring radioactive material which is not processed for its radioactive, fertile or fissile properties (NORM). [Online]
Available at: https://www.hse.gov.uk/radiation/ionising/norm.htm
[Accessed 2021].

HEINEMANN, N., ALCALDE, J. AND MIOCIC, J.M., 2021. Enabling large-scale hydrogen storage in porous media – the scientific challenges. Energy & Environmental Science, 14(2).

HEMME, C. AND VAN BERK, W., 2018. Hydrogeochemical Modeling to Identify Potential Risks of Underground Hydrogen Storage in Depleted Gas Fields. Applied Sciences, 19 November.

HE, W., LUO, X. AND EVANS, D., 2017. Exergy storage of compressed air in cavern and cavern volume estimation of the large-scale compressed air energy storage system. Applied Energy, Volume 208.

HINSON, S., 2018. Research Briefing: Potential for geothermal energy resources in the UK. [Online]
Available at: https://commonslibrary.parliament.uk/research-briefings/cdp-2018-0146/
[Accessed 23 February 2021]. [Accessed 05 August 2021].

HYUN, S., SHIN, D., MOON, H., HAN, Y-S., LEE, Y., JUNG, H., HWANG, Y., 2020. A multidisciplinary assessment of the impact of spilled acids on geoecosystems: an overview. Environmental Science and Pollution Research, Volume 27, p. 9803–9817.

INTERNATIONAL STANDARDS ORGANISATION, 2017. Carbon capture, transportation and geological storage, Switzerland: ISO.

JACOBS, T., 2020. CO2EOR could be industry's key to a sustainable future or its biggest missed opportunity, s.l.: Journal of Petroleum Technology

JESSOP, A., 1995. Geothermal energy from old mines at Springhill, Nova Scotia, Canada. Florence, International Geothermal Association, pp. 463-468.

JIA, Y., FANG, Y., ELSWORTH, D. AND WU, W., 2020. Slip Velocity Dependence of Friction-Permeability Response of Shale Fractures. Rock Mechanics and Rock Engineering, Volume 53, pp. 2109-2121.

JOHNSON, C. AND BURGMANN, R., 2017. Stress modulation of earthquakes: A study of long and short period stress perturbations and the crustal response, s.l.: UC Berkeley.

JUBILEE POOL, 2021. Jubilee Pool. [Online]
Available at: https://jubileepool.co.uk/pool-info/geothermal

KAGEL, A., BATES, D. AND GAWELL, K., 2007. A guide to Geothermal Energy and the Environment, Washington D.C.: Geothermal Energy Association.

KHARAKA, Y., THORDSEN, J. AND KAKOUROS, E., 2010. Changes in chemistry of shallow groundwater related to the 2008 injection of CO2 at the ZERT field site, Bozeman, Montana. Environmental Earth Science, Volume 60, pp. 273-284.

KHOSRAVY, M., 2021. Recent Progress in District Heating with Emphasis on Low-Temperature Systems. In: District Heating [Working Title]. s.l.:IntechOpen.

KIM, J., UM, E. AND MORIDIS, G., 2018. Integrated simulation of vertical fracture propagation induced by water injection and its borehole electromagnetic responses in shale gas systems. Journal of Petroleum Science and Engineering, Volume 165, pp. 13-27.

KIM, H-M., RUTQVIST, J., KIM, H., DOHUN, P., RYU, D-W., PARK, E-S., 2016. Failure Monitoring and Leakage Detection for Underground Storage of Compressed Air Energy in Lined Rock Caverns. Rock Mech Rock Eng., 49(DOI 10.1007/s00603-015-0761-7), pp. 573 - 584.

KING, M., JAIN, A. AND BHAKAR, R., 2021. Overview of current compressed air energy storage projects and analysis of the potential underground storage capacity in India and the UK. Renewable and Sustainable Energy Reviews, Volume 139.

KNAUSS, K., DIGBY., M.J., LEIF, R.N., MEW, D.A., AINES, R.D., 2000. The aqueous solubility of trichloroethene (TCE) and tetrachloroethene (PCE) as a function of temperature. Applied Geochemistry, 15(4), pp. 501-512.

KREVOR, S., 2016. Multiscale characterisation of CO2 storage in the United Kingdom, s.l.: UKCCS Research Centre.

LAW, R., CHENDORAIN, M., FREE, M. AND COLLINS, M., 2016. Development and Deployment of Deep Geothermal Single Wells in the UK. Strasbourg, s.n.

LEDINGHAM, P., COTTON, L. AND LAW, R., 2019. The United Downs Deep Geothermal Power Project. Stanford, s.n.

LEFORT, P., 2016. Geothermal Potential of Offshore Mature Hydrocarbon Fields, Bedford: s.n.

LIU, W. AND RAMIREZ, A., 2017. State of the art review of the environmental assessment and risk of underground geo-energy resource exploitation. Renewable and sustainable energy reviews, Volume 76, pp. 628-644.

LOPEZ, S., HAMM, V., LE-BRUN, M., SCHAPER, L., BOISSIER, F., COTICHE., GIUGLARIS, E. 2010. 40 years of Dogger aquifer management in Ile-de-France, Paris Basin, France. Geothermics, 39(4), pp. 339-356.

LOREDO, C. AND MIGUEL, E. 2016. Prediction of the flooding of a mining reservoir in NW Spain, s.l.: Journal of Environmental Management.

LUND, J., SANNER, B., RYBACH, L. AND CURTIS, R., 2004. Geothermal (ground source) heat pumps - A world overview. GHC Bulletin.

LU, S.-M., 2018. A global review of enhanced geothermal system (EGS). Renewable and Sustainable Energy Reviews, 81(2), pp. 2902-2921.

MANZELLA, A., BONCIANI, R., ALLANSDOTTIR, A., BOTTEGHI, S., DONATO, A., GIAMBERINI, S., LENZI, A., PACI, M., PELLIZZONE, A. AND SCROCCA, D., 2018. Environmental and social aspects of geothermal energy in Italy. Geothermics, Volume 72, pp. 232-248.

MARTY, N.C.M., HAMM, V., CASTILLO, C., THIERY, D., KERVEVAN, C., 2020. Modelling water-rock interactions due to long-term cooled-brine reinjection in the Dogger carbonate aquifer (Paris Basin) based on in-situ geothermal well data. Geothermics, Volume 88.

MYERS, M., WHITE, C., PEJCIC, B., 2020. CSIRO: In-Situ Lab: A multi-pronged approach to surface gas and groundwater monitoring at geological CO2 storage sites. Chemical Geology, Volume 545.

MA, X., ZHANG, X. AND TAIN, D., 2020. Farmland degradation caused by radial diffusion of CO2 leakage from carbon capture and storage. Journal of Cleaner Production, Volume 255.

MEDIMURIC, N., 2010. The influence of CO2 on cement. Zagreb, The 3rd South East Europe Conference on Sustainable Development of Energy, Water and Environment Systems.

MENÉNDEZ, J., FERNÁNDEZ-ORO, J. M. AND GALDO, M., 2020. Efficiency analysis of underground pumped storage hydropower plants. Journal of Energy Storage, Volume 28.

MENÉNDEZ, J., SCHMIDT, F. AND KONIETZKY, H., 2019. Stability analysis of the underground infrastructure for pumped storage hydropower plants in closed coal mines. Tunnelling and Underground Space Technology, Volume 94, pp. 103 - 117.

MONAGHAN, A.A., STARCHER, V., DOCHARTAIGH, B.O., SHORTER, K., BURKIN, J., 2018. UK Geoenergy Observatories: Glasgow Geothermal Energy Research Field Site : science infrastructure., Nottingham: Unpublished British Geological Survey.

MORENO, W., 2019. Review of studies on corrosion of steel by CO2 focussed on the behaviour of API steel in geological CO2 storage environment. Materials and geoenvironment, 66(3), pp. 149-172.

NAMASWA, S.W., OKOTH, C. AND MAKORI, B., 2018. Analysis of Natural Radioactivity and Radiation Exposure Levels in Eburru Geothermal Field, Kenya. Engineering and Technology.

NIKOLAEV, D., 2020. Numerical Simulation of Bio-reactive Transport Process: Application of Underground Methanation Reactor, s.l.: Montan Univeristy Leoben.

NORBECK, J., MCCLURE, M. AND HORNE, R., 2018. Field observations at the Fenton Hill enhanced geothermal system test site support mixed-mechanism stimulation. Geothermics, Volume 74, pp. 135-149.

NORSK OLJE & GASS, 2019. NORSOK D-0101 Revision. Oslo, Norsk olje & gass.

NORTHERN LIGHTS CCS, 2021. About the project. [Online]
Available at: https://northernlightsccs.com
[Accessed 2021]. [Accessed 05/08/21]

NOYES, P., MCELWEE, M.K., MILLER, H.D., CLARK, B.W., VAN TIEM, L.A., WALCOTT, K.C., ERWIN, K.N., LEVIN, E.D., 2009. The toxicology of climate change: Environmental contaminants in a warming world. Environment International, 35(6), pp. 971-986.

OIL & GAS JOURNAL, 2014. CO2EOR set for growth as new CO2 supplies emerge. [Online]
Available at: https://www.ogj.com/drilling-production/production-operations/ior-eor/article/17210639/co2eor-set-for-growth-as-new-co2-supplies-emerge
[Accessed 2021]. [Accessed 05/08/21]

OIL AND GAS CLIMATE INVESTMENT, 2019. Teeside Cluster Carbon Capture, Usage and Storage (CCUS) Project, Teeside: Oil and Gas Climate Investment.

OIL AND GAS UK, 2018. Well Decommissioning Guidelines, s.l.: Oil and Gas UK.

OKAMOTO, K., YI, L., ASANUMA, H., OKABE, T., YASUYUKI, A., TSUZUKI, M., 2018. Triggering processes of microseismic events associated with water injection in Okuaizu Geothermal Field, Japan. Earth, Planets and Space, Volume 70.

OLADYSHKIN, S., 2011. A concept for data-driven uncertainty quantification and its application to carbon dioxide storage in geological formations. Advanced Water Resources, 32(1), pp. 82-93.

OLGAN, G. AND ABDELAZIZ, S.L., 2013. Long-term performance of heat exchanger piles. In: Coupled Phenomena in Environmental Geotechnics. s.l.:s.n., pp. 511-517.

ORIO, C., JOHNSON, C. AND POOR, K., 2006. Geothermal standing column wells: ten years in a New England school. ASHRAE Transactions, 112(2), pp. 57-64.

PALE BLUE DOT, 2016. Progressing development of the UK's strategic carbon dioxide storage resource, London: Department of Energy and Climate Change (now BEIS).

PARKES, D., EVANS, D. AND WILLIAMSON, P., 2018. Estimating available salt volume for potential CAES development: A case study using the Northwich Halite of the Cheshire Basin. Journal of Energy Storage, 18(https://doi.org/10.1016/j.est.2018.04.019), pp. 50 - 61.

PICKARD, W.F., 2012. The History, Present State, and Future Prospects of Underground Pumped Hydro for Massive Energy Storage. IEEE, Issue DOI: 10.1109/JPROC.2011.2126030.

PIMM, A.J., YANG, J. AND WIDJAJA, K., 2019. Hydrogen Technology State of the Art, s.l.: University of Leeds.

PLAINS CO2 REDUCTION PARTNERSHIP (PCOR), 2019. Weyburn - Midal CO2 Project. [Online]
Available at: https://undeerc.org/pcor/co2sequestrationprojects/Weyburn.aspx
[Accessed 2021].

POULAIN, A., DREUZY, J.-R.D. AND GODERNIAUX, P., 2018. Pump Hydro Energy Storage systems (PHES) in groundwater flooded quarries. Journal of Hydrology, Volume 559.

POWER STATIONS UK, n.d. Decline of coal and oil fired power stations in the UK. [Online]
Available at: https://www.powerstations.uk/
[Accessed 2021]. [Accessed 05/08/21].

PUJADES, E., JURADO, A. AND ORBAN, P., 2018. Hydrochemical changes induced by underground pumped storage hydropower and their associated impacts. Journal of Hydrology.

PUJADES, E., ORBAN, P. AND ARCHAMBEAU, P., 2020. Underground Pumped-Storage Hydropower (UPSH) at the Martelange Mine (Belgium): Interactions with Groundwater Flow. Energies, 13(doi:10.3390/en13092353), pp. 23 - 53.

PUJADES, E., ORBAN, P. AND BODEUX, S., 2017. Underground pumped storage hydropower plants using open pit mines: How do groundwater exchanges influence the efficiency? Applied Energy, Volume 190, pp. 135 - 146.

RAG AUSTRIA AG, n.d. Project description. [Online]
Available at: https://www.underground-sun-conversion.at/en/project/project-description.html
[Accessed 23 February 2021]. [Accessed 05/08/21].

RATHNAWEERA, T., WU, W., JI, Y. AND GAMAGE, R., 2020. Understanding injection-induced seismicity in enhanced geothermal systems: From the coupled thermo-hydro-mechanical-chemical process to anthropogenic earthquake prediction. Earth-Science Reviews, Volume 205.

RATTLE, I., VAN ALSTINE, J., PETERSON, E., SHAWN, N., TRIMBY, S., 2020. Using the underground to fight climate change. , s.l.: Report. Brief 2, SRI 29. Policy Leeds, University of Leeds.

RAYMOND, J., THERRIEN, R. AND HASSANI, F., 2008. Overview of Geothermal Energy Resources in Québec (Canada) Mining Enviroments. Ostrava, s.n.

RICHTER, A., 2020. Onshore oil and gas exploration and production company, IGas has announced the acquisition of GT Energy, a UK-based geothermal heating developer. [Online]
Available at: thinkgeoenergy.com/uk-based-geothermal-heat-developer-gt-ene
[Accessed 2021]. [Accessed 05/08/21].

ROBERTS, J. AND STALKER, L., 2017. What have we learned about CO2 leakage from field injection sites? Energy Procedia, Volume 114, pp. 5711-5731.

ROBERTS, J. AND STALKER, L., 2020. What have we learned about CO2 leakage from CO2 release field experiments, and what are the gaps for the future? Earth-Science Reviews, Volume 209, pp. 1029-1039.

ROCHELLE, C., BUSBY, J., KILPATRICK, A., SHAIL, R., YEOMANS, C., EYRE, M., DEN HARTOG, S., ARNOLD, D., GEIGER, S., BUSCH, A. AND LEDINGHAM, 2020. Geothermal Power Generated from UK Granites (GWatt). Reykjavik, s.n.

ROSE, P., 2018. The CCS hub on Norway: some insights from 22 years of saline aquifer injection. International carbon conference, Volume 146, pp. 166-172.

RPS, 2021. Seaham Garden Village [Online]
Available at: https://www.rpsgroup.com/projects/seaham-garden-village/.

SAINZ-GARCIA, A, E. A. V. R. e. a., 2017. Assessment of feasible strategies for seasonal underground hydrogen storage in a saline aquifer. International Journal of Hydrogen Energy, 42(26), pp. 1-10.

SAYED, E.T., WILBERFORCE, T., ELSAID, K., RABAIA, M.K.H., ABDELKAREEM, M.A., CHAE, K.J. AND OLABI, A.G., 2021. A critical review on environmental impacts of renewable energy systems and mitigation strategies: Wind, hydro, biomass and geothermal. Science of The Total Environment, Volume 766.

SCHIMMEL, M., LUI, W. AND WORREL, E., 2019. Facilitating sustainable geo-resource exploitation: a review of environmental and geological risks of fluid injection into hydrocarbon reserves. Earth-Science Reviews, Volume 18.

SHAO, H., FREIBURG, J.T. AND BERGER, P.M., 2020. Mobilization of trace metals from caprock and formation rocks at the Illinois Basin - Decatur Project demonstration site under geological carbon dioxide sequestration conditions. Chemical Geology, Volume 550.

SMINCHAK, J., 2018. Integrated wellbore integrity analysis program for CO2 storage applications: project results. Ohio, US Department of Energy.

SMITH, K.L., STEVEN, M.D., JONES, D.G., WEST, J.M., COOMBS, P., GREEN, K.A., BARLOW, T.S., BREWARD, N., GWOSDZ, S., KRÜGER, M. AND BEAUBIEN, S.E., SMITH, K., 2013. Environmental impacts of CO2 leakage: recent results from the ASGARD facility, UK. Greenhouse Gas Technology Conference, Volume 37, pp. 791-799.

STONE, H.B.J., VELDHUIS, I. AND RICHARDSON, R.N., 2015. Underground hydrogen storage in the UK, s.l.: University of St Andrews.

STROBEL, G., HAGEMANN, B. AND HUPPERTZ, T.M., 2020. Underground bio-methanation: Concept and potential. Renewable and Sustainable Energy Reviews, Volume 123.

TALWANI, P. AND ACREE, S., 1984. Pore pressure diffusion and the mechanism of reservoir-induced seismicity. Pure and Applied Geophysics, Volume 122, pp. 947-965.

TESTER, J. AND OTHERS, 2006. The Future of Geothermal Energy - impact of enhanced geothermal systems (EGS) on the United States in the 21st century, s.l.: Massachusetts Institute of Technology and US Department of Energy.

THE COAL AUTHORITY, 2020. New maps reveal heat stored in Britain's abandoned coal mines. [Online]
Available at: https://www.gov.uk/government/news/new-maps-reveal-heat-stored-in-britains-abandoned-coal-mines
[Accessed 01 March 2021]. [Accessed 05/08/21].

THE MINISTRY OF ECONOMIC AFFAIRS AND CLIMATE POLICY, 2019. Energy in transition - the subsurface at our service, Amsterdam: The Ministry of Economic Affairs and Climate Policy.

THE MINISTRY OF PETROLEUM AND ENERGY OF THE GOVERNMENT OF NORWAY, 2018. Memorandum of Understanding on the Cooperation in the field of Carbon Capture and Storage. Edinburgh, UK: s.n.

TODD, F., MCDERMOTT, C., HARRIS, A.F., BOND, A. AND GILFILLAN, S., 2019. Coupled hydraulic and mechanical model of surface uplift due to mine water rebound: implications for mine water heating and cooling schemes. Scottish Journal of Geology, Volume 55, pp. 124-133.

TONG, L., LIU, L. AND YU, Q., 2013. Tunneling in abandoned coal mine areas: Problems, impacts and protection measures. Tunnelling and Underground Space Technology, Volume 38, pp. 409 - 422.

TONG, Z., CHENG, Z. AND TONG, S., 2021. A review on the development of compressed air energy storage in China: Technical and economic challenges to commercialization. Renewable and Sustainable Energy Reviews, Volume 135.

TOWNSEND, D.H., NAISMITH, J.D., TOWNSEND, P.J., MILNER, M.G. AND FRASER, U.T., 2020. "On The Rocks" – Exploring Business Models for Geothermal Heat in the Land of Scotch. Reykjavik, s.n.

TRIPLE POINT HEAT NETWORKS, 2020. Innovative Mine Water Heat Network secures Government funding in HNIP Round 3. [Online]
Available at: https://tp-heatnetworks.org/innovative-mine-water-heat-network-secures-government-funding-in-hnip-round-3/ [Accessed 05/08/21].

TURCOTTE, D. AND SCHUBERT, G., 2002. Geodynamics. 2nd ed. Cambridge: Cambridge University Press.

US DOE, 2007. Final risk assessement report for the FutureGen Project Environmental Impacts Statement, California: United State Department of Energy.

VAN HOOL ROAD TANKERS, 2021. Road Tankers. [Online]
Available at: https://www.vanhool.be/en/industrial/tankopleggers
[Accessed 2021]. [Accessed 05/08/21].

VASILE, M., BRUGGEMAN, M., VAN MEENSEL, S., BOS, S. AND LAENEN, B., 2017. Characterization of the natural radioactivity of the first deep geothermal doublet in Flanders, Belgium. Appl Radiat Isot., Aug, Volume 126, pp. 300-303.

WANG, J., LU, K. AND MA, L., 2017. Overview of Compressed Air Energy Storage and Technology Development. Energies, Volume 10.

WARREN, J., 2016. Evaporites: A Geological Compendium, Switzerland: Springer International Publishing.

WATSON, S., WESTAWAY, R. AND FALCONE, G., 2019b. A Review of Deep Geothermal Energy and Future Opportunities in the UK. Den Haag, s.n.

WATSON, S., WESTAWAY, T. AND BURNSIDE, N., 2019a. Digging deeper: The influence of historical mining on Glasgow's subsurface thermal state to inform geothermal research. Scottish Journal of Geology, Volume 55, pp. 107-123.

WEN LIU, A.R., 2017. State of the art review of the environmental assessment and risks of underground geo-energy resources exploitation. Renewable and Sustainable Energy Reviews, 76(http://dx.doi.org/10.1016/j.rser.2017.03.087), pp. 628 - 644.

WILDBOLZ, C., 2007. Life cycle assessment of selected technologies for CO2 transport and sequestration, Zurich: Swiss Federal Institute of Technology.

YOUNGER, P.L., MANNING, D.A., MILLWARD, D., BUSBY, J.P., JONES, C.R. AND GLUYAS, J.G., 2016. Geothermal exploration in the Fell Sandstone Formation (Mississippian) beneath the city centre of Newcastle upon Tyne, UK: the Newcastle Science Central Deep Geothermal Borehole. Quarterly Journal of Engineering Geology and Hydrogeology, Volume 49, pp. 350-363.

YOUNGER, P., WOLERSDORER, C., AMEZAGA, J. AND BARESEL, C., 2004. Mining Impacts on the fresh water environment: Technical and Managerial Guidelines for Catchment Scale Management. Mine Water and the Environment, Volume 23, pp. 2-80.

YU, C., VAVRYČUK, V., ADAMOVÁ, P. AND BOHNHOFF, M., 2018. Moment Tensors of Induced Microearthquakes in The Geysers Geothermal Reservoir From Broadband Seismic Recordings: Implications for Faulting Regime, Stress Tensor, and Fluid Pressure. Journal of Geophysical Research: Solid Earth, 123(10), pp. 8748-8766.

ZERO CARBON HUMBER, 2020. Capture for Growth: Roadmap for the world's first zero carbon industrial cluster, s.l.: Zero Carbon Humber.

ZHANG, Q., CHEN, S., TAN, Z., ZHANG, T. AND MCLELLAN, B., 2019. Investment strategy of hydrothermal geothermal heating in China under policy, technology and geology uncertainties. Journal of Cleaner Production, Volume 207, pp. 17-29.

ZHENG, L., ZHANG, Y., XU, T. AND BIRKHOLZER, J., 2010. On mobilization of lead and arsenic in groundwater in response to CO2 leakage form deep geological storage. Transport in Porous Media, Volume 82, pp. 215-246.

ZHU, K., FANG, L., DIAO, N. AND FANG, Z., 2017. Potential underground environmental risk caused by GSHP systems. Procedia Egineering, Volume 205, pp. 1477-1483.

ZIVAR, D., KUMAR, S. AND FOROOZESH, J., 2020. Underground hydrogen storage: A comprehensive review. International Journal of Hydrogen Energy, Issue https://doi.org/10.1016/j.ijhydene.2020.08.138.

List of abbreviations

Abbreviation	Definition
A-CAES	Adiabatic compressed air energy storage
AA-CAES	Advanced adiabatic compressed air energy storage
ASGARD	Artificial soil gassing and response detection
BEIS	Department for Business, Energy and Industrial Strategy
BGS	British Geological Survey
BTEX	Benzene, toluene, ethylbenzene and xylene
CAES	Compressed air energy storage
CCS	Carbon capture and storage
CCUS	Carbon capture, usage and storage
D-CAES	Diabatic compressed air energy storage
DBHE	Deep-borehole heat exchanger
DGSW	Deep geothermal single well
EGS	Enhanced geothermal systems
GHG	Greenhouse gas
GSHP	Ground-source heat pump
HDR	Hot dry rock
I-CAES	Isothermal compressed air energy storage
LRC	Lined rock caverns
MOU	Memorandum of understanding

QICS	Quantifying and monitoring potential ecosystem impacts of geological carbon storage
QSR	Quick scoping review
SPR	Source, pathway, receptor
TD	Total depth
TES	Thermal energy storage
UGS	Underground gas storage
UHS	Underground hydrogen storage
UKGEOS	UK Geoenergy Observatories
UPSH	Underground pumped storage hydropower
ZCH	Zero Carbon Humber

Would you like to find out more about us or your environment?

Then call us on

03708 506 506 (Monday to Friday, 8am to 6pm)

Email: enquiries@environment-agency.gov.uk

Or visit our website

www.gov.uk/environment-agency

incident hotline

0800 807060 **(24 hours)**

floodline

0345 988 1188 **(24 hours)**

Find out about call charges (https://www.gov.uk/call-charges)

Environment first

Are you viewing this onscreen? Please consider the environment and only print if absolutely necessary. If you are reading a paper copy, please don't forget to reuse and recycle.