Specific environmental risks from repurposing oil and gas wells

Chief Scientist's Group research report

November 2022

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Dr Robert Bradburne
Chief Scientist

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Executive summary

England has over 2,000 onshore oil and gas wells. Energy transition technologies, such as geothermal energy or storage of hydrogen, that are not as energy dense as oil and gas, require access to the deep subsurface. These technologies might become more economic and cause less environmental disruption if they repurpose existing oil and gas infrastructure such as wells, rather than constructing new wells. However, the associated potential environmental impacts of repurposing oil and gas wells are not fully understood.

This report considers the possible environmental impacts from repurposing onshore oil and gas wells for a range of uses, including abstracting heat or fluids, testing tools, and permanent or temporary storage of gases. It describes the ways in which onshore oil and gas wells can be repurposed, discusses potential leakage pathways and contaminants, identifies factors that might make wells suitable for repurposing and finally applies these factors to a screening of wells in England.

Generally, once a well has fulfilled its purpose it will be decommissioned. However, there are established processes that allow the oil and gas industry to repurpose wells (for example, for wells that produce (extract) oil and gas to be changed to wells that inject other fluids). For a well to be repurposed, the operator must demonstrate that fluids are controlled within the well at all times (has sufficient integrity) and under all possible operational conditions. Not all wells can be repurposed, for example, it is extremely unlikely that a fully decommissioned well will be repurposed. The material used in the well-bore must be suitable for the new operating conditions and fluids. New standards might be required for carbon dioxide (CO_2) and hydrogen (H_2) wells. Other factors can indicate wells have a higher likelihood of meeting the integrity requirements for repurposing, such as operational status, age and orientation. Although wells that are not identified by these factors could also meet requirements.

There are 2 main potential leakage pathways for contaminants from repurposed sites: through an active or decommissioned well and through a geological pathway in the subsurface (within the overburden, or laterally along the ‘reservoir’ formation). Factors such as the pressure within the reservoir should be considered. It is important to model and monitor the pressures and fluids in the ‘storage site’ to ensure secure containment. Potential leakage pathways from the repurposed field and any possible mechanical instability in the reservoir or overburden could limit the potential of sites even if wells are suitable to be repurposed. While there is likely to be greater knowledge about geological uncertainty in depleted oil and gas fields than in new sites, which could reduce leakage risk, there is also likely to be a higher number of wells in depleted fields that could increase risk.

Sources of potential contamination from repurposed wells include all injected material (CO_2, H_2, corrosion and scale inhibitors, viscosifiers, biocides) and fluids produced from the reservoir (for example, oil, gas, brine, hydrogen sulphide and carbon dioxide, microorganisms, naturally occurring radioactive material) as well as those that are a consequence of mixing with reservoir or overburden fluids. Understanding the different fluid compositions and the impact of pressure and temperature changes in the system is crucial in protecting the environment from inadvertent harm.

Stepwise screening of onshore oil and gas wells in England is demonstrated. This indicates the numbers of wells that are fully decommissioned and that have higher relative likelihoods of meeting the well integrity standards to be repurposed (although it is noted that any well that has not been fully decommissioned could be repurposed if it can be demonstrated that it meets required integrity standards related to the new purpose).

1. Introduction

The ‘energy transition’ describes the move away from energy-dense but greenhouse gas producing oil and gas (and coal) to other energy forms, some of which may need to use require use of the deep subsurface. These would include geothermal energy, storage of high-energy gases such as hydrogen (H_2), the disposal of unwanted gases such as carbon dioxide (CO_2) as well as thermal and mechanical technologies for energy storage. Many of these new and renewable energy technologies have low economic returns and therefore reusing oil and gas facilities may help improve their economic viability as well as reducing uncertainty in the reservoir conditions compared with new sites. Reusing facilities could also lower the potential environmental impact by reducing the need for new materials or drilling new wells (and associated waste, emissions and potential spillages).

However, it is not yet clear what the overall potential environmental impacts might be from reusing existing wells for purposes for which they were not originally intended.

The Environment Agency commissioned this report in November 2021 to consider the specific environmental risks of repurposing onshore oil and gas wells. It aims to build on our existing knowledge about the sources and pathways of pollution from oil and gas wells and other technologies, to understand the specific environmental risks from repurposed wells. This work is based on expert judgement and experience of both the contractor and the Environment Agency steering group, literature review (including current industry best practices) and insight from the oil and gas operator Third Energy, particularly in relation to the processes for repurposing wells for geothermal energy extraction.

To understand the specific environmental risks, it is necessary to understand:

- how the wells could be repurposed (sections 2 and 3)
- the process through which an individual well could be repurposed (section 4)
- general considerations for repurposing wells (section 5)
- sources of potential contaminants (section 6)
- potential leakage pathways (section 7)

The report then identifies main areas of knowledge gaps (section 8) and finally demonstrates how well attributes available in the North Sea Transition Authority (NSTA) wells database could be used to indicate whether onshore oil and gas wells in England might be suitable for repurposing from an environmental point of view (section 9).

This report provides background information on the environmental considerations for repurposing onshore oil and gas wells, but does not claim that it is possible to do this for any specific well without further investigation. In addition, this report does not comment in any depth on the economic viability of repurposing a well; this will be evaluated by the operator.

2. Well repurposing overview

2.1 History of UK onshore wells

Globally, over 1,000,000 oil and gas wells have been drilled in onshore settings. Since the start of the twentieth century there have been over 2,000 deep wells drilled onshore in the UK; most of those wells are in England and they are the focus of this report. Almost all have been drilled to explore for or produce oil and gas. Around 12 wells have been drilled for geothermal energy.

In 1895 a water well drilled at Heathfield (East Sussex) encountered gas and led to the chance discovery of the UK's first commercial gas field. Further wells were drilled to increase gas production (Goffey and others, 2020). The first well drilled in the UK for oil was at Tibshelf in Derbyshire in 1919. It was successful and produced about 20,000 barrels (about 3,000m^3) at a rate of up to 14 barrels of oil a day (about 2.2m^3/day) (Craig and others, 2018). This well was one of 7 wells drilled on behalf of the British Government of the time. Another well at D'Arcy Farm, east of Edinburgh, was also successful and produced about the same volume of oil. The remaining wells did not find any oil or found only traces, and each was decommissioned.

The second phase of oil exploration in the UK occurred in the late 1930s. This resulted in the discovery of commercial quantities of oil at Eakring in Nottinghamshire (Kent, 1984). This field, along with other subsequent discoveries in both Nottinghamshire and Lincolnshire, formed the core of home oil production for the following 30 years.

In 1957, a successful well was drilled on the cliff top at Kimmeridge Bay in Dorset (Gluyas and others, 2003). This was a precursor to the discovery of the Wytch Farm oil field on the Dorset coast and beneath Poole Harbour (Hogg and others, 1999). Oil and gas have also been discovered and produced in Hampshire, Sussex and Surrey (Trueman, 2003) and gas alone in North Yorkshire (Harrison and others, 2020). Small amounts of production have occurred in the West Lancashire, Cheshire, and North Staffordshire basins.

Oil and gas exploration has taken place in many parts of the UK, including Buckinghamshire, Cheshire, Cleveland, Cumbria, Derbyshire, Dorset, Essex, Gloucestershire, Hampshire, Hertfordshire, Humberside, Isle of Wight, Kent, Lancashire, Leicestershire, Lincolnshire, Merseyside, Northumberland, Nottinghamshire, Shropshire, Surrey, East Sussex, West Sussex, Staffordshire, Tyne and Wear, Warwickshire, Wiltshire, North Yorkshire, South Yorkshire and West Yorkshire. However, no commercial discoveries have been made outside the areas mentioned in the previous paragraphs and wells were typically decommissioned shortly after drilling.

2.2 Historical repurposing of wells in oil and gas fields

Once discovered, an oil or gas field will typically undergo a phase of appraisal, aimed at determining the quantity of oil and gas and its distribution in the subsurface. A development plan will define how the oil and gas will best be extracted. For onshore settings, the discovery and appraisal wells are likely to be reused for production. In all but the smallest of fields, the development phase usually involves drilling more wells to increase the number available for production. Over the lifetime of an individual well within an oil and gas field the well may be repurposed; for example, an initial production well may become more useful as a water injector or an exploration well could become a producer. Therefore, many oil and gas production operators have experience in repurposing wells.

A typical onshore oil or gas field may therefore have either within it, or nearby, some decommissioned wells, and may have one or more active injection or production wells (Figure 1).

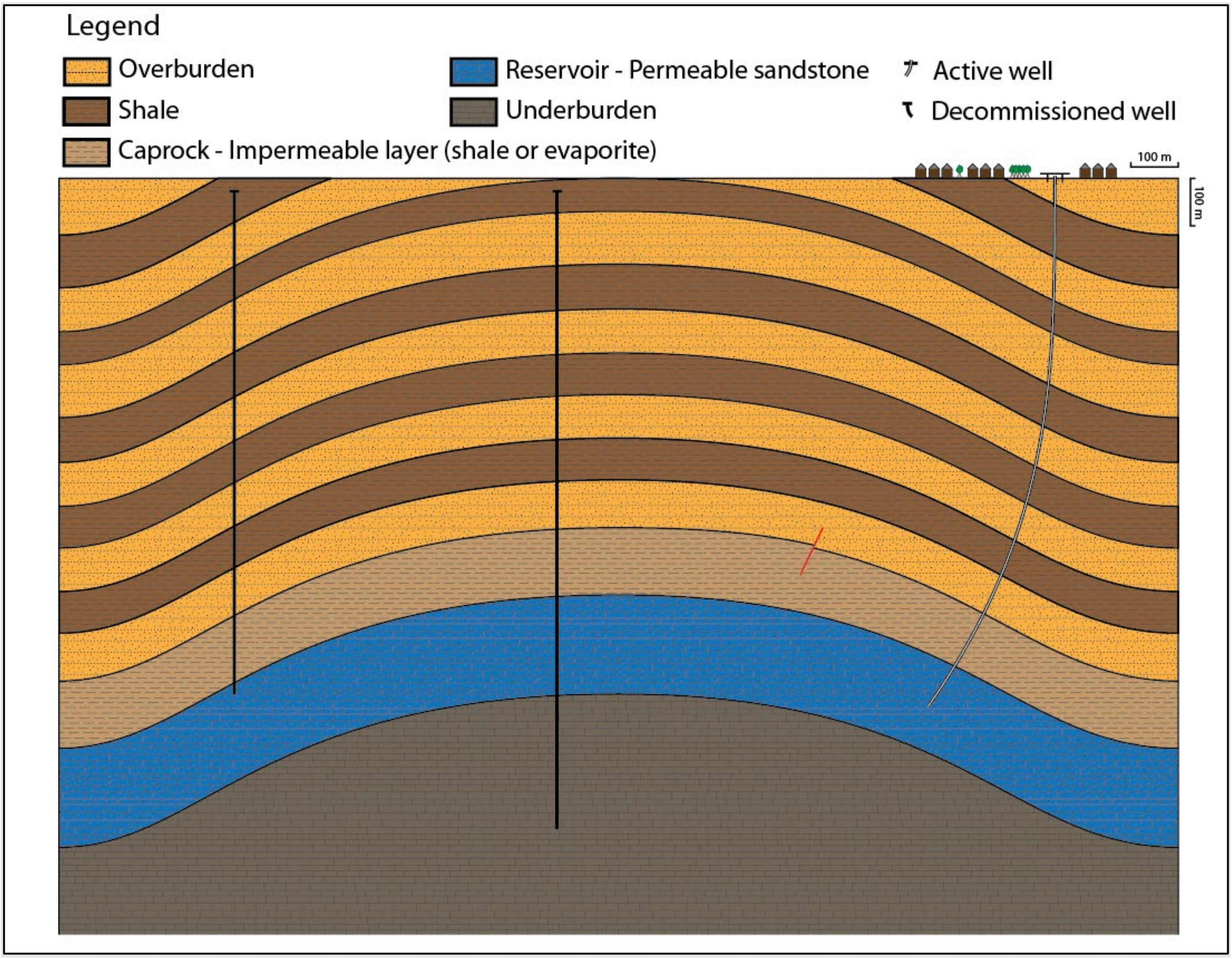

Figure 1: A schematic diagram of a depleted oil and/or gas field. The 'reservoir' horizon is coloured blue, with an overlying top seal (also called caprock) that has served to keep the oil and/or gas contained for millions of years, despite their buoyancy. There are 2 decommissioned wells, both vertical, and both cut off below the surface. There is one active well, which is deviated. The overburden is shown as both sandstone and shale.

2.2.1 Deepening and/or sidetracking of wells

It is possible to re-enter and deepen an active or recently active well to extend below the original 'terminal depth' (TD). This may be required, for example, to reach a deeper target. Wells can also be sidetracked. This is where a hole is cut in the casing above the original TD and the 'drill string' directed through the hole to reach to a new TD at a distance away from the original TD location. It is possible to drill many sidetracks from an original (mother) bore. Typically, in order to offer a greater surface area between the well and the formation in which it is completed, a well may be 'deviated' to a high angle (away from vertical) or even horizontal. Extended reach drilling may produce a well which is 10km or more away from the top-hole location. This deepening or sidetracking of a well typically has a significant cost attached to it and the costs are more likely to escalate than when drilling a simple vertical well. This is due to the additional work required to mill out (cut and remove downhole metal) of the original casing. The decision to deepen or sidetrack a well would be based on factors such as the structure and the permeability (transmissivity) of the target horizon, as well as economic and environmental considerations. For example, in the 1990s British Petroleum used extended-reach deviated wells at Wytch Farm, Dorset to avoid building artificial islands in Poole Harbour from which to drill.

2.3 Repurposing for non-oil and gas purposes

Oil and gas wells could be repurposed for a variety of new uses. The following list includes theoretical uses, even if not allowed within the existing regulatory framework.

2.3.1 Passive use

'Passive' reuse of an oil or gas well would not involve any fluids moving from the reservoir to the wellbore or from the wellbore to the reservoir. It can be divided into 3 sub-categories; closed loop abstraction of heat, mechanical energy storage and tool testing.

Closed loop abstraction of heat: Given that temperature increases with depth below the ground surface, a deep well can be used for heat abstraction. Fluids are circulated within the well, heating up as they descend and the heat is harvested at surface. Fluids are not transmitted in or out of the borehole (Westaway, 2018). This is known as a 'closed loop geothermal borehole'.

Mechanical energy storage: Potential energy can be stored by suspending heavy weights in the well void using cables engaged with an electric winch capable of lifting the weights. Electricity is stored as potential energy by raising the weights. Power can then then be generated by lowering the weights to turn a generator. These systems are typically designed for use in mine shafts (Moore, 2021). It is not clear whether these systems could be used on an industrial scale in oil and gas boreholes, which are only tens of centimetres in diameter and which are typically tapered, with wider tops than bottom sections. Given the relatively small mass that could be used to freefall inside a repurposed well, this option to repurpose a well is unlikely to be effective or economically attractive. Repurposing a well for mechanical energy will therefore not be considered further in this report.

Tool testing: A borehole could be used for research and development purposes. This could involve testing tools to be used in renewable and sustainable energy technologies. Tool testing in a repurposed former oil and gas well is highly desirable ahead of operational deployment.

2.3.2 Injection of fluids

In England, the injection of substances in the subsurface is subject to strict regulatory controls, and reuse of onshore oil and gas wells for this purpose is not currently permitted other than for research. It is theoretically possible that oil and gas wells could be re-engineered for disposal of unwanted fluids (for example, CO_2). This could include the injection of modest volumes of dense phase CO_2 to evaluate storage options on analogue offshore sites (Kummerow and Spangenberg, 2011), to test CO_2 plume geothermal technology (Adams and others, 2021) or to test containment and monitoring for permanent offshore storage sites for CO_2 (there have been many test cases globally, for example, in Ketzin, Germany 67,000 tonnes of carbon dioxide was injected for permanent storage at depth between 2008 and 2013 (Liebscher & Münch, 2016)).

2.3.3 Production of fluids

An oil and gas well could be repurposed for production of geothermal fluids (Auld and others, 2014) or abstraction of elements such as lithium (Li) for use in low carbon technologies (Gluyas and others, 2016). It is likely that, in most instances, the fluids produced, once the heat or other elements were extracted, would be reinjected some distance away from the production site. The ‘injection well’ could also be a well repurposed from the oil and gas industry.

2.3.4 Injection and production of fluids

‘Natural gas’ storage in the subsurface, including the reuse of former oil and gas fields, is a common occurrence, for example, at Humbly Grove in Hampshire (Gluyas and others, 2020). Natural gas is not the only fluid that could be stored and retrieved in this way. It should also be possible to store hydrogen (Heinemann and others, 2018). It is, however, unlikely that compressed air would be stored in a former oil and gas field, simply because it is unlikely that a sufficient rate of production could be achieved to make use of the kinetic energy during the release of air to drive a turbine and generate electricity in the relatively low permeability systems typical of natural reservoirs.

3. Possible new purposes

This section provides an overview on potential new purposes for onshore oil and gas wells, with sections on geothermal energy, permanent underground storage of carbon dioxide and temporary underground storage of natural gas and hydrogen.

3.1 Geothermal energy

In geothermal systems, heat energy is extracted from a geothermal reservoir, commonly via a borehole. Temperature typically increases with depth, Figure 2. The increase in temperature per kilometre of depth is referred to as the 'geothermal gradient'. The geothermal gradient in the UK varies between about 25°C/km and almost 40°C/km, with the highest values recorded in Cornwall and Weardale, County Durham, associated with granites (Busby, 2014, Younger and others, 2016). At shallow levels, the temperature can be perturbed (for example, from interference from the built environment, Banks and others, 2009). In general, the deeper the well, the higher the downhole temperature.

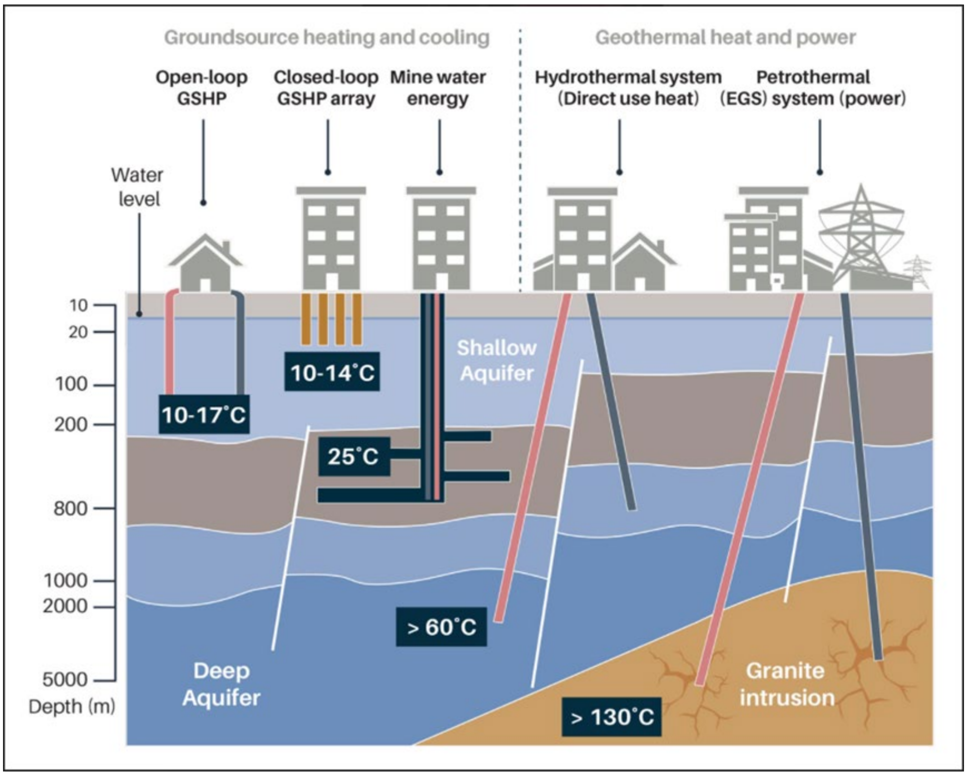

Figure 2: Possible geothermal uses for repurposed wells and the link between temperature and depth in a geothermal well (from British Geological Survey, 2022). Note the depth scale is non-linear and the buildings are overscale so that all the information can be shown in a single figure.

The economic value of the heat increases with increasing temperature. Heat can be used to generate electricity, but at many of the locations that have been drilled for oil and gas in the UK, the difference in temperature between the reservoir and surface is <50°C (Watson and others, 2020), so the fluids can be used for heating, for example, buildings, greenhouses or fish farming. Heat is difficult to transport without energy loss, and so the heat needs to be used close to where it is produced. It is possible to design a cascade of processes with decreasing heat requirements; for example, hot water initially used to heat domestic properties could then be reused to heat water for fish farming, for which the temperature required is lower. Heat pumps can also be used to upgrade heat by concentrating a large volume of heat from a substance with a low temperature. The power required to do this is typically much less than that which would be used for heating with electricity alone.

The main geothermal 'saline aquifers' in England are the Carboniferous-aged Limestone (Narayan and others, 2021) and Permo-Triassic-aged sandstones (Busby, 2014). The main 'aquifers' in England and Wales that extend deeper than 500m and that may locally provide both heat and sufficient flow rate include the Devonian Old Red Sandstone, Carboniferous Fell Sandstone, Carboniferous Limestones, the Basal Permian Sands (Yellow Sands), the Magnesian Limestone, Triassic Sherwood Sandstone, Jurassic Greater Oolite, Corallian Limestone, Lower Greensand and Chalk (British Geological Survey, 2021).

3.1.1 Geothermal doublet wells

Geothermal fluids are typically reinjected into the subsurface once the heat has been extracted, using either doublet wells or single closed loop wells.

Injection and production wells can be vertically and/or laterally offset to avoid reinjected, cooler fluids breaking through to the production well. The position of wells and operational injection/production rates should consider the need to avoid breakthrough of the cooler water at the abstraction site while managing the pressure to ensure stability of the reservoir. The rates of transmission and equilibration of the pressure differential will be site specific.

3.1.2 Engineered geothermal systems (EGS)

If there is not enough fluid or natural permeability within a formation, fluid can be added into the reservoir and/or reservoir permeability increased. This is a useful solution to harvesting heat from hot dry rocks, such as the Cornubian granites. This technique is applicable down to depths of about 5.5km and temperatures in excess of 75ºC with current technology. The first United Downs well drilled in Cornwall in 2019 (that reached a depth of 5.3km and reported a temperature of 193ºC) will use this technique (Busby and Terrington, 2017; ThinkGeoenergy 2022).

3.1.3 Closed loop wells

Closed loop geothermal wells can also be used where there isn't sufficient permeability. In such passive wells there is neither injection nor production from the reservoir. This isolation means the 'reservoir pressure' should not change because of well operations, nor should there be any interactions with the 'reservoir fluids'. This is less efficient than a doublet system.

3.1.4 Temporary thermal energy storage

Seasonal ambient temperature variations can lead to a reversal between injection and production, with warm water extracted for heating in winter and injected for cooling in summer. For this system to work the groundwater temperature must be between injection and production temperatures for the site location. Open loop doublet well systems (commonly called 'aquifer thermal energy storage' or ATES) are common in the Netherlands (for example, Bonte and others, 2011). Here, background aquifer temperatures of 9ºC to 12ºC rise to 15ºC to 20ºC in summer and drop back by 5ºC to 10ºC in winter because of the ATES. Higher temperature heat storage is used at Neubrandenburg (Germany) where surplus heat from a geothermal heating plant associated with a low temperature district heat supply system is stored and recovered (Kabus and others, 2009). The site reported a 46% recovery coefficient (efficiency) between 2005 and 2008, with temperatures at a 'cold' well ranging from 40ºC to 60ºC and at a 'warm' well from 65ºC to 84ºC.

Single well closed loop thermal energy storage systems, commonly called 'borehole thermal energy storage' (BTES), provide an alternative, if less efficient, option.

3.2 Permanent geological storage of carbon dioxide (CCS/CCUS)

Geological storage of carbon dioxide involves injection of gaseous or dense phase carbon dioxide that has been captured at power stations or other industrial plants, via wells, into a permeable formation deep below the surface. The whole chain is referred to as 'carbon capture (utilisation) and storage' (CC(U)S. To be identified as an appropriate site for storage, a site must be expected to be 'very likely' to retain more than 99% of the injected carbon dioxide for 100 years (in other words, to remove it from atmospheric circulation) and 'likely' to retain more than 99% for over 1,000 years (IPCC 2005). The reservoir must allow a sustainably high injection rate with sufficient capacity to enable economic operations.

Carbon dioxide is a reactive compound compared with many 'formation fluids', introducing the possibility of reactions with well materials (casing, cement, valves), the reservoir fluids, the reservoir lithology or even the seal. Reactions between carbon dioxide and well materials are considered in section 4.1.4. Reactions between carbon dioxide and reservoir fluids and lithology are considered in section 6.

The UK North Sea Transition Authority (NSTA) manages licences and awards permits for carbon dioxide storage offshore of the UK to ensure any storage of carbon dioxide is both safe and secure. At the time of writing, storage of carbon dioxide in the subsurface onshore is not aligned with current government policy in the UK. However, approval could be granted to inject small amounts into the subsurface for research purposes subject to permitting from the NSTA. If it were permitted to store CO_2 onshore in the UK, the following criteria would be important considerations:

- A minimum top reservoir depth of 800m below surface since the injected carbon dioxide will be unlikely to be stable in dense phase at shallower depths when the storage site is at capacity, which maximises the storage potential of the site (Chadwick and others, 2008).
- A monitoring strategy must be defined to be awarded a permit for offshore UK permits, so is likely to be required for any onshore storage. This is important to prove containment and ensure early detection of any potential issues. Access to land overlying the proposed storage site is needed to allow regular and ongoing monitoring. Current best practice for monitoring includes repeat seismic surveys, which require access to a grid of land overlying the storage site.
- The suitability of wells for reuse with storage of carbon dioxide will rely on the type and grade of casing materials, in addition to requirements discussed in sections 4 and 5.

Note 1: Operating wells that were originally for oil and gas production are more likely to be suitably positioned to act as monitoring wells (near the crest of any accumulation) rather than carbon dioxide injection.

Note 2: The aim of carbon dioxide storage is the permanent storage of carbon dioxide via injection into a reservoir. To optimise efficiency within the storage site, it may be appropriate to manage the pressure within the reservoir using brine production wells. This can increase the amount of carbon dioxide that can be stored in a site, while keeping reservoir pressure below a designated upper limit. The produced fluids may represent an extra source of contamination (as they might if produced during depletion of oil or gas fields) and will need to be dealt with according to the regulations.

3.3 Temporary underground natural gas storage

Natural gas can be stored underground when there is surplus, and reproduced when demand increases. Typically, as gas prices increase, gas storage becomes more economically attractive. Underground natural gas storage takes place predominantly in depleted gas fields in the USA, although it can be in aquifers or salt caverns. Humbly Grove in Hampshire, a repurposed oil and gas field, is currently the only active gas storage facility developed in a porous media system in the UK. Salt caverns are used for gas storage in northern England, but are unlikely to be accessible via onshore oil and gas wells.

To be suitable for natural gas storage, a site must contain the injected gas securely, and be able to withstand repeat pressure cycles without loss of integrity. The site needs to have sufficient porosity (the volume that can be stored) and permeability (the rate at which the gas can be produced and injected). To maintain sufficient injection and production rates, an amount of ‘cushion gas’ (or ‘base gas’) remains in the reservoir at all times. Typically for natural gas storage, the cushion gas will also be natural gas. In a saline aquifer, the cushion gas would be unrecovered after its injection. In a depleted field, the cushion gas is already present as the unrecoverable gas.

3.3.1 Temporary storage of natural gas in a depleted field

The benefits of using a depleted gas field include the economic incentive of reusing above-ground infrastructure (with adaptation, for example, to allow flow in either direction). A depleted field could also present lower risks as natural gas is native to the storage reservoir, and therefore less likely to cause undesired chemical reactions, and greater recovery due to the natural presence of cushion gas prior to operations.

3.3.2 Temporary storage of natural gas in an aquifer

Aquifer storage of natural gas is typically the most expensive option for subsurface storage. Even if aquifer storage is associated with reuse of a gas well, the costs of appraising the site, repurposing well(s), and any compression equipment are higher for aquifers than depleted fields (where there is a greater understanding of the site conditions and compression is less likely to be required as the formation pressure is likely to be lower). Additionally, aquifers require more cushion gas than depleted fields.

3.3.3 Temporary storage of natural gas in salt caverns

Using salt caverns for temporary underground storage of natural gas allows little escape of gas, provides very high deliverability (production/injection rate) and little cushion gas (for example, the Stublach Site in Northwich, Cheshire which began commercial operations in 2014).

3.4 Temporary underground hydrogen storage

If the UK transitions to a hydrogen energy source to replace natural gas, underground storage of hydrogen will likely become necessary to meet inter-seasonal demand variations (Hassanpouryouzband and others, 2021). The legislative framework in the UK does not currently allow for this, either onshore or offshore. However, it is already recognised within the UK Department for Business Energy and Industrial Strategy (BEIS)'s UK Hydrogen Strategy (BEIS, 2021), the Hydrogen Investor Roadmap and the BEIS hydrogen funding landscape: timings for competitions launching 2022 to 2023 (BEIS, 2022).

Underground hydrogen storage has strong parallels with other underground gas storage, and likewise could occur within depleted oil and gas fields, aquifers or salt caverns. Hydrogen storage would also need an amount of 'cushion gas' (or 'base gas') to maintain sufficient injection and production rates, although this might be hydrogen or another inert gas. There are some significant differences between hydrogen and natural gas, including:

- chemical and biological reactivity (including solubility in water)
- high diffusivity and low density (which impacts buoyancy, Alcalde and others, 2020)

The increase in density with pressure for hydrogen is such that for increased storage efficiency, sites below depths of about 1,500m are likely to be most suitable (Hassanpouryouzbands and others, 2021, Alcalde and others, 2020). When stored underground, a small amount of hydrogen is likely to be fixed into the formation through dissolution in formation waters, residual trapping in pore spaces and adsorption onto clay mineral surfaces, so would not be recoverable. Water vapour could contaminate the hydrogen, or if stored in a depleted field, mixing with residual gas could contaminate the hydrogen. Changes in store temperature and pressure combined with dissolution of hydrogen in 'formation fluids' could cause mineral dissolution, changing store permeability and porosity though time. Reactions with common minerals such as pyrite to pyrrhotite could release hydrogen sulphide (H_2S), which is toxic and associated with increasing corrosivity of reservoir fluids (although below 90º C this is a relatively slow reaction). The corrosivity of fluids will have impacts for the casing grade necessary in a well. If carbon monoxide (CO) or dioxide (CO_2) are present in the reservoir, abiotic reactions to produce hydrocarbons could occur. Microbial action could also contaminate the stored fluids, and even obscure permeability (this might be inhibited at higher salinity sites). The higher diffusivity and lower density of hydrogen compared with carbon dioxide or methane indicate that there might be greater potential for significant losses of hydrogen through diffusion. Contrasting vertical to horizontal permeability in the reservoir could increase the risk that hydrogen migrates laterally. Research and experience in underground storage of hydrogen is relatively immature, and these factors require further work to fully understand the impact for secure storage of hydrogen.

Cyclic storage site pressure variations below and above pre-oil and gas production pressures will be common in both hydrogen and natural gas storage sites.

4. Repurposing onshore oil and gas wells

Repurposing oil and gas wells to extract or store fluids other than oil and gas can bring economic and environmental benefits, either reducing costs or disturbance associated with drilling new wells.

Current best practice for drilling oil and gas wells is technologically highly advanced and subject to a mature regulatory framework in the UK regulated by the North Sea Transition Authority (NSTA, 2022). The original purpose of a well is a fundamental aspect that is considered from the earliest stages of well planning. Within the life of an oil or gas field, it is commonplace for wells to be repurposed; this necessarily requires comprehensive design iterations that consider both old and new purposes of the well.

This has 2 important implications: firstly, repurposing an existing well once it is no longer needed for oil and gas will also require a comparable re-design process; secondly, the oil and gas industry has the expertise necessary to be able to design and implement such repurposing.

The considerations associated with repurposing are discussed in the following sections. The process that each well will be subject to, to demonstrate it is of suitable integrity for the new purpose, is described in sections 4.1 and 4.1.1. Considerations as to what changes may be made within a well to repurpose it are discussed in sections 4.1.2 and 4.1.3. The final 2 sections provide a brief overview on choosing suitable materials for use within a well (section 4.1.4) and typical well integrity issues (section 4.1.5).

4.1 Well management in the oil and gas industry

Oil and gas operating companies must comply with the Health and Safety at Work Act (1974), the Well Design and Construction Regulations (1996) and Borehole Site Operations Regulations (1995) and associated guidance. To support this, oil and gas operators have developed very clear standards and processes to manage their well stock. For example, Offshore Energies UK (OEUK), the leading representative body for the UK oil and gas industry, offers a full range of publications of best practice for constructing, operating, maintaining and decommissioning wells. Although these are focused on offshore wells, many of the practices will be directly relevant to onshore wells.

It is considered good practice by the oil and gas operating companies to complete regular ‘well reviews’ of their well stock to develop a plan for each well to ensure that they maximise the value from these assets. There are many different outcomes from these reviews, and many result in a change of the ‘well functional requirements’. For example, initially a production well may be designed to allow oil to flow to surface driven by the reservoir pressure. Then as production continues and the well produces more water, artificial lift is required to flow oil and water to surface. Even later the well may become a water injector. For each of these changes in the well functional requirements, the subsurface hazards, risks and environmental exposure will be carefully considered before any change is made.

Figure 3 highlights the main well integrity life cycle phases and some of the elements that are common to each phase.

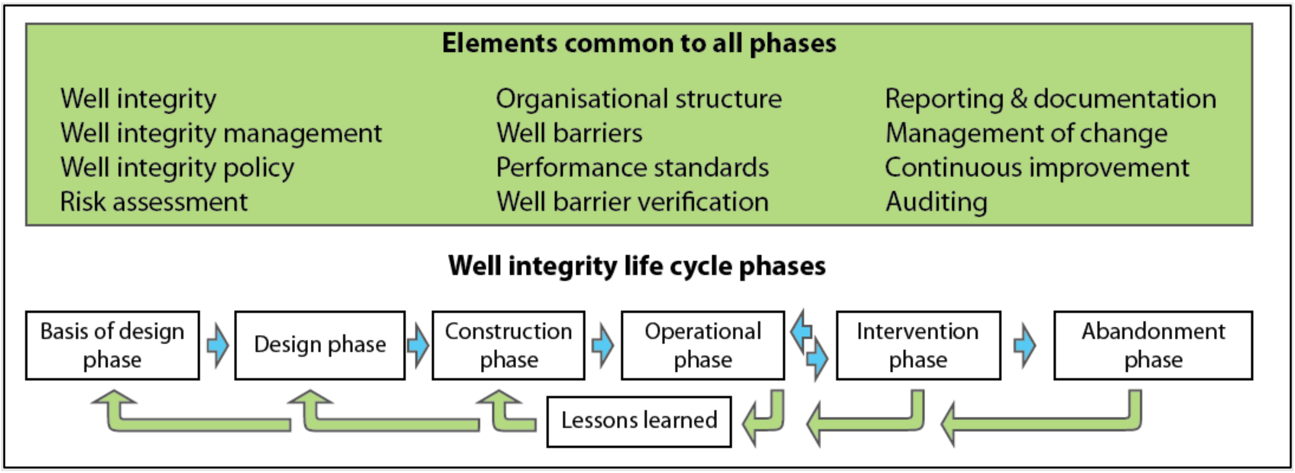

Figure 3: Elements common to the phases of well integrity management (after ISO-16530-1).

4.1.1 Well integrity

Wells are a collection of concentric pipes, cement, seals and valves that form multiple barriers between well fluids and the outside environment. A series of 'casing strings' and 'liner strings' are cemented in place to reach from the surface to the subsurface target. At the surface, these concentric casings and liner strings are held in place by a wellhead. A dedicated steel tubing string called a 'completion' is run inside these concentric casings and liner strings. This enables the fluids to be produced or injected from the surface to the reservoir. The completion consists of tubing, valves to control the flow with pressure and temperature gauges to monitor the well performance. Well barriers consist of different elements and may be active or passive. Active barriers, such as valves, can enable or prevent flow, while passive barriers are fixed structures such as casing and cement. Performance standards are established for each barrier and barrier element during the design phase of the well design to ensure the hazards and risks associated with the well construction and operation can be managed. These performance standards are then used during the well operating phase to support monitoring, maintenance and testing to verify the condition of the barriers. Typically, there are 2 independent barriers, so if one barrier fails the second barrier can prevent the leak or hazard from occurring while the first barrier is repaired. Figure 4 shows a well in the operating phase, with the 2 well barriers and the elements that make up those well barriers highlighted in red and blue.

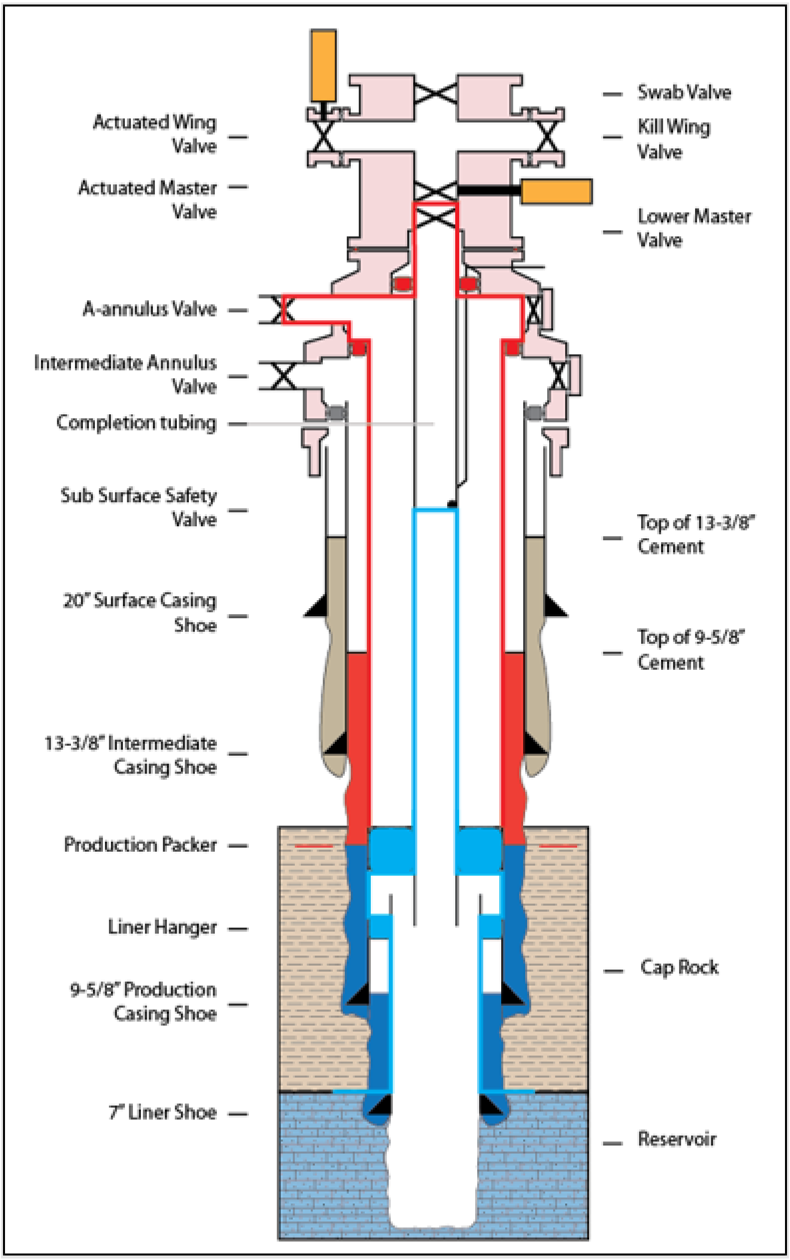

Figure 4: Well schematic showing well barriers during the operational phase highlighted in red and blue.

Well integrity is generally defined as “maintaining full control of fluids within a well at all times by employing and maintaining one or more well barriers to prevent unintended fluid movement between formations with different pressure regimes or loss of containment to the environment” (ISO 16530-1 2017). Accepted processes to assure well integrity over the life cycle of the well are included in documents such as ISO 16530-1 Well integrity - Part 1 Life cycle governance (2017) or NORSOK D-010:2021+AC2:2-21 (2021). International Standards Organisation (ISO) and American Petroleum Institute (API) have standards that have been developed with the support of oil and gas operators, and cover topics from material selection to production systems.

Wells are designed so that integrity is managed during construction, operation, future interventions and decommissioning.

Once the well is no longer required it will be decommissioned. To decommission a well, permanent barriers, for example, cement plugs, are installed in the well to prevent fluid movement between formations with different pressure regimes or loss of containment to the environment. These permanent barriers are designed, installed and tested so that no further inspection is required. The surface wellhead, 'Xmas tree' and the upper sections of casing are removed so the surface location can be returned to the original condition.

4.1.2 Well completions and repurposing

The completion consists of tubing, valves to control the flow with pressure and temperature gauges to monitor the well performance to enable the fluids to be produced or injected from the surface to the reservoir. The 'completion' is shown in blue in in Figure 5.

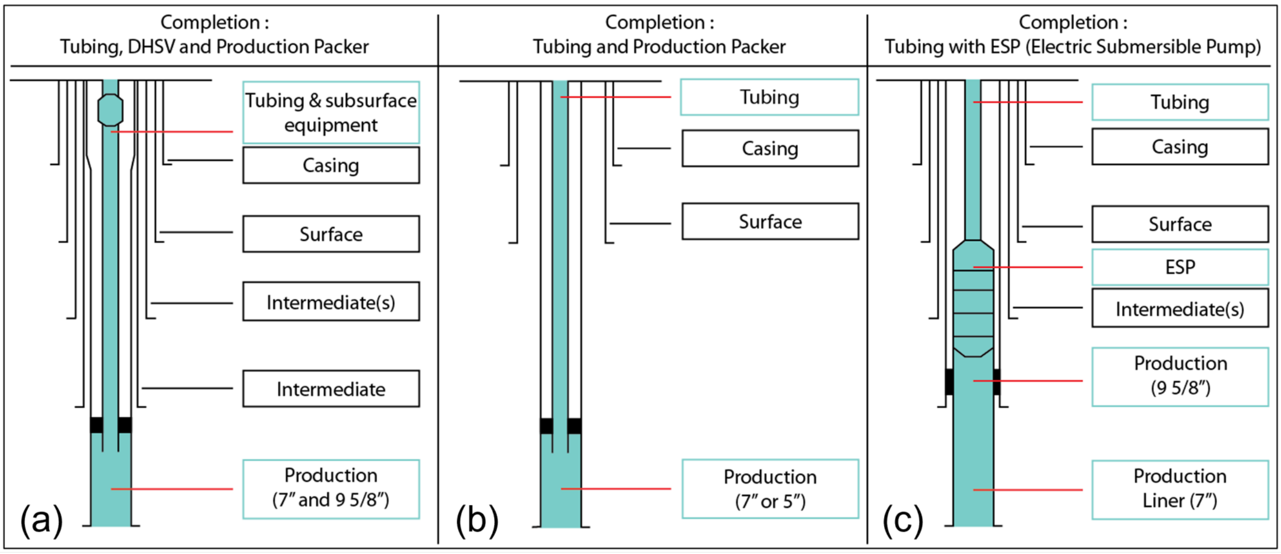

Figure 5: Simplified oil and gas wells with completions shown in blue: (a) Naturally flowing oil or gas production well, (DHSV) - downhole safety valve; (b) water injection or disposal well into low pressure system (no surface controlled subsurface safety valve (SSSV)); (c) oil producer that uses an electric submersible pump (ESP) for artificial lift. Not to scale: in these schematic depictions the height of the wells is greatly foreshortened; the producing section of the well is usually hundreds or thousands of metres below the top of the well.

There are 3 main ways of repurposing a well:

1. The existing well casing strings and completion remain in place.
2. The completion string is pulled (removed) and replaced, but the existing well casing strings remain in place.

3. The well is sidetracked or deepened to a new subsurface location. The completion string is pulled, and the original subsurface target decommissioned (permanently sealed with cement) prior to the drilling phase.

1. The existing well casing strings and completion remain in place.

This is the simplest and cheapest option, where the existing well and completion can meet the new well functional requirements. In this scenario it is likely that well barriers will need to be tested to ensure that they meet the new or repurposed well functional requirements (potentially requiring a wireline unit and/or a pumping unit for the related verification).

2. The completion string is pulled and replaced.

In some cases, the completion string may need to be replaced to meet the new requirements, for example, to change the 'tubing' size or completion metallurgy. A workover rig or hydraulic workover unit will be required to pull (remove) the old completion and install a new completion.

The size of the production casing (Figure 5a and b) or liner (Figure 5c) will determine the maximum diameter of the tubing and completion that can be installed. The tubing diameter will affect the ability of the repurposed well to meet the new functional requirements.

Repurposing a well to be used for natural gas, hydrogen or carbon dioxide storage will require a completion design that is similar to Figure 5a. The completion tubing and subsurface equipment would need to be pulled and replaced depending on the repurpose:

- Natural gas storage (gas injector well and gas 'producer well'): with tubing, SSSV valve, permanent downhole gauge and perforations.
- Hydrogen storage (hydrogen injector well and hydrogen producer well): with tubing, SSSV, permanent downhole gauge and perforations.
- Carbon dioxide storage: with tubing, SSSV, permanent downhole gauge, distributed temperature system, perforations and maybe a downhole choke to manage potential carbon dioxide phase changes during injection.

Repurposing a well to be used for a geothermal doublet (or geothermal open loop) would require one well to produce water to surface using a completion with an electric submersible pump (ESP) similar to Figure 5c. The cold water can be reinjected back into the reservoir using a completion similar to Figure 5a or b. Repurposing a well to be used for a 'geothermal closed loop' well requires a completion with concentric tubing strings. The warm/hot water flows up through a central tubing string, and once the heat has been extracted for use then the cold water can be reinjected into the 'annulus' of the concentric tubing strings (see Figure 6). The well does not need to provide a hydraulic or pressure connection between the surface and the subsurface.

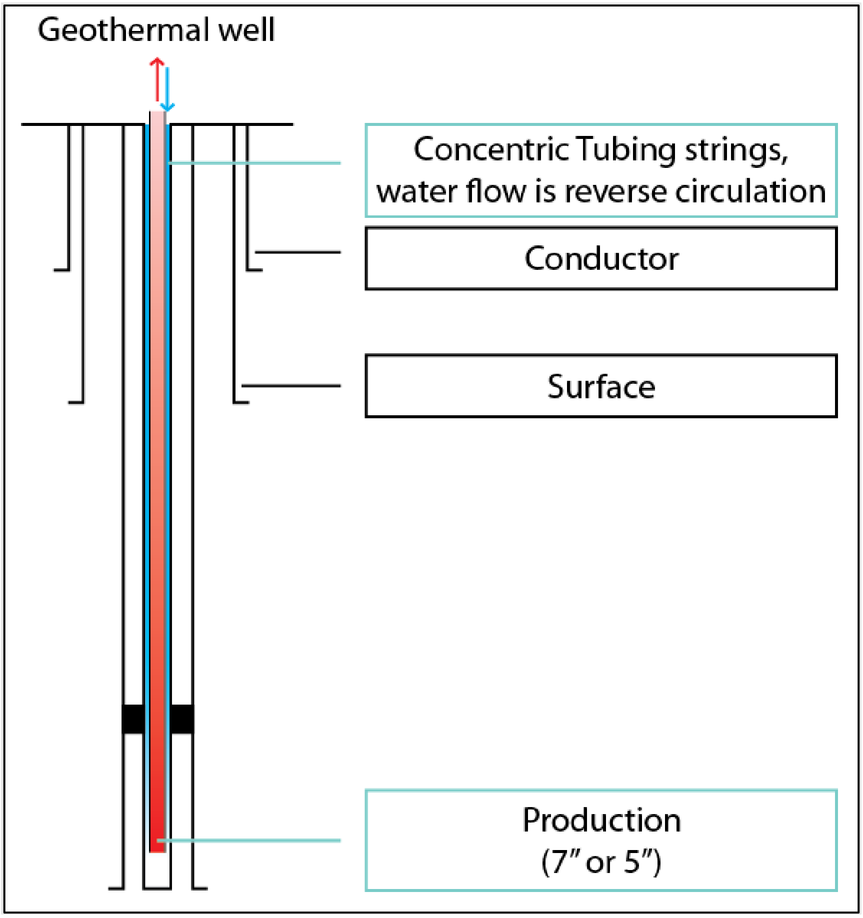

Figure 6: Geothermal well – closed loop completion.

3. **The well is sidetracked or deepened to a new subsurface location.**

A well sidetrack or deepening will require a drilling rig with services that will have a similar environmental and cost impact to drilling a new well.

4.1.3 Well repurposing

When repurposing a well is being considered, the entire well integrity life cycle needs to be reassessed. For any operator to repurpose a UK onshore oil and gas well, they would be expected to follow a process that would cover the 2 main building blocks of well integrity:

1. The well design phase – to design the well so integrity can be managed during construction, operation, future interventions and decommissioning.
2. Managing the well integrity through the well life cycle until it is decommissioned.

A new set of well functional requirements would be identified which would be the starting point for the revised well design phase. The well functional requirements should contain the following information as a minimum, the:

- pressure and temperature profiles along the well
- composition, including impurities and properties, of the fluids in the well
- expected or required flow rates
- expected time the well will be under these conditions

With this information it will be possible to provide a first pass at a ‘well operating envelope’ and that will guide the well concept, material and equipment selection. In addition, the potential hazards associated with the well design, construction and operation can be identified, along with the well integrity barriers for the different phases. Performance standards and the verification requirements for the well barriers can be defined to meet the regulations and industry standards.

Prior to the start of any work or activities, the requirements to maintain well integrity during well design and construction, and throughout the remaining well life, need to be understood and to be subjected to a technical challenge process and ‘well examination scheme’ (HSE, 2022).

The well functional requirements will drive the well operating envelope, well integrity barriers and the performance standards. The operator will then review their well stock to identify wells that have the potential to meet the new well functional requirements. Before a well is commissioned to meet its new purpose, the operator will have to demonstrate that the well integrity barriers are in place and that the well can be operated within its well operating envelope, this is irrespective of the service or condition of the original well.

When assessing if a well is suitable to be repurposed, one of the main challenges is having accurate information on the current status of the well to check how this aligns with the first pass ‘well operating envelope’ and well barriers required. This should be straightforward for wells that are operational, but could be more challenging for wells that have been ‘shut-in’ or temporarily plugged over an extended period (Table 1), as recognised by The Petroleum Safety Authority (2006), stating “there are indications on insufficient transfer of critical information during licence acquisitions and change of operator, and a general need for improved ‘hand-over’ documents in operations.”

Table 1: Summary of the various states of active, suspended and partly and fully decommissioned wells, according to the NSTA’s well operation notification systems (WONS) definition (NSTA, 2020).

WONS completion status	Definition

Completed (Operating)	Completed wellbore that is currently active.
Completed (Shut-in)	Wellbore shut-in at tree valves or SSSV, normally only applied if planned to be shut-in for 90 days or more.
Plugged	A well bore that has been plugged with a plug rather than an abandonment barrier.
Abandoned phase 1 (AB1)	Reservoir has been permanently isolated. Tubing may be left in place, fully or partly retrieved.
Abandoned phase 2 (AB2)	All intermediate zones with flow potential have been permanently isolated.
Abandoned phase 3 (AB3) – can be considered fully decommissioned	Wellhead and conductor are removed. Well origin at surface is removed. The well will never be used or re-entered again.

The basic well information required to assess if the well is suitable for repurposing includes the completion tubing size, casing size (see Figures 4 and 5), with weight and metallurgy, the fluids in the well, the pressure profiles in the well, and casing cement status. It is possible that the materials originally used to construct the well have degraded with time, and the subsurface conditions may have also changed. Verification steps to confirm that the well is a suitable candidate for the change in well functional requirements may include:

1. wellsite, wellhead and Xmas tree inspection – wellsite visit
2. pressure monitoring of all annuli and tubing – pressure recorders
3. completion drift checks to confirm access to the well TD – wireline unit
4. confirm well cement bonds, casing and tubing wall thickness, downhole and well pressure measurements – specialist 'logging tools' and wireline unit
5. pressure tests to confirm well barrier elements – pumping units
6. injectivity tests to assess well injectivity – pumping units

Peterhead CCS Project Well Integrity Assessment (Shell, 2014) provides an example of a well integrity assessment of an offshore gas production well; this approach can also be used for an onshore well.

Well construction technology and techniques are constantly evolving with improvements to materials, including metal to metal tubular connections, new cements, well diagnostic tools and other learnings from previous experience. The older the well, the less likely it will have been constructed with the latest technology required for current performance standards and commissioning criteria, which can make their repurposing less likely. The verification steps listed above can be used to better assess these risks. Sustained casing pressures (API-RP-90) are recognised as being a common well issue *(*King & King, 2013*)* that is attributed to cement leaks and tubular connection failures. These are also the most difficult and expensive issue for the operator to rectify.

4.1.4 Equipment and material selection

Tubing and completion equipment qualification standards are available through the ISO standards or API standards. The testing protocols used in these standards are focused on the operating conditions experienced by oil, gas and water wells. For wells that operate outside these conditions, including carbon dioxide injection wells, high temperature geothermal wells or hydrogen storage wells, there will be a requirement to review, update and modify these testing protocols.

To select appropriate equipment and metallurgy for use in a well requires a good understanding of the well operating conditions, during both normal steady-state operations and transient operations (such as well start-up, shutdown, and potential failure scenarios to avoid further escalation of the situation). The well operating envelope can then be used to guide the equipment and material testing protocols. This can be illustrated with a carbon dioxide ‘injection well’. The well ‘tubulars’ and connections of a CO_2 completion need to be able to withstand the corrosive nature of carbon dioxide (in the presence of water it creates carbonic acid), plus any impurities (NO_x, SO_x, O_2). They also need to be able to withstand low temperature operations (caused by cooling during well start-up when there can be large pressure drops across control valves or if there is a carbon dioxide leak to a lower pressure). This can cause embrittlement that reduces the mechanical strength needed to withstand the pressure regime and tubing movement forces.

It is possible that the operating conditions for 2 carbon dioxide injectors will be different and that the material selected for one well is not suitable for the other. Consistency of material composition and properties cannot always be assumed; for example, ‘22 Chrome’ material from one supplier can have different characteristics to 22 Chrome material from a second supplier. This highlights the importance of understanding the well operating envelope and completing appropriate equipment testing. Sonke and others (2022) provide useful insight into the process for selecting materials.

4.1.5 Common causes of well integrity issues

The NSTA periodically produces a report to review trends and performance benchmarks on well activity in the UK Continental Shelf (UKCS) (offshore). There are currently 2,625 offshore wells (status operated, shut-in or plugged temporarily) in the UKCS (Table 1). The operator must now report when a well is shut-in and the reason for the shut-in. In the 2021 report, a total of 1,356 well shut-in reports were made. The top 5 reasons for these are reported in Figure 7, of these, 310 were related to well integrity issues. It is important to recognise that these well integrity issues do not link directly to a leak or contamination. Wells are designed to have a primary and secondary set of barriers such that if one fails the second will prevent the leak, and the failed barrier element can be repaired.

Within the ‘well integrity’ category, the most reported sub-issue was related to the annulus and SSSV issues. It is reasonable to expect that onshore wells will have similar issues as the offshore wells, as none of the categories used here are unique to the offshore wells. The categories, water production, reservoir pressure and scale relate to well and reservoir performance; the ‘other’ category includes wells that are temporarily shut-in prior to decommissioning.

Pre-agreed monitoring plans with performance standards are used to ensure anomalies are identified early so that small low-risk actions can be carried out to avoid the subsequent need for high-risk remedial activities.

Once a well integrity issue is identified, for example, if a SSSV fails to meet its performance standard, the operator will complete a risk assessment. This may result in the well being shut-in, with mitigating actions included into well operating envelopes and procedures.

Well annulus management issues sometimes referred to as ‘sustained casing pressures’ are common in many wells and this is attributed to poor cementation and tubing leaks *(*King & King, 2013*)*. ‘API Recommended Practice 90 Annular Casing Pressure Management’ provides guidance on how to manage these.

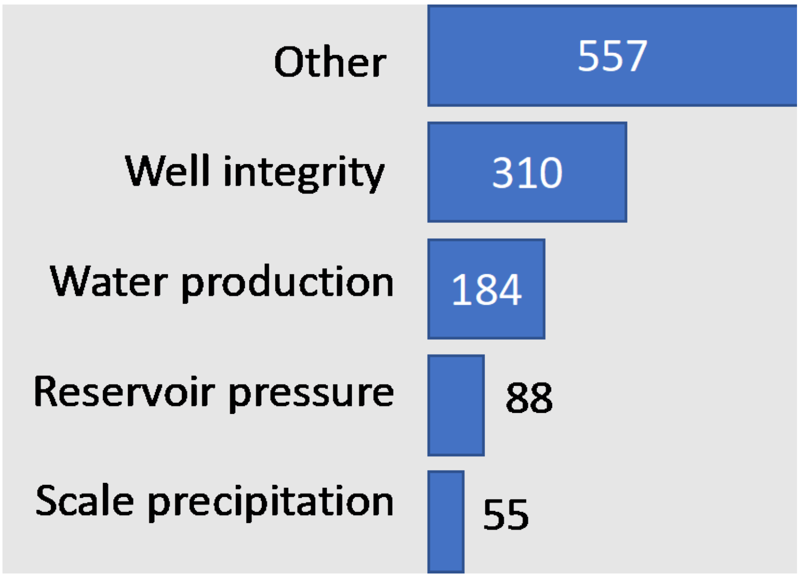

Figure 7: Reasons for UKCS (offshore) well shut-ins by numbers of wells (OGA, 2021).

5. General considerations for repurposing wells

This section of the report describes factors that could be used to indicate whether English onshore oil and gas wells could be suitable for repurposing from an environmental point of view (for example, through minimising the likelihood of leaks or containment issues), with some criteria relating to the new purpose.

5.1 Well completion status

In principle, any well, whatever its current status (Table 1), can be considered for repurposing.

Before a well is commissioned to meet its new purpose, the operator will have to demonstrate that the well integrity barriers are in place and that the well can be operated within its well operating envelope; this is irrespective of the service or condition of the original well.

The challenge for the operator is to avoid spending money on a well where the well barriers do not meet the performance standards required for commissioning. The older the well, the less likely it will be to have the latest technology. There may be uncertainty around the basic well information, which can make them less attractive to be repurposed due to the higher perceived risk that the repurposed well will not meet the performance standards and commissioning criteria. To avoid this scenario, this may require some or all of the verification steps listed in section 4.1.3 to be completed before the operator makes the final decision to repurpose the well. The cost (to the operator) associated with identifying whether the well is of suitable condition for repurposing may be different for wells of different completion status:

- Fully decommissioned wells (with status AB3) are extremely unlikely to be reused. Once a well has been fully decommissioned, the technical challenges to locate and reuse the well, combined with the uncertainty on the condition, make reuse an economically unattractive option.
- Incompletely decommissioned wells (with status AB1 or AB2) may be considered as suitable candidates to be sidetracked or deepened to a new reservoir target. The part of the original well to be reused above the permanently isolated levels would require investigation to prove it meets regulatory standards.
- Wells with status ‘plugged’ are likely to require investigation to prove they meet regulatory standards.

- Active wells (status completed – operating, or completed – shut-in) may be already known to have suitable integrity for repurposing (from operational verifications), meaning there would be a reduced cost of proving the status of the well is suitable.

Of the 2,121 onshore wells in England listed in the NSTA data, 696 wells (about 33%) have not yet been fully decommissioned (AB3, NSTA, 2021). Further discussion of factors that could be used for screening suitable wells is given in section 9.

5.2 Other well attributes

Wellbore integrity failure in decommissioned wells is a known issue for a small percentage of wells (Environment Agency 2021a). The Environment Agency 2021a report identified 6 main factors that are likely to influence the overall long-term integrity status of decommissioned onshore wells. While the report considers these factors in relation to decommissioned wells (for prioritising stewardship), these factors are also relevant for active wells and could be used to identify which wells are most likely to meet the required standard for being repurposed. Wells that do not align favourably with these factors could also be successfully repurposed. They have a higher likelihood of being found not to meet the standard required for the new purpose when undergoing verification of integrity (and therefore not qualifying to be repurposed). However, there is no increased environmental risk if wells that do not align with these criteria are repurposed after they have met the required standards.

Table 2: 6 main factors which are likely to influence the overall long-term integrity status of decommissioned onshore wells (from Environment Agency 2021a, Table 2). (Note: These attributes do NOT indicate the suitability for repurposing per se, rather the likelihood that the well will be found to be in a suitable condition for repurposing).

Well attribute	Comment
Drilled post-1996	Modern regulatory framework with highly prescriptive guidance on abandonments (1996 Well Design and Construction Regulations, 1995 Borehole Sites and Operations Regulations).
Drilled pre-1996, post 1953	Weaker regulatory framework and little guidance, however, cementing practices were developed.
Drilled pre-1953	Cementing practices poorly developed, making effective construction and abandonments less likely.

Drilled during extreme drilling activity	Pressure on supply chains and urgency, leading to chance of lower quality cementing job (of particular note in the UK were the years 1986, 1943 and 1939 when more than 66 wells were completed).
Wellbore deviated from vertical	Studies have shown that there is a statistically significant association between deviated wells and integrity failure.
Well intent	Production and appraisal wells have been shown to suffer poorer integrity in the long term due to the presence of casing/tubing, leading to complexities with construction and abandonment compared to exploration wells.

6. Sources of potential contamination

6.1 Sources of potential contaminants for repurposed wells

Understanding the different fluid compositions and the impact of pressure and temperature changes in the system is to being able to mitigate for leaks and prevent environmental harm. If chemicals are added to the well, they are potential contaminants and their impact on the fluid composition and well integrity also need to be fully understood. Table 3 identifies potential sources of contamination for different types of repurposing, indicating areas where more information may need to be requested to fully understand the potential environmental impact. Table 4 shows potential sources of contamination combined with possible well leakage pathways, described further in section 7.

Table 3: Potential sources of contamination and possible impacts on wells for different repurposes (injection, production and passive) for onshore oil and gas wells with considerations for specific uses.

Potential sources of contaminants	Injection well fluids	Production well fluids	Injection and production systems	Passive wells
Injection of fluids (both stored and circulating fluids)	CO_2 injection: impact on cement, metallurgy selection (corrosive, embrittlement), elastomer selection (a polymer used within the SSSV). H_2 Injection: impact on metal embrittlement, elastomer selection. Oil and gas, brines and water: oil and gas industry standards and best practices would be applicable.	Routine testing and fluid sampling will identify any changes in produced fluid composition (for example entrained contaminants). Oil and gas industry standards and best practices would be applicable.	A combination of the impacts for injection and production wells. Uncertainty in breakthrough time (injected fluids seen at production wells) impacts mitigation response.	Geothermal closed loop or test wells: use of additives, corrosion inhibitors, scale inhibitors and biocides to condition water being circulated.
Operational treatments	To improve injectivity Acid stimulation: hydrochloric and hydrofluoric acid plus additives. Permeability enhancement: viscosifiers, proppants and additives. Hydrate prevention: methanol and glycol. Remove well debris: backflow tubing contents. In CO_2 wells: fresh water to avoid precipitation of halites, most common in saline aquifers.	To improve productivity Acid stimulation: hydrochloric and hydrofluoric acid plus additives. Fracturing: viscosifiers, proppants and additives Hydrate prevention: methanol and glycol Workovers: to replace failed ESP.	To improve injectivity & productivity Acid stimulation: hydrochloric and hydrofluoric acid plus additives. Fracturing: viscosifiers, proppants and additives. Hydrate prevention: methanol and glycol. Remove well debris: backflow tubing contents with debris. In CO_2 wells: fresh water to avoid precipitation of halites.	Replace completion fluid (see above).

Geological fluids and solutes (within target reservoir, overburden, underburden)	Formation fluids could include injected or naturally occurring chemicals (including brine, sulphur, calcium, magnesium, oil and gas, heavy metals, as for production wells).	Formation fluids, entrained oil and gas or dissolved elements, heavy metals and/or high salinity brines can be produced. Naturally occurring radioactive material (NORM) can accumulate in separators or pipework.	Formation fluids, entrained oil and gas or dissolved elements, heavy metals and/or high salinity brines can be produced. Naturally occurring radioactive material (NORM) can accumulate in separators or pipework.	Isolated from subsurface.
Reactions between reservoir and injected fluids	The formation of scales and/or precipitates in the reservoir due to incompatibility between water types. Accidental injection of micro-organisms. Reservoir cooling from injection lowers fracture pressure and could change well mechanical stability.	Scaling risk in reservoir and wells with pressure and temperature changes. Scale on pipework can act to concentrate NORM. Action of micro-organisms, for example, sulphate reducing bacteria, could produce contaminants. Accelerated corrosion of tubing and casing due to ESP electric motor stray current.	A combination of the impacts for injection and production wells.	Isolated from subsurface. Requires a leak/ loss of containment for injection fluids to interact with reservoir fluid.

Well interventions on injection or production wells will often use a combination of different additives. These additives have many different functions for example, viscosifiers, corrosion inhibitors, demulsifiers, emulsifiers, scale inhibitors, hydrate inhibitors. These chemicals are available under different brand names which have different concentrations of the active ingredients. An exhaustive list of these additives is impractical here. The material safety data sheets (MSDS) for any well intervention can be requested from the well operator (who will obtain them from their supplier). Fluid compositions used by operators in England will be subject to their use being permitted by regulators.

Table 4: Potential sources of contamination and well leakage pathways (further details on pathways in section 7). Coloured text relates to well barriers shown in Figure 4.

Potential contamination source fluid	Pathway	Pathway description	Migration mechanisms
Reservoir, injected fluid and reactants	Leakage pathways from deep within an active well (below primary containment barriers, below the SSSV) and interacting with the geology.	Within completion tubing	Pressure and buoyancy
		Production packer	
		Caprock breached by pre-existing or induced fault/fracture	
		Along production casing/ liner cement interface	
		Through SSSV	
Reservoir, injected fluid and reactants	Active well leakage pathways from mid to shallow levels in the well (between SSSV and *xmas tree*)	Within production casing	Pressure and buoyancy driven bubble flow
		Within wellhead	Pressure and buoyancy
		Production casing to annulus	From void space to porous media; multiphase flow
Reservoir, injected fluid and reactants, intermediate and shallow formation fluid	Active well pathway to shallow level	Along annuli	Combination of bubble/conduit flow
	Active well leakage at shallow levels interacting with geology	From annulus into intersected strata	Void space to porous media multiphase flow
		Within intersected strata	Porous media; multiphase flow
		From intersected strata to strata	Porous media; multiphase flow

		Dissolved phase transport in groundwater	Solute transport
		From saturated to unsaturated zone	Porous media multiphase flow to ebullition (bubble formation)
		From unsaturated zone to atmosphere	Porous media multiphase flow to surface efflux
Reservoir, injected fluid and reactants	Pre-existing well leakage	Reservoir decommissioned wells	Pressure and buoyancy
		Wells that have penetrated below target reservoir	
Reservoir, injected fluid and reactants, intermediate and shallow formation fluid	Geological pathways	Lateral migration from the reservoir beyond storage complex	Porous media: multiphase flow
		Fault or fracture above storage complex	
		Geological pathway: induced seismicity	

6.2 Regional variations in oil and gas reservoirs

The main producing intervals for oil and gas in the UK are detailed here, with significance for fluid composition in the reservoirs (and therefore for sources of contaminants) (see Figure 12 for location of basins). In addition to variations associated with specific geological formations, in the UK the salinity of ground water (or formation water) varies with depth. Shallow aquifers are typically fresh, with a transition to brackish water around 500m depth and saline water at about 700m (Bloomfield and others, 2020).

- In the Cleveland Basin of Yorkshire, the main productive interval is Upper Permian Zechstein Group carbonates. The Lower Permian Yellow Sands Formation and Namurian-aged sandstones are also productive, with one gas field having produced from the Lower Jurassic-aged interval (DECC 2013). The groundwater salinity is highest in the Zechstein carbonates (Bloomfield and others, 2020).
- Production in the East Midlands is predominantly from Carboniferous sandstones (Millstone Grit Group and Pennine Coal Measures Group) and, less commonly, the Carboniferous Limestone Supergroup. It is possible that, in some areas, Devonian-aged Old Red Sandstone occurs below well TDs (Fraser & Gawthorpe 1990) and may have good permeability (as in the Old Red Sandstone of the offshore Argyll Field, at about 3km depth), as indeed might the Carboniferous Limestone (Narayan and others, 2021). The Triassic Sherwood Sandstone Group overlies almost all of these reservoirs eastwards of the Triassic outcrop. At shallow levels this is a potable aquifer (BGS, 2021). Salinities are typically higher in reservoirs that lie beside Zechstein (Permian) and Triassic evaporites (salts) (Bloomfield and others, 2020).
- In West Lancashire, the main reservoir is the Triassic Tarporley Siltstone Formation (for example, at the Formby Oilfield) and either Permian or Triassic sandstone at Elswick Gasfield, with secondary Pleistocene sand reservoirs (DECC, 2013). Salinity will typically be higher in the deeper reservoirs (Bloomfield and others, 2020).
- The Cheshire Basin is not a proven oil and gas province despite a history of gas, oil and tar seeps (DECC, 2013). Carboniferous (Pennine Coal Measures Group, sandstones of the Millstone Grit Group and Dinantian-aged sandstones), Permian (Kinnerton Sandstone Formation and Collyhurst Sandstone Formation) and Triassic (Sherwood Sandstone Group) strata have been targeted as reservoirs. The Collyhurst Sandstone Formation has been productive at Nooks Farm. Salinity is typically higher in the deeper reservoirs (Bloomfield and others, 2020).
- In Southern England (the Wessex Basin), the Triassic-aged Sherwood Sandstone Group is the main reservoir at Wytch Farm and the aquifer in the Southampton geothermal well (DECC 2013, Downing and others, 1983). The Jurassic-aged Bridport Sand Formation and Frome Clay Formation (limestone) are secondary oil and gas reservoirs. The salinity is highest in the Sherwood Sandstone Group (Bloomfield and others, 2020).

- Most oil and gas fields in Hampshire, Kent and Sussex (the Weald Basin) are in the Jurassic Great Oolite Group, with minor accumulations in Jurassic-aged sandstones. It is possible that below the wells a deeper aquifer within the Sherwood Sandstone Group may have good permeability (DECC 2013).
- The highest concentrations of potentially economically interesting solutes can be associated with granites (for example, lithium from Cornwall and County Durham and evaporites (for example, boron and lithium) (Brooks, 2020).

7. Potential leakage pathways

Any leak of material either from the well or the reservoir to the surface or shallow levels below surface is potentially polluting. This section is focused on potential leakage pathways, and the importance of fluid pressures on the tendency to leak, to better understand the likelihood and consequence of a leakage event. Properties of the injected material such as the density (in comparison to the formation fluid, the density will drive the buoyancy) or viscosity will also link to the tendency to leak. These depend on the specific reuse and are not considered in detail here.

When considering repurposing oil and gas wells and oil and gas fields, there are 3 main potential leakage pathways (Figure 8):

1. Through an active or decommissioned well.
2. Through a geological pathway in the subsurface (within the overburden, or laterally along the reservoir formation).
3. A combination of both wells and geology.

In general, the probability of a leakage pathway associated with wells is higher than leakage pathways through the subsurface, although both are judged to be extremely unlikely, with probabilities of significantly less than 1% (DECC 2012). It is possible that a leakage pathway could extend through a well and then pass into the overburden. Whether or not leaked material would cause pollution in overlying environmental receptors would depend on the structure and permeability of the overburden.

The tendency to leak is linked to the pressure changes within the reservoir as well as the presence of a fluid pathway, and so will depend on the new purpose and the specifics of each site. Any development plans will need to demonstrate that the whole of the repurposed site, including both the wells and the subsurface, will be secure. This will likely include modelling the development through time and evaluating the safe pressure ranges based on site-specific conditions. A monitoring plan to demonstrate secure containment (or conversely whether such a leak has occurred) is important for detecting potential issues and mitigation early.

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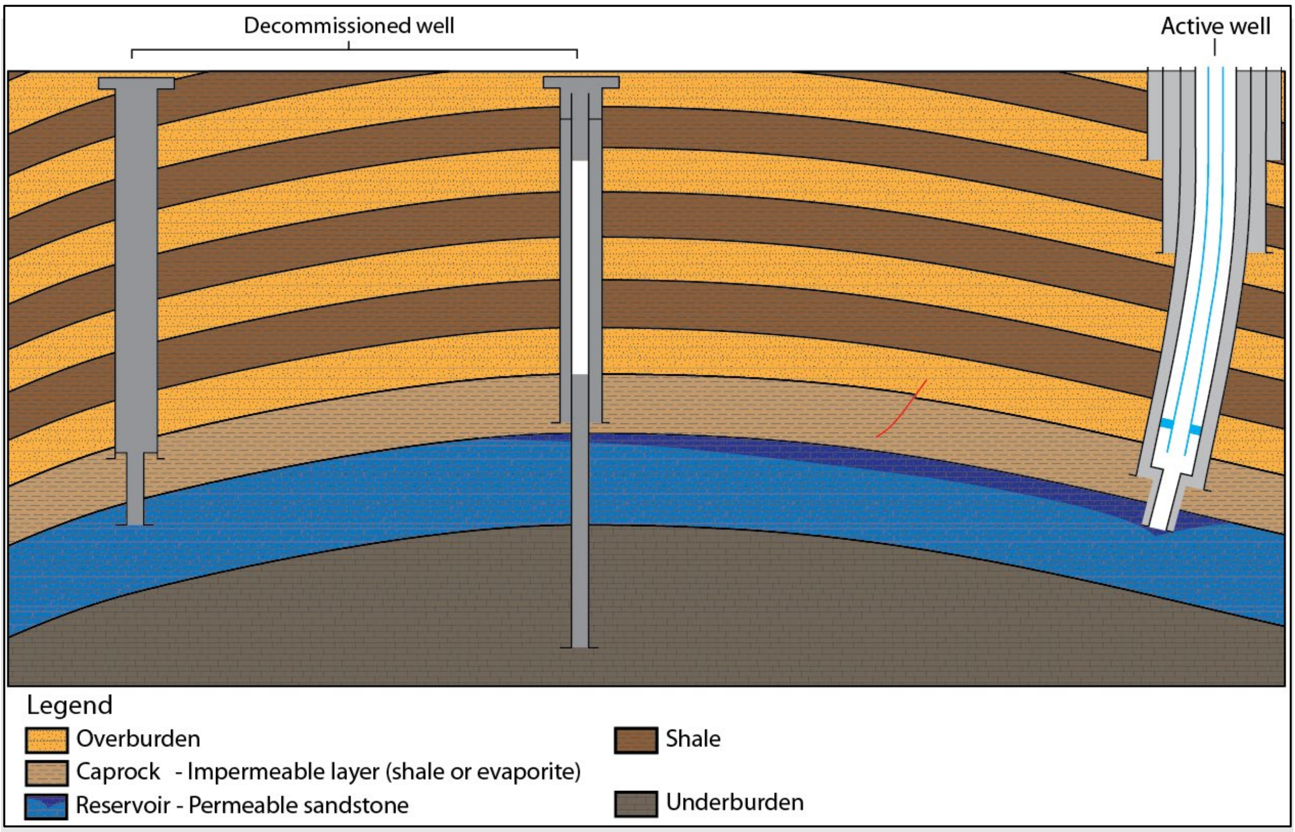

Figure 8: Schematic image of a hypothetical former oil and gas field, showing 2 decommissioned wells and an active well with darker blue material injected into the reservoir. The reservoir horizon is coloured blue, with an overlying top seal (also called caprock), a fault is shown in red.

7.1 Potential leakage pathways through wells

Active wells: The risks associated with leakage pathways from repurposed wells are linked to the design, operating and testing processes at the time of repurposing the well. Robust design, good construction practices, effective barrier monitoring, testing and maintenance are crucial in reducing the leakage risk through wells. Active wells can be continuously monitored for properties, including pressure, flow rate and temperature. This enables any anomaly, trend, significant change or measurements that exceed minimum or maximum values to be identified so actions can take place quickly to avoid any escalation of an issue or problem. Active wells are relatively easy to remediate compared with decommissioned wells.

Decommissioned wells: The risk profile of an abandoned or decommissioned well may be affected by the proposed re-development of a nearby well, reservoir or licence area. Any plans to repurpose a well, reservoir or licence area would involve a review of all wells that could be affected to understand their status, condition and operating envelope. An example of this is in the Peterhead CCS Project Well Integrity Assessment (Shell, 2014). The review will highlight particular wells with the following issues:

- The operations and pressure tests applied to a decommissioned well while it was active may not be consistent with the requirements of the new purpose.
- The procedures, standards and regulations for well decommissioning have changed through the years.
- Individual wells may have had derogations from the decommissioning regulations at the time of approval.

As discussed in section 5.2, there are 5 main factors associated with different levels of long-term integrity (Table 2 and Figure 9). Decommissioned wells that rank within the higher numbered tiers according to these criteria have a higher likelihood of integrity issues. Decommissioned wells cannot be monitored internally for pressure or temperature variations. However, they can be monitored at surface for signs of leakage, although this can be difficult to detect (Environment Agency, 2021b). If a leakage at surface has been detected, it is unlikely that the subsurface source of that leak can be identified with sufficient confidence to justify the impact and cost of drilling a relief well. The source of the leak detected at surface may not be from the decommissioned well target, but from another source in the overburden, and the well has acted to concentrate/channel fluids to surface location (Vielstadt and others, 2015). It is possible that a relief well could be drilled to intersect at or close to the reservoir which might be able to stem the leak. Remediating fully decommissioned wells is likely to be challenging, as their surface locations are not marked and they have not been designed to be re-entered.

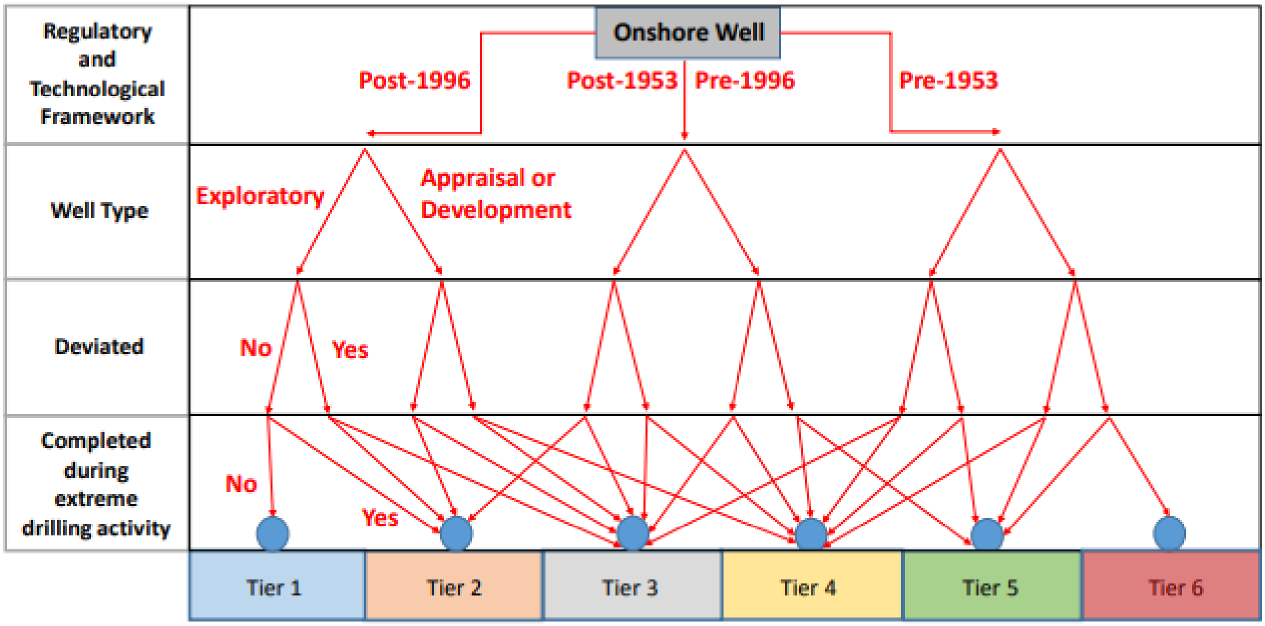

Figure 9: Tier assignment decision tree showing how identified factors are used to assign wells to tiers, based on factors known to induce potentially lower overall long-term well integrity (Figure 4 from Environment Agency 2021a). The tiers correspond to different levels

of potential long-term integrity, tier 1 containing wells with the lowest relative potential to release methane and tier 6 contains wells with the greatest relative potential to release methane.

7.2 Potential leakage pathways through the subsurface

Apart from passive re-use of wells or purposes that access a different horizon, repurposing an oil or gas well involves reusing the oil and gas reservoir itself. Shown schematically in Figures 8 and 10, the reservoir is where the oil and gas was originally stored within the permeable rock (or if repurposing an exploration well, the reservoir is what the well was drilled to explore). A top seal (or caprock, typically a very fine-grained sediment such as mudstone or evaporite, for example, rock salt) and a structural or stratigraphic barrier to lateral flow retained the buoyant oil or gas within a particular location within the reservoir over millions of years.

If repurposed for either temporary or permanent storage, injected material will refill some, or all, of the pore space that was previously filled by oil and gas. The fact that oil and gas were securely contained over geological time increases the confidence that the top seal will be secure for the new purpose.

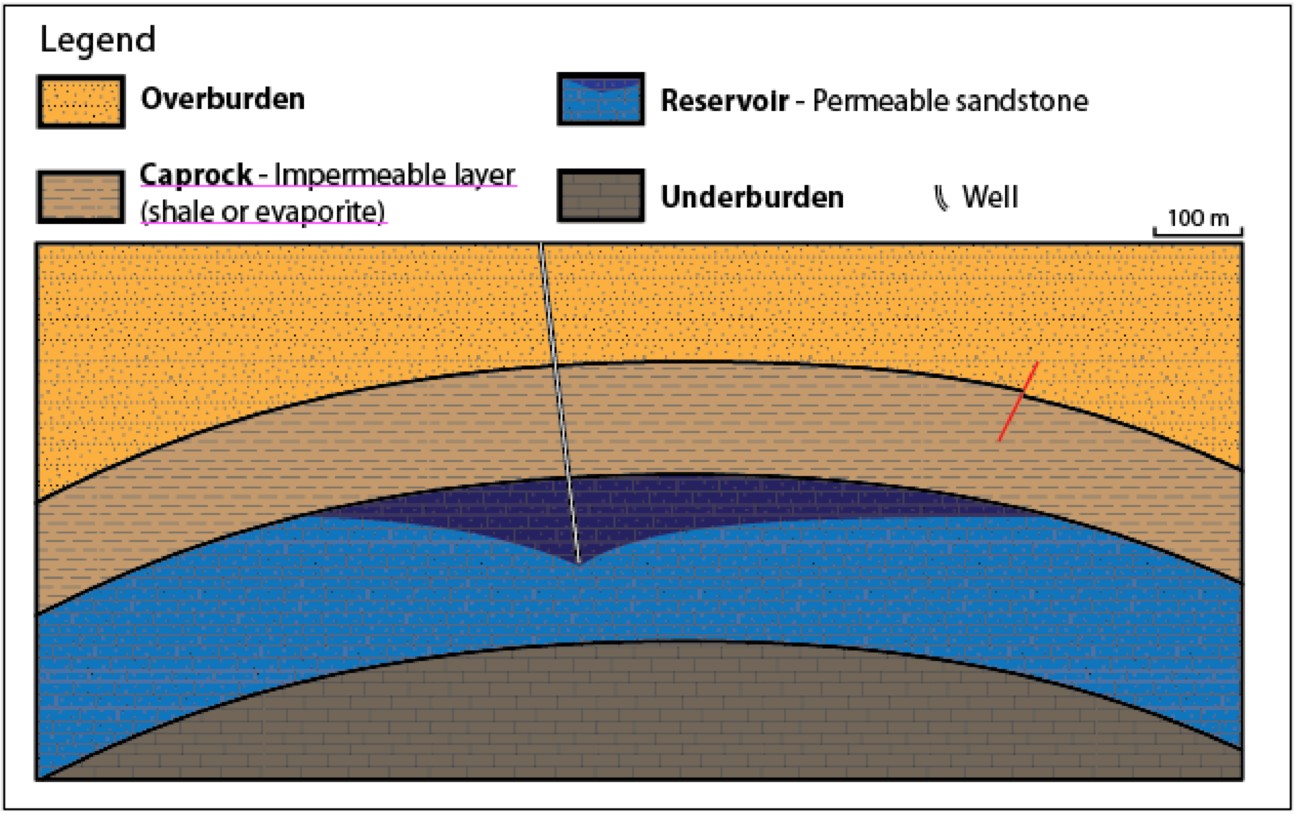

Figure 10: Schematic showing a plume of injected gas or fluid in a structurally confined storage site. The well is injecting a material coloured dark blue that is infilling any porosity within the reservoir.

If repurposing a well to access a permeable layer other than the reservoir, the effectiveness of the top seal above the permeable layer will need to be demonstrated to prove that the injected material will not flow vertically to the surface. In a saline aquifer (a permeable formation containing brine) the lateral extent of the injected material might be less constrained than within a depleted field. It remains important to predict the location of the injected material to ensure that the injected fluid can neither escape nor interfere with other subsurface operations nearby (such as oil or gas production or the techniques documented in section 3). It will also be important to demonstrate that there are no geological features that could allow breaching of the seal, for example, faults or fractures, which can be sealing to fluids or transmissive.

Modelling flow within the subsurface is of critical importance in managing potential leakage pathways. Prior to injection, the modelling parameters will be less well constrained in a saline aquifer than in a depleted field (with corresponding lower confidence in staying within safe operating pressures), although models will be updated with dynamically derived parameters once injection begins.

Monitoring techniques can be used to demonstrate containment. Active wells can be equipped with sensors to monitor well and field performance. The behaviour of injected material within a site and the overburden can be inferred using repeat seismic surveys and near-surface gas monitoring. Remote sensing, including satellite interferometry (InSAR), isuseful in detecting leaks.

7.2.1 Pressure changes within the reservoir

Generally, as fluid is produced through a well from the subsurface, the pressure in the subsurface will decrease. If fluid is injected into the subsurface, the pressure will increase. At the time of repurposing an oil and gas field, it is likely that the reservoir will be under-pressured compared with surrounding strata (although this will depend on the produced verses injected fluid volumes and how quickly the site re-equilibrates). This will translate to an increased tendency for fluids to flow into the reservoir from surrounding strata. On injection, the pressure will start to increase, localised at an injection well initially. If the fluid pressure of the site becomes over-pressured with respect to the surrounding strata, this will lead to an increased tendency for fluids to flow outwards from the reservoir. If reusing a depleted field, it would be unusual to plan for the final pressure at the top of the reservoir to be greater than the original pressure prior to producing oil and gas. If injecting into a saline aquifer, however, the final pressure could be higher than the initial pressure, although managing the reservoir pressure with brine production wells could avoid increases significantly above original pressure. Over time, any changes in fluid pressure will naturally re-equilibrate with the surrounding strata. The time to re-equilibrate will be site-specific and could range from a few years (in a large, well-connected volume) to many millennia (in a poorly connected volume). During temporary underground storage of gases such as natural gas, the reservoir behaves elastically, with reservoir pressure increasing as material is injected and reducing as material is produced.

As pressure differentials can drive fluid flow in the subsurface, there is a direct link between unequilibrated relatively high fluid pressures in the subsurface and tendency to leak (if there is a leakage pathway to exploit). If the injected material is less dense than formation fluid, it will be buoyant, which will also drive the tendency to leak. In depleted fields, the successful storage of oil and gas provides confidence that any pre-existing geological features are not likely to allow significant leakage, but this is not indicated in a saline aquifer (and will need to be proven prior to any storage). Smaller fault and fracture networks are unlikely to provide a permeable pathway from reservoirs to potable groundwater (for example, Mazzoldi and others, 2012), but this is not impossible. There may be a higher likelihood of natural formation fluids leaking from the reservoir than injected material (because the extent of the pressure plume associated with injection of fluids is typically much greater than the extent of the plume of injected material, (White & Foxall, 2016)).

Additionally, above and below critical thresholds, fluid pressures can induce seismicity and cause new faults or fractures to form, potentially creating new leakage pathways. Active operations will typically be kept well within the critical thresholds to avoid this occurring. In general, there is sparse data on the impact of seismicity on well leakage, as detection and attribution of any detected well leakage to seismicity is challenging. There will likely be other contributing factors, (Kang and others, 2019), however this is a possible outcome. Fault movement associated with seismicity is unlikely to be sufficient to juxtapose permeable formations that were not previously in contact. However, seismic events induced by changes in fluid pressure could cause changes in permeability along faults (Segall & Fitzgerald, 1998), meaning a previously sealing fault could act as a conduit for reservoir fluids. Induced seismicity is unlikely to create a contamination pathway to receptors such as potable water through faults since sites are unlikely to be allowed near large faults that would be visible on seismic surveys. In depleted fields the risk of induced seismicity is likely lower than in saline aquifers.

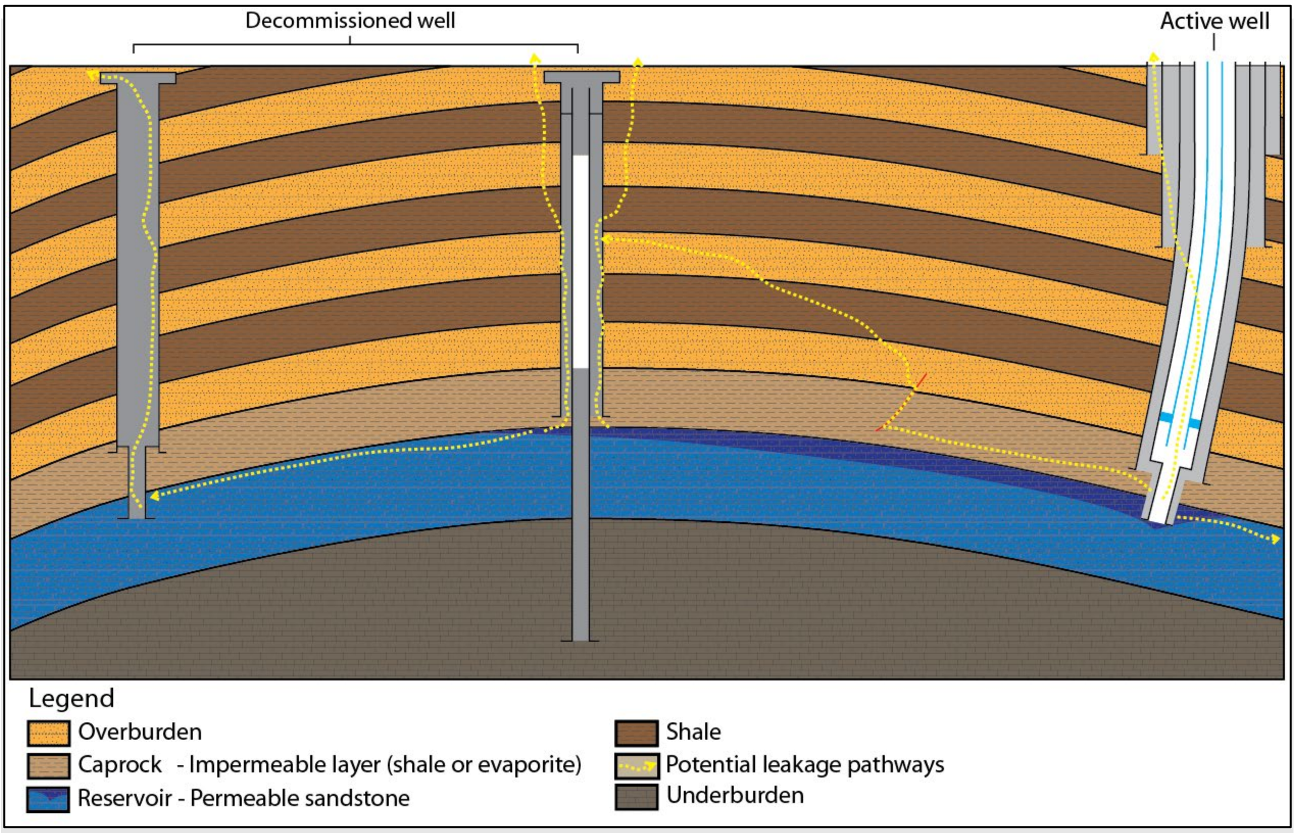

Figure 11: Demonstrating potential leakage pathways in yellow within a schematic image of a hypothetical former oil and gas field (see Figure 8 for further details).

If the reservoir pressure has increased through injection, the physical and chemical conditions in the reservoir, including the conditions around any pre-existing wells will change. It is important to evaluate that there are no likely reactions with fluids or minerals within the reservoir which could contribute to the formation of a leakage pathway.

The highest likelihood of a leakage event occurs within an injection system, where the pressure in the reservoir is raised from original pressure, for example, in a carbon storage site if the pressure is permitted to exceed original pressure (regulatory guidance on this is not yet published). If a leakage event were to occur, only a small proportion of the injected material is likely to escape, as geological systems are typically self-sealing as the pressure drops. In addition, any injected material would be distributed across a wide plume, with some injected material fixed into pore spaces, dissolved in formation waters or even precipitated in minerals. Studies to evaluate likelihood of geological and well leakage events for carbon dioxide storage sites (DECC 2012, Alcalde and others, 2018, ZEP 2019) indicate that on a permitted site, well leakage pathways are more likely to occur than geological leakage pathways. Probabilities of well leakage events in a CO_2 storage site for an active or abandoned well are cited as 0.5% over 500 years and for a leakage through a geological fault in a generic storage site as 0.2% over 500 years (50 years of which are injection operations, ZEP 2019). This means that there is a greater than 99% chance that a reused well and storage site will securely contain CO_2 over 500 years.

8. Knowledge gaps

- There is no experience of operating CCS and hydrogen wells in England. The only purpose-drilled CCS appraisal well drilled in England at the time of writing was offshore in the Southern North Sea, and this used water to test injection into the site rather than carbon dioxide. Material and equipment testing protocols for CCS and hydrogen wells are being developed using the standards and best practice available from ISO, API and NSTA that are based on experience with operating oil and gas fields. As the operating experience grows, these standards and the material selection criteria will need to be updated. The standards and material selection criteria will be used to inform the suitability of specific existing wells for reuse. It should be noted that in the past some fields have produced oil and gas with contaminants such as carbon dioxide or H_2S that will have necessitated higher grade well materials.
- There are still many uncertainties associated with underground hydrogen storage. Further research is needed in several areas, including understanding the possible reactions with wells, reservoirs and top seals and the impact of the high diffusivity and low density of hydrogen on storage containment. The outcome of this research will further inform which fields and which well properties will be suitable for hydrogen storage sites.
- With respect to geothermal energy, the only long-term geothermal production well in the UK is in Southampton. There have been no environmental concerns. Similarly, geothermal water co-produced from oil and gas wells from Wytch Farm in the Wessex Basin and many fields in the East Midlands has been handled safely and effectively. However, it is possible that long-term production of geothermal energy from wells could produce unwanted solutes and/or scale precipitates in small quantities. In general, the deep connate waters of the UK onshore are not well characterised, and this represents a knowledge gap (Bloomfield and others, 2020).

9. Examples of screening criteria for repurposing wells in England

In theory, any of the existing onshore oil and gas wells in England could be a target for repurposing and reuse, although in practice some wells are much more likely to be suitable for reuse than others. For example, after careful assessment, an operator might decide to present a case to the regulator to reuse a deviated (non-vertical) well that had been drilled and fully abandoned many years ago. However, this would be highly unusual, and, in most cases, such a scenario would not be viable on commercial or environmental grounds. In this section, we give examples of some possible ways that initial screening of the existing wells could be used to indicate potential suitability for reuse. The data set of wells that we use for screening is openly available from the NSTA (NSTA 2021), and consists of the spatial location and other attribute data for 2,121 onshore wells (downloaded on 9 December 2021). Most of the wells are located in 4 main oil and gas provinces (Figure 12).

It is important to emphasise that the purpose of this type of screening is to provide an indication of the overall proportion of wells for which reuse is possible, compared with those for which reuse is less likely. Consequently, while this ‘top-down’ screening can provide a useful overview of England’s well stock, the suitability for reuse of any individual well will be subject to detailed evaluation based on specific regulatory requirements. A further point to note is that there is no definitive set of criteria or thresholds to use for screening; the ones we describe here focus on environmental considerations of well reuse.

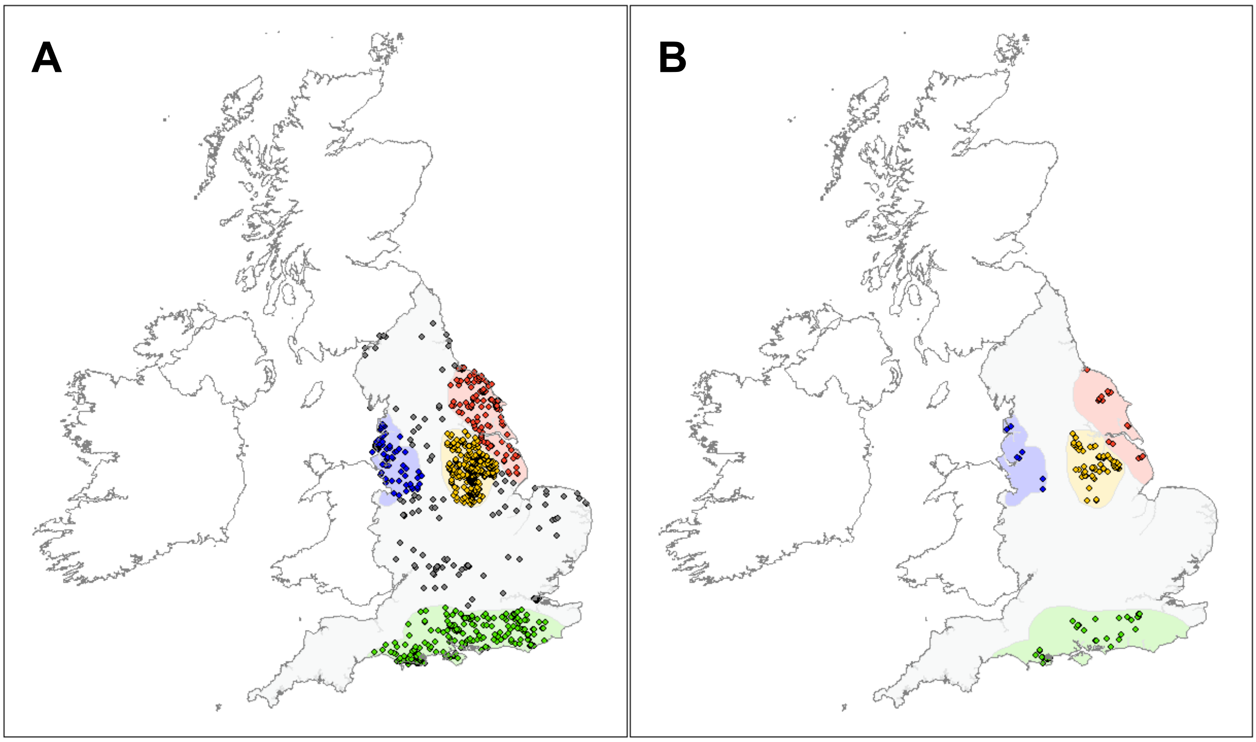

Figure 12: Onshore oil and gas wells in England, from the NSTA online database (downloaded 09/12/2021). (A) 2,007 of the total 2,121 wells are located in the 4 main oil and gas provinces: north-east England (Cleveland and South Humber), red points; East Midlands, yellow; north-west England (West Lancashire, Cheshire, North Staffordshire), blue; Wessex-Weald, green. (B) 458 active wells (neither partially or fully decommissioned, that is, operational status is not 'AB1' or 'AB2' or 'AB3').

9.1 Screening by completion status

The screening criterion by completion status is based on the premise that for a well to be a viable candidate for re-use it is likely to be a currently or recently active production or injection well (Table 5, Figure 13A). Correspondingly, those wells that are undergoing or have already undergone decommissioning are unlikely to be reused. In the NSTA documentation, the completion status of an active well is given as 'completed (operating)', 'completed (shut-in)', or 'plugged', while decommissioning is recorded in terms of 3 phases of 'abandonment' (AB1, AB2, AB3), with phase 3 being fully decommissioned (section 4.1.3).

Of the 2,121 onshore oil and gas wells in England, 458 wells are recently active, while 1,663 are at some stage of decommissioning – 696 are partially and 967 fully decommissioned.

Table 5: Significance of the different screening factors for various well repurposing functions, as identified in section 4.

Potential repurpose	Factor for higher likelihood of suitability for repurposing	Comments
Any	Active or plugged well (completion status = ‘completed (operating)’ or ‘completed (shut-in)’ or ‘plugged’), see section 4.1.3 for definitions.	Condition of these wells better known than for a decommissioned well. Decommissioning cost may be deferred. Less uncertainty in repurposing cost.
Any	Lower risk of not meeting regulatory standards for operational wells (lowest risk wells are vertical, drilled after 1996, and drilled in a year of low to normal drilling activity (Environment Agency 2021a).	Lower risk than older or deviated wells or wells drilled in year of extreme drilling activity.
CO_2 injection	Top reservoir depth at or below 800m.	Secure containment. CO_2 more likely to be within dense phase at site closure (storage efficiency).

9.2 Screening by age and orientation of well

A number of different risk factors were identified in Environment Agency (2021a) and are used here to screen those wells that have a lower likelihood of meeting well integrity standards for the new purpose. These factors include when a well was drilled. Examples of wells that are more likely to have long-term well integrity issues include wells drilled prior to 1996, wells drilled in years of abnormally high drilling activity, and wells that are ‘deviated’, that is, not vertical (Table 5, Figure 13 B & C). Wells that do not meet these criteria are not necessarily precluded from repurposing.

9.3 Screening by vertical depth of well

This criterion applies to wells that could be repurposed for CCS only. Wells are more suitable for repurposing for storing carbon dioxide where the depth of reservoir is greater than 800m below ground level (Table 5, Figure 13D). Additional wells that do not currently reach this depth might nevertheless be repurposed if they can be extended or sidetracked to reach a suitable reservoir at greater depth. There may be other depth constraints for other reuses, such as the depth required to reach suitable temperatures for a geothermal well or proximity to potable aquifers, although these factors are beyond the specific scope of the screening presented here.

9.4 Screening by proximity of decommissioned wells that are rated as high risk

This criterion is relevant for any repurposing with injection, however it has not been applied in the following screening example. Nearby decommissioned wells represent a higher risk of well leakage pathway forming (especially those rated as higher risk according to Environment Agency 2021a); this would be evaluated on a site-specific basis (and is not considered further here).

9.5 Screening based on combined criteria

Combining the individual criteria suggests that the overall number of wells that have the highest likelihood of meeting the well integrity standards to be repurposed is likely to be low (Figure 14, Table 6). However, wells that do not meet these criteria could still be repurposed (for example, a well that is deviated and/or drilled before 1996). Prior to repurposing, the verification tests (as detailed in section 4.1.2) will need to be carefully assessed for each well.

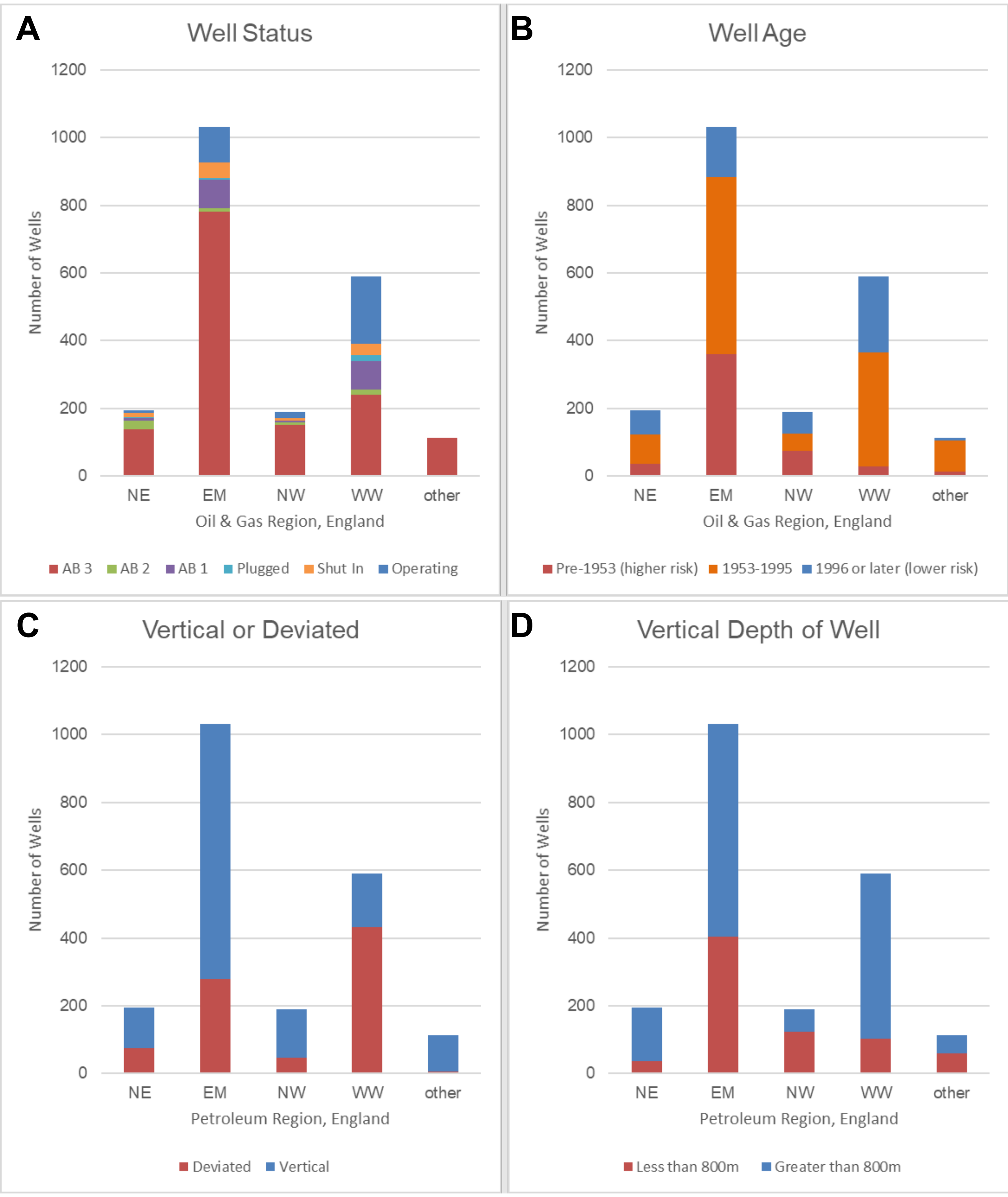

Figure 13: Individual screening factors for onshore wells in England as described in Table 5. See Figure 12 for the delineation of the regions (NE = north-east, including Cleveland and South Humber; EM = East Midlands; NW = north-west, including West Lancashire, Cheshire, North Staffordshire; WW = Wessex-Weald; other = outside of the main basins).

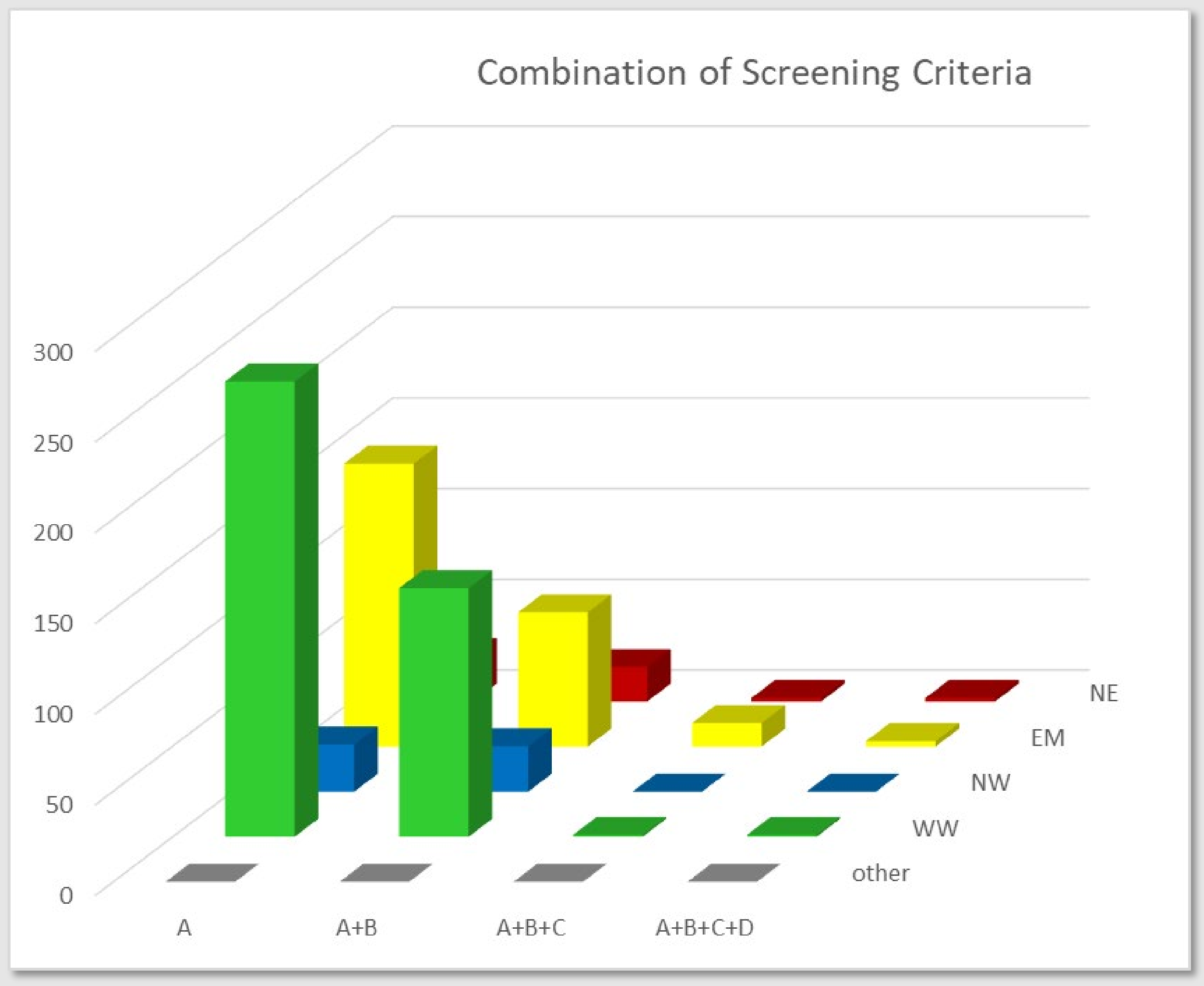

Figure 14: Numbers of wells that are more likely to be suitable when combining multiple screening criteria. (NE = north-east, including Cleveland and South Humber; EM = East Midlands; NW = north-west, including West Lancashire, Cheshire, North Staffordshire; WW = Wessex-Weald; other = outside of the main basins) See Figure 13 for the delineation of the regions. A = well status, B = well age, C = vertical or deviated, D = vertical depth of well (criteria explained in Table 6).

Table 6: Numbers of wells that are more likely to be suitable when combining multiple screening criteria.

	Total no. of recorded onshore oil and gas wells	No. of wells not **fully** de-commissioned	**A.** No. of wells not **fully *or* partly** de-commissioned	**A + B** No. of wells not de-commissioned, and drilled in 1996 or later	**A + B + C** No. of wells not de-commissioned, and drilled in 1996 or later, and vertical (not deviated)	**A + B + C + D** No. of wells not decommissioned, and drilled in 1996 or later, and vertical, and 800m or deeper (potentially suitable for CO_2 storage)
England (all onshore wells)	**2,121**	**696**	**458**	**255**	**16**	**6**
NE England (including Cleveland Basin and S. Humber)	**196**	**58**	**25**	**19**	**2**	**2**
East Midlands	**1,032**	**251**	**156**	**74**	**13**	**3**
NW England (W. Lancs, Cheshire, N. Staffs)	**189**	**37**	**26**	**25**	**0**	**0**
Wessex/ Weald	**590**	**350**	**251**	**137**	**1**	**1**
Other (not within the above provinces)	**114**	**0**	**0**	**0**	**0**	**0**

Screening results indicate that approximately one-third of the oil and gas wells in England could be repurposed as they are not fully decommissioned. Any of those wells could be repurposed if they meet the required well integrity standard. If the approach described here is used to identify which wells are most likely to meet those standards the numbers reduce. If wells are active or recently shut-in, an operator may already know the integrity of the well regardless of whether it meets the screening criteria, which reduces the risk that the well is not up to standard for repurposing. There are wells across all of the active hydrocarbon basins that could be suitable for repurposing, with the greatest number in the East Midlands.

10. Conclusions

Onshore oil and gas wells in England, of which there are more than 2,000, could be repurposed for a variety of non-oil and gas uses:

- Passive use (without materials passing between the reservoir and wellbore), for example, for abstracting heat in a closed loop geothermal borehole or tool testing.
- Injection of fluids into the reservoir from the wellbore, for example, for permanently storing materials such as carbon dioxide (although storing commercial quantities of carbon dioxide onshore in the UK is not currently within government policy).
- Temporary storage, for example, of natural gas or hydrogen, or for extraction of a heat resource. This would involve repurposing wells for injection and production.

When a well has fulfilled its purpose, it is decommissioned. Alternatively, the well may be repurposed for a use associated with energy transition. Reusing oil and gas wells is common practice within the oil and gas industry (for example, turning an oil-producing well into a water injector or sidetracking the well to reach another target). There are established processes that allow the oil and gas industry to repurpose wells, which would also apply to reusing an oil or gas well for energy transition purposes. Prior to repurposing a well, it must be demonstrated to have a level of integrity appropriate for the new functional requirements that will be secure throughout construction, operations and decommissioning.

The new functional requirements will take account of the fluid circulating in the well and its properties (for example, whether it is corrosive in the presence of water, as is the case for carbon dioxide). The reservoir and wells will need to withstand changes associated with the new purpose to be secure (for example, pressure changes associated with injection or production).

It is unlikely that a well that has already been decommissioned will be repurposed as the condition of the well will not be known, so it may fail to meet the required standards for its new function. There are 6 additional factors, identified previously (Environment Agency 2021) that link to the likelihood of an existing well meeting the required standards for its new function.

The injected fluids, operational treatments and deep formation fluids are all potential contaminants. Reactions between the injected fluids and the well can increase the tendency for leakage pathways. There are 2 main potential leakage pathways for contaminants into the environment, through:

i. an active or decommissioned well
ii. a geological pathway in the subsurface (within the overburden, or laterally along the reservoir formation)

When fully decommissioned wells are filtered out from England’s 2,121 onshore oil and gas wells, 696 wells remain (458 of which are not even partly decommissioned). Once other factors as identified previously (Environment Agency 2021) are applied, these numbers reduce rapidly. However, any wells that are not fully decommissioned could be repurposed if shown to meet the required well integrity standard.

Oil and gas development is mature in the UK, however geoenergy transition techniques are not all as mature. For example, standards for wells for carbon capture and storage (CCS) and hydrogen storage are not yet developed, and further research on geological storage of hydrogen is also required.

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Glossary

Annulus/annuli	The void between well completion and well casing.
Aquifer	A body of permeable rock that can transmit groundwater.
Casing string	Metal pipe that is cemented into a wellbore to prevent it from collapsing and to ensure separation of well and formation fluids at unplanned locations.
(Well) completion	The portion of the well that transmits produced or injected fluids between surface and reservoir.
Drill string	Pipe extending between the drill bit at the bottom of the wellbore, any other tools within the assembly, and rig surface equipment.
Formation fluid	Naturally occurring fluids and gases contained in geological formations.
Injection well	A well that is used to flow fluid or gas into a permeable formation.
Logging tools	Tools that can be inserted into a well and measure properties of the well and rocks behind the well along the wellbore.

Liner string	Metal pipe that is cemented into lowest section of a wellbore to prevent it from collapsing and to ensure separation of well and formation fluids at unplanned locations. Does not extend to surface.
Natural gas	Naturally occurring mixture of hydrocarbon gases consisting primarily of methane in addition to various smaller amounts of longer chain alkanes and other gases like CO_2, N and water vapour, among others.
Passive well	Wells which are hydraulically isolated from the surrounding rock along the entire length of the wellbore.
Producer well	A well that is used to flow fluid or gas from a permeable formation.
Reservoir	A body of permeable rock that contains or could contain a resource.
Reservoir fluid	Naturally occurring fluids and gases contained within the pores of the reservoir.
Reservoir pressure	Pressure of fluids held within the pores of the reservoir.
Saline aquifer	A body of permeable rock that contains brine (saline water) in the pore spaces.
Storage site	A reservoir (permeable rock) with a top seal (or caprock) within which injected fluid or gas can be securely contained temporarily or permanently.
Terminal depth (TD)	Total drilled depth of the well.
Tubing	Part of the completion, internal pipe to convey fluid/gas between reservoir and surface.
Tubular	Oilfield pipe used in a wellbore.
Xmas Tree (XT)	A system of valves above the wellhead used to regulate the flow of fluid into or out of an operational well.

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