Underground storage of Hydrogen:

Mapping out the options for Australia

Deliverable 5: Final Summary Report

July 2021

Project number: **RP1-1.04**

Underground storage of hydrogen: mapping out the options for Australia

Authors:

Jonathan Ennis-King, Karsten Michael, Julian Strand, Regina Sander, Chris Green

Project team:

CSIRO Energy

Australian Government
Department of Industry, Science, Energy and Resources

AusIndustry
Cooperative Research Centres Program

This work is funded by the Future Fuels CRC, supported through the Australian Government's Cooperative Research Centres Program. We gratefully acknowledge the cash and in-kind support from all our research, government and industry participants.

IMPORTANT DISCLAIMER

ACKNOWLEDGEMENT

This work is funded by the Future Fuels CRC, supported through the Australian Government's Cooperative Research Centres Program. We gratefully acknowledge the cash and in-kind support from all our research, government and industry participants.

The CSIRO Hydrogen Future Science Platform provided funding support.

PROJECT INFORMATION	
Project number	RP1-1.04
Project title	Underground Storage of Hydrogen
Research Program	RP1
Milestone Report Number	5
Description	This final report summarizes the options for underground storage of hydrogen in Australia
Research Provider	CSIRO
Project Leader and Team	Jonathan Ennis-King, Karsten Michael, Julian Strand, Regina Sander, Chris Green
Industry Proponent and Advisor Team	Dennis Van Puyvelde (ENA), Tim Aujard (AGIG), Tawake Rakai (AGIG), Aiden Trend (APA Group), Ashley Roberts (Woodside)
Related Commonwealth Schedule	Output Milestone 2.2-01
Project start/completion date	May 2020/ July 2021
IP Status	Public
Approved by	Dr Dennis Van Puyvelde, Energy Networks Australia
Date of approval	July 2021

Contents

Figures

Tables

Executive summary

Widespread adoption of hydrogen in Australia as an energy carrier will require storage options to buffer the fluctuations in supply and demand, both for domestic use and for export. Once the scale of storage at a site exceeds tens of tonnes, underground hydrogen storage (UHS) is the preferred option for reasons of both cost and safety.

The literature on UHS was reviewed, highlighting the main options for UHS under consideration, and the technical challenges that surround each one. The reservoir engineering aspects of UHS in porous media were also explored, providing some of the tools for assessing storage capacity, losses, and containment. The literature of UHS economics was also surveyed, indicating the variance in costs estimates and the need for an integrated assessment of total costs of hydrogen production, transport, and storage.

The energy landscape in Australia was summarised, and the scale of potential future demand for UHS was estimated by considering plausible scenarios in three areas of application for energy storage. For stabilisation of the electricity network, this corresponds to around 10,000 tonnes of hydrogen. For security of the gas network (fully converted to hydrogen), the amount is about 2.5 million tonnes. For potential export, the storage requirements are similarly around 2.5 million tonnes.

A methodology was developed for assessing the suitability of UHS options in Australia, and for making storage capacity estimates (only for depleted gas fields). This methodology was then applied to the whole of Australia. The key aim was to estimate the scale of prospective storage in each region, and classify options by their suitability, rather than to rank potential storage sites. The focus at this stage was on a technical assessment of geological factors and the assessment does not take social, environmental or economics issues into consideration.

UHS in salt caverns (created by circulation of water) is an established technology internationally, with individual sites able to store a few thousand tonnes of hydrogen. Various Australian sedimentary basins contain salt deposits potentially suitable for the creation of storage caverns; however, most of these salts are in areas that are not near potential hydrogen generation, ports, or processing infrastructure. The most likely locations are in the north-western part of the Canning Basin, which is relatively close to the North West Shelf gas processing facilities and in the vicinity of new renewable wind and solar energy projects. The salt deposits in the Adavale Basin in western Queensland, and the Amadeus Basin in the Northern Territory, may also be suitably located for some projects. Further exploration for salt deposits may open up additional locations where salt cavern storage for UHS is viable.

Depleted gas fields have also been used previously for storage of hydrogen-rich gas mixtures as well as natural gas storage and appear to be the most promising and widely available UHS option in Australia. There are still technical challenges to be addressed, such as the extent of possible contamination of the stored hydrogen with residual hydrocarbons, and the possible effects of geochemical reactions and microbial processes. The total prospective UHS capacity in such sites has been estimated using reserves and production data to be 310 million tonnes. Most Australian sedimentary basins contain multiple gas fields with an individual prospective storage capacity of more than 200,000 t H_2. A much more detailed site-by-site assessment would be required to estimate how much of this prospective storage capacity could be commercial, considering various operating parameters and costs, as well as social and environmental factors.

UHS in saline aquifers is also possible, building upon widespread international experience with underground gas storage in such locations. Many Australian basins contain multiple reservoir-seal pairs that should be suitable for UHS. The further requirement is then to locate suitable structures which could contain the stored hydrogen. That will require additional exploration and characterisation in these basins, and so a quantitative estimation of UHS capacity was not possible within the scope of this project. Although UHS in saline aquifers has not yet been demonstrated in industrial applications, it represents an option with a larger regional extent than storage in depleted gas reservoirs and may be considered if contamination issues from residual hydrocarbons are found to be significant.

UHS in engineered hard-rock caverns, whether purpose-built or re-purposed from mining infrastructure, is a concept that builds on international experience with compressed air storage. It has a much lower technology readiness level (TRL) than the options discussed above, and there are major technical challenges around both containment and geomechanical stability. The main area of application would be in regions with significant potential for renewables but away from sedimentary basins, where the other geological options are not available. Each of the five regions analysed has some areas in which engineered caverns could be created, including mines with modern infrastructure which could be potentially be lined and re-purposed for UHS. Given the abundance of prospective storage capacity in Australian gas fields it would seem unlikely that repurposing underground excavations is a necessary or practical large-scale storage option. There is perhaps the possibility of smaller-scale application in remote mining areas or in conjunction with temporarily storing export hydrogen in NW WA.

Even if only a small fraction of the prospective storage capacity in depleted gas fields (310 million tonnes) could be realised commercially, this would significantly exceed the storage needs of a fully developed hydrogen industry in Australia (estimated at around 5 million tonnes). This is also true in each of the five regions analysed. The most likely scenario is that the required UHS capacity could be met by a handful of storage facilities in each region. The focus will then be on finding the most suitable sites that match the needs of the emerging hydrogen production industry, considering the economic, social, and environmental constraints.

Additional research is needed to resolve the technical challenges around each UHS option, and to provide suitable criteria for site selection. Salt cavern storage will require better characterisation of known salt deposits, and exploration for new ones. Depleted gas field storage needs quantification of the impact of geochemical and microbial reactions on hydrogen purity, the impact of hydrogen on the properties of the storage reservoir and the seal, and more sophisticated modelling of how these processes affect the operation. Saline aquifer storage will require further exploration and characterisation of suitable structures for retaining the hydrogen. For hard rock caverns, the challenges are around containment and geomechanical stability, including the material used for liners, and the choice of excavation techniques. The techno-economic analysis requires an integration of the total costs of production, transport and supply of hydrogen, and a comparison between the different types of storage sites and possible applications.

Introduction

Australia has large potential for hydrogen production from various sources as identified by Feitz et al. (2019). Large-scale use of hydrogen, whether produced from renewables, coal, or gas (Figure 1), is expected to require significant amounts of storage to cope with seasonal fluctuations in demand (and variable supply in the case of renewables). Underground storage of hydrogen (UHS) is a leading option for reasons of cost and safety, and the objective of this study is to assess the most suitable options for UHS in Australia. This high-level assessment emphasises geological storage suitability (injectivity, capacity) and distance to potential hydrogen sources and transport infrastructure. Other factors, like economic, social and environmental aspects, can only be discussed in general terms because a detailed analysis would require additional information on hydrogen production locations, volumes, usage, timing and regulations that are not yet available.

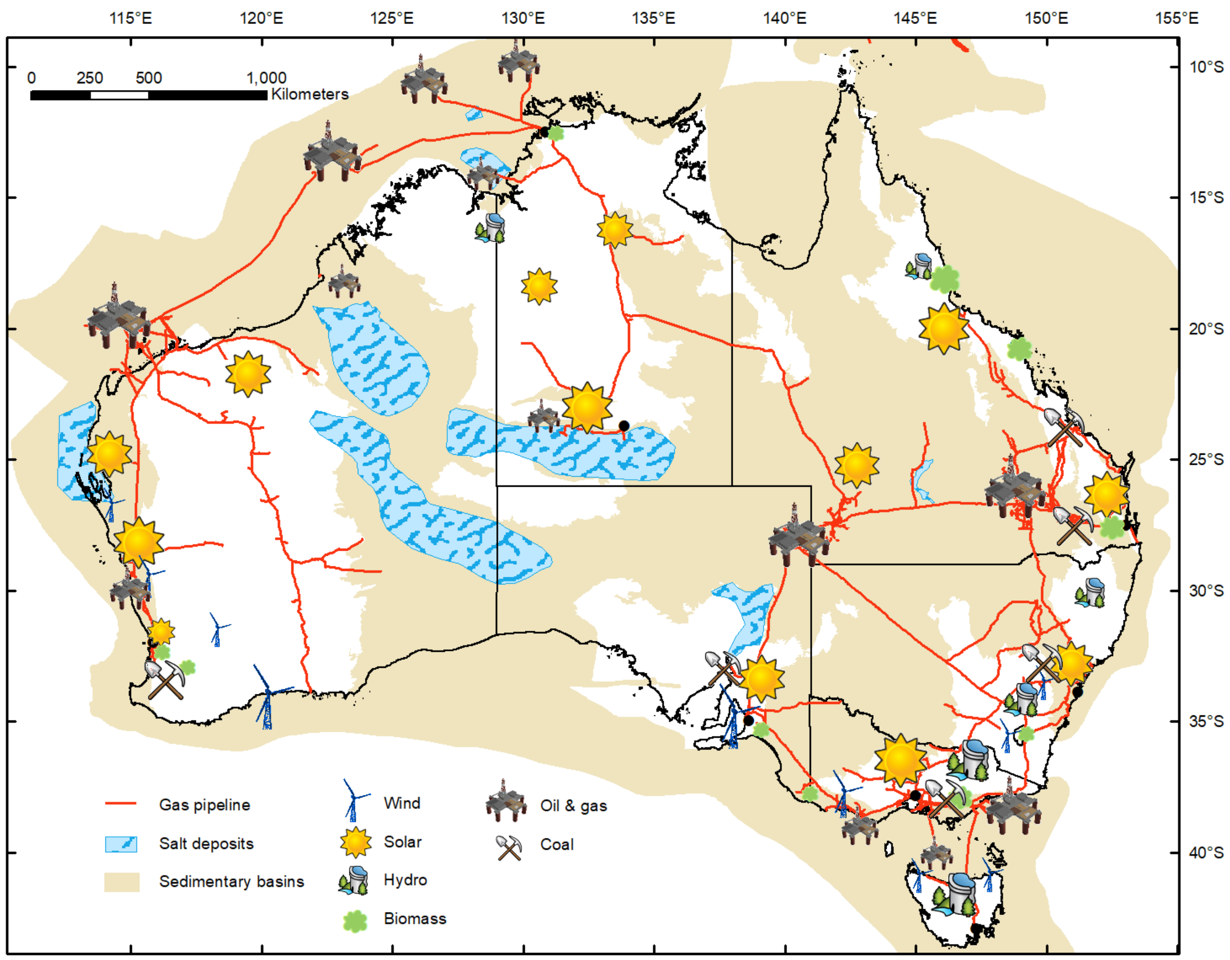

Figure 1. Types and distribution of current energy production in Australia and location of major salt deposits.

The aim of the assessment is not to rank sites from best to worst, but to estimate (in each area) the scale of the potential underground storage capacity for hydrogen in sites that are broadly suitable. The focus is on prospective storage capacity i.e., storage capacity without regard to commercial considerations. The main point of interest is how the scale of prospective storage compares to the estimates of the possible demand for hydrogen storage in each area.

In the next sections, the options for UHS are reviewed, and some of the reservoir engineering aspects and techno-economics of UHS are assessed. The methodology for capacity estimation for UHS is then explained and applied to Australia at a regional scale.

Review of UHS options

There are four main forms in which hydrogen is stored in the subsurface (Panfilov, 2016).

1. Pure hydrogen can be obtained from excess electricity by chemical electrolysis, or from hydrocarbon processing (e.g. steam methane reforming). It is commonly stored in salt caverns, but other UHS options are possible. It can be used in fuel cells to produce electricity (e.g. for electric vehicles), but direct combustion is also possible.
2. A mixture of natural gas with a low hydrogen concentration (6-15 mole percent) can potentially be used in existing natural gas infrastructure, including underground gas storage facilities (DBI, 2017). H_2 and CH_4 could also be separated after storage.
3. Rich hydrogen mixtures with CH_4, CO, and CO_2 have been produced from superficial or underground coal gasification. This can be in the form of syngas - a mixture of H_2 (20-40%) and CO – or town gas - a mixture of H_2 (50-60%), CO and CH_4. It has been stored in salt caverns (Teesside, UK; Kiel, Germany) and aquifers (Beynes,France; Lobodice, Czechoslovakia) (see Panfilov et al.,2006; Liebscher et al., 2016). It can then be used in gas turbines or as fuel for lighting and heating.
4. Another proposal is an underground methanation reactor, where a mixture of H_2 and CO_2 stored in the subsurface is enriched in CH_4 by methanogenic bacteria in aquifers or depleted gas reservoirs (Strobel et al, 2020). The resulting gas mixture is injected into the natural gas grid and used as fuel.

The four main geological options for UHS are salt caverns, depleted oil and gas reservoirs, aquifers, and hard rock caverns (Lord et al. ,2014), and these are now discussed in detail (see also recent reviews by Heinemann et al. (2020) and Zivar et al. (2021)).

SALT CAVERNS

Salt caverns can be created in various ways within salt domes or within bedded salt deposits by leaching out large cavities through the injection of freshwater. The salt surrounding the caverns is of very low permeability and a very effective barrier to gas leakage. Caverns are usually constructed within domes that are structurally stable for the required operating conditions and located above a depth of approximately 1800 m. The increased pressure and temperature below 1800 m can result in salt deformation and create instability issues for the caverns.

Bedded salts are typically found at much shallower depths than domes and are less homogeneous, alternating between salt (halite) and non-soluble beds such as dolomite, anhydrite, and shale. Hence, caverns created in these formations are relatively thin and laterally extensive and may not be as stable as those created within salt domes. Induced slippage between bedding planes can cause gas to migrate laterally and operating pressures will be limited by the fracturing pressure of the weakest lithology, the minimum pressure to prevent roof creep and instability, and the maximum threshold pressures that could induce bedding plane slip (Bruno and Dusseault, 2002).

Storage caverns can be operated under variable pressures, where approximately one third of the cavern volume will contain cushion gas. As the pressure decreases in response to working gas withdrawal, cushion gas is injected to maintain adequate operating pressures and prevent stability issues. Alternatively, caverns can be operated under constant pressure, whereby saturated brine is injected to compensate pressure decrease due to gas withdrawal. Cushion gas is not needed under these operating conditions. Economics optimisation of the operating conditions is also needed, based on fit-for-purpose modelling (Gabrielli et al., 2020). The cycling of hydrogen in the salt caverns also creates thermal stresses which can affect cavern stability (Böttcher et al., 2017; Groenenberg et al., 2020).

Current use of salt caverns for UHS includes (Panfilov et al., 2006) Teesside in the UK (210,000 m^3 of storage corresponding to 700-1000 tonnes of hydrogen), and three facilities in the Gulf Coast region of Texas, USA: Spindletop (906,000 m^3 of storage), Clemens Dome (580,000 m^3 of storage, around 2500 tonnes of hydrogen (Forsberg, 2006)), and Moss Bluff Dome (566,000 m^3 of storage). These all operate as part of the hydrogen supply network for the chemical industry and refineries. Town gas storage operations occurred in salt caverns in Europe until the 1970s e.g. in Germany, Kiel (32,000 m^3 of storage) and Bad Lauchstaedt (Liebscher et al., 2016).

UHS in salt caverns may become a viable option for large-scale energy storage in areas of suitable geology, significant amounts of and surplus from intermittent renewable energy production, low electricity costs, a CO_2 price and/or emergence of a hydrogen mobility market (HyUnder, 2014b). In Europe, a large focus has been on underground storage in salt caverns, which is based on the abundance of salt deposits, particularly in northern European sedimentary basins co-located with renewable electricity from wind production (HyUnder, 2014a; Caglayan et al., 2020). Pilot projects in Germany are planned for a salt cavern at Bad Lauchstaedt previously used for town gas and natural gas storage (HYPOS, www.hypos-eastgermany.de/en) and for a salt cavern in Gronau-Epe (GET H2, www.get-h2.de). Regional surveys of UHS potential have also flagged salt caverns as storage options in France (Le Duigou et al.,2017), the Netherlands (Groenenberg et al., 2020), Poland (Stygar and Brylewski, 2013; Tarkowski, 2017; Tarkowski and Czapowski, 2018; Lewandowska-Smierzchlska et al., 2018; Lankof et al., 2020), Romania (Iordache et al., 2014; Iordache et al. 2019), Spain (Simon et al., 2015; Sainz-Garcia et al., 2017) , Turkey (Ozarslan, 2012; Deveci, 2018), the United Kingdom (Stone et al., 2009), China (Liu et al., 2020; Qiu et al.,2020), Canada (Lemieux et al., 2019) and the USA (Lord et al., 2014).

DEPLETED HYDROCARBON RESERVOIRS

Depleted gas reservoirs have been the most common option for underground natural gas storage (UGS) to date. Depleted oil fields are used for UGS (e.g. Guo et al., 2006), but this is often optimised to also improve oil recovery (Coffin and Lebas, 2008; Yanze et al., 2009; Snow et al., 2014). Due to the existing infrastructure (wells, pipelines), depleted reservoirs are generally easy to develop, operate, and maintain for UGS. These reservoirs also have demonstrated containment because they have trapped natural gas over geological time scales. Traps that successfully contain gas are either structural, such as an anticline, or stratigraphic, such as an impermeable layer, e.g. caprock.

Analogous to UGS, UHS requires a site with adequate storage capacity (i.e. high porosity to store the required gas volumes), adequate injectivity (i.e., high permeability in order for gas to be injected and extracted at adequate rates), and safe containment in the form of an impermeable caprock along with a geologic structure to contain and trap gas (salt and hard rock caverns contain gas by the very low permeability of the surrounding host rock). The operating pressures are limited by two geomechanical processes: the tensile fracture pressure of the reservoir rock and the stresses at which faulting or other mechanical damage may be induced in either the reservoir or the caprock (Bruno et al., 1998). In addition, retention beneath a water-saturated caprock depends on capillary forces at the gas-water interface, and the magnitude of the capillary entry threshold limits the allowable overpressure (Thomas and Katz, 1968).

Scoping studies in other countries have considered the potential of depleted fields for UHS (Lord et al., 2011; Bai et al., 2014; Liebscher et al., 2016; Lemieux et al., 2019; Lewandowska-Śmierzchalska et al., 2018; Tarkowski, 2017; Groenenberg et al., 2020). However, there are several differences between UGS and UHS that may affect the suitability. Due to hydrogen having a greater diffusivity than methane, additional technical assessment is needed of the scale of its loss through the underlying aquifer and the caprock above (Amid et al., 2016). The low solubility of hydrogen in formation water, discussed below, implies that the possible loss through the caprock will be low (estimated at 2% by Carden and Paterson (1979) – Amid et al. (2016) examined a scenario where such losses could be reduced to below 0.1 %). Pre-existing facilities (especially wells and pipelines) might need to be replaced or upgraded for hydrogen, depending on the materials previously used. The contamination of the injected hydrogen with residual hydrocarbons could also occur (Tarkowski, 2019; Lord et al., 2011), which would require some processing of the hydrogen upon withdrawal. The contamination issue will be examined in more detail below and includes the potential for geochemical and microbiological alteration of the stored gas. Field projects in Austria (Underground Sun Storage, 2017; Hassannayebi et al., 2019) and Argentina (Perez et al., 2016; Dupraz et al., 2018) have provided insight into these issues.

To maintain reservoir pressure and adequate withdrawal rates for UHS, typically around 30-50% of the reservoir volume must contain cushion gas, which could be sourced, at least partly, from the non-produced natural gas remaining in the reservoir (this is based on experience with UGS). The actual amount of cushion gas required depends on the reservoir properties and the operational design and can range from 15 to 75 % (Namdar et al, 2019b). Note that the cushion gas is a large proportion of the initial storage cycle, but a small proportion over many storage cycles. For example, if 50% of the initial storage amount is cushion gas, over 100 storage cycles this amounts to only 0.5% of the total stored.

Monitoring of UHS in depleted hydrocarbon reservoirs can build upon industry practices in UGS, which mostly focus on pressure responses at the injection and withdrawal wells, and some sampling at peripheral water wells. However, the microbiological aspects of UHS suggest that it may also be necessary to monitor the chemistry and microbiology of the reservoir during operation (Dopffel et al., 2021). Techniques are also being investigated for detecting hydrogen leaks into shallow aquifers (Lafortune et al., 2020; Gombert et al., 2021), although based on similar work in CCS monitoring, this is likely to function more as assurance monitoring (evidence that the environment has remained the same within natural variation) than as leakage detection.

AQUIFERS

In regions where salt formations or depleted reservoirs are not available, saline aquifers can be developed for gas storage. A suitable aquifer for storage may have geology similar to a depleted gas reservoir and requires a trapping structure (i.e. anticline) for the injected gas. Similar to a depleted reservoir, the aquifer should have adequate porosity and permeability and sufficient storage capacity.

Aquifers are often more expensive to develop than depleted reservoirs due to uncertain geology and lack of infrastructure. Geologic characteristics of undeveloped aquifers are commonly uncertain, and data must be acquired to confirm injectivity and containment. In addition to the well and pipeline infrastructure, a system must be emplaced that will dehydrate gas.

Cushion gas requirements for aquifers are greater than those for depleted reservoirs because there is no naturally occurring gas present to offset the total volume needs. The amount of cushion gas required may be as high as 80% of the total reservoir volume. This is a large proportion of the initial storage cycle, but small when averaged over many cycles. There are also options to use other less expensive gases as part of the cushion gas e.g. nitrogen.

As with depleted reservoirs, some loss of gas is inevitable and can occur through loss of hydrogen to cushion gas (unrecoverable), escape via leaky wells, and dissolution or diffusion into formation water. Fingering between gas and water can cause the gas to travel down structure and become unrecoverable (Paterson, 1983). Well placement and operations can be optimised to maximise hydrogen recovery (Azretovna et al., 2020)

As referenced above, the storage of hydrogen-rich town gas in aquifers e.g Beynes,France; Lobodice, Czechoslovakia (see Panfilov 2006; Liebscher et al., 2016) is a close analogue for UHS in aquifers, and indicates adequate containment of the injected gas.

ENGINEERED CAVERNS

The potential for storage of hydrogen in excavated caverns (generally in hard rock) has been canvassed (Kruck et al., 2013; Matos et al., 2019), based on experience with other forms of storage. Existing applications include liquid hydrocarbons (Lu, 2010; Shi et al., 2018), natural gas storage (Meddles, 1978; Trotter et al., 1985; Stille et al., 1994; Lu, 2010; Kruck et al., 2013) and compressed air energy storage (CAES) (Evans and West, 2008; Kovari, 1993; Geissbühler et al., 2018; Menéndez and Loredo, 2019; Wu et al., 2020). The key technical challenges are containment, and structural integrity, and at this stage the concept is still under development. The Hybrit project is proposing to create a hard rock cavern of volume 100 m^3 for hydrogen storage as part of a pilot operation for production of 'green steel' (https://www.hybritdevelopment.se/en/a-fossil-free-development/hydrogen-storage)

The necessary degree of containment depends on the vapour pressure of the storage. Hydrocarbon liquids with low vapour pressure are successfully stored in shallow unlined rock caverns, while liquids with higher vapour pressure (e.g. LPG) require a more involved strategy (Kurose et al., 2014). For deeper caverns, the natural hydrostatic pressure above the cavern may be sufficient to prevent vapour entry into fractures and pores, or it may be necessary to supplement this with a 'water curtain' – the injection of water in a series of small boreholes above and around the cavern (Goodall et al., 1988; Liang et al., 1994; Lindblom, 1997). This has been studied extensively in the field and the laboratory, and the design criteria have been refined (Kjørholt et al., 1992; Li et al., 2009; Zhang et al., 2020). One drawback of the water curtain approach is the need to pump water out of the cavern. The use of liners for caverns has also been studied, particularly for shallower caverns where the water curtain is less effective (Kovari, 1993; Kruck et al., 2013). Linear materials that have been studied include steel, polyethylene, polyvinylchloride and butylorubber (Liang et al., 1994), and more recent work has looked at the hydrogen permeability of epoxy resins (Gajda and Lutyński, 2021).

Structural integrity of caverns under pressure depends on the interactions between the strength of the surrounding rock, the size and shape of the cavern, the distribution of fracture networks, the prevailing stress field, and the possible use of liners. Theoretical studies using geomechanical simulation have shown how better understanding of these interactions can refine the design, particularly for shallow caverns (Rutqvist et al., 2012; Zhou et al., 2020; Perazzelli and Anagnostou, 2016; Carranza-Torres et al., 2017; Wu et al., 2020).

Abandoned mines have also been canvassed as a potential option for UHS (Kruck et al., 2013; Matos et al., 2019), one of the main attractions being the potential cost savings due to the previous excavation. The key challenges again are containment and structural integrity. The obvious problem is that the original mining was not designed with these criteria in mind, and so the selection process would rule out many mines e.g. mining processes that fracture the surrounding rock, such as long-wall mining, would exclude those locations (Kruck et al., 2013; Lu, 2010). The complexity of the tunnel geometries in many mines would likely also exclude the use of liners, so hydrodynamic containment would probably be necessary. There are a small number of field examples of abandoned mines being used for natural gas storage: e.g. the Leyden coal mine in Colorado, USA (discussed in Lu, 2010), two coal mines in Belgium (Lu, 2010; Kruck et al., 2013), and a potash mine in Bernsdorf in Germany (Kruck et al., 2013). So far there are no examples of UHS in abandoned mines. As a comparison, compressed air storage in abandoned mines has been proposed (e.g. Menéndez and Loredo, 2019; Parkinson, 2020), as has CO_2 storage (Piessens and Dusar, 2003; Piessens and Dusar, 2004; Jalili et al., 2011; Dieudonne et al., 2015). As for natural gas and hydrogen, there are challenges around containment, particularly the sealing of shafts (Dieudonne et al., 2015).

Reservoir engineering aspects of UHS

HYDROGEN DENSITY

The density of hydrogen gas at subsurface conditions is a key element in the assessment and modelling of UHS. The ideal gas representation has

$$\rho = \frac{M_w P}{R\,T}$$

where ρ is the density, P is pressure, R is the universal gas constant

(8.314462 m^3 Pa K^{-1} mol^{-1}) and M_w is the molecular weight (0.002015 kg/mol for hydrogen). The high-accuracy representation of Leachman et al. (2009), used in the NIST webbook, incorporates corrections to the ideal gas model, and is fitted to extensive experimental data, but is more complicated to compute.

For the purposes of underground storage, there are simple corrections to the ideal gas representation of hydrogen density that improve the accuracy without the complexity of the high-accuracy representation. At low densities, the first correction to the ideal gas law (expressed as a power series in density) is the second virial coefficient, which depends on the pairwise interactions between two hydrogen molecules. Thus, one has

$$\rho_{id} = \frac{M_w P}{R\,T} = \rho + B\rho^2 + O(\rho^3)$$

where ρ_{id} is the ideal gas density. Ignoring the third order terms in ρ, and solving for ρ, one obtains

$$\rho = \frac{1}{2\,B}\left((1 + 4\,B\rho_{id})^{\frac{1}{2}} - 1\right)$$

The coefficient B depends on temperature. Fitting of experimental data gives the following representation for B (Goodwin et al., 1964)

$$B = B_0\left(1 - \left(\frac{T_0}{T}\right)^{\frac{5}{4}}\right)$$

The fitted values of the coefficients are B_0=19.866 cm^3/(g mol) = 0.00985 m^3/kg, and T_0=109.83 K.

In subsurface conditions, the pressure increases approximately linearly (from an average pressure of 1 atmosphere or 0.101325 MPa at sea level) according to the hydrostatic gradient, which depends on the density (and therefore the salinity) of the formation water via ρ g, where ρ is the density and g is the acceleration due to gravity. A typical value of the hydrostatic gradient is 10 MPa/km. Similarly, the subsurface temperature increases approximately linearly with depth from an average surface temperature which is taken here to be 15 C. This geothermal gradient varies with location, but a typical value is 25 C/km.

Figure 2 shows the density of hydrogen gas as a function of depth for these choices of gradients. The blue curve is the ideal gas representation, the red curve is the virial representation, and the green curve is the high-accuracy representation. The increase in temperature with depth, on top of the increase in pressure, means that the ideal gas representation only deviates gradually from the high-accuracy result, being 15 % higher at 5km depth. The virial coefficient representation is a noticeable improvement on the ideal gas case (for these purposes), being within 5% of the high-accuracy result at 5km depth, and it is of sufficient accuracy to be useful at 2-3km depth. The first observation is that hydrogen remains very much less dense than formation water over the whole range of depths (water density being around 1000 kg/m^3, depending on salinity). Thus, the buoyancy of the injected hydrogen will be a strong effect under all storage conditions. The second observation is that hydrogen density continues to increase significantly between 1 and 3 km depth, indicating that deeper storage sites are much more efficient in terms of use of pore volume.

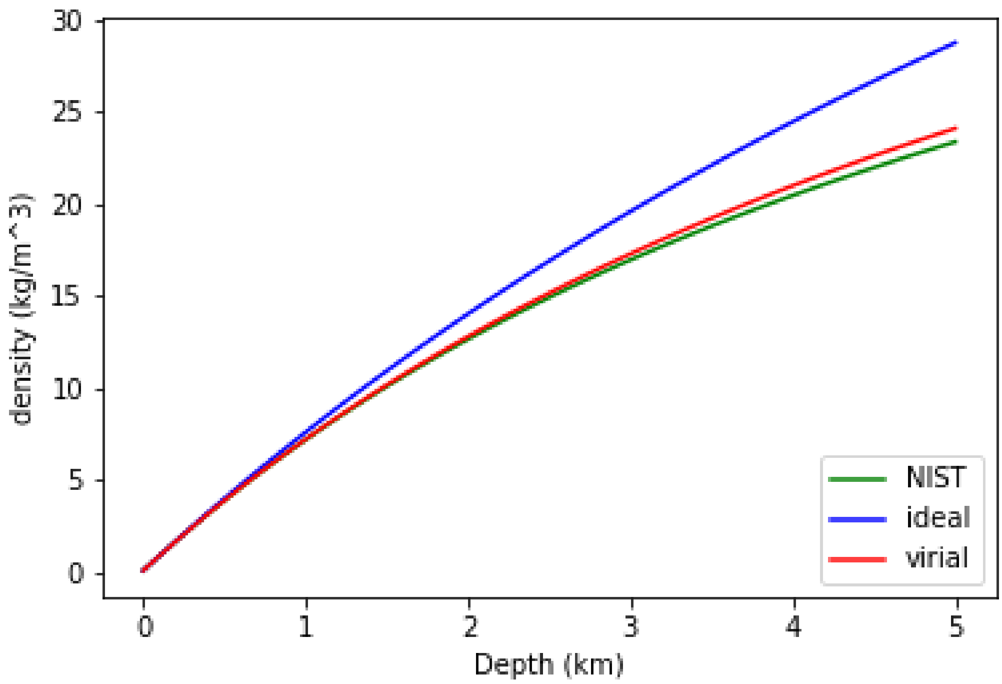

Figure 2: Comparison of representations for hydrogen density as a function of depth, for a hydrostatic gradient of 10 MPa/km, and a geothermal gradient of 25 C/km, with an average surface pressure of 0.101325 MPa and an average surface temperature of 15C. The blue curve is the ideal gas representation, the red curve is the representation using the second virial coefficient, and the green curve is the high-accuracy representation used in the NIST webbook (based on Leachman et al., 2009)

Figure 3 shows that ratio of methane density to hydrogen density as a function of depth varies between 8 and 10, where the ratio at shallow depths is close to the ratio of molecular weights (7.96), which one would expect in the low-density limit where the ideal gas law is a good approximation. This is particularly useful for estimating the amount of hydrogen that might be stored in depleted gas fields.

The density of hydrogen mixtures with natural gas, nitrogen or carbon dioxide can be represented through well-established equations of state such as GERG-2008 (Hassanpouryouzband et al., 2020).

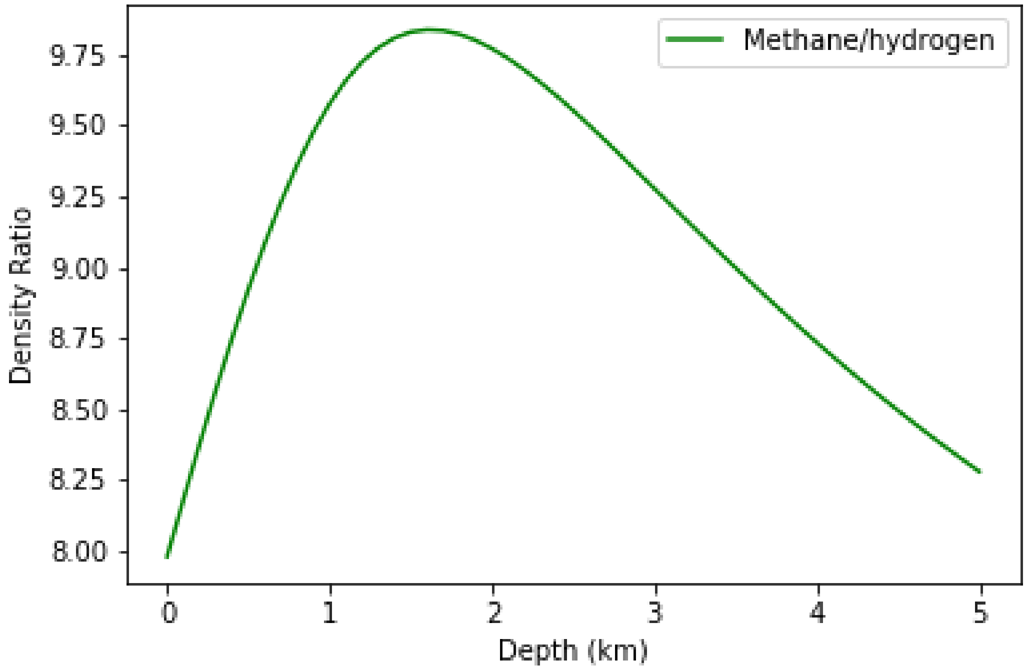

Figure 3: Ratio of methane density to hydrogen density as a function of depth in km, for a hydrostatic gradient of 10 MPa/km, and a geothermal gradient of 25 C/km, with an average surface pressure of 0.101325 MPa and an average surface temperature of 15C.

HYDROGEN SOLUBILITY

It is also important to assess the solubility of hydrogen in formation water during underground storage. Figure 4 shows the solubility as a function of temperature for various pressures, comparing the experimental data of Wiebe and Gaddy (1934) to the representation of Li et al. (2018). More recent work has focused on hydrogen solubility in brines (Torin-Ollarves and Trusler, 2021; Chabab et al., 2020). The solubility increases with pressure, while the variation with temperature has a minimum around 323 K (50 C). The key observation is that the solubility is quite low – at 20 MPa (corresponding to conditions at about 2km depth), the solubility as a mole fraction is below 0.003. This translates to a mass fraction of less than 0.00034. In comparison the mass fraction solubility of carbon dioxide in low salinity formation water at subsurface conditions is generally below 0.05, and the corresponding mole fraction solubility is 0.021. Hydrogen is about 7 times less soluble than carbon dioxide in mole fraction terms, and two orders of magnitude less soluble in mass fraction terms.

Figure 5 gives the pressure dependence of solubility at two temperatures, 298 K (25 C) and 373 K (100 C) comparing the representation of Li et al. (2018) to experimental data. The dependence on pressure is nearly linear, while the comparative dependence on temperature is quite weak for subsurface conditions (and as Figure 4 indicates, not linear or monotonic). Thus, a Henry's law style of representation will be adequate for hydrogen solubility, where the coefficients depend on temperature and salinity (increased salinity leading to lower solubility, referred to as 'salting out').

The potential losses of hydrogen due to dissolution in formation water during storage will depend on the degree of contact between the injected hydrogen and unsaturated formation water. Once the first injection cycle has been completed, the residual formation water in contact with the hydrogen will be saturated with dissolved hydrogen. During subsequent cycles of withdrawal and injection, contact with unsaturated formation water will only happen at the edges of the gas plume, and will depend on the properties of bounding aquifer units. In any case the dissolution will be a small proportion of the injected amount, and smaller than occurs in natural gas storage. The transport of dissolved hydrogen away from the gas/water interface depends on diffusion and will be very slow on the timescales of storage operations (years to decades).

Diffusion of hydrogen through the caprock has also been suggested as a mechanism for losses, since the diffusion coefficient of hydrogen is larger than for similar gases. As the caprock will be water-saturated, diffusion of hydrogen in the water phase is the limiting factor for transport. However, the very low solubility of hydrogen in formation water imposes a significant limit on the losses. Thus, the total losses through this mechanism in a storage cycle are likely to be less than for natural gas storage.

The relative losses to caprock diffusion can be quantified as follows. The amount of hydrogen that enters the caprock through diffusion in the water phase can be estimated as

$$A\ \phi_S C_H\ 2\sqrt{\tau\ D\ t}$$

where A is the lateral area of the gas cap, ϕ_S is the porosity of the seal, C_H is the solubility of hydrogen in brine, D is the bulk diffusion coefficient of hydrogen in brine, τ is the tortuosity factor for the seal, and t is the storage time. The amount of hydrogen contained in the reservoir can be estimated as

$$A\ \phi_R \rho_H h$$

where ϕ_R is the porosity of the reservoir rock, ρ_H is the bulk density of hydrogen at subsurface conditions, and h is the thickness of the gas layer. If for simplicity it is assumed that $\phi_S = \phi_R$ then the ratio of the mass of hydrogen in the seal to the mass in the reservoir is

$$\frac{C_H\ 2\sqrt{\tau\ D\ t}}{\rho_H h}$$

The literature on hydrogen diffusivity in water is rather sparse (e.g. Wise and Houghton, 1966; Verhallen et al., 1964; Kallikragas et al., 2014; Zhao et al., 2019), but a typical value is

5×10^{-9} m^2 s^{-1}. For a storage time of 1 year, a tortuosity factor of 0.5, a gas layer thickness of 10 m, and a depth of 1 km, this ratio is approximately 0.0014. A storage time of 25 years would only increase this ratio by a factor of 5, so in these circumstances the diffusive loss into the caprock is under 1% of the stored amount.

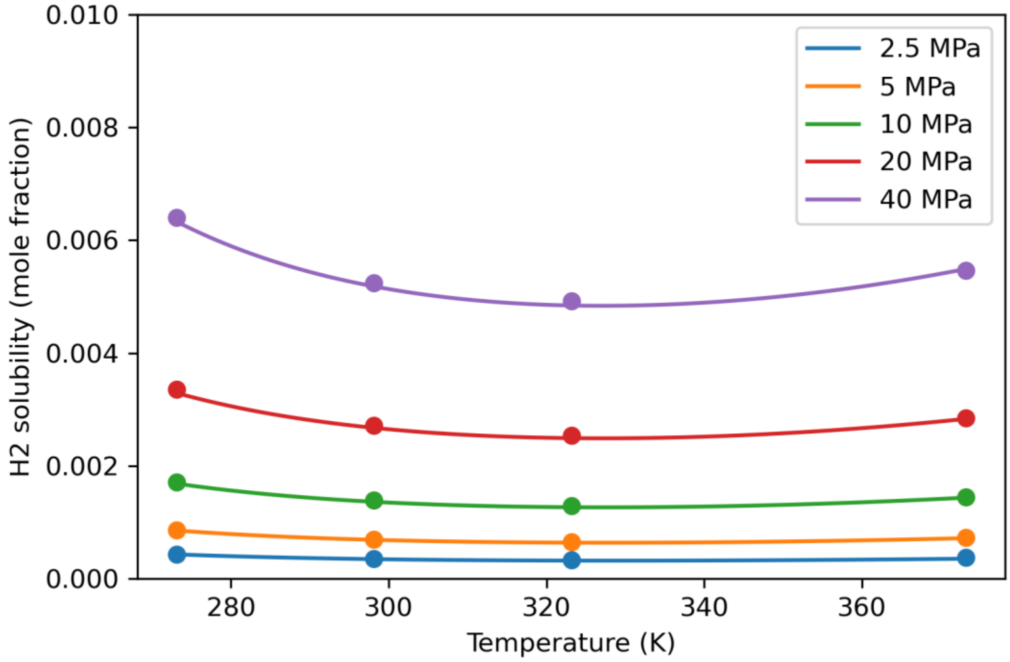

Figure 4: Solubility of hydrogen in water as a function of temperature, for various pressures. The solid lines are the representations of Li et al. (2018), and the dots are the experimental data of Wiebe and Gaddy (1934).

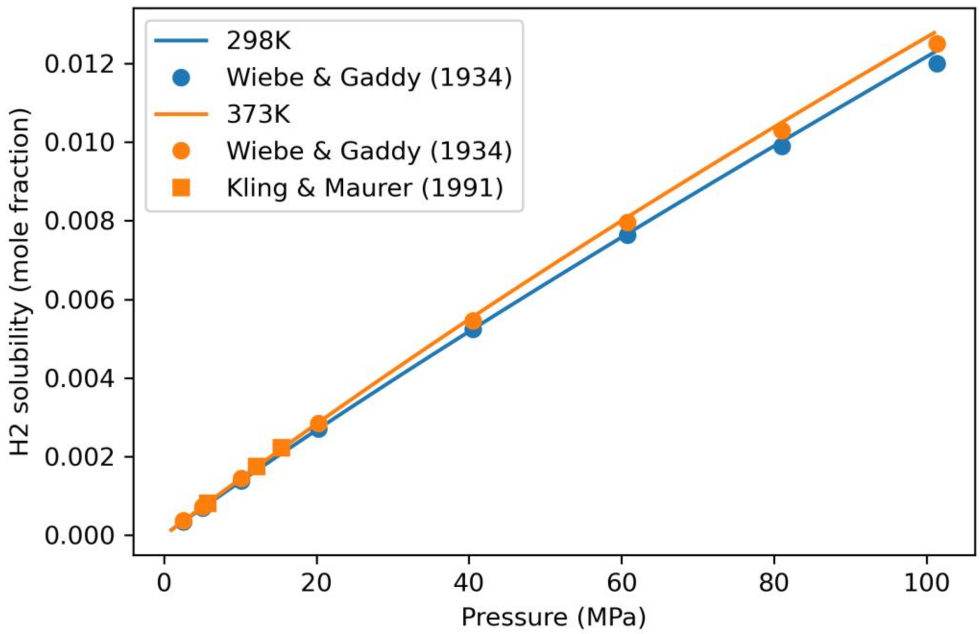

Figure 5: Solubility of hydrogen in water as a function of pressure, for 298 K (25 C) and 373 K (100 C). The solid lines are the representations of Li et al. (2018), the dots are the experimental

data of Wiebe and Gaddy (1934) and the squares are the experimental data of Kling and Maurer (1991).

RELATIVE PERMEABILITY AND CAPILLARY PRESSURE

The movement of injected hydrogen in the subsurface depends strongly on the gas-water-rock interaction which is manifested in the relative permeability and capillary pressure curves. The default assumption is that relative permeability curves for hydrogen-brine will be very similar to methane-brine in the same reservoir unit (strongly water wet). The few recent investigations that have looked at hydrogen-water contact angles in simple systems have mostly found contact angles less than 50 degrees (Al Yaseri et al., 2021; Hashemi et al., 2021b; Yetka et al., 2018a) and so strongly water-wet, although experiments on quartz aged with stearic acid found intermediate wetting (Iglauer et al., 2021). Yetka et al. (2018a) have also measured hydrogen-water relative permeabilities (using a steady state method) and capillary pressure curves (using mercury injection capillary porosimetry, or MICP) on sandstone cores. These results have been used to calibrate pore-network modelling of hydrogen-water relative permeabilities, which allow analysis of the sensitivity to data such as the contact angle (Hashemi et al., 2021a).

The ability of seals in depleted gas fields to retain injected hydrogen depends on the seal facies being water-wet (which is true in the cases mentioned above) and on the hydrogen-water interfacial tension. If the capillary entry pressure for hydrogen into the seal is P_H, then the height h_H of a column of hydrogen that can be retained by that seal is

$$h_H = \frac{P_H}{g\ (\rho_b - \rho_H)}$$

where g is the acceleration due to gravity, ρ_b is the brine bulk density, and ρ_H is the hydrogen bulk density at reservoir conditions. Similarly, for methane (as a proxy for natural gas), if the capillary entry pressure for methane into the seal is P_M, then the height h_M of a column of methane that can be retained by that seal is

$$h_M = \frac{P_M}{g\ (\rho_b - \rho_M)}$$

where ρ_M is the methane bulk density at reservoir conditions. Using the standard approach for converting between capillary entry pressures for different fluids (Vavra et al., 1992), one obtains

$$\frac{h_H}{h_M} = \frac{\sigma_H(\rho_b - \rho_M)\cos\theta_H}{\sigma_M(\rho_b - \rho_H)\cos\theta_M}$$

where σ_H and σ_M are the interfacial tension between hydrogen and brine, and methane and brine respectively, and θ_H and θ_M are the contact angles between hydrogen and brine, and methane and brine respectively. Using literature data and representations for interfacial tensions (Slowinski et al., 1957; Massoudi and King, 1974; Chow et al., 2018; Chow et al., 2020), and assuming θ_H and θ_M are approximately equal (for water-wet conditions), the ratio $\frac{h_H}{h_M}$ is greater than one at typical reservoir conditions (see also Hassanpouryouzband et al., 2021). Thus, the seal for a gas field that has retained a certain vertical column of methane will retain at least as large a vertical column of hydrogen. This is important for UHS in depleted gas fields, since the height of the column of hydrogen will not exceed the original gas column (due to the spill points of the structure), and so the stored hydrogen will be contained.

MIXING IN DEPLETED HYDROCARBON RESERVOIRS

Better understanding is needed of the potential for contamination of the stored hydrogen by residual hydrocarbons. This contamination will depend on the extent of mixing processes in the depleted field, and the possible exchange with the hydrocarbon phases. The degree of mixing will then affect the proportion of cushion gas that will be required, and the need for gas purification on withdrawal, both of which feed into the techno-economics of suitability for storage sites.

A useful analogue is found in studies which considers using an inert gas (often nitrogen) to act as part of the cushion gas in a UGS field, and this has been studied in field examples in France and Denmark (Laille et al., 1986; Laille et al., 1988; Labaune and Knudsen, 1987; de Moegen and Giouse, 1989; Carriere et al., 1985). Theoretical studies have also examined the option in other settings (Sonier et al., 1993; Lebon et al., 1998; Kilinçer and Gümrah, 2000; Turta et al., 2007; Kim et al, 2015; Davarpanah et al., 2019; Namdar et al, 2019a and 2019b). The inert gas is denser than the natural gas. Factors that were found to be favourable to the use of inert gas as base gas were (Misra et al., 1988): the presence of structural closure, or an isolated area away from the injection/withdrawal (I/W) wells, the absence of large-scale heterogeneity and the absence of natural fractures. These requirements also favour thin reservoirs with an edge water drive, where a significant part of the reservoir volume is on the flank of the structure and some distance from the I/W wells.

The literature on the use of a base gas in UGS can be applied to the case of UHS: instead of injecting an inert gas as a part of the cushion gas, with the natural gas then being injected and withdrawn for storage, now consider the residual natural gas in the reservoir as comprising some of the base gas, and hydrogen is injected and withdrawn for storage purposes. For UHS, the residual natural gas that forms part of the cushion gas is about 8 times denser than the hydrogen injected on top of it. With careful site selection, it is then possible to minimise the mixing between the injected hydrogen and the cushion gas.

Depleted oil fields are used for UGS (e.g. Guo et al., 2006; Yanze et al., 2009; Coffin and Lebas, 2008), but in a more complex manner than depleted gas fields. In general oil field operation, the re-injection of produced gas from another part of the field (perhaps enriched by ethane and propane) may be used to improve oil recovery as part of a miscible injection strategy. Here the gas both dissolves into the oil phase (altering the viscosity) and displaces it (e.g. Brodie et al., 2012; Snow et al., 2014). When UGS is carried out in such a field, there can be issues around production of additional impurities (e.g. Coffin and Lebas, 2009).

There is not any published experience on using depleted oil fields for UHS but based on the comparison with UGS there are several mechanisms which would need to be examined. Solution gas could ‘flash’ from the oil phase into the hydrogen phase at the front, alongside the potential for mixing with residual gas. Hydrogen is soluble in liquid hydrocarbons (this is a key element of the ‘cracking’ process done in refineries at high temperatures), so there would be greater losses there than in residual water, where the solubility is much lower. Microbial interaction with the stored hydrogen is also possible (especially given the availability of carbon sources), with end-products including methane and hydrogen sulphide. Depending on the location and design of the injection wells relative to oil production wells, and the amount of cushion gas needed, it should be possible to keep the contaminants in the stored hydrogen to a low level, although gas separation is likely to be needed, with associated costs.

SUBSURFACE MICROBIAL PROCESSES

Microbial activity is limited by the depletion of essential inorganic nutrients (such as phosphorus and nitrogen), and the availability of suitable electron acceptors such as nitrate, ferric iron, manganese, sulphate and carbon dioxide. The threshold concentration of hydrogen for oxidation depends on the redox potential of the electron acceptor (Cord-Ruwisch et al., 1988; Lovley and Goodwin, 1988).

The reduction of sulphate ions (or elemental sulphur) is a serious issue for UHS or UGS, because it results in the formation of hydrogen sulphide. This gas is toxic to humans, affects gas quality, and may lead to corrosion of steel in wellbore materials or surface equipment (DBI, 2017). It can also react with ferrous iron to precipitate iron sulphide, which can clog equipment. Sulphate-reducing microbes (SRM), both bacteria and archaea (SRB/SRA), are present in many subsurface environments (Gregory et al., 2019). The implications of this for UHS are scoped out by Thaysen et al. (2021) and Groenenberg et al. (2020).

Another important microbial process is methanogenesis, in which species of Archaea combine hydrogen with carbon dioxide to produce methane. Alternatively, there are acetogenic bacteria that combine hydrogen and carbon dioxide to produce acetate (acetogenesis). The acetate can also be subsequently transformed into methane by microbial processes. Although sulphate reduction is energetically favoured over methanogenesis (Colman et al., 2017; Gniese et al., 2014; Gregory et al., 2019), the amount of activity depends on the availability of sulphate (either in the formation water or in the reservoir mineralogy). Lovley and Klug (1986) show that in freshwater sediments, sulphate reduction is favoured for sulphate concentrations above 30 µM. When sulphate concentrations are not limiting, then SRM reduce the hydrogen concentration low enough that methanogenesis is not favoured. Methanogenesis can be detrimental to gas quality (in that the conversion of hydrogen into methane can reduce the stored energy). However, some recent projects are focusing on the storage of hydrogen and carbon dioxide and aiming for methanogenesis to convert the hydrogen into methane (Strobel et al., 2020).

Microbial processes in UHS can potentially lead to alteration of rock properties (Dopffel et al., 2021; Eddaoui et al., 2021), either through the formation of biofilms, or the net dissolution or precipitation of minerals. These changes could then impact the porosity and permeability of the reservoir or caprock, the geomechanical properties and fluid-rock interactions such as wettability.

Modelling of microbial interactions with hydrogen is at an early stage, with the development of simplified models that incorporate the key underlying biology and chemistry. The interactions of microbes with injected hydrogen in a porous medium has been modelled in two ways. The first is a pore-scale model, in which the water-solid and water-gas interfaces are explicitly represented, the motion of water and gas depends on hydrodynamics (Stokes flow), and the transport of microbes, chemical species or gas components is by a combination of advection and diffusion (Ebigbo et al., 2013). The second way is an effective porous medium model (at the level of Darcy flow) with multi-phase flow represented by phase saturations, relative permeability and capillary pressure curves and pressure distributions, and there is transport of concentration distributions of microbes or components (Panfilov et al., 2006; Panfilov, 2010; Panfilov et al., 2012; Toleukhanov et al., 2015a; Toleukhanov et al., 2015b; Panfilov et al., 2016; Hagemann et al., 2016b). The choice of kinetic growth functions, and the parameter values for these models, influences the qualitative behaviour observed (Panfilov et al., 2016; Hagemann et al., 2016b). Pore-clogging and permeability reduction from bio-films has also been modelled (Eddaoui et al., 2021). At this stage the models are mainly qualitative and are yet to be tested thoroughly either in the laboratory or the field.

NATURAL ANALOGUES

There are natural subsurface environments with elevated levels of hydrogen (Zgonnik, 2020), and microbial communities in some of these locations have been studied. There are communities dominated by methanogens in hydrothermal fluids at Lidy Hot Spring (Idaho, USA), where geothermal hydrogen is the primary energy source (Chapelle et al., 2002). In Kansas (USA) the discovery of hydrogen-rich gas was attributed to a combination of deep, crustal sources, and reactions with the tubing in the well (Guélard et al., 2017). There are other examples beneath the Central Indian Ocean Ridge, in deep basaltic aquifers and in marine sediments (see Gregory et al. (2019) for references). Methanogenesis tends to increase at lower salinities. There is a hydrogen-rich gas seep at Chimaera in Turkey, which shows evidence of microbial methanogenesis and subordinate sulphate reduction (Gregory et al., 2019).

The discovery of large natural hydrogen accumulations (e.g. Prinzhofer et al., 2018) is also evidence for the ability of seals to retain hydrogen for significant time periods. Commercial exploration for these occurrences is in its early stages, and there has been characterisation work on hydrogen-rich seeps (Prinzhofer et al., 2019; Moretti et al., 2021a). Such seeps also give insights into the transport of hydrogen in the near-surface, which could be important for monitoring and detection of potential leaks from UHS facilities e.g. the occurrence of ‘fairy circles’ (Larin et al., 2015; Myagkiy et al., 2020; Moretti et al., 2021b).

FIELD EXAMPLES OF MICROBIAL EFFECTS FROM UHS AND UGS

The underground storage of town gas has provided importance field evidence for microbiological effects on stored hydrogen. Analysis of the performance of aquifer storage in Lobodice, Czechoslovakia gave clear evidence of alteration in the composition of the stored gas (Šmigáň et al., 1990), and isotopic analysis indicated that the methane was of biological origin (Buzek et al., 1994). The presence of a large source of carbon (through the injected carbon dioxide and carbon monoxide) allowed the microbial conversion of a large amount of hydrogen into methane. For pure hydrogen storage, or hydrogen mixed with natural gas, the process is limited by the supply of carbon from other sources, such as carbonates present in the reservoir mineralogy. The microbial conversion is sensitive to temperature and salinity, and the species in this field example were inactive at higher temperatures and therefore greater depths. At another town gas storage site in the Paris Basin, hydrogen storage has been found to induce long-lasting changes on microbial communities (Ranchou-Peyruse et al., 2019).

A recent field trial of UHS has been conducted by the Austrian gas company RAG in a depleted gas field in the Molasse sub-basin (Underground Sun Storage, 2017), injecting 1.22 million N m^3 of a mixture of 9.4 mole % hydrogen and 90.6 mole % natural gas. In mass terms, these equate to 750 t of natural gas and 10 t of hydrogen. Tests of microbiological effects on cores in the presence of hydrogen mixtures showed there was a shift in the consortium of microbes over the test to favour methanogenic Archaea. After three months of injection, there was a three-month shut-in period, and then the gas was back produced. The amount of back production was 1.24 million N m^3 including 0.094549 million N m^3 hydrogen which is 82% of the injected amount of hydrogen. The back-production curve indicates decreasing hydrogen concentration over time. There was a small proportion of carbon dioxide in the injected gas, which similarly shows a decreasing concentration in the back-production curve.

The loss of some proportion of the injected hydrogen in the RAG field experiment is most likely due to diffusion and hydrodynamic dispersion as the injected gas mixture displaces the native gas. Dissolution of the hydrogen in the residual water in the reservoir may also play a role. Although there were sulphate ions in the reservoir water, sulphate minerals, and sulphate-reducing bacteria present, no H_2S was detected in the produced gas. Sampling of formation water during the test shows shifts in the microbial consortium towards a greater proportion of methanogens. There was shift in pH from about 8.7 to 8.0 during storage, but no evidence was found for microbiological pH lowering processes such as homoacetogenesis.

Studies of microbial activity in relation to UGS have mainly focused on the production of hydrogen sulphide by SRM (Ranchou-Peyruse et al., 2017; Kleinitz and Böhling, 2005), and the possibility for SRM to degrade BTEX (Aüllo et al., 2016; Berlendis et al., 2010). In environments with high sulphate concentrations in formation water, SRM dominate methanogens (Basso et al, 2009; Ranchou-Peyruse et al., 2017), whereas with low sulphate concentration, methanogens are favoured (Ivanova et al., 2007a; Ivanova et al., 2007b). Magot et al. (2000) survey the optimum conditions for SRM, with 80-90 C being the maximum temperature for activity, and a range of sensitivities to salinity. These considerations may be important for hydrogen storage, since the combination of a sufficient concentration of sulphate ions and suitable conditions for SRM would result in hydrogen sulphide being formed. A study of the North Stavropol UGS facility (Tarasov et al., 2011a; Tarasov et al., 2011b) showed that when natural gas with low levels of hydrogen is stored underground, along with sufficient carbon dioxide, microbial activity can consume all of the injected hydrogen, producing additional methane but also hydrogen sulphide (if there is sufficient sulphate present in the formation water).

The overall significance of microbial processes for specific UHS sites is still difficult to assess without samples and laboratory testing as a first step. However, the ranges of temperature and salinity within which particular microbial species are active do give a guide to the magnitude of the effects (Groenenberg et al., 2020). Thaysen et al. (2021) have developed criteria to distinguish sites where no microbial activity would be expected e.g. deep locations with temperatures above 122 C, and sites with high salinities (above 4.4 M NaCl).

GEOCHEMICAL EFFECTS

Preliminary experimental and theoretical studies of geochemical reactions of hydrogen with minerals indicate very little alteration on the time-scales relevant for UHS (months to years). However, this is inevitably site-specific, and needs further investigation for typical Australian conditions. Batch experiments have been carried out to assess the reactivity of hydrogen with core samples. In general, these tests have shown limited reactions with hydrogen (Yekta et al., 2018b; Henkel et al., 2014; Flesch et al., 2018), although there is some evidence of changes in permeability with hydrogen-natural gas mixtures (Shi et al., 2020).

Geochemical modelling of interactions with hydrogen has also been undertaken, in part to extend the experimental results (Yekta et al. 2018b; Hassannyebi et al., 2019; Hemme and van Berk, 2018), although there is usually a significant uncertainty around kinetic rates in field settings. Scoping studies have outlined the reactions that can occur between minerals and stored hydrogen (Foh et al., 1979; Thaysen et al., 2021; Groenenberg et al., 2020), such as the formation of pyrrhotite from pyrite, but the quantitative impact again depends on kinetics. Modelling of geochemical changes due to the potential introduction of hydrogen into two Australian UGS facilities (Tubridgi and Mondara) indicates small losses of hydrogen due to reactions (Bo et al., 2021).

Economics of UHS

UHS is expected to be the most cost-effective option when the volumes of hydrogen that need to be accommodated are large. However, cost estimates can vary considerably depending on the type of storage - salt caverns, depleted hydrocarbon reservoirs, aquifers or hard rock caverns, the storage reservoir's size, its location and the utilisation, including the charge/discharge frequency, the stored volume per cycle and the rate of delivery.

CAPITAL COSTS OF UHS

For UHS in salt caverns capital investment is required for solution mining for cavern creation, including brine pipelines and lagoons, and injection/withdrawal borehole(s). Cushion gas to maintain a minimum storage pressure is also considered a capital investment since it remains in the cavern permanently (Taylor et al., 1986; Tarkowski, 2019), though in salt caverns it may be recovered by brine displacement at the end of a discharge cycle (Taylor et al., 1986). Tarkowski (2019) estimated the capital cost structure as 60% gas compressors, 29% solution mining, 6% borehole, 5% cushion gas. ETI (2015) on the other hand reported that the largest cost element in the construction of the cavern is the borehole. For storage in salt caverns no mineralogical or microbiological reactions are expected (Buenger et al., 2016).

The costs to develop a salt cavern for UHS are expected to be much higher than for depleted hydrocarbon reservoirs (Taylor et al., 1986; Crotogino et al. (2010); HyUnder, 2014b) as UHS in aquifers and depleted hydrocarbon reservoirs uses the existing pore volume as storage space. However, aquifers will require extensive characterisation to ascertain hydrogen can be safely contained, the costs of which are difficult to estimate and will vary by site (Lord et al., 2014). A significant consideration in these storage reservoirs is also the cost of cushion gas since the cushion gas requirements are likely to be notably higher than in salt caverns. However, the need for hydrogen cushion gas would be reduced if (some) gas was already present in the form of natural gas. However, Amid et al., (2016) suggested that the presence of natural gas in the reservoir will lead to some mixing of recovered hydrogen with other gas components and this may require an additional process step of purification. In depleted hydrocarbon reservoirs, existing wells are expected to be used for storage, though the integrity of the cement barrier over time needs to be ensured to prevent hydrogen diffusion into the cement (Bai et al., 2014). Austenitic stainless steel may be used to extend the service time of the wellbore (Bai et al., 2014), though this increases the cost of the completion.

For storage in hard rock caverns more costly excavation is necessary to create the required storage volume, including lining of the cavern. There are also higher compressor costs, but the cushion gas cost is less than for depleted gas reservoirs.

OPERATING COSTS OF UHS

Operating costs are the cost of energy and maintenance related to gas compression for storage and possibly boosting the pressure after withdrawal (Amos, 1998), as well as working gas losses estimated at 1-3% per year (Barbir, 2013). The ratio of operating costs to total costs depends on the type and the utilisation of the storage facility (see next section), e.g. for long-term storage operating costs may only constitute a small fraction of the total cost of storage (Oy 1992; Carpetis, 1994; Amos, 1998; Crotogino et al., 2010).

THE EFFECT OF UTILISATION ON UHS ECONOMICS

The cost of UHS is a function of a storage facility's utilisation (Carpetis, 1980), i.e. the charging volume per cycle and the number of charging/discharging cycles over a defined period. Salt and hard rock caverns can undergo multiple cycles per year, while depleted hydrocarbon reservoirs and aquifers are likely limited to one or two cycles each year (Lord et al., 2014; Reddi et al., 2016). The limited number of cycles for porous reservoirs is a consequence of the large storage capacity of these reservoirs and the comparatively low deliverability (Amid et al., 2016). Salt caverns allow flexible operation with high gas injection and withdrawal gradients and frequent turnovers for a comparatively moderate amount of cushion gas (Buenger et al., 2016). Due to the ability to undergo multiple cycles per year, salt caverns have significantly higher cumulative hydrogen throughput than depleted gas fields when fully utilised (Taylor et al., 1986). As a result, they have a lower unit cost, or specific cost, of H_2 stored (Taylor et al., 1986; Crotogino et al. (2010); HyUnder, 2014b). However, when the throughput is the same, the specific storage cost for salt caverns exceeds that for depleted gas fields due to the higher initial capital outlay (Lord et al., 2014). The utilisation of a storage site can be captured by the static and dynamic storage cost (HyUnder, 2014b – compare Table 1); the static cost only accounts for one cycle while the dynamic cost considers full utilisation (i.e., multiple cycles). In addition, the rate of delivery also affects storage costs (ETI, 2015; Bai et al., 2014).

COST ESTIMATES FOR UHS

Cost estimates for underground hydrogen storage can vary widely based on the type of the storage reservoir, its size, location and utilisation. To improve comparison between different storage options, the specific cost of storage in \$/kWh or \$/kg H_2 stored are typically used. Table 1 presents a summary of some literature cost estimates for the total specific cost of UHS. All costs are adapted to 2019 US\$ for comparison (not accounting for technological advancement). It must be noted that individual components included in the cost estimates are often not apparent and these affect the validity of the comparison. Table 1 highlights significant variations in the total specific cost estimates for UHS, which can be a result of the underlying cost assumptions, the project components that are included in the analysis, the assumed utilisation of the facility, as well as the time span between assessments and the associated changes in technology. Therefore, the costs presented here must be treated with great care and the original assumptions need to be assessed before applying these estimates elsewhere to determine UHS costs. For example, Lord et al. (2014) model the same throughput for storage in depleted hydrocarbon reservoirs and salt caverns and thus arrive at a higher specific storage cost for salt caverns than for depleted reservoirs (compare **Error! Reference source not found.**Table 1). By comparison, HyUnder (2014b) highlight the effect of storage utilisation by comparing storage cost for one cycle (static storage cost) to storage cost under full utilisation (dynamic storage cost).

Still, despite the above-mentioned uncertainties, Table 1 highlights the decrease in specific cost over the years for the different storage options driven by technological learnings.

Table 1: Total specific cost of hydrogen storage, including both capital investment and operating and maintenance expenses, for different storage options in chronological order (with most recent cost estimates first) in 2019 US$

Storage option	Total specific cost, US$/kg H_2	Total specific cost, US$/kWh	Reference
Depleted oil and gas reservoir	1.42	0.043	Lord et al., 2014
Depleted gas wells	4.02	0.121	Taylor et al., 1986
Aquifer	1.49	0.045	Lord et al., 2014
Hard rock cavern	0.36	0.011	Ahluwalia et al., 2019
Hard rock cavern	3.20	0.096	Lord et al., 2014
Salt cavern	0.14	0.004	Bruce et al., 2018
Salt cavern	0.21	0.006	Ahluwalia et al., 2019
Salt cavern	1.71	0.069	Lepszy et al., 2017
Salt cavern	1.86	0.056	Lord et al., 2014
Salt cavern, static storage cost	2.31	0.069	HyUnder, 2014b
Salt cavern, dynamic storage cost	0.38	0.011	HyUnder, 2014b
Salt cavern for load levelling	4.04-14.08	0.12-0.43	Crotogino et al., 2010
Salt cavern for long term storage	3.64-12.95	0.11-0.39	Crotogino et al., 2010
Salt cavern	14.03	0.421	Amos, 1998
Salt cavern	1.56	0.047	Taylor et al., 1986

THE SIGNIFICANCE OF UHS COSTS IN THE HYDROGEN VALUE CHAIN

The cost of UHS may only constitute a comparatively small fraction of the whole hydrogen value chain. This is demonstrated in the analysis presented by Schoenung (2011), which highlights that the cost of UHS in a hydrogen energy storage system consisting of electrolyser, bulk storage subsystem and fuel cell for power generation contributes only a very small fraction to the total cost of the hydrogen system. HyUnder (2014a) also found that electrolysis dominates the total specific hydrogen plant-to-gate costs of an integrated hydrogen storage facility with a share of over

80%. The same observation was made by Le Duigou et al. (2017), who noted that salt cavern development is a significant upfront investment but a comparatively small contribution to the total specific hydrogen cost. Similarly, Bruce et al. (2020) estimate the cost of the most effective hydrogen storage option to add around 0.14 US$/kg, while the cost of hydrogen production via electrolysis range from 3.4 – 5.2 US$/kg based on 2018 technology (Bruce et al., 2018). Even with the forecasted reduction in production cost down to 1.6 – 2.2 US$/kg (Bruce et al., 2018), their storage cost estimate would only represent a small fraction of the total cost of hydrogen.

Assessment methodology

To address the challenge of estimating storage capacity for UHS, a methodology was developed, based on previous experience with capacity estimation for CCS, and assessment of underground gas storage. As will be seen below, the methodology depends on the quality and availability of data, and the need for consistency across fields. A comparable approach is seen in the recent UK study of Mouli-Castillo et al. (2021), focussing on gas fields, which uses both the original gas in place (OGIP) and the recoverable gas to estimate hydrogen storage capacity.

The assessment of the capacity for UHS can be compared to the equivalent problem of estimating storage capacity for CCS. Allinson et al. (2014) proposed a CO_2 Storage Capacity Management System, based on the SPE's Petroleum Resource Management System. The distinction is then made into prospective storage capacity, contingent storage capacity, and commercial storage capacity. This system can be adapted for UHS. For example, prospective storage capacity is "that storage capacity estimated, as of a given date, to be potentially available in unverified sub-surface formations to future development projects. Prospective Storage Capacity has both an associated chance of discovery and a chance of development." (Allinson et al., 2014). This definition, applied directly to hydrogen instead of carbon dioxide, is the focus of the current basin-scale assessment for UHS. Contingent storage capacity is the categorisation of sites with a more detailed assessment of the sub-surface formations, but which are not mature enough for commercial development. Commercial storage capacity depends on the further assessment of techno-economic factors which are also beyond the scope of the current report.

The key aim of this report is to estimate the magnitude of the prospective storage capacity across Australia on a basin scale. As is seen below, this requires the use of available data at the field level, but it is important to emphasise that the capacity estimates at this level are necessarily very approximate. To go beyond this to more refined capacity estimates (contingent or commercial storage capacity) would require a large amount of field-specific data, much of which is held by operators and is not publicly accessible.

For the first-order assessment of UHS storage in Australia, storage suitability was evaluated using qualitative levels (suitable, possibly suitable, unlikely suitable) in each region for the four storage options: salt caverns, depleted gas fields, aquifers, and engineered caverns. Different criteria were used for these four UHS options based on publicly available data.

At this high level, there is a straightforward way to estimate UHS capacity in depleted hydrocarbon fields, as outlined in the following section, but it is less clear how to do equivalent calculations for other storage types. For salt caverns the possible dimensions of a single cavern depend on the nature of the salt deposit, and multiple caverns in an area are clearly possible (with suitable lateral separation due to geomechanical constraints), so the limits are likely to be imposed by geology, land-use and economics. The current assessment of UHS in salt caverns is limited to mapping suitable salt deposits on the basin scale.

The assessment of UHS in aquifers begins by considering the depth and thickness of aquifer (reservoir)/aquitard (seal) pairs, and potential conflict with other subsurface resources, specifically potable groundwater. In some regions, aquifers have been previously assessed more locally with respect to their CO_2 geological storage potential, including first-order capacity estimates. Unlike CO_2 geological storage, UHS in aquifers depends on finding structures that will trap the injected hydrogen and allow it to be withdrawn, so the capacity for UHS in aquifers at a basin scale will only be a small fraction of the CO_2 storage capacity in the same basin. In the UK, Scafidi et al. (2021) considered aquifer storage in the offshore continental shelf, using an existing database for CO_2 storage which already identified structures. In the Australian context there is not a similar database, and UHS capacity estimates in aquifers, while certainly large, would also be very uncertain.

Engineered hard rock caverns are still at an early stage of technological development for hydrogen storage, and it is not yet clear what pressures could be sustained in such caverns. However, it may present the only subsurface storage option if storage is required in close vicinity to renewable hydrogen sources in parts of Australia where storage potential in sedimentary basins is lacking. The detailed assessment of the suitability of abandoned or newly created mines for UHS was beyond the scope of this study, largely because this option is currently not being used and it relies on the lining of shafts for which the material requirements are still a matter of research. Therefore, the lining of existing mines and potential for creating new mine shafts for UHS are discussed in general terms in areas where storage in porous formations is not feasible.

DEPLETED HYDROCARBON RESERVOIRS

The assessment of UHS in petroleum fields is purely based on capacity (from reservoir volumetrics) and injectivity/producibility (from reservoir characteristics) if the geological and operational data is available. Further considerations include the costs and accessibility of onshore versus offshore fields, as well as potentially higher contamination issues in oil reservoir versus gas reservoirs.

Then the hydrogen capacity C_H in mass units for a specific field is:

$$C_H = V_C * \rho_{H2}$$

where V_C is the volumetric capacity (the available pore volume at subsurface conditions) and ρ_{H2} is the hydrogen density computed at the subsurface conditions.

Typical properties of natural gas are an energy content of 38.61 MJ/m^3 at ‘normal pressure and temperature’ (NTP). In the Australian gas industry this is generally chosen as 15 C and 0.101325 MPa, but in other contexts the pressure can be 0.1 MPa, and the temperature up to 20 C. The relative density (relative to air at NTP) is 0.59, which implies an average molecular weight of 17.1 g/mol (compared to 16.04 for pure methane). This gives an absolute density of 0.723 kg/m^3 at NTP, and an energy density of 53.4 MJ/kg. The equivalent properties for pure hydrogen are 10.6 MJ/m^3 at NTP, molecular weight 2.015 g/mol and a density of 0.0852 kg/m^3, giving an energy density of 124 MJ/kg. The analyses of subsurface gas densities given above shows that the ratio of methane density to hydrogen density varies in the range 8-10 between the surface and 5km depth. Since the ratio of natural gas density to hydrogen density is approximately constant with depth, this will also be true for replacement of subsurface volumes of natural gas by hydrogen. The energy value of the equivalent reservoir volume of hydrogen is then 0.27 times the natural gas energy value, which comes from the ratio of energy densities in MJ/m^3, so 10.6/39=0.27.

From the above values, volumetric gas reserve estimates (assuming pure methane) for each field were converted to prospective hydrogen energy values according to:

E_{H2} (PJ) = 0.27 * E_{CH4} = * 0.27* V_{CH4} (m^3) * 0.0732 kg/m^3 * 53.4*10^{-9} PJ/kg

where V_{CH4} is the volume of produced gas and remaining gas reserves, and prospective UHS capacity according to:

M_{H2} (kt) =2.2 kt/PJ * E_{CH4} (PJ)

These prospective volumes for hydrogen storage do not consider the amount of that total volume that is working gas (i.e., available for withdrawal), since that proportion depends on both site-specific and operation factors and can range from 25 to 85 % (Flanagan, 1995; Amid et al., 2016; Namdar et al, 2019b). As discussed above, some of the cushion gas could be residual hydrocarbons, or even a cheaper inert gas such as nitrogen, which would reduce the costs of storage without changing the amount of working gas. Mouli-Castillo et al. (2021), in looking at the storage capacity for hydrogen in UK depleted gas fields, assume no more than 50% of the available volume is working gas.

Since the Australia-wide prospective hydrogen storage capacity in depleted gas fields is estimated below to be nearly two orders of magnitude greater than the anticipated demand, the discount for working gas capacity does not affect the overall conclusion that there is far more prospective storage than required. This conclusion also holds true at the level of the regions considered. However, for future site-specific assessments the proportion of working gas will be an important factor in the techno-economics.

Australian energy landscape

Australian energy production consists of the extraction of fossil fuels (coal and petroleum) and renewable energy generation, which reached a total of 19,700 PJ annually in 2018-19. In that period, approximately 15,900 PJ were exported in the form of fossil fuels or refined products, and domestic energy consumption totalled 6,200 PJ, with the difference covered by energy imports (Department of Industry, Science, Energy and Resources, 2020). Transport and electricity supply contributed 28% (1,750 PJ) and 26% (1,600 PJ) of the energy consumption, respectively. The contribution of renewables to electricity ranges widely between states, from 94% in Tasmania to 4% in the Northern Territory.

Independent from the fuel type, energy storage requirements will be different for domestic energy requirements (electricity market, domestic gas, industry, transport) compared to energy exports. UHS is only one option within the energy storage portfolio and techno-economically most suitable when storage requirements are on the order of 1 GWh to 1 TWh (0.0036-3.6 PJ) (European Commission, 2017). A study by Godfrey et al. (2017) suggests that, for the eastern Australian electricity grid, energy storage requirements for providing adequate energy quantities are relatively low (<5 GWh) until high proportions of renewable energy are reached (105 GWh). Until then, storage requirements are governed largely by the need for system security, i.e. to provide the ability to compensate for the cyclicity of energy production versus demand, and to buffer sudden shocks to the system.

Small-scale household batteries in Australia had a total storage capacity in excess of 1 GWh in 2019 (Clean Energy Council, 2020). The capacity of large-scale batteries co-located with wind and solar projects is on the order of 100 MWh; for example the Hornsdale Power Reserve in South Australia is one of the largest lithium-ion batteries in the world and was expanded in 2020 to 194 MWh at 150 MW. In comparison, Snowy 2.0 (https://www.snowyhydro.com.au/), a pumped-hydro storage project in New South Wales is planned to provide approximately 350,000 MWh of large-scale storage to the NEM (Australian Energy Market Regulator, 2018). Therefore, considering the capacity demands and competing storage options for the domestic electricity market, UHS will only have niche opportunities in this sector in Australia; possibly in regions outside the NEM with conditions that are not favourable to pumped hydro or batteries.

If hydrogen rather than electricity will replace the current domestic gas market, storage requirements will be similar to the existing natural gas storage capacity of 295 PJ (79 TWh). In this case, UHS would be the only suitable storage option because other options would require the inefficient conversion of hydrogen to electricity and back. Based on existing projects, individual storage sites would range in capacity between 0.5 and 23 PJ (0.14-6.4 TWh) (Table 2).

Table 2. Natural gas underground storage facilities in Australia (aemo.com.au/energy-systems/gas/gas-bulletin-board-gbb/data-portal; company websites). The two columns on the right are the equivalent UHS capacity in PJ and kt.

Storage facility	Basin	Depth (m)	Inj. Capacity (TJ/d)	Withdrawal (TJ/d)	Storage capacity (PJ)	UHS capacity	
						(PJ)	(kt)
Ballera (Chookoo)	Eromanga		20	40	11	3	25
Iona	Otway	1300	155	500	23.5	6.3	53
Moomba	Eromanga	2400	110	30-120	85	23	191
Newstead	Bowen-Surat	1450	8	7.5	2.0	0.5	4.4
Roma	Bowen-Surat	1000	105	58	54	15	122
Silver Springs	Bowen-Surat	1900	16	20	46	12	104
Newcastle LNG	Sydney		14	120	1.5	0.4	3.4
Tubridgi	Carnarvon	550	90	60	57	15	128
Mondarra	Perth	2700	70	150	15	4	34

The scale of the current Australian energy export sector (~19,700 PJ) is an order of magnitude larger than the domestic electricity market with respect to energy production, hence will have comparatively higher energy storage capacity demands.

If hydrogen was to become the main export commodity, this hydrogen could come from different sources and production technologies, i.e. from renewables through electrolysis (‘green hydrogen’), natural gas through SMR with CCS (‘blue hydrogen’) or coal through gasification (‘brown hydrogen’). Hydrogen could then be exported as liquified hydrogen or in the form of alternative carriers e.g. ammonia. Energy storage requirements would be based on fluctuations in hydrogen production, conversion, and transport capacity, and could be based either at the production site or at the export location.

The renewable energy industry in Australia has been expanding rapidly in the last decade and will play a significantly increasing role in electricity generation. Current renewable energy sources are largely concentrated in coastal areas, close to the domestic electricity market. However, there are some projects, particularly solar power generation, located in the central and inland parts of Australia. Currently, the renewable energy is produced solely for the domestic market and contributed 21% to Australia’s electricity generation in 2019, including wind (7%), solar (7%) and hydro (5%) (www.energy.gov.au/data/renewables). New projects with the intent of producing hydrogen from renewable resources, largely for export, are also located close to the coast because export would require access to ports and shipping lanes. For example, the Asian Renewable Energy Hub (https://asianrehub.com/) in Western

Australia proposes to generate 26 GW from large-scale wind and solar farms with up to 100 TWh of total annual generation, and of which approximately 85% would be used towards the production of green hydrogen and green ammonia, largely for export.

Australian sedimentary basins are a major source of petroleum production and these resources, at least partially, could be transformed into hydrogen as a new source for domestic energy supply, but also as a major export commodity. Therefore, volumes of remaining resources, particularly of those of natural gas (~250,000 PJ), provide an upper limit estimate of the potential blue hydrogen resource in Australia. Realistically, only a yet to be determined fraction of the available natural gas will be converted to hydrogen.

Aside from being an important export commodity and being used in electricity generation, natural gas is used in various industry processes and in Australian households. Australia has more than 38,000 km of underground gas transmission pipelines which form a major network on the east coast (SA, Queensland, NSW, Victoria and Tasmania) and cover vast distances in Western Australia and the Northern Territory. Some transmission pipelines deliver directly to end users such as manufacturing facilities or electricity generators, while others deliver the gas to an energy distribution company, which supplies gas to retail customers including businesses and households. Energy Networks Australia estimates the total storage capacity of the Australian transmission pipeline system to be on the order of 7,000 TJ (approx. 2,000 GWh).

Natural gas storage provides a helpful analogue for the subsurface storage of hydrogen because relevant reservoir parameters and injection/production processes are very similar. Historically, there is an overlap between the two storage options in the form of town gas storage, and there have been recent field trials of blending of natural gas and hydrogen in porous storage reservoirs in Austria (Hassannayebi et al., 2019) and Argentina (Perez et al., 2016; Dupraz et al., 2018). Existing natural gas storage facilities in Australia could provide suitable reservoirs for hydrogen storage (or methane-hydrogen mixtures), but their operational history can also give an indication of what reservoir properties would be required for anticipated hydrogen storage capacity as well as injection and withdrawal rates (Table 2).

Coal is an important energy source and export commodity for Australia and contributed about 56% to the nation's electricity generation in 2019. Black coal is also used in metallurgical applications, cement manufacturing, alumina refineries, paper manufacture and a range of industrial applications. Black coal resources occur in New South Wales, Queensland, South Australia, Tasmania and Western Australia, the former two states having the largest resources and being the largest coal producers. Brown coal occurs in South Australia, Western Australia, Tasmania, Queensland and Victoria. The Gippsland Basin in Victoria is currently the only region where mining occurs in open-cut mines supplying coal to nearby power stations. Other important brown coal deposits can be found in the Otway Basin (VIC), the

Murray Basin (VIC and SA), the North St Vincents Basin (SA) and the Eucla Basin (WA).

From a hydrogen perspective, coal deposits have the potential to provide a source for brown hydrogen production. For example, the Hydrogen Energy Supply Chain project (HESC, https://hydrogenenergysupplychain.com/) in Victoria involves conversion of brown coal into hydrogen, liquefication and transport via ship to Japan. The carbon dioxide from the conversion process would be geologically stored in deep saline formations in the Gippsland Basin, which is currently assessed by the CarbonNet Project (https://earthresources.vic.gov.au/projects/carbonnet-project).

Table 3 summarises the estimates of UHS capacity requirements in Australia for different areas of application.

Table 3. Estimates of storage capacity requirements in Australia for different hydrogen usage.

Hydrogen usage	Storage capacity requirement in PJ (kt H_2)	
	Australia total	Per project
Stabilisation of electricity network[1]	1.26 – 1.62 (10 – 13)	0.00036 – 1.26 (0.003 – 20)
Security of gas network[2]	~300 (2,420)	0.25 - 25 (2 – 200)
Export[3]	~300 (2,420)	1.25 - 12.5 (10 – 100)
Total	~600 (4840)	

[1]based on AEMO ‘neutral’ scenario requiring 350-450 GWh energy storage by 2040 and 50% conversion efficiency; site storage ranges from 100 MWh (current battery storage at wind/solar farms) to 350 GWh (Snowy 2.0) (Australian Energy Market Regulator, 2018)
[2]based on gas storage capacity in existing UGS facilities in 2020.
[3]assuming 1 week storage of 2019 annual energy export (15,900 PJ) and weekly hydrogen production from large-scale projects of 10 to 100 kt H_2.

UHS options in Australia

Underground storage options for hydrogen and their potential suitability were assessed in five regions of Australia. The investigated storage options include petroleum reservoirs, aquifers and engineered storage reservoirs in salt or in the form of underground mines.

UHS ASSESSMENT IN SOUTHWESTERN AUSTRALIA

In southwestern Australia energy production is widely distributed with industry centres around Perth and Geraldton along the coast and multiple mining projects in the interior (Figure 6). Notably, UHS potential in porous formation (reservoirs and aquifers) is limited to a relatively narrow region that is covered by sedimentary basins along the coast, while the remainder of the area is covered by crystalline basement rocks.

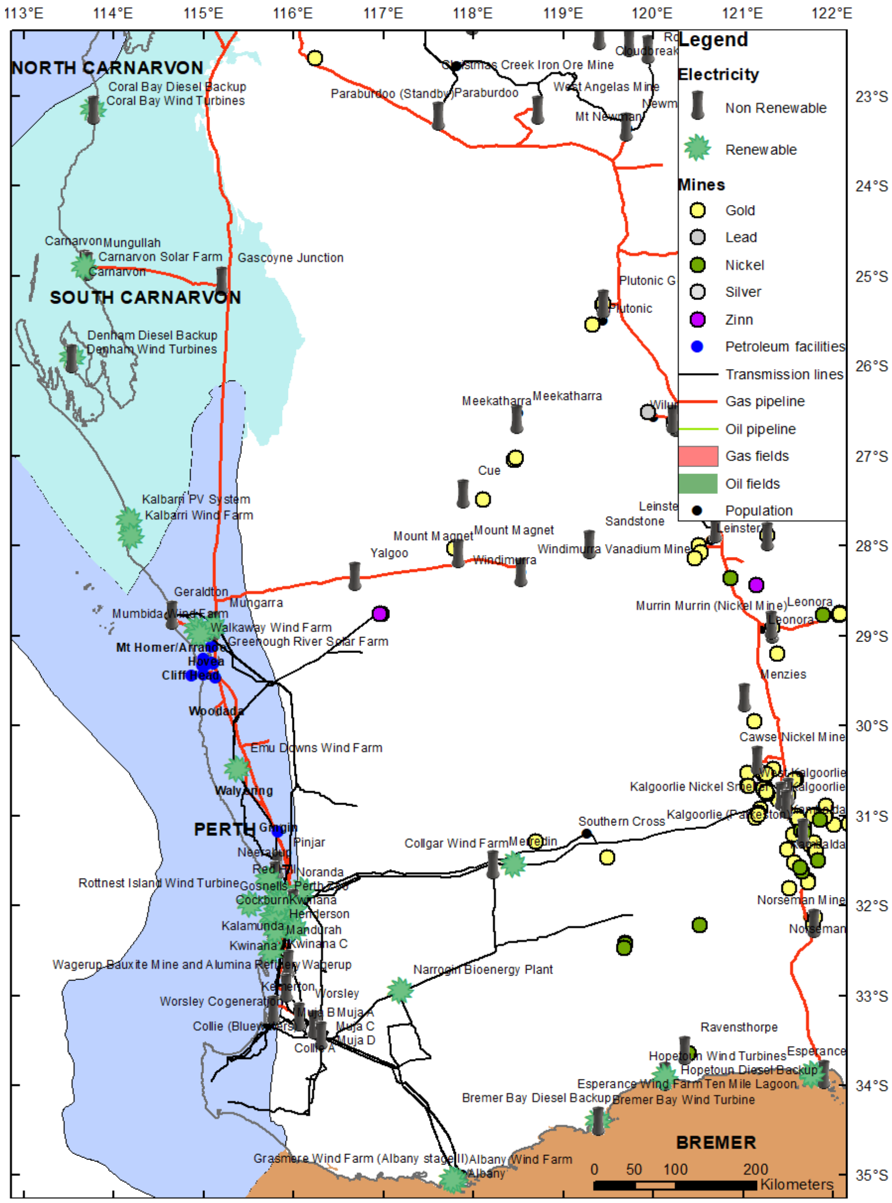

Figure 6. Resource operations and electricity generation in southwestern Australia.

Depleted hydrocarbon reservoirs

Hydrocarbon fields are only found in the northern Perth Basin, mainly containing gas and clustered in the Dongara area (Figure 7). Of note is that the Mondarra gas field was converted into a natural gas storage facility.

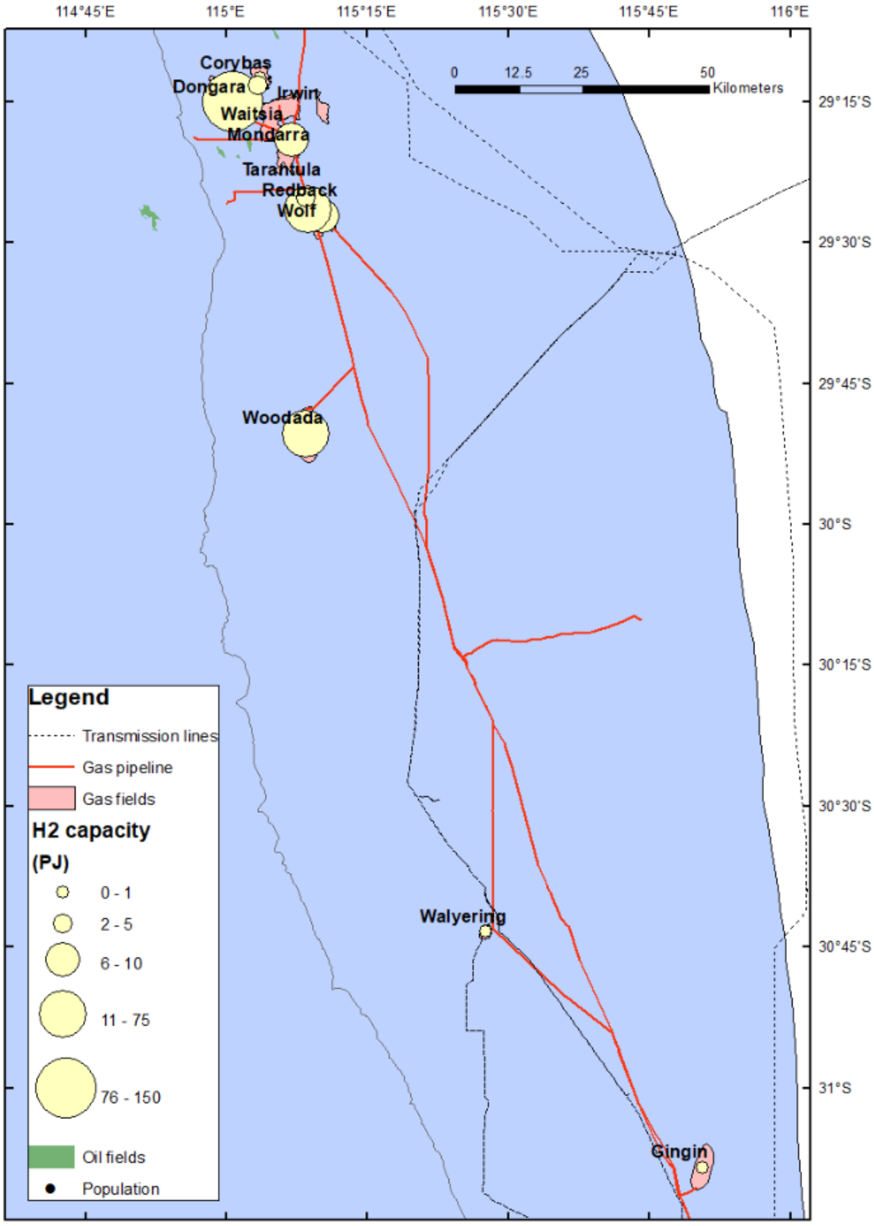

Figure 7. Distribution of oil and gas fields and prospective UHS capacity in gas fields in the northern Perth Basin.

The sandstone reservoirs are found between 1200 m and 4000 m depth, have a relatively small net thickness of less than 40 m and generally low porosity. The exceptions are the larger Dongara, Beharra Springs and Woodada fields. The prospective UHS capacity ranges between less than 0.3 kt and more than 1000 kt with a total prospective storage capacity of 1,600 kt (Figure 7).

Aquifers

The Perth Basin was assessed with respect to its potential for carbon geological storage in saline aquifers by 3D-GEO (2013) and Varma et al. (2013). Although capacity requirements are generally much larger for CO_2 storage, containment and porosity/permeability characteristics of the assessed structures give some indication that they may be suitable for UHS, pending more detailed characterisation. Eight possible storage leads were identified by 3D-GEO (2013) in the entire Perth Basin, which partly overlap with sites assessed in more detail by Varma et al. (2013) in the north Perth Basin.

The Dongara/Yaradino area in the northern part of the basin has the highest overall potential with over 350,000 m^3 (12.6 Tcf) of pore volume in multiple reservoirs. A more detailed prospect analysis of several smaller areas results in a total pore volume of only 8,000 m^3. The area also contains hydrocarbon fields (see above), which reduces the overall uncertainty with respect to containment and reservoir properties but may delay UHS implementation until the depletion of these fields.

Aquifers in the Harvey and Whicher Range areas also have large potential storage capacity at the appropriate depth, however thick contiguous aquitards/sealing units are absent and vertical containment is uncertain. While the two areas in the onshore Carnarvon Basin, Rough Range and South Giralia, are too small to be considered for CO_2 storage, they could be suitable prospects for UHS. The southern Perth Basin contains various aquifer-aquitard (reservoir-seal) configurations that could be suitable for UHS, based on previous hydrogeological and carbon storage assessments.

The main offshore option for UHS in aquifers is the Gage Sandstone, which has also been considered for CO_2 geological storage. Onshore, sandstone aquifers with UHS potential are in the lower Jurassic to Permian sedimentary succession, which have generally brackish to saline water quality and are hydraulically isolated from shallower groundwater resources. However, these deeper aquifers are not penetrated by many wells and data for detailed reservoir characterisation is limited.

Engineered caverns

There is an abundance of underground mines in southern WA (Figure 8) and they occur in areas which are not sedimentary basins, where there is not the option for using depleted reservoirs, aquifers or salt caverns for storage. The only large town associated with the mines, Kalgoorlie, is on the SW electricity grid. There is significant potential for turning renewables into hydrogen in these areas and large local energy requirements for the various mine operations. Small-scale underground storage for hydrogen for mine-related activities is a possible solution in these areas but is subject to significant technical challenges.

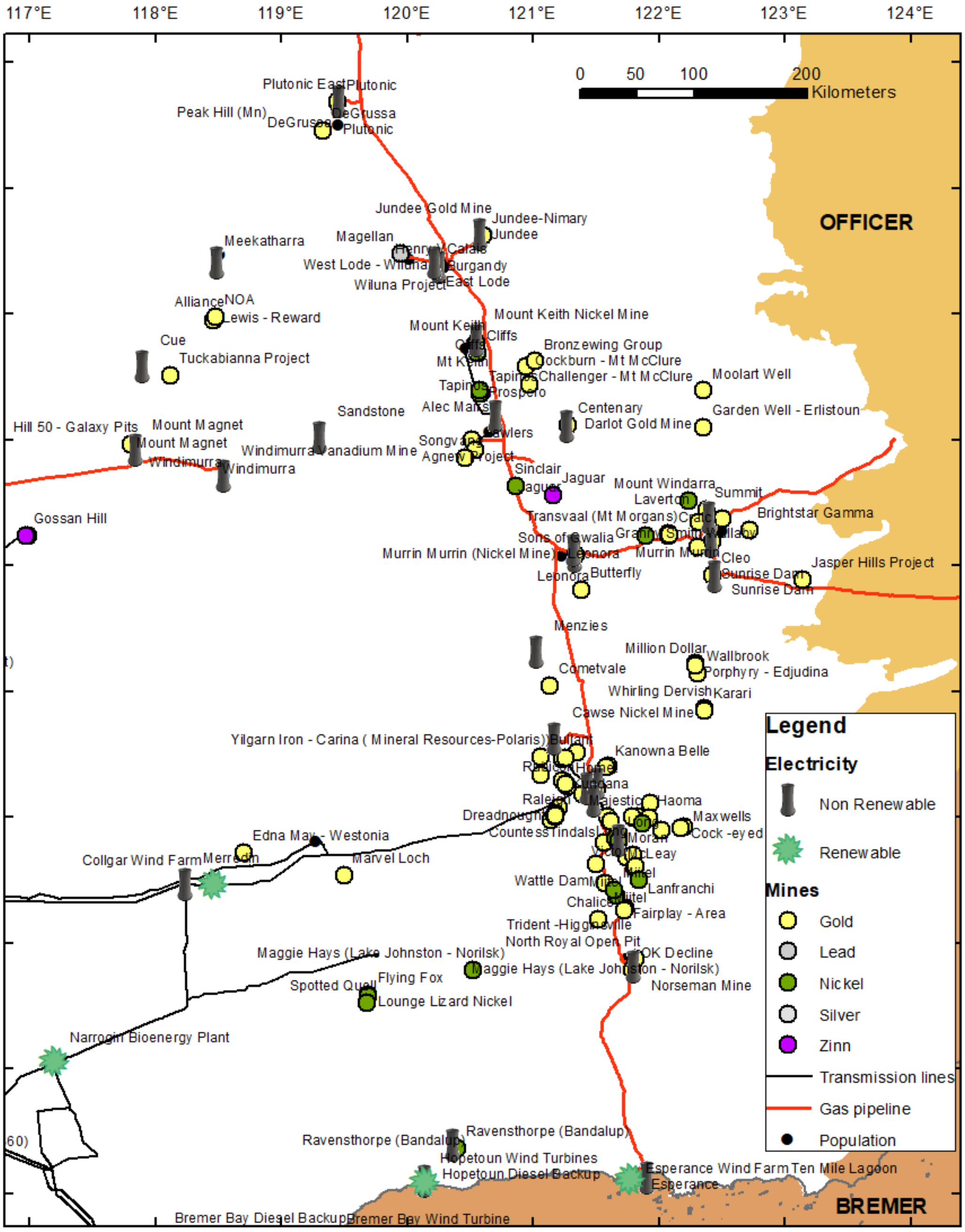

Figure 8. Location of current/recent underground mines in southwestern Western Australia.

UHS ASSESSMENT IN NORTHWEST AUSTRALIA

Northwest Australia is associated with large natural resource projects: oil, natural gas and LNG operations in the largely offshore Carnarvon, Browse and Bonaparte basins, as well as mining operations in the Pilbara region (Figure 9). Although this region has large renewable resource potential, currently energy for domestic use and mining operations is largely covered by natural gas, or even diesel in more remote locations. There is a wide range of prospective UHS options available including the large offshore gas fields of the North Carnarvon and Northwest Shelf basins, aquifers and salt deposits in the onshore Canning Basin, as well as some underground mines in the Pilbara.

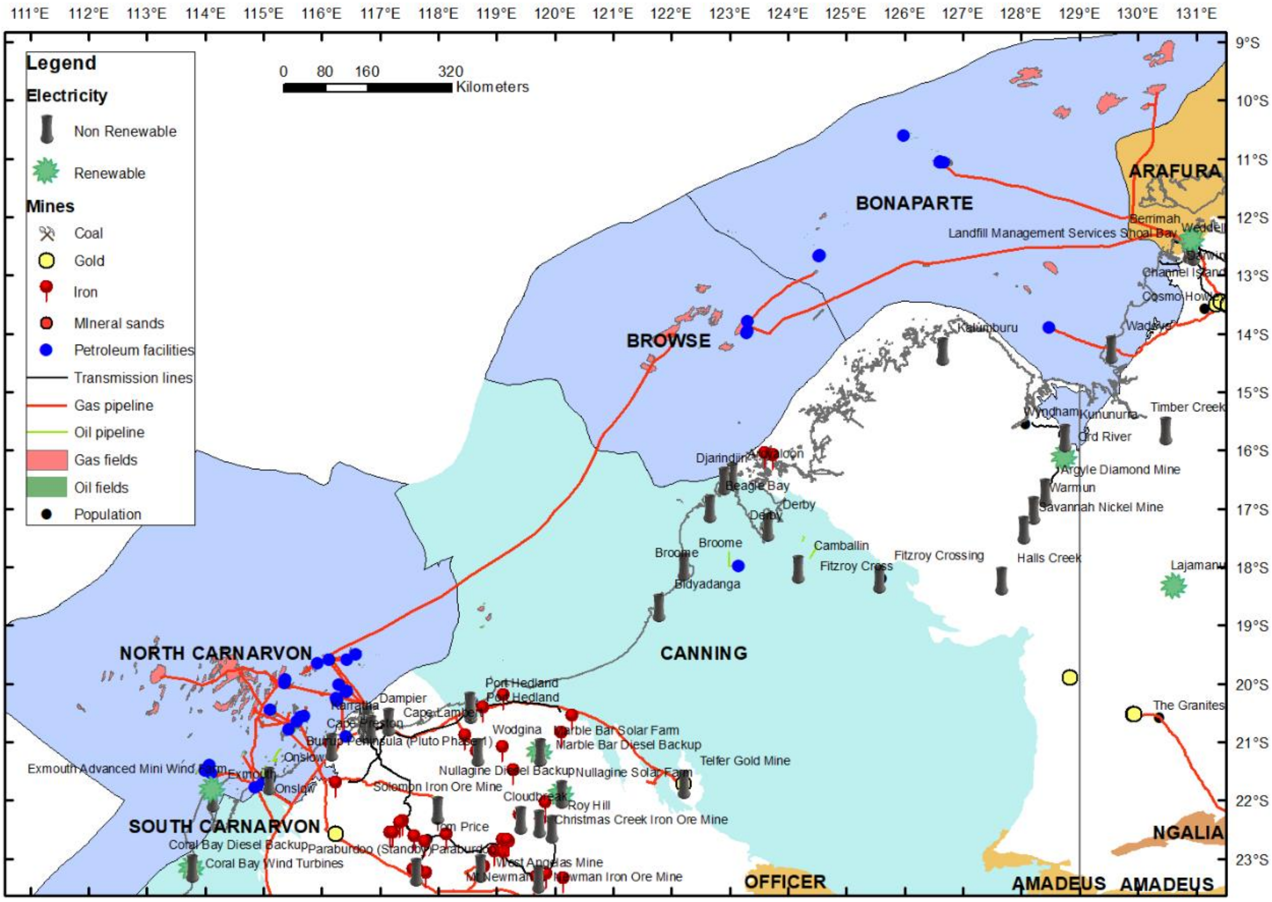

Figure 9. Resource operations and electricity generation in northwest Australia.

Depleted hydrocarbon reservoirs

The North Carnarvon Basin has many hydrocarbon fields, from small oil fields to giant gas fields (Figure 10) in various stages of depletion. Most of these fields lie offshore, apart from Tubridgi, which was converted into a gas storage facility. Otherwise, onshore storage options are restricted to small oil fields (e.g. Ungani, Blina, Boundary, Lloyd, Sundown, West Kora, West Terrace) in the northern Canning Basin between Broome and Fitzroy Crossing , which have not been assessed with respect to their prospective storage capacity. However, these fields confirm the existence of adequate reservoir-seal pairs and the potential for aquifer storage in equivalent stratigraphic units. The prospective UHS capacity in the offshore gas fields ranges widely from less than 100 tonnes to up to 30,000 kilotonnes, with a total prospective storage capacity of 190,000 kilotonnes. It should be noted that only fields for which reserves figures were available were included in the capacity assessment, and there are many fields that are currently ‘stranded’ assets for which reserves figures have not been published.

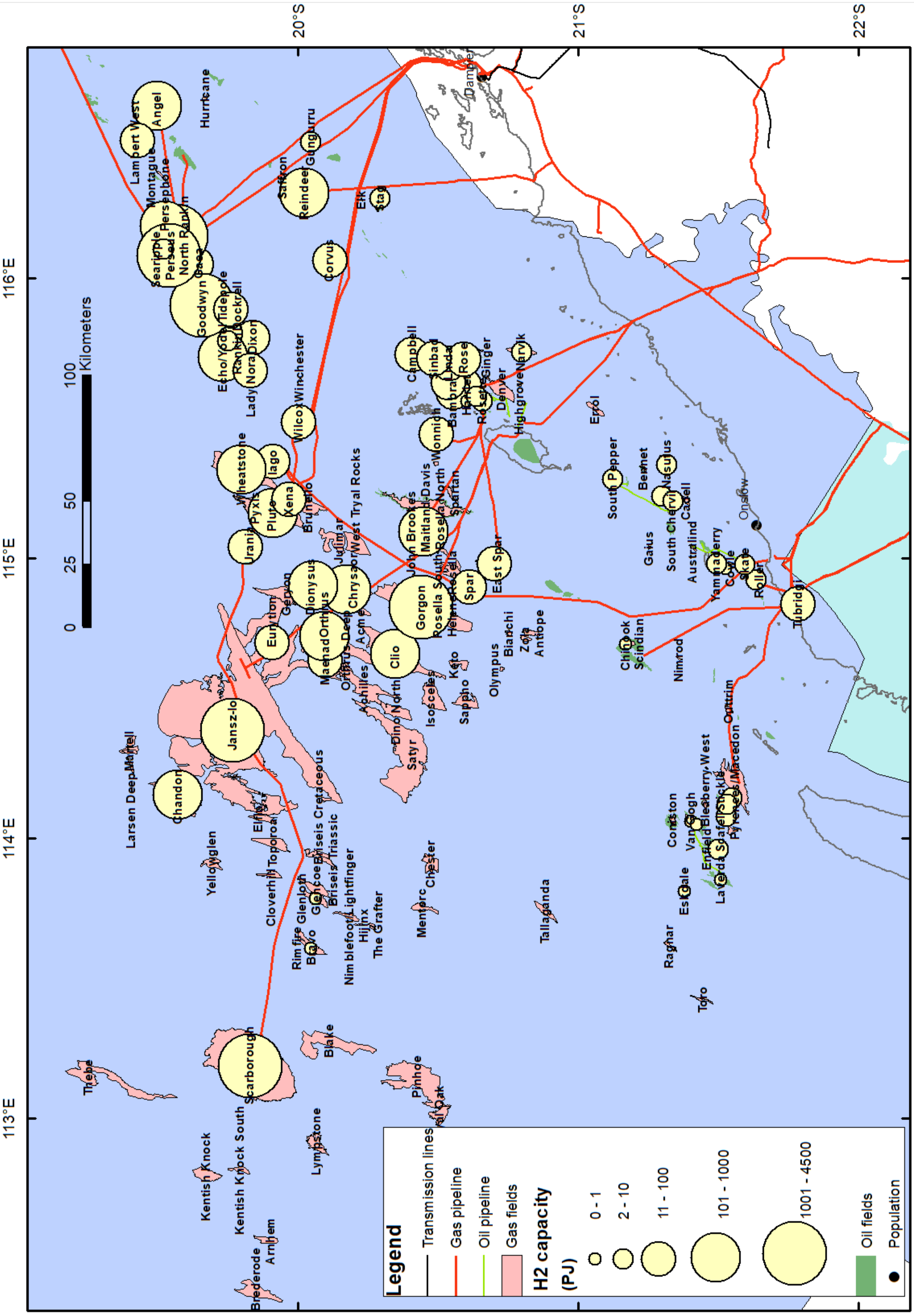

Figure 10. Prospective UHS capacity in gas fields in the Carnarvon Basin.

Although less developed than the North Carnarvon Basin, offshore gas fields in the Browse and Bonaparte basins have a total prospective storage capacity of almost 90,000 kt (Figure 11). These are mostly in giant gas fields that, apart from Bayu-Undan, are in early stages of development and would not be available for storage in the near term. However, these gas accumulations are found in large extensive sandstone units that may provide additional storage potential in laterally connected or underlying aquifers.

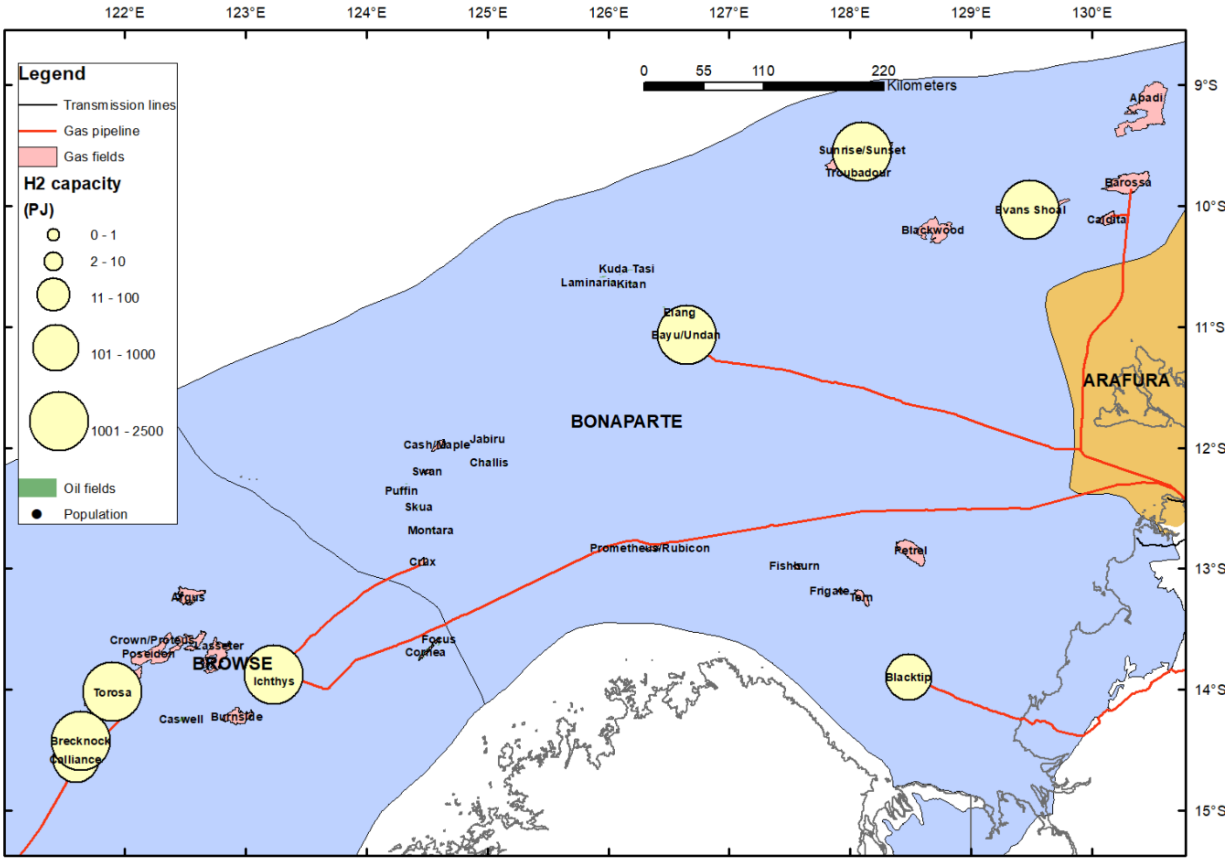

Figure 11. Prospective UHS capacity in gas fields in the Browse and Bonaparte basins.

Aquifers

Onshore options for aquifer storage exist mainly in the Canning Basin. Potential reservoirs are Silurian-Ordovician (Willara Fm), Lower Devonian (Tandalagoo Fm) and Permo-Carboniferous sandstones (Anderson Fm, Reeves Fm, Grant Gp) and seals are formed by Upper Devonian carbonates (Gumhole Fm) and Permian shales (Noonkanbah Fm).

Well-defined closures with large CO_2 storage volumes were identified in the Canning Basin by 3D-GEO (2013). Of these, the Fraser River lead in the Fitzroy Trough was assessed to have the highest storage potential due its relatively simple structure, high reservoir quality, and significant storage volume (3D-GEO, 2013). More detailed studies are needed to confirm to what extent these prospects would also be suitable for UHS.

Offshore options for CO_2 storage in aquifers were previously identified in the Petrel Sub-basin in the Bonaparte Basin. A lower reservoir-seal pair is represented by the Jurassic sandstone of the Plover and Elang formations which are sealed by the Jurassic Frigate Shale. At shallower depth, the Cretaceous Sandpiper Sandstone reservoir is confined by the Cretaceous Bathurst Island Group regional seal. These two aquifers were estimated to have a total effective CO_2 storage capacity of 15.9 Gt (300 Tcf) (Consoli et al., 2014). However, due to the low amount of well data, the regional distribution of reservoir and seal properties in the Petrel Sub-basin is associated with large uncertainties.

Salt caverns

The Ordovician Mallowa Salt has been identified by well intersection and seismic lines covering large parts of the southern and central Canning Basin and is the most voluminous halite formation in Australia (Haines, 2010). The Minjoo Salt is a lower halite-bearing interval in the Carribuddy Group, it is thinner than the Mallowa Salt, and is locally up to 300 m thick in the far south of the Canning Basin. Salt diapirism has also been identified in the Fitzroy Trough, the northern sub-basin of the Canning Basin (Haines, 2010). Patchy seismic coverage and a lack of deep wells means that the morphology of the Mallowa Salt is uncertain in many places, but the formation would appear to have great potential for hosting UHS in salt caverns.

Salt diapirs and salt pillows are common in the southernmost offshore parts of the Bonaparte Basin, particularly the Petrel Sub-basin and have played an important role in the structural and depositional history of the basin. Most salt pillows ceased to grow or collapsed in the earliest Carboniferous due to continued extension and limited salt supply, resulting in the formation of turtle structures in Bonaparte Group sediments. Locally, some of the salt pillows evolved into piercement diapirs, breaking through their sedimentary overburden. The piercement diapirs in the Bonaparte Basin formed preferentially at locations where two basement fault trends intersect, such as the western margin of the Cambridge Trough.

Silurian evaporites have been found in wells in southern part of the Carnarvon Basin, though no significant intersections. Salt due to instability during burial and tectonic events commonly produces highly uneven morphology in the subsurface. As such, it is probably worth examining seismic data in the area to see whether diapir formation has occurred. If suitable diapirs do occur, they would be nearer to the rest of the NW shelf infrastructure than the salt in the Canning Basin.

Engineered caverns

Although large-scale mining occurs in the Pilbara it is predominantly open cut mining, mostly for iron ore. Historically there were many underground mines in the area but there has not been as much recent activity as in areas in the SW of WA. There are however some recently operating (this century) underground mines quite near the Pilbara coast (Figure 12). Given potentially large-scale production of hydrogen sourced from methane in this region then the question is whether the capacity would be enough on its own.

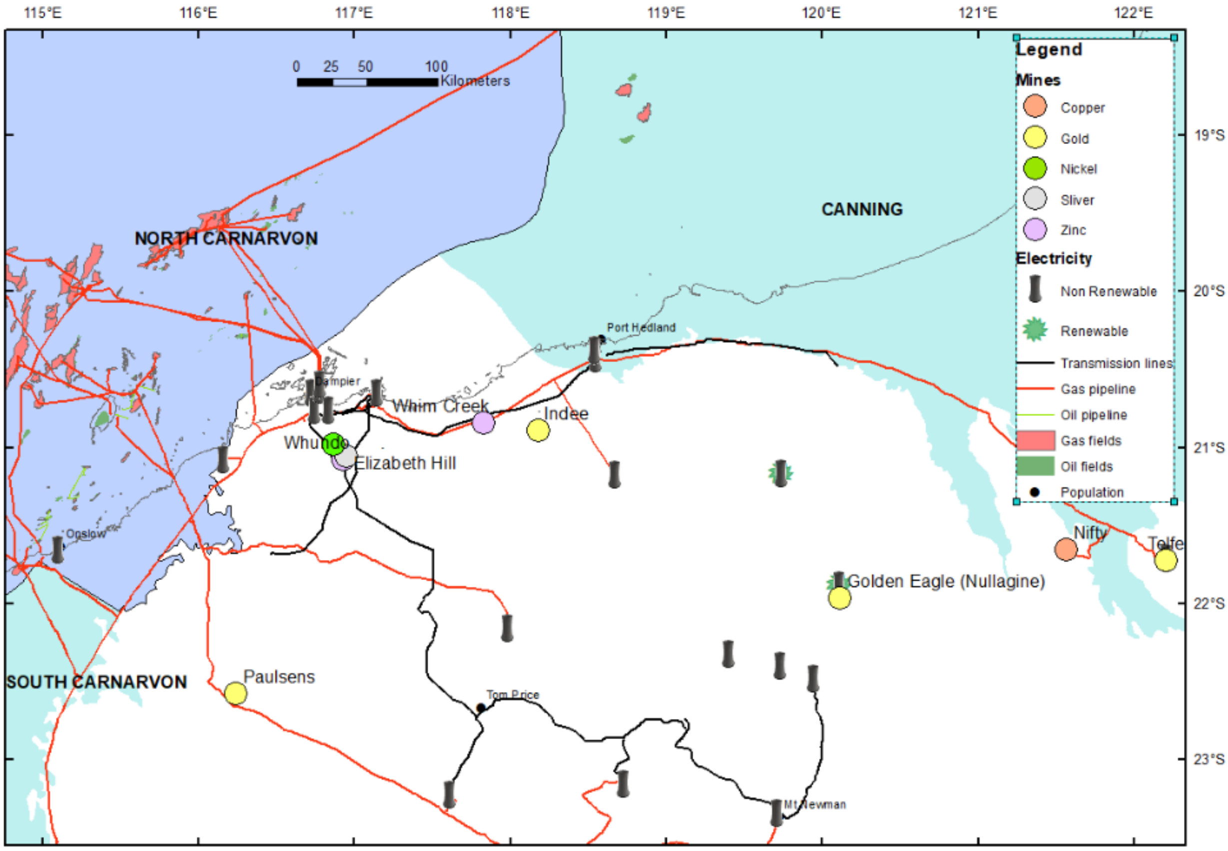

Figure 12. Current/recent underground mines in the Pilbara.

UHS ASSESSMENT IN SOUTHERN AUSTRALIA

Southern Australia has a large resources industry (petroleum, coal, gold mining) and a wide range of electricity generation including renewables (solar, wind, hydro) and fossil fuels (brown coal, natural gas) (Figure 13). Potential UHS options are largely constrained to aquifers or deleted fields in sedimentary basins (Otway and Gippsland) along the coast.

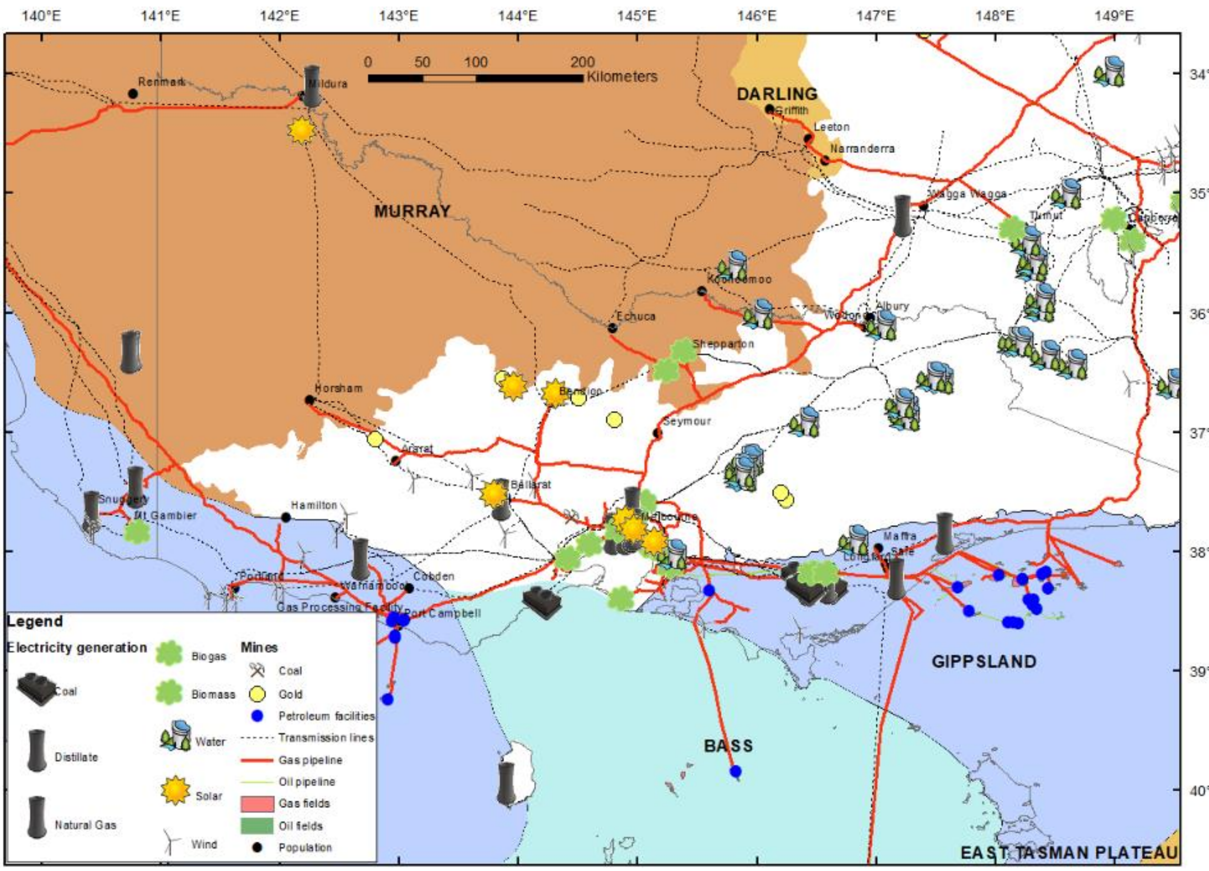

Figure 13. Resource operations and electricity generation in southern Australia.

Depleted hydrocarbon reservoirs

The best storage potential is probably in depleted onshore gas fields in the Otway Basin because these have already been used (e.g. Iona) or have been recently assessed for their potential to store natural gas. As a result, there is comprehensive data available for storage suitability characterisation (Mehin and Kamel, 2002; Bagheri, 2019; Buschkuehle et al., 2019; VicGSV, 2020). The onshore location has also the advantage of having easier and cheaper accessibility.

The prospective storage capacity of individual onshore fields ranges between less than 100 tonnes and 57,000 tonnes, and in offshore fields reaches up to 800,000 tonnes (Figure 14). The total prospective storage capacity is 4 million tonnes.

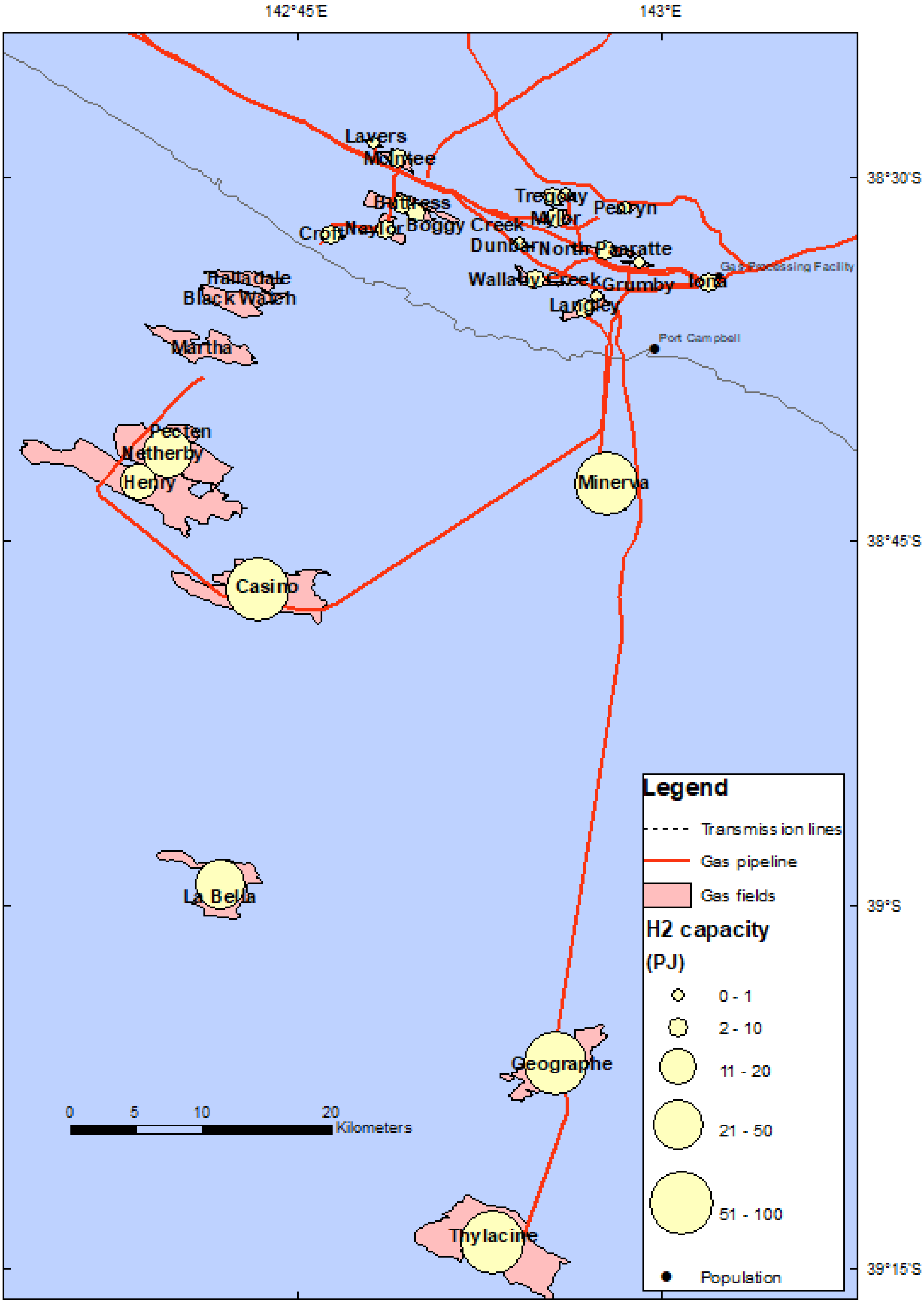

Figure 14. Prospective UHS capacity in gas fields in the Otway Basin.

The prospective UHS capacity in gas fields in the offshore Gippsland Basin is shown in Figure 15. The total prospective UHS capacity is more than 25 million tonnes.

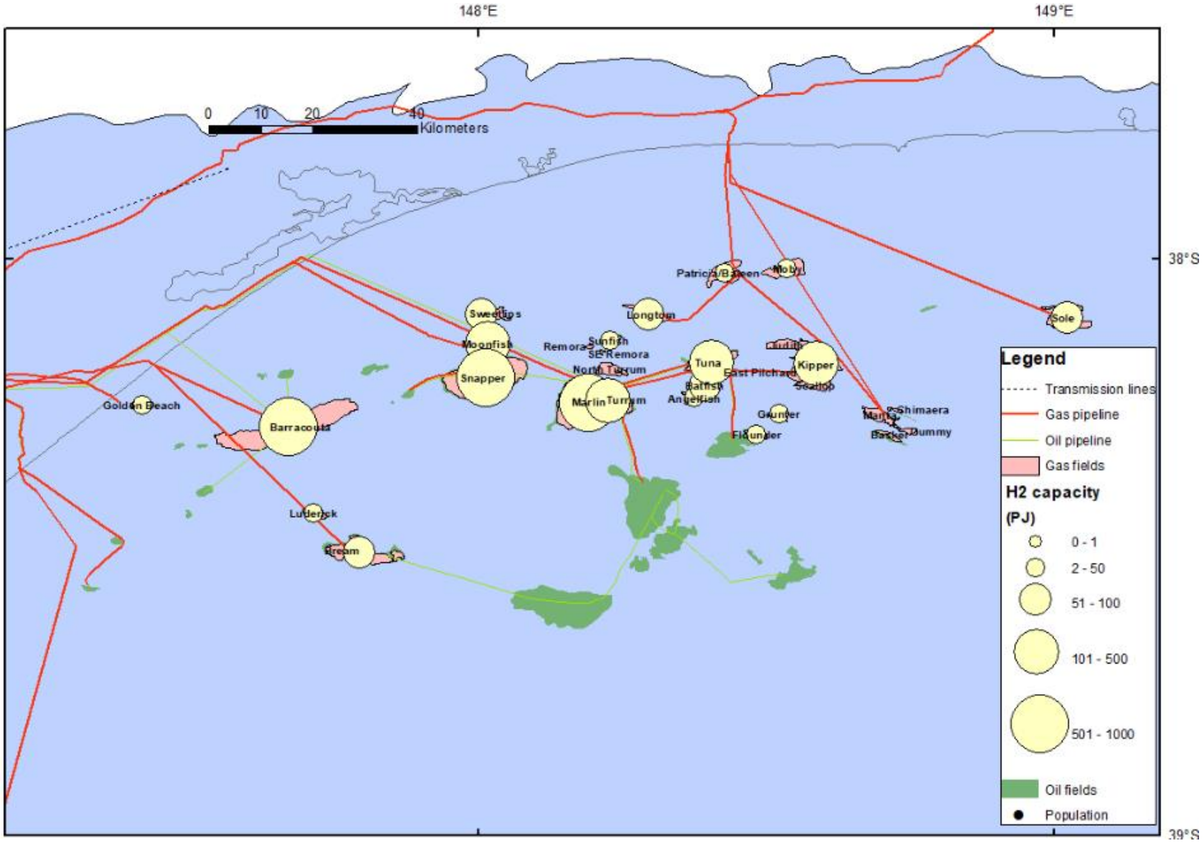

Figure 15. Prospective UHS capacity in gas fields in the Gippsland Basin.

Aquifers

The three sedimentary basins in southern Australia, Gippsland, Otway and Murray, all contain a succession of aquifers and aquitards with different potential UHS suitability. There have been extensive studies on the hydrogeology of the Otway Basin (Torkzaban et al., 2020) and the Gippsland Basin (e.g. Kuttan et al., 1986; Nahm, 2002; Schaeffer, 2008; Varma and Michael, 2012). The high-level suitability assessment of aquifers in southern Australia for UHS is summarised in Table 4: the most prospective storage options are provided by the Permo-Cretaceous and lower Tertiary aquifers in the onshore Otway Basin and the Latrobe aquifer in the offshore Gippsland Basin.

Table 4. UHS suitability in aquifers in Victorian sedimentary basins. Green = likely suitable, yellow = possibly suitable, red = unsuitable.

<table>
<tr><th rowspan="2">Aquifer</th><th rowspan="2">Otway</th><th colspan="2">Gippsland</th><th rowspan="2">Murray</th></tr>
<tr><th>Onshore</th><th>Offshore</th></tr>
<tr><td>Quaternary/U. Tertiary</td><td>Shallow, unconfined</td><td>Shallow, unconfined</td><td>Shallow, unconfined</td><td>Shepperton FM: Shallow, unconfined</td></tr>
<tr><td>U.-M. Tertiary</td><td>Port Campbell Lst: largely inconfined</td><td>Balook Fm, Morwell: good reservoir quality, only local aquitards, no known structural traps</td><td>Cobia Fm, Gippsland Lst.: low reservoir quality, no defined structures</td><td>Murray Gp Lst.:</td></tr>
<tr><td>M.to L. Tertiary</td><td>Clifton Fm. Dilwyn, Pebble Pt, Timboon Sand</td><td>Traralgon Fm: good reservoir quality, only local aquitards, no known structural traps</td><td rowspan="2">Latrobe Gp: good reservoir quality, mapped structural closures & extensive seal</td><td>Renmark Gp: some good reservoir quality, interbedded with local seals</td></tr>
<tr><td>Permo-Cret.</td><td>Paaratte and Waarre formations: good reservoir quality, mapped structural closures & extensive seals/aquitards</td><td>Not present</td><td>Monash FM (?)</td></tr>
</table>

Salt caverns

The Callanna Group megabreccias occur in the northern part of the Neoproterozoic to Cambrian age Adelaide Superbasin. The megabreccias originated in the older portion of the superbasin stratigraphy, they are Tonian (or possibly early Cryogenian) in age concurrent with the salt deposits in the successor basins to the Centralian Superbasin (Amadeus, Officer).

The evaporites have undergone extensive classic salt tectonic deformation forming into wall and diapirs. The Flinders and Willouran ranges of South Australia contain over twenty examples of exposed allochthonous salt sheets and canopies comprising the Callanna Group megabreccias. Bodies of Neoproterozoic (Willouran) Callanna Group megabreccia originally interpreted as products of thrusts and tectonic decollements are now recognised as having been emplaced as salt diapirs.

The modern consensus is that the megabreccias represent altered caprock, i.e. the insoluble remnants of salt diapirs after halite dissolution, of diapirs that grew at or just beneath the ground surface or sea floor during concurrent sedimentation (Rowan et al., 2020) and have subsequently undergone uplift and extensive erosion and dissolution. Not much information exists as to the evaporites' subcrop depth, thickness and composition. If the subsurface salt is composed of megabreccia as in the Blinman-2 core (Telfer, 2013) there is limited potential for cavern creation.

Engineered caverns

In the Victorian case engineered energy storage in pre-existing mine infrastructure is not necessarily a requirement as gold mining areas, predominately in the central/west part of the state, are connected to the electricity grid so theoretically there is no need for energy storage beyond pumped hydro energy storage (PHES) (Figure 16). But there are current challenges regarding the capacity of the electricity and gas networks in those regions to accommodate additional power or hydrogen (Mhanna et al., 2020), so further energy storage options may be desirable. The gold mining areas do however correlate with the areas of Victoria's significant wind renewable capacity (Figure 16) and if the requirement arose for locally storing wind generated hydrogen in these areas underground voids are present. Some mines are present in northern Tasmania but again all these areas are on the electricity grid so it would be possible to send excess electricity production to PHES.

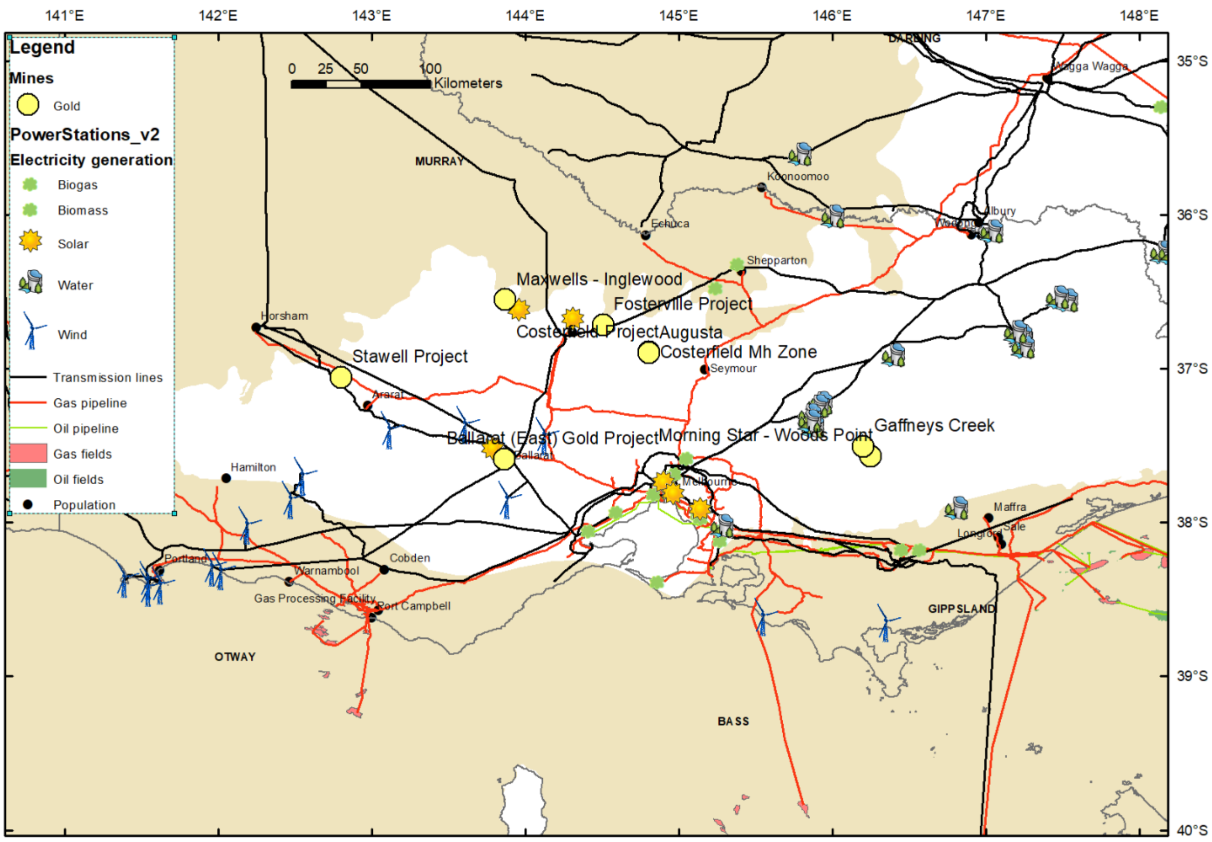

Figure 16. Current/recent underground mines in SE Australia.

UHS ASSESSMENT IN CENTRAL AUSTRALIA

Central Australia is relatively remote, the main industry being oil and gas production in the Eromanga (and underlying) Basin (Figure 17). Additionally, much smaller petroleum operations are located in the Amadeus Basin, which also hosts some solar energy projects, and there are gold mining activities in the Mount Isa area.

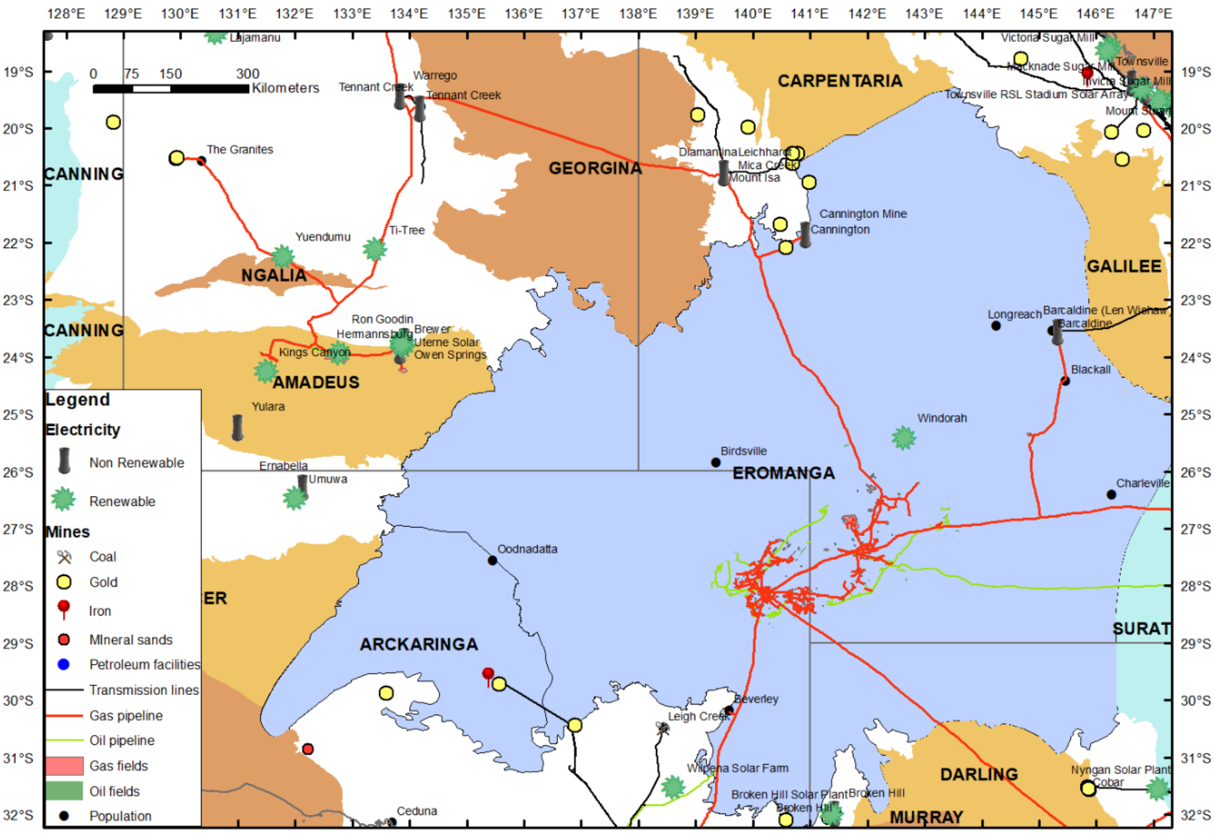

Figure 17. Resource operations and electricity generation in central Australia.

Depleted hydrocarbon reservoirs

There are many small to medium sized oil and gas fields in the Eromanga and underlying Cooper basins. The prospective hydrogen storage capacity in these fields ranges from 1 kilotonne to 3 million tonnes, and a total prospective storage capacity of 22.8 million tonnes (Figure 18). One of the largest fields, Moomba, is divided into sub-areas and the southern flank contains Australia's largest natural gas storage facility. Most of the gas fields are well-connected to the regional pipeline system connected to population centres and ports in South Australia, New South Wales, the Northern Territories and Queensland. There is an additional prospective storage capacity totalling approximately 1 million tonnes in gas fields in the Amadeus Basin.

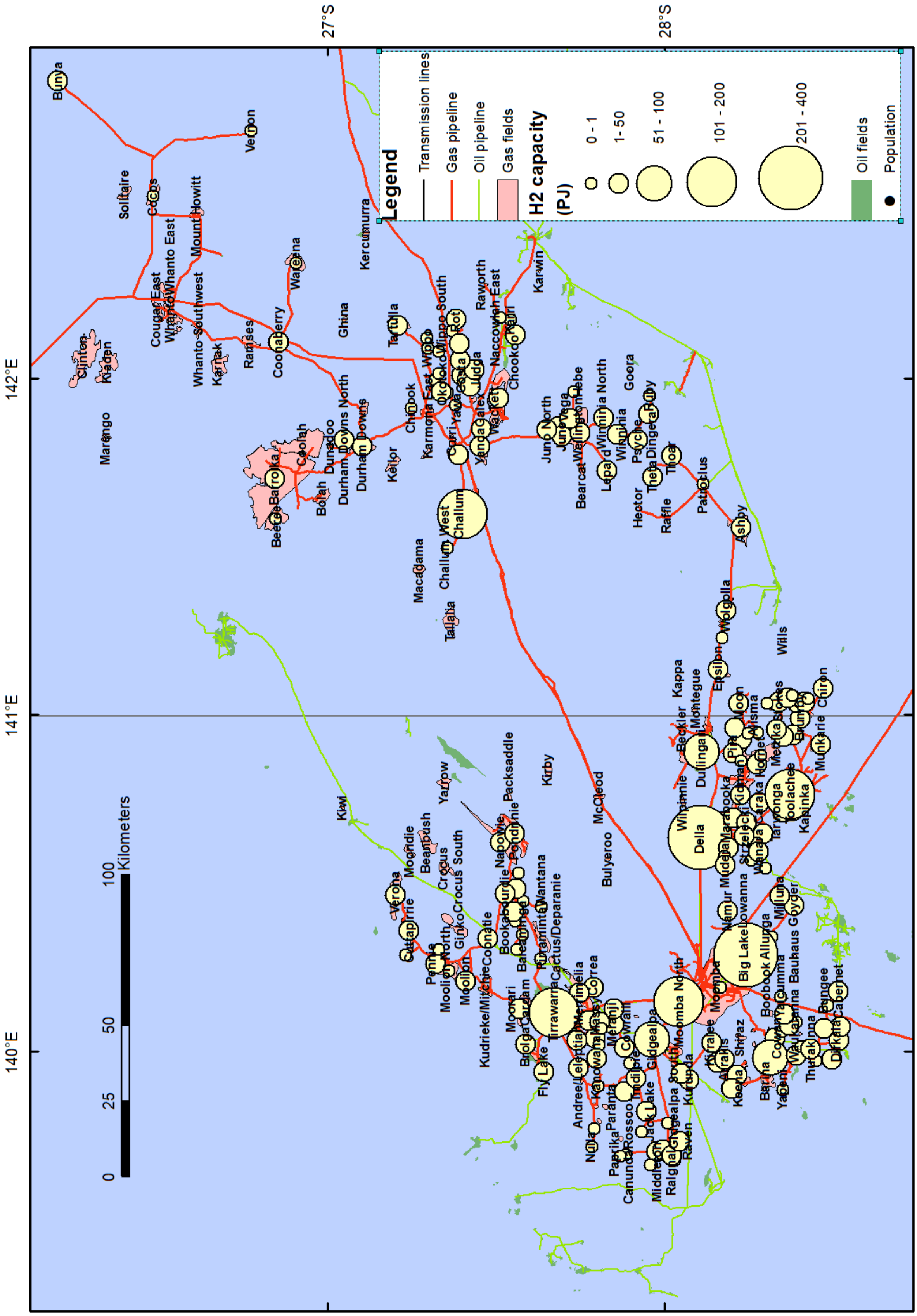

Figure 18. UHS capacity in gas fields in the Eromanga Basin.

Aquifers

In central Australia, the thick sediments of the Eromanga Basin (up to 3000 m thick) form a series of stacked aquifers separated by aquitards, which are underlain in large portions by the Cooper Basin sediments. The Cadna-owie Formation and Hooray Sandstone are the main aquifers in the Eromanga Basin sequence. In the underlying Cooper Basin sequence, coarser sandstone units of the Patchawarra and Toolachee formations represent the highest porosity units, and the Tinchoo, Patchawarra, Epsilon, Daralingie and Toolachee formations, along with the Tirrawarra Sandstone and Merrimelia Formation also forming reservoir units (Smith et al., 2015).

Aquifers previously identified by Bradshaw et al. (2011) as suitable CO_2 storage formations include the Wyandra, Adori, Hooray, Hutton, Lower Poolowanna and Toolachee sandstones, which are confined by competent sealing aquitards and hence should also have UHS potential in local structural closures. Additional aquifers in the lower parts of the Cooper Basin that are prospective for UHS include the Daralingie, Epsilon and Patchawarra formations.

Salt caverns

Evaporites occur in the Gillen Formation (Bitter Springs Group) in the Amadeus Basin and the Browne Formation (Buldya Group) in the Officer Basin. Diapirism is recorded in both basins but particularly well documented in the Amadeus. The salt thickens into diapirs which reach the surface producing local extreme vertical salt thicknesses and in other places the mobilised salt flows away (welds) removing the salt at that locality.

The Officer Basin is poorly explored, with only about 15 000 line-km of 2D seismic coverage and only about 20 exploration wells have been drilled (Geoscience Australia, 2021). Interpretation of Officer basin seismic indicates that the evaporites have mobilised and formed into salt walls which are oriented approximately NW-SE (Carr, et al., 2012). Apart from the areas impacted by salt mobilisation, the Pre-Cambrian salt units are relatively thin for cavern creation (200 m Amadeus, 70 m Officer).

Engineered caverns

There are a few underground gold and copper mines in central NSW, central SA and the NT (Figure 19). As before, the concept of UHS in engineering underground storage still needs to resolve important technical challenges before it is viable, so other options will be preferred if they are geographically and economically suitable.

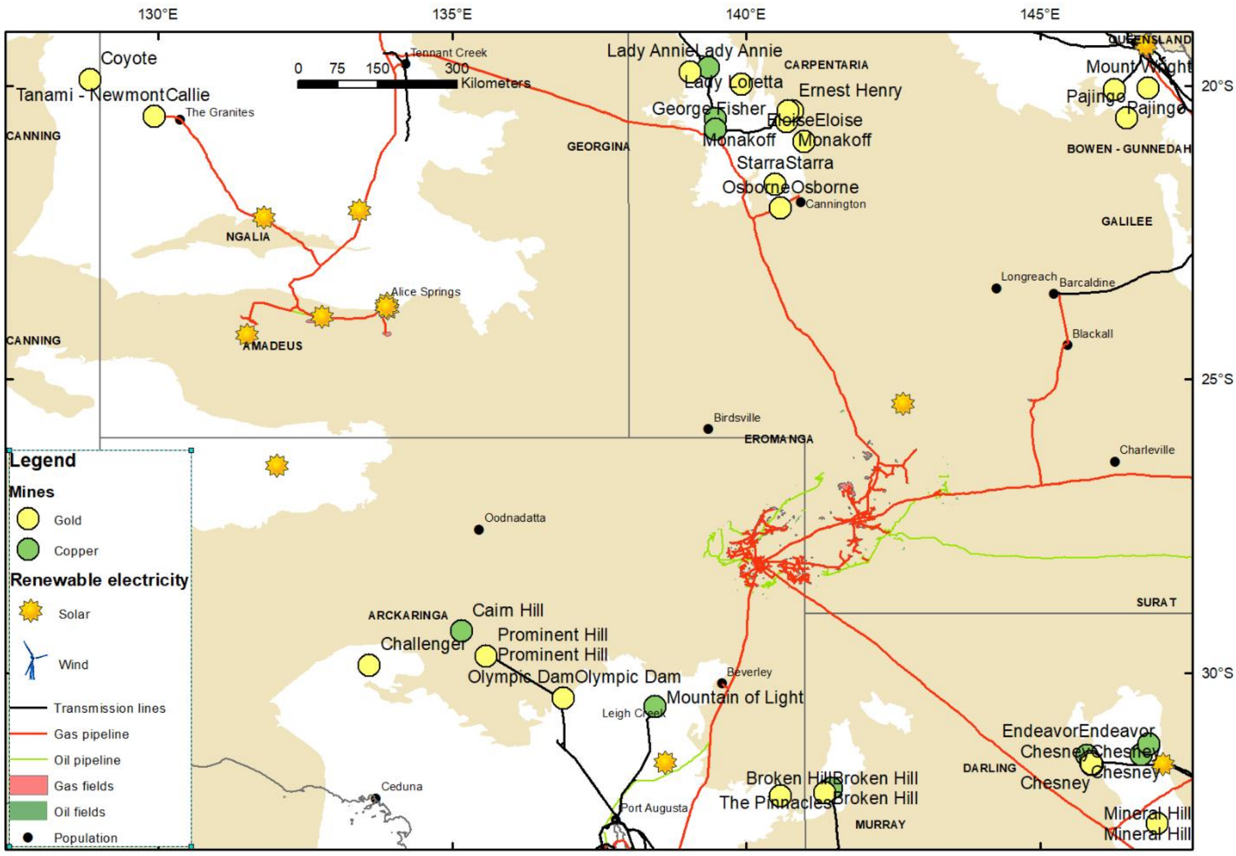

Figure 19. Current/recent underground mines in central Australia

UHS ASSESSMENT IN NORTHEAST AUSTRALIA

North-eastern Australia has a large resources industry (petroleum, coal, coal seam gas) and a wide range of electricity generation including renewables (solar, wind, hydro) and fossil fuels (black coal, natural gas) (Figure 20). Specific to this part of Australia are the large coal seam gas operations in the Clarence-Moreton Basin and black coal mines in the northern Surat and Sydney basins, both having an important contribution to Australia's energy export. Potential UHS options are largely constrained to aquifers or depleted fields in sedimentary basins (Surat and Bowen-Gunnedah) in Queensland, whereas storage options in porous media are limited in New South Wales.

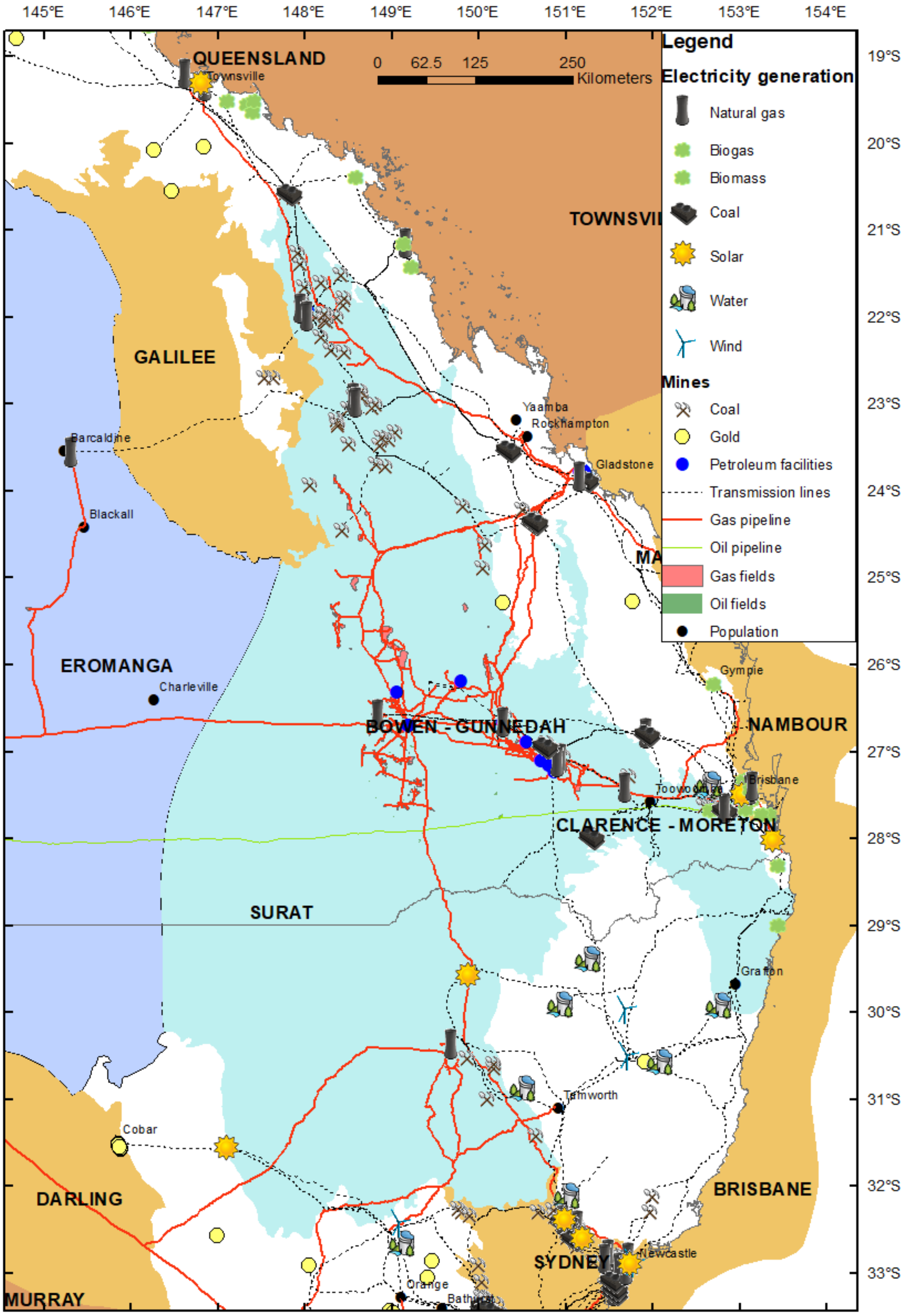

Figure 20. Resource operations and electricity generation in northeast Australia.

Depleted hydrocarbon reservoirs

There are many small to medium sized oil and gas fields in the Surat and Bowen-Gunnedah basins. The prospective hydrogen storage capacity in individual gas fields ranges up to 235 thousand tonnes, and the total prospective storage capacity is 2.5 million tonnes (Figure 21). Four of these gas fields (Ballera, Newstead, Roma, and Silver Springs) are being used as gas storage facilities. Most of the gas fields are well-connected to the regional pipeline system connected to population centres and ports in New South Wales, the Northern Territories and Queensland.

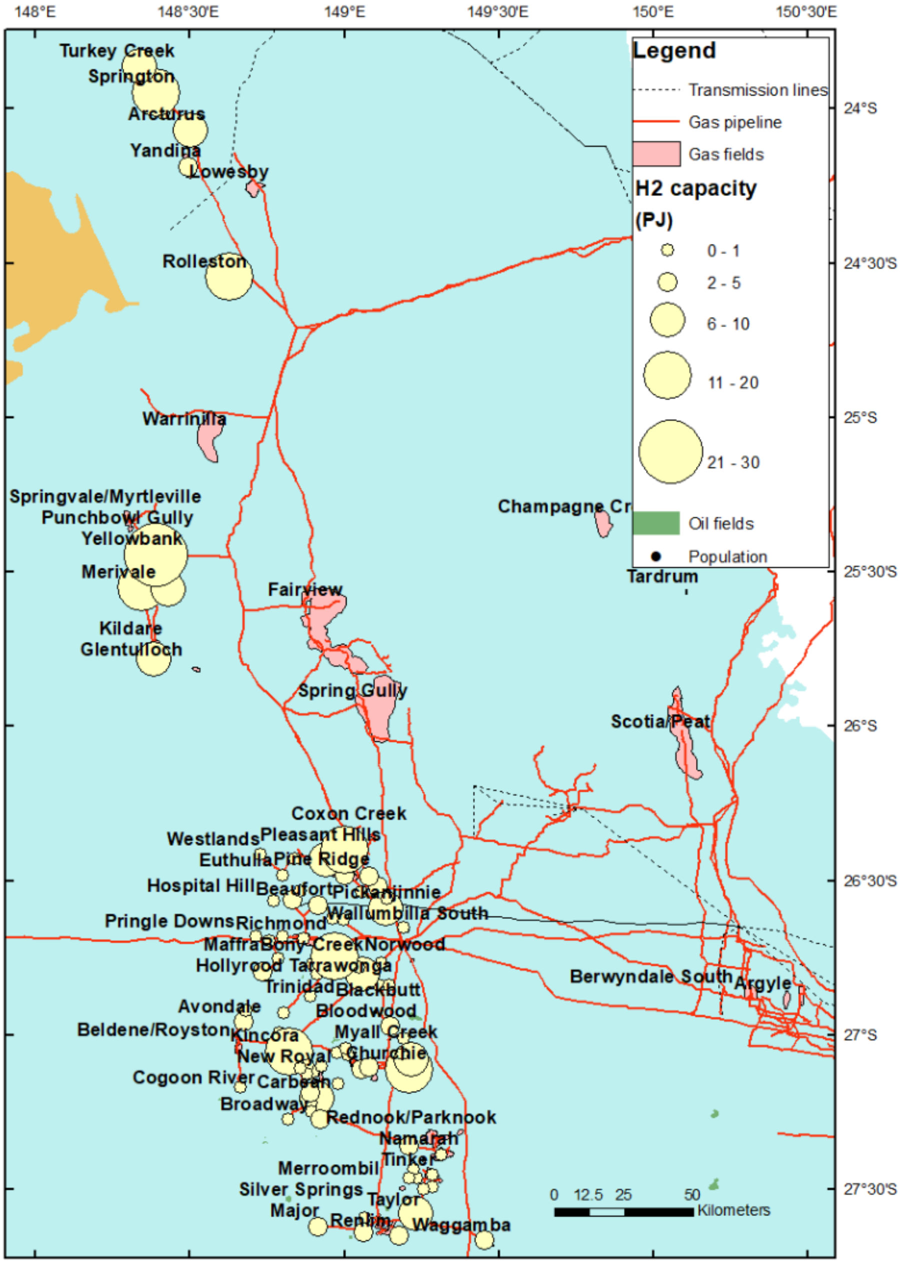

Figure 21. Prospective UHS capacity in gas fields in the Bowen and Surat basins.

Aquifers

Major aquifers in the Bowen, Galilee and Surat basins were assessed to be highly prospective for CO_2 geological storage (Bradshaw et al., 2009; 2011; Hodgkinson et al., 2009), which also makes them potentially suitable targets for UHS e.g. the Hutton and Precipice Sandstones. Detailed locations and capacity estimations will require the mapping and identification of suitable structural closures. Other basins were deemed to have either low prospectivity (e.g. Adavale, Carpentaria, Clarence-Moreton) or to be unsuitable (e.g. Nabour, Warbuton) for geological storage. However, the low prospectivity ranking was often based on either insufficient knowledge or highly variable reservoir quality and uncertain containment potential due to extensive faulting. Further assessment is required to confirm whether these basins are locally suitable for UHS.

Salt Caverns

In the Adavale Basin, the Giventian Borree Salt does not necessarily cover a wide geographical area, about 8000 km^2, but there are significant intersections (900 m) as the salt has mobilised into pillows along faults (Wells, 1980). There is a pipeline to/from the main Ballera-Brisbane pipeline through the basin to the power station at Barcaldine, which is the limit of the electricity grid in central Queensland. This geographical arrangement of infrastructure, with gas fields, pipelines, power stations, location in an advantageous location for renewable production and access to the electricity grid combines to give the Adavale Basin potential for various UHS options.

Engineered caverns

There are underground mines in Queensland particularly in the Mount Isa-Cloncurry area in NW of the state (Figure 22). This area is not on the electricity grid but is connected to the natural gas network. There are no depleted field, aquifer, or salt cavern options in the immediate vicinity. Hydrogen storage in redundant excavated caverns in conjunction with renewable electricity production is one possibility in the Mount Isa-Cloncurry area. As discussed above, this kind of storage is still under development and faces several technical challenges.

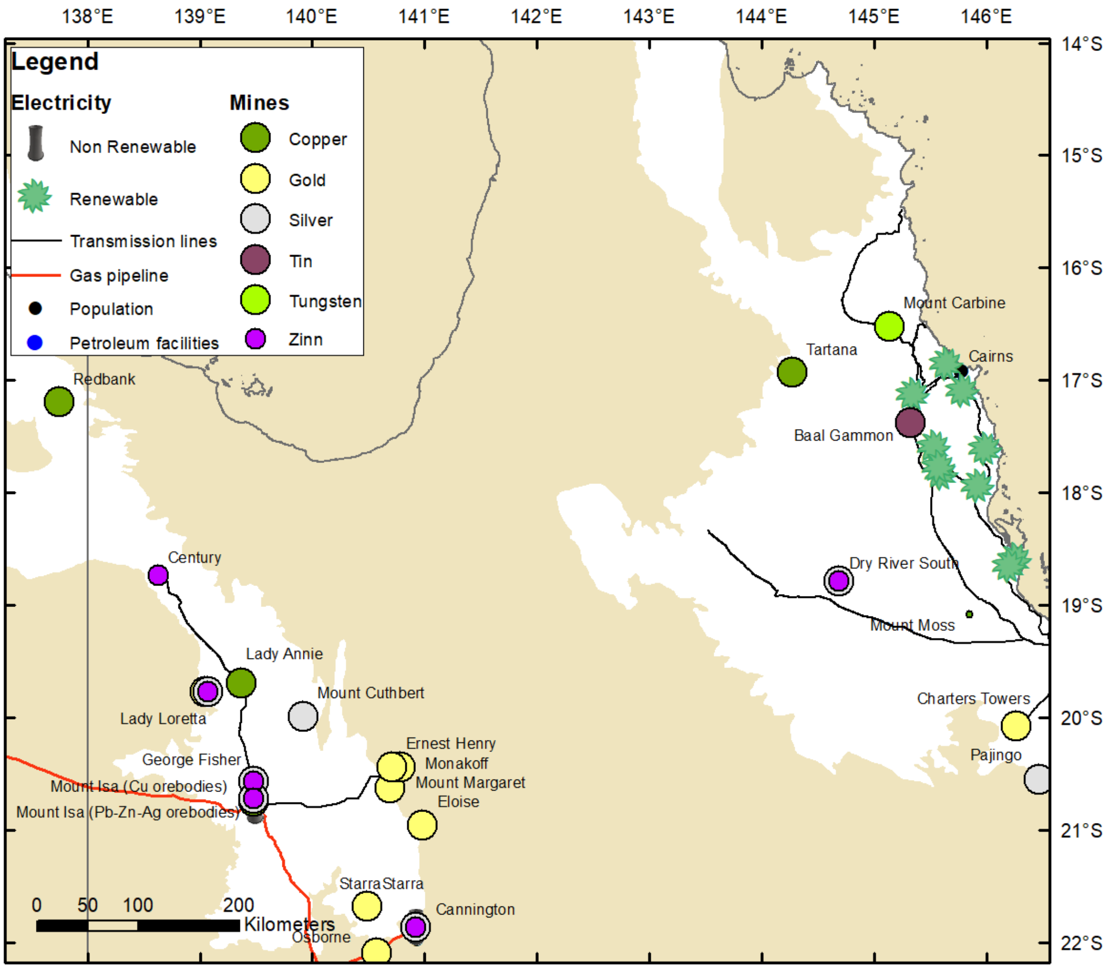

Figure 22. Current/recent underground mines in Queensland.

Conclusions

This report reviewed the options for underground hydrogen storage that are currently being investigated worldwide, including (in order of descending technological readiness levels) salt caverns, depleted hydrocarbon reservoirs, aquifers and engineered hard rock caverns.

The reservoir engineering aspects of UHS were explored, particularly in relation to depleted gas fields, and this gave tools to estimate the UHS capacity and containment of such fields. The density of pure hydrogen in the subsurface is 8-10 times less than methane at the same conditions, and thus the energy storage capacity of a UHS facility is 3-4 times less than an equivalent depleted gas field. Hydrogen solubility in brine is low, and thus the expected losses due to diffusion and dissolution are also very low. The caprock sealing capacity for hydrogen is at least as much as the equivalent for methane, so that depleted gas fields will be able to retain pure hydrogen.

The techno-economics of UHS were found to be a function of the individual characteristics of a storage reservoir as well as its utilisation and thus are to a large degree uncertain. Depleted oil and gas reservoirs require little initial investment, while salt caverns have considerable capital outlay. Aquifers are also expected to be a low-cost hydrogen storage option, though their site characterisation costs are an unknown variable and could be significant. While expensive, salt caverns have the advantage that they can undergo multiple charge and discharge cycles per year. This reduces the specific cost of hydrogen storage significantly. Depleted hydrocarbon reservoirs on the other hand are expected to be limited to one to two discharge cycles per year.

A concurrent assessment of storage economics and transport economics is required to determine the most cost-effective means of delivering hydrogen. This includes the consideration of potential points of hydrogen production and points of delivery, the quantities produced and delivered and the frequency (i.e., discharge cycles per year) of delivery, as well as the longevity of the hydrogen demand.

The high-level assessment methodology for UHS options was then outlined. The first aspect is the general suitability of each storage option in each geographical area. On top of this, a method was developed to estimate prospective storage capacity in depleted gas fields, using the reservoir engineering calculations in the earlier section.

The energy landscape in Australia was then summarised, and an estimate developed of the possible future demand for UHS if hydrogen becomes widely adopted as an energy carrier for both domestic use and export. Stabilisation of the electricity network was estimated to require around 1.3 PJ (10 kt of H_2) (Australian Energy Market Regulator, 2018), while security of the domestic gas network and the export market are each estimated at 300 PJ (2,400 kt of H_2), for a total of about 600 PJ (4,800 kt of H_2).

UHS options and their potential suitability were then assessed in various regions of Australia and are summarised in the following sections.

SALT CAVERNS

Various Australian basins contain salt deposits suitable for the creation of storage caverns (Figure 24); however, most of these salts are in areas that are not close to potential hydrogen generation, ports or processing infrastructure. The most likely locations that could be integrated into a hydrogen infrastructure are salts in the north-western part of the Canning Basin, which are relatively close to the North West Shelf gas processing facilities and in the vicinity of new renewable wind and solar energy projects. Also, the salt deposits in the Adavale Basin are near to onshore gas developments in western Queensland and have already been potentially considered for natural gas storage. If there was a larger development of wind and solar resources in central Australia, salts in the Amadeus Basin may represent suitable cavern storage options with an already existing pipeline to Darwin.

DEPLETED HYDROCARBON RESERVOIRS

Depleted gas fields appear to be the most promising and widely available UHS option in Australia. Depleted gas fields are already used for natural gas storage in several locations and are being considered for storing a blend of natural gas and hydrogen. The total prospective UHS capacity is 38,000 PJ (~310,000 kt H_2), ranging from approximately 130 PJ (~1000 kt H_2) in the Amadeus Basin to more than 23,000 PJ (~190,000 kt H_2) in the North Carnarvon Basin (Figure 23). Most sedimentary basins contain multiple gas fields with an individual prospective storage capacity in excess of 25 PJ (~200 kt H_2).

How much of this prospective storage capacity can be turned into actual storage capacity and how many fields are technically suitable for UHS depends on various parameters (e.g. hydrogen losses, operating pressure range, degree of aquifer support, number of wells/development strategy, etc.) that need more detailed assessment or that are currently unknown (e.g. storage economics). Social and environment factors would also need to be included in the assessment.

To put the need for storage capacity in perspective, Australia's annual energy production, consisting of the extraction of fossil fuels (coal and petroleum) and renewable energy generation, reached a total of 19,700 PJ in 2018-19. The natural gas storage capacity of the largest Australian gas storage facility at Moomba in the Cooper Basin is 23 PJ (~200 kt H_2). This implies that even if only a fraction of the prospective storage capacity could be realised, there is more than sufficient storage capacity available in depleted gas fields for a fully developed hydrogen industry in Australia.

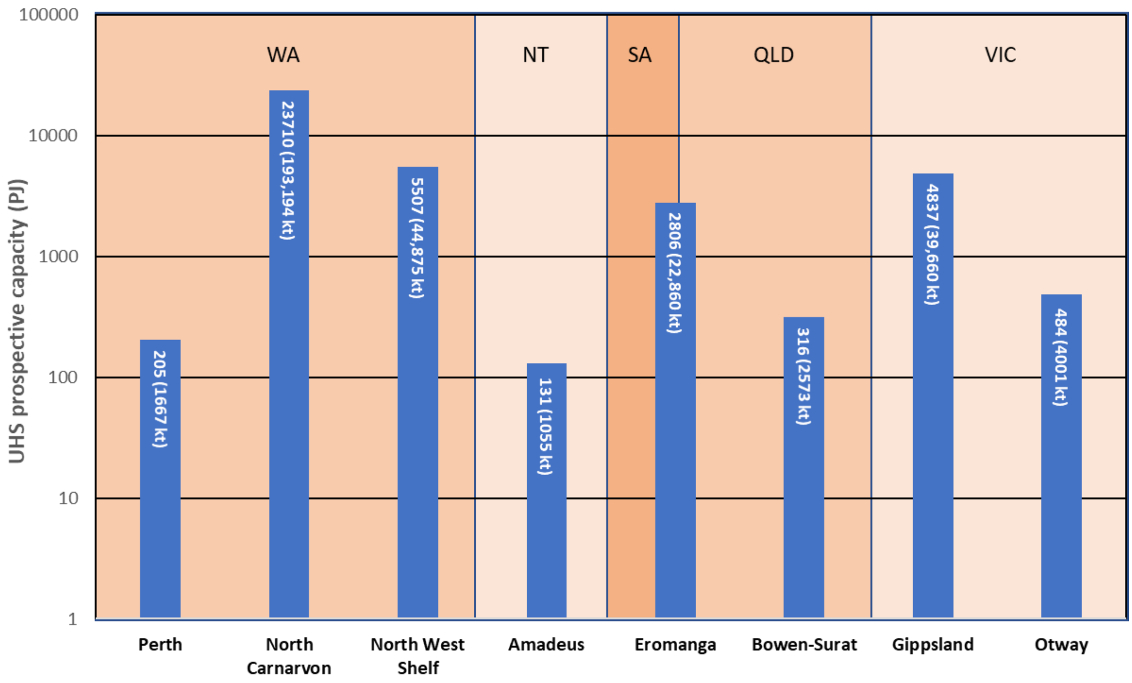

Figure 23: Prospective UHS storage capacity in gas fields in Australian basins.

AQUIFERS

Many Australian basins contain multiple aquifer-aquitard pairs that should be suitable for UHS. Many of these storage systems are in mature petroleum basins and form an extension of reservoir-seal pairs that host hydrocarbon reservoirs. Again, some of these have been previously assessed with respect to their suitability to store carbon dioxide, which can be used as an analogue, yet at a much smaller scale, for hydrogen storage. While a quantitative estimation of UHS capacity was not possible within the scope of this project and has not yet been demonstrated in industrial applications, aquifer storage represents an alternative option that has a larger regional extent than storage in gas reservoirs and may be considered if the blending of residual natural gas and hydrogen proves to result in contamination issues.

ENGINEERED CAVERNS

UHS in engineered caverns, whether purpose-built or re-purposed from mining infrastructure, is still under development. It has a much lower technology readiness level (TRL) than salt cavern storage (which has been commercial for decades), or depleted field or aquifer storage (which build upon very similar concepts and experience in UGS). The main area of application would be in regions with significant potential for renewables but away from sedimentary basins, where the other geological options are not available.

Each of the five regions analysed has some areas in which engineered caverns could be created, including mines with modern infrastructure which could be potentially be lined and re-purposed for UHS. Areas with (non-coal) underground mines are widely distributed across Australia, most notably for the purposes of this study in central Victoria, central NSW, NW Queensland and across western WA. The underground mines are in areas with outcropping or shallowly sub-cropping geological basement. As such, underground mines are predominantly away from the recent sedimentary basins which host hydrocarbon reservoirs, aquifers and salt deposits, so these mines offer potential storage solutions where other options are unavailable. At the same time, the mining areas are largely remote from areas of hydrogen production and consumption. Additionally, areas such as central Victoria, central NSW and SW WA, where many mines are concentrated, are connected to the regional electricity grid reducing the necessity for local energy storage. However, in some of these locations the constraints on grid capacity may also be a factor.

Again, given the abundance of prospective storage capacity in Australian gas fields it would seem unlikely that repurposing underground excavations is a necessary or practical large-scale storage option. There is perhaps the possibility of smaller-scale application in remote mining areas or in conjunction with temporarily storing export hydrogen in NW WA.

OVERALL SUMMARY OF UHS OPTIONS IN AUSTRALIA

Table 5 gives the suitability of each storage option in the five regions using qualitative levels. Overall, there is more than sufficient prospective hydrogen storage capacity, particularly in gas fields (Figure 24), where the total is estimated as 38,000 PJ (~310,000 kt H_2). This is two orders of magnitude greater than the estimated demand for UHS (600 PJ, or 4,800 kt H_2). Thus, the total UHS needs could be met by a small number of storage facilities, and future work should focus on finding the best options in terms of economics, storage characteristics, location in relation to production and infrastructure.

Table 5. Qualitative suitability of UHS options in various regions of Australia. Red indicates no suitable options in that basin; yellow indicates possible options and green indicates suitable options.

<table>
<tr><th>UHS option</th><th>South
(VIC,TAS,SA)</th><th>North-East
(QLD, NSW)</th><th>Central
(NT, SA)</th><th>North-West
(WA, NT)</th><th>South-West
(WA)</th></tr>
<tr><td rowspan="2">Salt caverns</td><td rowspan="2"></td><td rowspan="2">Adavale</td><td>Amadeus</td><td>Canning</td><td rowspan="2"></td></tr>
<tr><td colspan="2">Officer</td></tr>
<tr><td>Depleted reservoirs</td><td rowspan="2">Gippsland (offshore)
Otway (on-/offshore)</td><td rowspan="2">Bowen
Surat</td><td>Eromanga</td><td>Carnarvon
Browse-BNP</td><td>N Perth Basin</td></tr>
<tr><td>Aquifers</td><td>Eromanga (GAB)</td><td>Canning (onshore)
NWS (offshroe</td><td>N & S Perth Basin</td></tr>
<tr><td>Engineered caverns</td><td>Central VIC</td><td>Mt Isa</td><td></td><td>Pilbarra</td><td>Gold fields</td></tr>
</table>

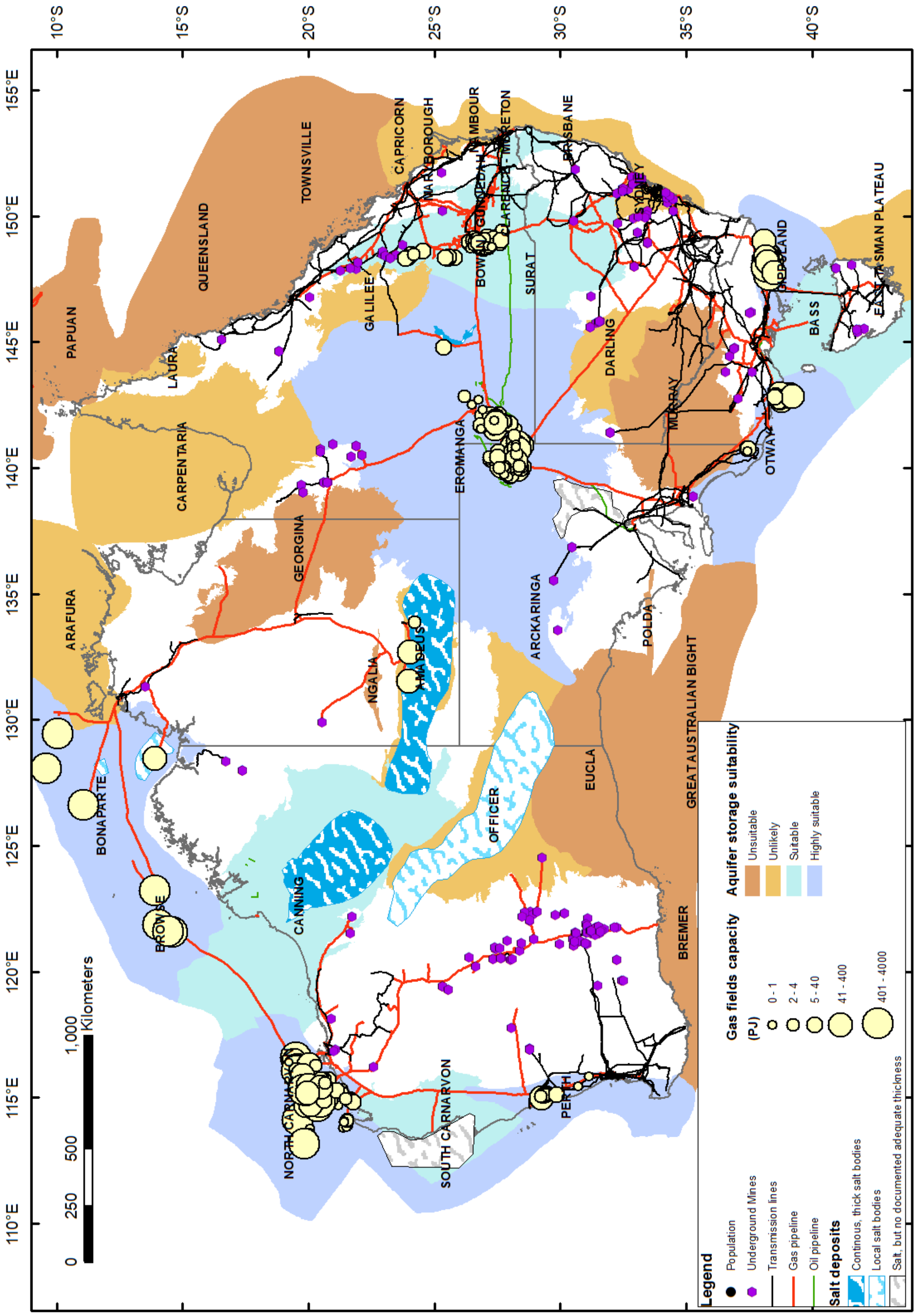

Figure 24. UHS options in Australia. Prospective storage capacity in gas fields was estimated from production/reserves data. Suitability of aquifer storage is based on the CO_2 storage suitability assessment by Carbon Storage Taskforce (2009). The extent of salt deposits and location of underground mines are potentially available for salt caverns or lined caverns, respectively.

Future work

None of the proposed UHS options have been implemented in Australia. Although there is experience with storing hydrogen in salt caverns, and, to a certain extent, with storage in porous formations globally, these options need to be tested in Australian conditions. The most advanced storage options in Australia are depleted gas reservoirs because of the experience with natural gas storage operations.

The choice of storage sites, either for pilot or commercial implement of UHS, will require the development of selection criteria for both geological attributes and geographical location (and the associated techno-economics). For each storage option there are also technical challenges that will need to be resolved, and these are explored below (see also Heinemann et al. (2020) for a list of research challenges).

SALT CAVERNS

Salt cavern storage is the technologically most advanced UHS option as demonstrated by existing UHS projects in the US, France, Germany and the U.K. However, Australia requires

- a more detailed mapping and characterisation of known salt deposits,
- exploration for new salt deposits,
- UHS pilot/demonstration in Australian salt caverns

Getting to the pilot or demonstration stage would require selecting a feasible location in one of the Australian salt basins that is in the vicinity of a suitable hydrogen source, ideally in an area associated with a hydrogen project in an advanced planning stage. Examples that could be realised in the short term would be blue or renewable hydrogen projects near the Canning Basin or Adavale Basin salts.

DEPLETED HYDROCARBON RESERVOIRS

Although storage in depleted gas fields is at a lower technological readiness level (TRL) than salt cavern storage, Australia has a large prospective UHS capacity in gas fields, which would be available in large parts of Australia with potential hydrogen sources. However, the actual capacity would need to be confirmed, initially through reservoir simulations, but ultimately by performing pilot hydrogen injection and production experiments. Specific aspects to be tested include:

- Amount of cushion gas needed (which is affected by the mixing with residual hydrocarbons), and relies on analysis of existing UGS operations, and modelling of UHS operations.
- Impact of hydrogen on seal properties, specifically the capillary pressure thresholds (which require interfacial tension measurements of hydrogen gas mixtures with brine), diffusion into the seal, geochemical reactions, and geomechanical strength.

- Impact of hydrogen on reservoir properties, specifically relative permeability, wettability, geochemical reactions and geomechanics.
- Contamination of hydrogen with reservoir gas or with new products from geochemical reactions and microbial activity.
- Microbiological effects on stored hydrogen, including laboratory experiments on characterising microbes from field samples and measuring their response to hydrogen gas mixtures, and calibration of theoretical models for microbial effects.
- Improved modelling of UHS operations, including more accurate equations of state for hydrogen-gas mixtures and brine (tested against laboratory data), a code comparison of simulating simplified UHS scenarios, development and calibration of modelling of coupling flow to microbiology and geochemistry.
- Development of improved monitoring strategies in the reservoir (e.g. of microbial and geochemical response) and for detecting shallow leakage.

Australia is in an excellent position to progress to a pilot/demonstration stage for UHS in gas reservoirs, because in contrast to salt caverns that still would need to be created and tested, existing natural gas storage operations could be easily converted to UHS test sites. This may initially involve blending of hydrogen with natural gas and progressing to pure hydrogen storage. Lessons learned from such pilot sites would provide critical parameters and operational constraints for UHS in these gas reservoirs, which would improve the suitability assessment and storage capacity calculations for other Australian gas fields.

AQUIFERS

Technically and geologically, aquifer storage is comparable to storage in gas fields. The future work is very similar to depleted gas fields, except for the lack of contamination with residual hydrocarbons, and lesser potential for microbial activity due to the lack of a major source of carbon. Aside from the site characteristics that would be required for UGS, there also needs to be work on additional screening criteria for UHS e.g. water chemistry, mineralogy and microbiology.

Given the abundance of prospective storage capacity in Australian gas fields and additional costs, the demonstration of UHS in aquifers has probably a lower priority. However, this may change if evidence should emerge that solving potential issues with depleted gas fields become unsurmountable or more expensive to solve than exploring for aquifer storage options.

ENGINEERED CAVERNS

UHS in engineered caverns is currently in the early stages of development and is not yet implemented anywhere. Hard rock caverns are current in use for compressed air storage, and for the storage of petroleum liquids with low vapour pressure (e.g. propane), so it is possible to build on this experience. Key research challenges include:

- Stability: The geomechanical stability of caverns needs to be demonstrated for the required range of storage pressure – this is more challenging if the concept is to re-use existing mine infrastructure.
- Containment: materials need to be selected for liners for UHS, and methods developed for deploying those liners. Alternatively, for unlined caverns, the water curtain approach would need to be validated for application to UHS.
- Excavation: for purpose-built caverns, the challenge is to find economically feasible methods for excavating hard-rock caverns without compromising either geomechanical stability or containment.

The possible advantage of engineered caverns in the Australian context is that they might offer an option for UHS in areas with significant potential for renewable electricity generation, but no nearby sedimentary basins and so no potential for UHS in depleted gas fields, salt caverns or aquifers.

TECHNO-ECONOMICS

The economic viability of a particular storage site will depend on the integration of all aspects of the hydrogen value-chain, from production, to transport, to storage, to end-use. These features will also strongly affect the required storage volumes, and the frequency of cycling of the storage, which are both critical to the total cost of storage. The next steps would then be:

- site-specific studies of the total costs of supply, transport and storage and usage
- comparison between the techno-economics of salt caverns, depleted gas fields and aquifers for specific applications, building on the site-specific studies.

References

3D-GEO Pty Ltd., 2013. Western Australia carbon dioxide geological storage atlas: Geological Survey of Western Australia Report 126, 300 p.

Ahluwalia, R.K., Papadias, D.D., Peng, J.-K., Roh, H.S., 2019. System Level Analysis of Hydrogen Storage Options. Project ID: ST001, U.S. DOE Hydrogen and Fuel Cells Program, presented at the 2019 Annual Merit Review and Peer Evaluation Meeting, Washington, D.C., USA, April 29 – May 1.

Allinson, W. G., Cinar, Y., Neal, P. R., Kaldi, J., Paterson, L., 2014. "CO_2 Storage Capacity – Combining Geology , Engineering and Economics." *SPE Econ. Mgmt* 6: 15–27. https://doi.org/10.2118/133804-PA

Al-Yaseri, A., Jha, N. K., 2021. On hydrogen wettability of basaltic rock. *J. Petrol. Sci. Eng.* 200: 108387. https://doi.org/10.1016/j.petrol.2021.108387

Amid, A., Mignard, D., Wilkinson, M., 2016. Seasonal storage of hydrogen in a depleted natural gas reservoir. *Int. J. Hydrogen Energy* 41:5549-5558.

Amos, W.A., 1998. Cost of storing and transporting hydrogen. National Renewable Energy Laboratory, Golden, Colorado, USA, NREL/TP 570-25106.

Aüllo, T., Berlendis, S., Lascourrèges, J. F., Dessort, D., Duclerc, D., Saint-Laurent, S., Schraauwers, B., Mas, J., Patriarche, D., Boesinger, C., Magot, M., Ranchou-Peyruse, A., 2016. New bio-indicators for long term natural attenuation of monoaromatic compounds in deep terrestrial aquifers. *Front. Microbiol.* 7: 1–16. https://doi.org/10.3389/fmicb.2016.00122

Australian Energy Market Operator (AEMO). Integrated System Plan for the National Electricity Market. Technical Report July 2018

Azretovna, L. A., Nabievich, S. Z., Pavlovich, D. A., Sumbatovich, E. Z., 2020. Formation of an effective hydrogen storage in an aquifer and control of its parameters. *SPE Russian Petroleum Technology Conference 26-29 October*. https://doi.org/10.2118/201999-ms

Bagheri, M. 2019. A review of the preliminary Underground Gas Storage site ranking, Onshore Otway Basin, Victoria. Victorian Gas Program Technical Report 11. Geological Survey of Victoria. Department of Jobs, Precincts and Regions. Melbourne, Victoria. 16p.

Bai, M., Song, K., Sun, Y., He, M., Li, Y., Sun, J., 2014. An overview of hydrogen underground storage technology and prospects in China. *J. Pet. Sci. Eng.* 124: 132-136.

Barbir, F., 2013. Chapter twelve – future of fuel cells and hydrogen; in: PEM Fuel Cells (2nd edition), Academic Press, 469-508

Basso, O., Lascourreges, J. F., Le Borgne, F., Le Goff, C., Magot, M., 2009. Characterization by culture and molecular analysis of the microbial diversity of a deep subsurface gas storage aquifer. *Res. Microbiol.* 160: 107–116. https://doi.org/10.1016/j.resmic.2008.10.010

Berlendis, S., Lascourreges, J. F., Schraauwers, B., Sivadon, P., Magot, M., 2010. Anaerobic biodegradation of BTEX by original bacterial communities from an underground gas storage aquifer. *Environ. Sci. Technol.* 44: 3621–3628. https://doi.org/10.1021/es100123b

Bo, Z., Zeng, L., Chen, Y., Xie, Q., 2021. Geochemical reactions-induced hydrogen loss during underground hydrogen storage in sandstone reservoirs. *Int. J. Hydrogen Energy* 6:19998-20009. https://doi.org/10.1016/j.ijhydene.2021.03.116

Böttcher, N., Görke, U. J., Kolditz, O., & Nagel, T., 2017. Thermo-mechanical investigation of salt caverns for short-term hydrogen storage. *Environ. Earth Sci. 76*(3), 98. https://doi.org/10.1007/s12665-017-6414-2

Bradshaw, B.E., Spencer, L.K., Lahtinen, A.C., Khider, K., Ryan, D.J., Colwell, J.B., Chirinos, A., and Bradshaw, J., 2009. Queensland carbon dioxide geological storage atlas. Compiled by Greenhouse Gas Storage Solutions on behalf of Queensland Department of Employment, Economic Development and Innovation.

Bradshaw, B. E., Spencer, L. K., Lahtinen, A.-L., Khider, K., Ryan, D. J., Colwell, J. B., Chirinos, A., Bradshaw, J., Draper, J. J., Hodgkinson, J., and McKillop, M., 2011, An assessment of Queensland's CO_2 geological storage prospectivity — The Queensland CO_2 Geological Storage Atlas. *Energy Procedia* 4:4583-4590.

Brodie, J., Jhaveri, B., Moulds, T., Hetland, S. M., 2012. Review of gas injection projects in BP. *SPE Improved Oil Recovery Symposium, Tulsa, Oklahoma, USA, 14-18 April*.

Bruce, S., Temminghoff, M., Hayward, J., Schmidt, E., Munnings, C., Palfreyman, D., Hartley, P., 2018. National Hydrogen Roadmap. CSIRO, Australia.

Bruno, M.S., Dusseault, M.B., T.T., B., Barrera, J.A., 1998. Geomechanical analysis of pressure limits for gas storage reservoirs. *Int. J. Rock Mech. Min. Sci.* 35: 569-571.

Bruno, M.S., Dusseault, M.B., 2002. Geomechanical analysis of pressure limits for thin bedded salt caverns. Spring 2002 solution mining research institute technical meeting, Banff, Alberta, Canada, April 29-30.

Buenger, U., Michalski, J., Crotogino, F., Kruck, O., 2016. Large-scale underground storage of hydrogen for the grid integration of renewable energy and other applications, Compendium of Hydrogen Energy, Volume 4: Hydrogen Use, Safety and the Hydrogen Economy, Woodhead Publishing Series in Energy, 133-163.

Buschkuehle, M., Eid, R., Goldie Divko, L. M., Ricard, L., 2019. A preliminary ranking of potential Underground Gas Storage sites, Onshore Otway Basin, Victoria.

Victorian Gas Program Technical Report 9. Geological Survey of Victoria. Department of Jobs, Precincts and Regions. Melbourne, Victoria. 67p.

Buzek, F., Onderka, V., Vančura, P., Wolf, I., 1994. Carbon isotope study of methane production in a town gas storage reservoir. *Fuel* 73: 747–752. https://doi.org/10.1016/0016-2361(94)90019-1

Caglayan, D.G., Weber, N., Heinrichs, H.U., Linßen, J., Robinius, M., Kukla, P.A., Stolten, D., 2020. Technical potential of salt caverns for hydrogen storage in Europe. *Int. J. Hydrogen Energy* 45: 6793-6805.

Carbon Storage Taskforce, 2009. *National Carbon Mapping and Infrastructure Plan – Australia: Full Report*, Department of Resources, Energy and Tourism, Canberra

Carden, P. O., Paterson, L., 1979. Physical and energy aspects of underground hydrogen storage. *Int. J. Hydrogen Energy* 4:559–569.

Carpetis, C., 1980. A system consideration of alternative hydrogen storage facilities for estimation of storage costs. *Int. J. Hydrogen Energy* 5: 423-437.

Carpetis, C., 1994. Technology and Costs of Hydrogen Storage. TERI Information Digest on Energy, 4: 1-13.

Carr, L.K., et al., 2012. Structural and stratigraphic architecture of Western Australia's frontier onshore sedimentary basins: the Western Officer and Southern Carnarvon basins. APPEA conference volume 52, May 2012.

Carranza-Torres, Carlos, Fosnacht, D., Hudak, G., 2017. Geomechanical Analysis of the Stability Conditions of Shallow Cavities for Compressed Air Energy Storage (CAES) Applications. *Geomech. Geophys. Geo-Energy Geo-Resour.* 3 (2): 131–74. https://doi.org/10.1007/s40948-017-0049-3

Carriere, J. F., Fasanino, G., Tek, M. R., 1985. Mixing in Underground storage reservoirs. In *Proceedings of SPE Annual Technical Conference and Exhibition, Las Vegas, NV, USA, Sep 22-25*. https://doi.org/10.2523/14202-ms

Chabab, S., Théveneau, P., Coquelet, C., Corvisier, J., Paricaud, P., 2020. Measurements and predictive models of high-pressure H_2 solubility in brine (H_2O+NaCl) for underground hydrogen storage application. *Int. J. Hydrogen Energy* 45:32206–32220. https://doi.org/10.1016/j.ijhydene.2020.08.192

Chapelle, F. H., O'Neill, K., Bradley, P. M., Methá, B. A., Ciufo, S. A., Knobel, L. R. L., Lovley, D. R., 2002. A hydrogen-based subsurface microbial community dominated by methanogens. *Nature* 415: 312–315. https://doi.org/10.1038/415312a

Chen, T.-P., 2010. Hydrogen Delivery Infrastructure Options Analysis. Final Report.

Chow, Y. T. F., Maitland, G. C., Trusler, J. P. M., 2018. Interfacial tensions of (H_2O + H_2) and (H_2O + CO_2 + H_2) systems at temperatures of (298–448) K and pressures up to 45 MPa. *Fluid Phase Equilibria* 475:37–44. https://doi.org/10.1016/j.fluid.2018.07.022

Chow, Y. T. F., Maitland, G. C., Trusler, J. P. M., 2020. Erratum to "Interfacial tensions of (H_2O + H_2) and (H_2O + CO_2 + H_2) systems at temperatures of (298 to 448) K and pressures up to 45 MPa" (Fluid Phase Equilibria (2018) 475 (37–44), (S0378381218302930), (10.1016/j.fluid.2018.07.022)). *Fluid Phase Equilibria* 503:112315. https://doi.org/10.1016/j.fluid.2019.112315

Clean Energy Council, 2020. Clean energy Australia – Report 2020, 86 p. cleanenergycouncil.org.au

Coffin, P., Lebas, G., 2008. Converting the Pécorade oil field into an underground gas storage. *SPE Projects, Facilities and Construction*, 3:4–6. https://doi.org/10.2118/117172-pa

Colman, D. R., Poudel, S., Stamps, B. W., Boyd, E. S., Spear, J. R., 2017. The deep, hot biosphere: Twenty-five years of retrospection. *Proc. Natl. Acad. Sci. USA* 114: 6895–6903. https://doi.org/10.1073/pnas.1701266114

Consoli, C.P., Higgins, K., Jorgensen, D., Khider, K., Lescinsky, D. T., Morris, R. and Nguyen, V., 2013, *Regional assessment of the CO_2 storage potential of the Mesozoic succession in the Petrel Sub-basin, Northern Territory, Australia: summary report*. Record 2014/11. Geoscience Australia, Canberra. http://dx.doi.org/10.11636/Record.2014.011

Cord-Ruwisch, R., Seitz, H.-J., Conrad, R., 1988. The capacity of hydrogenotrophic anaerobic bacteria to compete for traces of hydrogen depends on the redox potential of the terminal electron acceptor. *Arch. Microbiol.* 149:350–357

Crotogino, F., Donadei, S., Buenger, U., Landinger, H., 2010. Large-Scale Hydrogen Underground Storage for Securing Future Energy Supplies. Proceedings of the 18th World Hydrogen Energy Conference, May 16-21, Essen, Germany.

Davarpanah, A., Mazarei, M., Mirshekari, B., 2019. A simulation study to enhance the gas production rate by nitrogen replacement in the underground gas storage performance. *Energy Reports* 5:431–435. https://doi.org/10.1016/j.egyr.2019.04.004

DBI, 2017. Netherlands Enterprise Agency. The effects of hydrogen injection in natural gas networks for the Dutch underground storages.

de Moegen, H., Giouse, H., 1989. Long-Term Study of Cushion Gas Replacement by Inert Gas. In *SPE Annual Technical Conference & Exhibition, San Antonio, Texas, U.S.A., 8-11 October*.

Department of Industry, Science, Energy and Resources, 2020. Australian Energy Update 2020, Australian Energy Statistics, Canberra. 46 p.

Deveci, M. , 2018. Site selection for hydrogen underground storage using interval type-2 hesitant fuzzy sets. *Int. J. Hydrog. Energy* 43: 9353–9368. https://doi.org/10.1016/j.ijhydene.2018.03.127

Dieudonné, A. C., Cerfontaine, B., Collin, F., Charlier, R., 2015. Hydromechanical Modelling of Shaft Sealing for CO_2 Storage. *Eng. Geol.* 193: 97–105. https://doi.org/10.1016/j.enggeo.2015.04.016

Dopffel, N., Jansen, S., Gerritse, J., 2021. Microbial side effects of underground hydrogen storage – Knowledge gaps, risks and opportunities for successful implementation. *Int. J. Hydrogen Energy* 46: 8594–8606. https://doi.org/10.1016/j.ijhydene.2020.12.058

Dupraz, S., Stephant, S., Perez, A., Joulian, C., Blessing, M. et al. Patagonia Wind – Using Methanogenesis to Store Hydrogen on Large Scales. 22nd World Hydrogen Energy Conference - WHEC 2018, Jun 2018, Rio de Janeiro, Brazil. hal-01742093

Ebigbo, A., Golfier, F., Quintard, M., 2013. A coupled, pore-scale model for methanogenic microbial activity in underground hydrogen storage. *Adv. Water Resour.* 61:74–85. https://doi.org/10.1016/j.advwatres.2013.09.004

Eddaoui, N., Panfilov, M., Ganzer, L., Hagemann, B., 2021. Impact of Pore Clogging by Bacteria on Underground Hydrogen Storage. *Trans. Porous Med.* https://doi.org/10.1007/s11242-021-01647-6

ETI, 2015. Hydrogen, the role of hydrogen storage in a clean responsive power system. Energy Technologies Institute, Loughborough, UK.

ETSAP, 2014. Hydrogen Production and Distribution. Energy Technology System Analysis Programme, IEA Energy Technology Network, Technology Brief P12, February.

European Commission, 2017. Commission staff working document. Energy storage – the role of electricity. Brussels, February 2017. https://ec.europa.eu/energy/sites/ener/files/documents/swd2017_61_document_travail_service_part1_v6.pdf

Evans, D.J., West, J.M., 2008. An appraisal of underground gas storage technologies and incidents, for the development of risk assessment methodology. British Geological Survey for the Health and Safety Executive.

Feitz, A.J., Tenthorey, E., and Coghlan, R. 2019. Prospective hydrogen production regions of Australia. Record 2019/15. Geoscience Australia, Canberra. http://dx.doi.org/10.11636/Record.2019.015.

Fekete, J.R., Sowards, J.W., Amaro, R.L., 2015. Economic impact of applying high strength steels in hydrogen gas pipelines. *Int. J. Hydrog. Energy* 40:10547-10558.

Flanigan, O., 1995. Characteristics of underground storage. In: Underground Gas Storage Facilities: Design and Implementation. Houston, London, Paris, Zurich, Tokyo: Golf Publishing Company; pp 54–67.

Flesch, S., Pudlo, D., Albrecht, D., Jacob, A., Enzmann, F., 2018. Hydrogen underground storage—Petrographic and petrophysical variations in reservoir sandstones from laboratory experiments under simulated reservoir conditions. *Int. J. Hydrogen Energy* 43: 20822–20835. https://doi.org/10.1016/j.ijhydene.2018.09.112

Florisson, O., 2006. NaturalHy final publishable activity report. http://www.naturalhy.net/docs/project_reports/Final_Publishable_Activity_Report.pdf

Forsberg, C.W., 2006. Assessment of Nuclear-Hydrogen Synergies with Renewable Energy Systems and Coal Liquefaction Processes Oak Ridge National Laboratory, ORNL/TM-2006/114, 57 p.

Gabrielli, P., Poluzzi, A., Kramer, G. J., Spiers, C., Mazzotti, M., Gazzani, M., 2020. Seasonal energy storage for zero-emissions multi-energy systems via underground hydrogen storage. *Renewable and Sustainable Energy Reviews* 121:109629. https://doi.org/10.1016/j.rser.2019.109629

Gajda, D., Lutyński, M., 2021. Hydrogen permeability of epoxy composites as liners in lined rock caverns—experimental study. *Appl. Sci.* 11:3885. https://doi.org/10.3390/app11093885

Geissbühler, L., Becattini, V., Zanganeh, G., Zavattoni, S., Barbato, M., Haselbacher, A., Steinfeld, A., 2018. Pilot-Scale Demonstration of Advanced Adiabatic Compressed Air Energy Storage, Part 1: Plant Description and Tests with Sensible Thermal-Energy Storage. *J. Energy Storage* 17: 129–39. https://doi.org/10.1016/j.est.2018.02.004

Geoscience Australia, 2021. Officer Basin. https://www.ga.gov.au/scientific-topics/energy/province-sedimentary-basin-geology/petroleum/onshore-australia/officer-basin

Gniese, C., Bombach, P., Rakoczy, J., Hoth, N., Schlömann, M., Richnow, H.-H., Krüger, M., 2014. Relevance of Deep-Subsurface Microbiology for Underground Gas Storage and Geothermal Energy Production. *Adv. Biochem. Eng. Biotechnol.* 142:95–121. https://doi.org/10.1007/10

Godfrey, B., Dowling, R., Forsyth, M., Grafton, R.Q. and Wyld, I., 2017. The Role of Energy Storage in Australia's Future Energy Supply Mix. Report for the Australian Council of Learned Academies., www.acola.org.au.

Gombert, P., Lafortune, S., Pokryszka, Z., Lacroix, E., de Donato, P., Jozja, N., 2021. Monitoring scheme for the detection of hydrogen leakage from a deep underground storage. Part 2: Physico-chemical impacts of hydrogen injection into a shallow chalky aquifer. *Appl. Sci.* 11:2686. https://doi.org/10.3390/app11062686

Goodall, D. C., Åberg, B., Brekke, T. L., 1988. Fundamentals of Gas Containment in Unlined Rock Caverns. *Rock Mech. Rock Eng.* 21: 235–58. https://doi.org/10.1016/0148-9062(89)92443-1

Goodwin, R. D., Diller, D. E., Roder, H. M., Weber, L. A., 1964. Second and Third Virial Coefficients for Hydrogen. *J. Res. NBS* 68A:121–126. https://doi.org/10.1080/00268977100103441

Gregory, S. P., Barnett, M. J., Field, L. P., Milodowski, A. E., 2019. Subsurface Microbial Hydrogen Cycling: Natural Occurrence and Implications for Industry. *Microorganisms* 7: 53. https://doi.org/10.3390/microorganisms7020053

Groenenberg, R., Goncalvez, C., Dijkstra, H., Wassing, B., Orlic, B., Valk, K. Van Der, Meulen, T. H. Van Der, Kranenburg-Bruinsma, K., 2020. *Techno-Economic Modelling of Large-Scale Energy Storage Systems*. TNO 2020 R12004

Guélard, J., Beaumont, V., Rouhcon, V., Guyot, F., Pillot, D., Jézéquel, D., Ader, M., Newell, K.D., Deville, E., 2017. Natural H_2 in Kansas: Deep or shallow origin? *Geochemistry, Geophysics, Geosystems* 18:1841–1865. https://doi.org/10.2113/2.4.476

Guo, X., Du, Z., Guo, P., Du, Y., Fu, Y., Liang, T., 2006. Design and demonstration of creating underground gas storage in a fractured oil depleted carbonate reservoir. *SPE Russian Oil and Gas Technical Conference and Exhibition, Moscow, Russia, 3-6 October*, *1*, 544–557. https://doi.org/10.2118/102397-ms

Hagemann, B., Rasoulzadeh, M., Panfilov, M., Ganzer, L., Reitenbach, V., 2016b. Hydrogenization of underground storage of natural gas: Impact of hydrogen on the hydrodynamic and bio-chemical behavior. *Comput. Geosci.* 20: 595–606. https://doi.org/10.1007/s10596-015-9515-6

Haines, P.W., 2010. The Carribuddy Group and Worral Formation, Canning Basin, WA: reassessment of stratigraphy and petroleum potential. *APPEA J.* 50:425-444.

Hashemi, L., Blunt, M., Hajibeygi, H., 2021a. Pore-scale modelling and sensitivity analyses of hydrogen-brine multiphase flow in geological porous media. *Sci. Rep.* 11:8348. https://doi.org/10.1038/s41598-021-87490-7

Hashemi, L., Glerum, W., Farajzadeh, R., Hajibeygi, H., 2021b. Contact Angle Measurement for Hydrogen/Brine/Sandstone System Using Captive-Bubble Method Relevant for Underground Hydrogen Storage. *Adv. Water Resour.* (in press) https://doi.org/10.1016/j.advwatres.2021.103964

Hassannayebi, N., Azizmohammadi, S., De Lucia, M., Ott, H., 2019. Underground hydrogen storage: application of geochemical modelling in a case study in the Molasse Basin, Upper Austria. *Environ. Earth Sci.* 78:1–14. https://doi.org/10.1007/s12665-019-8184-5

Hassanpouryouzband, A., Joonaki, E., Edlmann, K., Heinemann, N., Yang, J.,2020. Thermodynamic and transport properties of hydrogen containing streams. *Sci. Data* 7: 1–15. https://doi.org/10.1038/s41597-020-0568-6

Hassanpouryouzband, A., Joonaki, E., Edlmann, K., Haszeldine, R. S., 2021. Offshore Geological Storage of Hydrogen: Is This Our Best Option to Achieve Net-Zero? *ACS Energy Lett.* 6:2181–2186. https://doi.org/10.1021/acsenergylett.1c00845

Heinemann, N., Alcalde, J., Miocic, J. M., Hangx, S. J. T., Kallmeyer, J., Ostertag-Henning, C., Hassanpouryouzband, A., Thaysen, E. M., Strobel, G. J., Schmidt-Hattenberger, C., Edlmann, K., Wilkinson, M., Bentham, M., Stuart Haszeldine, R., Carbonell, R., Rudloff, A., 2021. Enabling large-scale hydrogen storage in porous media – the scientific challenges. *Energy Environ. Sci.* 14:853. https://doi.org/10.1039/d0ee03536j

Hemme, C., van Berk, W., 2018. Hydrogeochemical modeling to identify potential risks of underground hydrogen storage in depleted gas fields. *Appl. Sci.* 8: 1–19. https://doi.org/10.3390/app8112282

Henkel, S., Pudlo, D., Werner, L., Enzmann, F., Reitenbach, V., Albrecht, D., Würdemannd, H., Heistere, K., Ganzer, L., Gaupp, R., 2014. Mineral reactions in the geological underground induced by H_2 and CO_2 injections. *Energy Procedia* 63:8026–8035. https://doi.org/10.1016/j.egypro.2014.11.839

Hodgkinson, J., Preda, M., Hortle, A., McKillop, M., Dixon, O., and Foster, L. 2009. The potential impact of carbon dioxide injection on freshwater aquifers: the Surat and Eromanga Basins in Queensland. (Edited by Draper, J). Department of Employment, Economic Development and Innovation, Queensland. 133 pp.

Hord, J., Parrish, W.R., 1979. Economics of Hydrogen, in Cox, R.I. (Ed), Hydrogen: Its Technologies and Implications, Implication of Hydrogen Energy – Volume V, CRC Press, Boca Raton.

Hydrogen Council, 2020. Path to hydrogen competitiveness. A cost perspective, Hydrogen Council.

HyUnder, 2014a. Assessment of the Potential, the Actors and Relevant Business Cases for Large Scale and Long Term Storage of Renewable Electricity by Hydrogen Underground Storage in Europe, Executive Summary. http://hyunder.eu/publications/.

HyUnder, 2014b. Assessment of the Potential, the Actors and Relevant Business Cases for Large Scale and Long Term Storage of Renewable Electricity by Hydrogen Underground Storage in Europe, Deliverable No. 6.2a, Representative Case Studies with a focus on salt cavern storage, Case Study Germany, Executive Summary.

Iglauer, S., Ali, M., Keshavarz, A., 2021. Hydrogen Wettability of Sandstone Reservoirs: Implications for Hydrogen Geo-Storage. *Geophys. Res. Lett.* 48: 1–5. https://doi.org/10.1029/2020GL090814

Iordache, I., Schitea, D., Gheorghe, A. V., Iordache, M., 2014. Hydrogen underground storage in Romania, potential directions of development, stakeholders and general aspects. *Int. J. Hydrogen Energy* 39:11071–11081. https://doi.org/10.1016/j.ijhydene.2014.05.067

Iordache, M., Schitea, D., Deveci, M., Akyurt, İ. Z., Iordache, I., 2019. An integrated ARAS and interval type-2 hesitant fuzzy sets method for underground site selection: Seasonal hydrogen storage in salt caverns. *J. Petrol. Sci. Eng.* 175:1088–1098. https://doi.org/10.1016/j.petrol.2019.01.051

Ivanova, A. E., Borzenkov, I. A., Tarasov, A. L., Milekhina, E. I., Belyaev, S. S., 2007a. A Microbiological Study of an Underground Gas Storage in the Process of Gas Injection. *Microbiol.* 76: 453–460. https://doi.org/10.1134/S002626170704011X

Ivanova, A. E., Borzenkov, I. A., Tarasov, A. L., Milekhina, E. I., Belyaev, S. S., 2007b. A Microbiological Study of an Underground Gas Storage in the Process of Gas Extraction. *Microbiol.* 76: 461–468. https://doi.org/10.1134/S0026261707040121

Jalili, P., Saydam, S., Cinar, Y., 2011. "CO_2 Storage in Abandoned Coal Mines." In *Proceedings of the 2011 Coal Operators' Conference, Mining Engineering, University of Wollongong, 18-20 February*, 355–60.

Johannsen, T.B., 1993. Renewable Energy: Sources for Fuels and Electricity.

Kallikragas, D. T., Plugatyr, A. Y., Svishchev, I. M., 2014. High temperature diffusion coefficients for O_2, H_2, and OH in water, and for pure water. *J. Chem. Eng. Data* 59: 1964–1969. https://doi.org/10.1021/je500096r

Kilinçer, N., Gümrah, F., 2000. Numerical simulation study on mixing of inert cushion gas with working gas in an underground gas storage reservoir. *Energy Sources* 22:869–879. https://doi.org/10.1080/00908310051128219

Kim, J., Choi, J., Park, K., 2015. Comparison of nitrogen and carbon dioxide as cushion gas for underground gas storage reservoir. *Geosys. Eng. 18*(3), 163–167. https://doi.org/10.1080/12269328.2015.1031916

Kjørholt, H., and E. Broch. 1992. "The Water Curtain-a Successful Means of Preventing Gas Leakage from High-Pressure, Unlined Rock Caverns." *Tunnelling and Underground Space Technology* 7: 127–32. https://doi.org/10.1016/0886-7798(92)90042-G

Kleinitz, W., Böhling, E., 2005. Underground gas storage in porous media - Operating experience with bacteria on gas quality. 67th European Association of Geoscientists and Engineers, EAGE Conference and Exhibition. https://doi.org/10.2523/94248-ms

Kling, G., Maurer, G., 1991. The solubility of hydrogen in water and in 2-aminoethanol at temperatures between 323 K and 423 K and pressures up to

16 MPa. *J. Chem. Thermodyn.* 23:531–541. https://doi.org/10.1016/S0021-9614(05)80095-3

Kovári, K., 1993. “Basic Consideration on Storage of Compressed Natural Gas in Rock Chambers.” *Rock Mech. Rock Eng.* 26: 1–27. https://doi.org/10.1007/BF01019867

Kruck, O., Crotogino, F., Prelicz, R., Rudolph, T., 2013. Overview on all known underground storage technologies for hydrogen. HyUnder Deliverable No. 3.1.

Kurose, H., Ikeya, S., Chang, C., Maejima, T., Shimaya, S., Tanaka, T., Aoki, K., 2014. “Construction of Namikata Underground LPG Storage Cavern in Japan.” *Int. J. JCRM* 10: 15–24. https://doi.org/10.11187/ijjcrm.10.15.

Kuttan, K., Kulla, J. B., and Newman, R. G., 1986. Freshwater influx in the Gippsland Basin: impact on formation evaluation, hydrocarbon volumes and hydrocarbon migration: *APPEA J.* 26: 242-249.

Labaune, F., Knudsen, J. E., 1987. Inert Gas in Tonder Aquifer Storage: a Complete Preliminary Computer Study. In *SPE Annual Technical Conference & Exhibition, Dallas, Texas, USA, 27-30 September* (pp. 289–298). https://doi.org/10.2523/16863-ms

Lafortune, S., Gombert, P., Pokryszka, Z., Lacroix, E., de Donato, P., Jozja, N., 2020. Monitoring scheme for the detection of hydrogen leakage from a deep underground storage. Part 1: On-site validation of an experimental protocol via the combined injection of helium and tracers into an aquifer. *Appl. Sci.* 10:6058. https://doi.org/10.3390/app10176058

Lahnaoui, A., Wulf, C., Heinrichs, H., Dalmazzone, D., 2019. Optimizing hydrogen transportation system for mobility via compressed hydrogen trucks. *Int. J. Hydrog. Energy* 44:19302-19312.

Laille, J. P., Coulomb, C., Tek, M. R., 1986. Underground storage in Cerville-Velaine, France: A case history in conversion and inert gas injection as cushion substitute. In *SPE Annual Technical Conference and Exhibition, New Orleans, LA, U.S.A, October 5-8*. https://doi.org/10.2523/15588-ms

Laille, J. P., Molinard, J. E.,Wents, A.,1988. Inert gas injection as part of the cushion of the underground storage of Saint-Clair-Sur-Epte, France. In *SPE Gas Technology Symposium, Dallas, Texas, June 13-15*. https://doi.org/10.2523/17740-ms

Lankof, L., Tarkowski, R., 2020. Assessment of the potential for underground hydrogen storage in bedded salt formation. *Int J. Hydrogen Energy* 45:19479–19492. https://doi.org/10.1016/j.ijhydene.2020.05.024

Larin, N., Zgonnik, V., Rodina, S., Deville, E., Prinzhofer, A., Larin, V. N., 2015. Natural Molecular Hydrogen Seepage Associated with Surficial, Rounded Depressions on the European Craton in Russia. *Nat. Resour. Res.* 24: 369–383. https://doi.org/10.1007/s11053-014-9257-5

Leachman, J. W., Jacobsen, R. T., Penoncello, S. G., Lemmon, E. W., 2009. Fundamental equations of state for parahydrogen, normal hydrogen, and orthohydrogen. *J. Phys. Chem. Ref. Data* 38:721–748. https://doi.org/10.1063/1.3160306

Lebon, M., Nabil, R., Lehuen, P., 1998. Case study of Gas BTU Control for Operational Strategy and Inert Gas Injection Planning. In *SPE Annual Technical Conference & Exhibition, New Orleans, Louisiana, U.S.A. 27-30 September*.

Le Duigou, A., Bader, A.-G., Lanoix, J.-C., Nadau, L., 2017. Relevance and costs of large scale underground hydrogen storage in France. *Int. J. Hydrogen Energy* 42: 22987-23003. https://doi.org/10.1016/j.ijhydene.2017.06.239

Lemieux, A., Sharp, K., Shkarupin, A., 2019. Preliminary assessment of underground hydrogen storage sites in Ontario, Canada. *Int. J. Hydrogen Energy* 44: 15193–15204. https://doi.org/10.1016/j.ijhydene.2019.04.113

Lepszy, S., Chmielniak, T., Mońka, P., 2017. Storage system for electricity obtained from wind power plants using underground hydrogen reservoir. *J. Power Technol.* 97: 61–68.

Lewandowska-Śmierzchalska, J., Tarkowski, R., Uliasz-Misiak, B., 2018. Screening and ranking framework for underground hydrogen storage site selection in Poland. *Int. J. Hydrogen Energy* 43: 4401-4414. https://doi.org/10.1016/j.ijhydene.2018.01.089

Li, Z., Wang, K., Wang, A., Liu, H., 2009. Experimental Study of Water Curtain Performance for Gas Storage in an Underground Cavern. *J. Rock Mech. Geotech. Eng. and Geotechnical Engineering* 1: 89–96. https://doi.org/10.3724/sp.j.1235.2009.00089.

Li, D., Beyer, C., Bauer, S., 2018. A unified phase equilibrium model for hydrogen solubility and solution density. *Int. J. Hydrogen Energy* 43: 512–529. https://doi.org/10.1016/j.ijhydene.2017.07.228

Li, X.J., Allen, J.D., Stager, J.A., Ku, A.Y., 2020. Paths to low-cost hydrogen energy at a scale for transportation applications in the USA and China via liquid-hydrogen distribution networks. *Clean Energy* 4:26-47.

Liang, J., Lindblom, U., 1994. Analyses of Gas Storage Capacity in Unlined Rock Caverns. *Rock Mech. Rock Eng.* 27: 115–34. https://doi.org/10.1007/BF01020306

Liebscher, A., Wackerl, J., Streibel, M., 2016. Geologic Storage of Hydrogen - Fundamentals, Processing, and Projects. *Hydrogen Science and Engineering: Materials, Processes, Systems and Technology* 2:629–658. https://doi.org/10.1002/9783527674268.ch26

Lindblom, U. E., 1997. Design Criteria for the Brooklyn Union Gas Storage Caverns at JFK Airport, New York. *Int. J. Rock Mech. Min. Sci.* 34: 179. https://doi.org/10.1016/S1365-1609(97)00040-3

Liu, W., Zhang, Z., Chen, J., Jiang, D., Wu, F., Fan, J., Li, Y., 2020. Feasibility evaluation of large-scale underground hydrogen storage in bedded salt rocks of China: A case study in Jiangsu province. *Energy* 198:117348. https://doi.org/10.1016/j.energy.2020.117348

Lord, A. S., Kobos, P. H., Klise, G. T., Borns, D. J., 2011. *A Life Cycle Cost Analysis Framework for Geological Storage of Hydrogen: A User's Tool*. *Sandia National Laboratories*. https://doi.org/SAND2011-6221

Lord, A.S., Kobos, P.H., Borns, D.J., 2014. Geologic storage of hydrogen: Scaling up to meet city transportation demands. *Int. J. Hydrogen Energy* 39: 15570-15582. http://dx.doi.org/10.1016/j.ijhydene.2014.07.121

Lovley, D. R., Klug, M. J., 1986. Model for the distribution of sulfate reduction and methanogenesis in freshwater sediments. *Geochim. Cosmochim. Acta* 50: 11–18. https://doi.org/10.1016/0016-7037(86)90043-8

Lovley, D. R., Goodwin, S., 1988. Hydrogen concentrations as an indicator of the predominant terminal electron-accepting reactions in aquatic sediments. *Geochim. Cosmochim. Acta* 52:2993–3003. https://doi.org/10.1016/0016-7037(88)90163-9

Lu, M., 2010. Rock Engineering Problems Related to Underground Hydrocarbon Storage. *J. Rock Mech. Geotech. Eng.* 2: 289–97. https://doi.org/10.3724/SP.J.1235.2010.00289

Magot, M., Ollivier, B., Patel, B. K. C., 2000. Microbiology of petroleum reservoirs. Antonie van Leeuwenhoek, *Int. J. Gen. Mol. Microbiol.* 77: 103–116. https://doi.org/10.1023/A:1002434330514

Massoudi, R., King, A. D., 1974. Effect of pressure on the surface tension of water. Adsorption of low molecular weight gases on water at 25°. *J. Phys. Chem.* 78: 2262–2266. https://doi.org/10.1021/j100615a017

Matos, C.R., Carneiro, J.F., Silva, P.P., 2019. Overview of Large-Scale Underground Energy Storage Technologies for Integration of Renewable Energies and Criteria for Reservoir Identification. *J. Energy Storage* 21:241-258. https://doi.org/10.1016/j.est.2018.11.023

Meddles, R.M., 1978. Underground gas storage in the Leyden lignite mine. Rocky Mt. Assoc. Geol. fall field conference, Colorado Springs, CO, USA, 9 Oct 1978.

Mehin, K., Kamel, M., 2002. *Gas Resources of the Otway Basin in Victoria.* Department of Natural Resources and Environment, East Melbourne. State of Victoria. 54p.

Menéndez, J., Loredo, J., 2019. Compressed Air Energy Storage plants in abandoned underground mines: Preliminary analysis and potential. IAPE '19, Oxford, UK.

Mhanna, S., Saedi, I., Mancarella, P., 2020. Regional Case Studies on Multi-Energy System Integration – Hydrogen Injection. Future Fuels Cooperative Research Centre, Project RP1.1-02, Milestone Report M18.

Michalski, J., Buenger, U., Crotogino, F., Donadei, S., Schneider, G.-S., Pregger, T., Cao, K.-K., Heide, D., 2017. Hydrogen generation by electrolysis and storage in salt caverns: Potentials, economics and systems aspects with regard to the German energy transition. *Int. J. Hydrogen Energy* 42: 13427-13443.

Misra, B. R., Foh, S. E., Berry, R. M., Labaune, F., 1988. The use of inert base gas in underground natural gas storage. In *SPE Gas Technology Symposium, Dallas, Texas, June 13-15* (pp. 353–360).

Moretti, I., Prinzhofer, A., Françolin, J., Pacheco, C., Rosanne, M., Rupin, F., Mertens, J., 2021a. Long-term monitoring of natural hydrogen superficial emissions in a Brazilian cratonic environment. Sporadic large pulses versus daily periodic emissions. *Int, J. Hydrogen Energy* 46: 3615–3628. https://doi.org/10.1016/j.ijhydene.2020.11.026

Moretti, I., Brouilly, E., Loiseau, K., Prinzhofer, A., Deville, E., 2021b. Hydrogen emanations in intracratonic areas: New guide lines for early exploration basin screening. *Geosci.* 11: 145. https://doi.org/10.3390/geosciences11030145

Mouli-Castillo, J., Heinemann, N., and Edlmann, K., 2021. Mapping geological hydrogen storage capacity and regional heating demands: An applied UK case study. *Appl. Energy* 283:116348.

Myagkiy, A., Moretti, I., Brunet, F., 2020. Space and time distribution of subsurface H_2 concentration in so-called “fairy circles”: Insight from a conceptual 2-D transport model. *Earth Sci. Bull.* 191:13. https://doi.org/10.1051/bsgf/2020010

Nahm, G.Y., 2002. The hydrogeology of the Gippsland Basin and its role in the genesis and accumulation of petroleum. PhD Thesis, University of Melbourne, Australia, 295 p.

Namdar, H., Khodapanah, E., Tabatabaei-Nejad, S. A., 2019a. Application of proxy model to optimize base gas replacement by smart gas in underground gas storage process. *SN Appl. Sci.* 1:1–13. https://doi.org/10.1007/s42452-019-0521-5

Namdar, H., Khodapanah, E., Tabatabaei-Nejad, S. A., 2019b. Comparison of base gas replacement using nitrogen, flue gas and air during underground natural gas storage in a depleted gas reservoir. *Energy Sources, Part A: Recovery, Utilization and Environmental Effects* 42:2778-2793. https://doi.org/10.1080/15567036.2019.1618989

Oy, N., 1992. New Hydrogen Technologies Project Report: Evaluation of Techniques. Finland.

Ozarslan, A., 2012. Large-scale hydrogen energy storage in salt caverns. *Int. J. Hydrogen Energy* 37: 14265–14277. https://doi.org/10.1016/j.ijhydene.2012.07.111

Panfilov, M., Gravier, G., Fillacier, S., 2006. Underground storage of H_2 and H_2-CO_2-CH_4 mixtures. ECMOR 2006 - 10th European Conference on the Mathematics of Oil Recovery, (September 2006). https://doi.org/10.3997/2214-4609.201402474

Panfilov, M., 2010. Underground Storage of Hydrogen: In Situ Self-Organisation and Methane Generation. *Trans. Porous Med.* 85: 841–865

Panfilov, M., Panfilova, I., Toleukhanov, A., Kaltayev, A., 2012. Bio-reactive two-phase transport and population dynamics in underground storage of hydrogen: Natural self-organisation. In ECMOR 13th European Conference on the Mathematics of Oil Recovery, Biarritz, France, 10-13 September. https://doi.org/10.3997/2214-4609.20143214

Panfilov, M., 2016. 4 - Underground and pipeline hydrogen storage A2 - Gupta, Ram B. In: Basile, A., Veziroğlu, T.N. (Eds.), Compendium of Hydrogen Energy. Woodhead Publishing, pp. 91-115.

Panfilov, M., Reitenbach, V., Ganzer, L., 2016. Self-organization and shock waves in underground methanation reactors and hydrogen storages. *Environ. Earth Sci.* 75:313. https://doi.org/10.1007/s12665-015-5048-5

Parkinson, G., 2020. Storage proponent for huge Broken Hill micro-grid fails to land finance for pilot plant. reneweconomy.com.au

Paterson, L., 1983. The implications of fingering in underground hydrogen storage. *Int. J. Hydrogen Energy* 8:53-59.

Perazzelli, P., Anagnostou, G., 2016. “Design Issues for Compressed Air Energy Storage in Sealed Underground Cavities.” *J. Rock Mech. Geotech. Eng.* 8: 314–28. https://doi.org/10.1016/j.jrmge.2015.09.006

Perez, A., Pérez, E., Dupraz, S., Bolcich, J., 2016. Patagonia Wind - Hydrogen Project: Underground Storage and Methanation. 21st World Hydrogen Energy Conference, Jun 2016, Zaragoza, Spain. hal-01317467

Piessens, K., Dusar, M., 2003. CO_2 sequestration in abandoned coalmines. Proceedings of the International Coal bed Methane Symposium, May 5-9, Tuscaloosa, Alabama. Paper No. 346.

Piessens, K., Dusar, M., 2004. “Feasibility of CO_2 Sequestration in Abandoned Coal Mines in Belgium.” *Geologica Belgica* 7: 165–80.

Prinzhofer, A., Tahara Cissé, C. S., Diallo, A. B., 2018. Discovery of a large accumulation of natural hydrogen in Bourakebougou (Mali). *Int. J. Hydrogen Energy* 43:19315–19326. https://doi.org/10.1016/j.ijhydene.2018.08.193

Prinzhofer, A., Moretti, I., Françolin, J., Pacheco, C., D'Agostino, A., Werly, J., Rupin, F., 2019. Natural hydrogen continuous emission from sedimentary basins: The example of a Brazilian H_2 -emitting structure. *Int. J. Hydrogen Energy* 44:5676–5685. https://doi.org/10.1016/j.ijhydene.2019.01.119

Qiu, Y., Zhou, S., Wang, J., Chou, J., Fang, Y., Pan, G., Gu, W., 2020. "Feasibility Analysis of Utilising Underground Hydrogen Storage Facilities in Integrated Energy System: Case Studies in China." *Appl. Energy* 269:115140. https://doi.org/10.1016/j.apenergy.2020.115140

Ranchou-Peyruse, M., Gasc, C., Guignard, M., Aüllo, T., Dequidt, D., Peyret, P., Ranchou-Peyruse, A., 2017. The sequence capture by hybridization: a new approach for revealing the potential of mono-aromatic hydrocarbons bioattenuation in a deep oligotrophic aquifer. *Microbiol. Biotechnology* 10: 469–479. https://doi.org/10.1111/1751-7915.12426

Ranchou-Peyruse, M., Auguet, J. C., Mazière, C., Restrepo-Ortiz, C. X., Guignard, M., Dequidt, D., Chiquet, P., Cézac, P., Ranchou-Peyruse, A., 2019. Geological gas-storage shapes deep life. *Environ. Microbiol.* 21: 3953–3964. https://doi.org/10.1111/1462-2920.14745

Reddi, K., Mintz, M., Elgowainy, A., Sutherland, E., 2016. Challenges and Opportunities of Hydrogen Delivery via Pipeline, Tube-Trailer, LIQUID Tanker and Methanation-Natural Gas Grid, in Stolten, D. and Emonts, B., (eds): Hydrogen Science and Engineering: Materials, Processes, Systems and Technology, First Edition, Wiley-VCH Verlag GmbH & Co. KGaA.

Reddi, K., Elgowainy, A., Rustagi, N., Gupta, E., 2018. Techno-economic analysis of conventional and advanced high-pressure tube trailer configurations for compressed hydrogen gas transportation and refuelling. *Int. J. Hydrog. Energy* 43:4428-4438.

Rowan, M. G., Hearon IV, T. E., Kernen, R. A., Giles, K. A., Gannaway-Dalton, C. E., Williams, N. J., Fiduk, J. C., Lawton, T. F., Hannah, P. T., Fischer, M. P., 2020. A review of allochthonous salt tectonics in the Flinders and Willouran ranges, South Australia, Australian Journal of Earth Sciences, 67:6, 787-813, DOI: 10.1080/08120099.2018.1553063

Rutqvist, J., Kim, H. M., Ryu, D. W., Synn, J. H., Song, W. K., 2012. "Modeling of Coupled Thermodynamic and Geomechanical Performance of Underground Compressed Air Energy Storage in Lined Rock Caverns." *Int. J. Rock Mech. Mining Sci.* 52: 71–81. https://doi.org/10.1016/j.ijrmms.2012.02.010

Sainz-Garcia, A., Abarca, E., Rubi, V., Grandia, F., 2017. Assessment of feasible strategies for seasonal underground hydrogen storage in a saline aquifer. *Int. J. Hydrogen Energy* 42:16657–16666. https://doi.org/10.1016/j.ijhydene.2017.05.076

Scafidi, J., Wilkinson, M., Gilfillan, S. M. V., Heinemann, N., Haszeldine, R. S., 2021. A quantitative assessment of the hydrogen storage capacity of the UK continental shelf. *Int. J. Hydrogen Energy* 46: 8629–8639. https://doi.org/10.1016/j.ijhydene.2020.12.106

Schaeffer, J., 2008. Scaling point-based aquifer data for developing regional groundwater models: application to the Gippsland groundwater system. PhD Thesis, University of Melbourne, Australia, 331 p. and appendices.

Schiebahn, S., Grube, T., Robinius, M., Tietze, V., Kumar, B., Stolten, D., 2015. Power to gas: Technology overview, systems analysis and economic assessment for a case study in Germany. *Int. J. Hydrogen Energy* 40: 4285-4294.

Schoenung, S., 2011. Economic Analysis of Large-Scale Hydrogen Storage for Renewable Utility Applications. SANDIA Report, Sandia National Laboratories, Albuquerque, New Mexico and Livermore, California, SAND2011-4845.

Shi, L., Zhang, B., Wang, L., Wang, H. X., Zhang, H. J., 2018. Functional Efficiency Assessment of the Water Curtain System in an Underground Water-Sealed Oil Storage Cavern Based on Time-Series Monitoring Data. *Eng. Geol.* 239: 79–95. https://doi.org/10.1016/j.enggeo.2018.03.015.

Shi, Z., Jessen, K., Tsotsis, T. T., 2020. Impacts of the subsurface storage of natural gas and hydrogen mixtures. *Int. J. Hydrogen Energy* 45: 8757–8773. https://doi.org/10.1016/j.ijhydene.2020.01.044

Simon, J., Ferriz, A. M., Correas, L. C., 2015. HyUnder - Hydrogen underground storage at large scale: Case study Spain. *Energy Procedia* 73:136–144. https://doi.org/10.1016/j.egypro.2015.07.661

Slowinski Jr., E. J., Gates, E. E., & Waring, C. E., 1957. The Effect of Pressure on the Surface Tension of Liquids. *J. Phys. Chem.* 61:808–810.

Šmigáň, P., Greksák, M., Kozánková, J., Buzek, F., Onderka, V., Wolf, I., 1990. Methanogenic bacteria as a key factor involved in changes of town gas stored in an underground reservoir. *FEMS Microbiol. Lett.* 73: 221–224. https://doi.org/10.1016/0378-1097(90)90733-7

Smith M, Karim F, Sparrow A, Cassel R and Hall L (2015) Context statement for the Cooper subregion. Product 1.1 for the Cooper subregion from the Lake Eyre Basin Bioregional Assessment. Department of the Environment, Bureau of Meteorology, CSIRO and Geoscience Australia, Australia.

Snow, T. M., McKay, I., Irwin, D. D., 2014. Bream Field (Phase 4) - EOR and late field life management. In *International Petroleum Technology Conference, Kuala Lumpur, Malaysia, 10-12 December*. https://doi.org/10.2523/iptc-18224-ms

Sonier, F., Lehuen, P., Nabil, R., 1993. Full-field gas storage simulation using a control-volume finite-element model. In *SPE Annual Technical Conference & Exhibition, Houston, Texas, 3-6 October* (pp. 515–524). https://doi.org/10.2523/26655-ms

Srinivasan, S.S., Sherif, S.A., Barbir, F., Veziroglu, T.N., Mahishi, M., Pratt, R., 2016. Hydrogen Energy Technologies. In Goswami and Kreith (eds.) Energy Efficiency and Renewable Energy Handbook, CRC Press.

Stille, H., Johansson, J., Sturk, R., 1994. High Pressure Storage of Gas in Lined Shallow Rock Caverns - Results from Field Tests. In *Eurock SPE/ISRM Rock Mechanics in Petroleum Engineering, Delft, The Netherlands, 29-31 August*, 689–96. https://doi.org/10.2118/28115-ms

Stone, H. B. J., Veldhuis, I., Richardson, R. N., 2009. Underground hydrogen storage in the UK. Geological Society Special Publication, 313, 217–226. https://doi.org/10.1144/SP313.13

Strobel, G., Hagemann, B., Wirth, M., Ganzer, L., 2020. Underground bio-methanation: Review and potential. *Oil Gas* 46: 35–43.

Stygar, M., Brylewski, T., 2013. Towards a hydrogen economy in Poland. *Int. J. Hydrogen Energy* 38: 1–9. https://doi.org/10.1016/j.ijhydene.2012.10.056

Tarasov, A. L., Borzenkov, I. A., Chernykh, N. A., Belyayev, S. S., 2011a. Isolation and investigation of anaerobic microorganisms involved in methanol transformation in an underground gas storage facility. *Microbiol.* 80:172–179. https://doi.org/10.1134/S0026261711020147

Tarasov, A. L., Borzenkov, I. A., Belyayev, S. S., 2011b. Investigation of the trophic relations between anaerobic microorganisms from an underground gas repository during methanol utilization. *Microbiol.* 80: 180–187. https://doi.org/10.1134/S0026261711020159

Tarkowski, R., 2017. Perspectives of using the geological subsurface for hydrogen storage in Poland. *Int. J. Hydrogen Energy* 42: 347–355. https://doi.org/10.1016/j.ijhydene.2016.10.136

Tarkowski, R., 2019. Underground hydrogen storage: Characteristics and prospects. *Renewable and Sustainable Energy Reviews* 105: 86-94.

Tarkowski, R., Czapowski, G., 2018. Salt domes in Poland – Potential sites for hydrogen storage in caverns. *Int. J. Hydrogen Energy* 3:21414–21427. https://doi.org/10.1016/j.ijhydene.2018.09.212

Taylor, J. B., Alderson, J. E. A., Kalyanam, K. M., Lyle, A. B., Phillips, L. A., 1986. Technical and economic assessment of methods for the storage of large quantities of hydrogen. *Int. J. Hydrogen Energy* 11:5–22. https://doi.org/10.1016/0360-3199(86)90104-7

Telfer, D., 2013, Formation of the Enorama Salt Diapir Weld, Flinders Ranges, South Australia. Honours Thesis, University of Adelaide.

Thaysen, E. M., McMahon, S., Strobel, G. J., Butler, I. B., Ngwenya, B., Heinemann, N., Wilkinson, M., Hassanpouryouzband, A., McDermott, C. I., Edlmann, K., 2021. Estimating Microbial Hydrogen Consumption in Hydrogen Storage in

Porous Media as a Basis for Site Selection. *Renewable and Sustainable Energy Reviews* (submitted). https://eartharxiv.org/repository/view/1799/

Thomas, L. K., Katz, D. L., Tek, M. R., 1968 Threshold pressure phenomena in porous media. *SPE J.* 8:174-184.

Toleukhanov, A., Panfilov, M., Kaltayev, A., 2015a. Storage of hydrogenous gas mixture in geological formations: Self-organisation in presence of chemotaxis. *Int. J. Hydrogen Energy* 40: 15952–15962. https://doi.org/10.1016/j.ijhydene.2015.10.033

Toleukhanov, A., Panfilov, M., Kaltayev, A., 2015b. Analytical and numerical study of the impact of methanogenic bacteria on gas composition in underground hydrogen storages. *Eurasian Chemico-Technological J.* 17:243–249.

Torín-Ollarves, G. A., Trusler, J. P. M., 2021. Solubility of hydrogen in sodium chloride brine at high pressures. *Fluid Phase Equilibria* 539:113025. https://doi.org/10.1016/j.fluid.2021.113025

Torkzaban, S., Hocking, M., Gaal, A., Manamperi, S. and Iverach, C.P., 2020. Groundwater impact assessment - conceptual report, onshore Otway Basin, Victoria. Victorian Gas Program Technical Report 34. Geological Survey of Victoria. Department of Jobs, Precincts and Regions. Melbourne, Victoria. 94p.

Trotter, J. T., Thompson, D. M. T., Paterson, T. J. M., 1985. First Mined Underground Storage in Great Britain. Tunnelling 85. Institution Mining Metallurgy, London.

Turta, A. T., Sim, S. S. K., Singhal, A. K., Hawkins, B. F., 2007. Basic investigations on enhanced gas recovery by gas-gas displacement. *J. Can. Pet. Technol.* 47:39–44. https://doi.org/10.2118/2007-124

Underground Sun Storage: Final Report. 31 October 2017. S. Bauer. https://www.underground-sun-storage.at/fileadmin/bilder/03_NEU_SUNSTORAGE/Downloads/Underground_Sun.Storage_Publizierbarer_Endbericht_English.pdf

US DRIVE, 2013. Hydrogen Delivery Technical Team Roadmap. US DRIVE Partnership, accessed 11 August 2020, <http://www1.eere.energy.gov/vehiclesandfuels/pdfs/program/hdtt_roadmap_june2013.pdf>.

Varma, S., and Michael, K., 2012. Impact of multi-purpose aquifer utilisation on a variable-density groundwater flow system in the Gippsland Basin, Australia. *Hydrogeology J.* 20:119-134.

Varma, S., Underschultz, J., Giger, S.B., Field, B., Roncaglia, L., Hodgkinson, J., Hilditch, D., 2013. CO_2 geosequestration potential in the Northern Perth Basin, Western Australia. *Australian J. Earth Sci.* 60:23-44.

Vavra, C. L., Kaldi, J. G., & Sneider, R. M., 1992. Geological Applications of Capillary Pressure: A Review. *AAPG Bull* 76: 840–850.

Venter, R.D., Pucher, G., 1997. Modelling of stationary bulk hydrogen storage systems. *Int. J. Hydrogen Energy* 22:791-798.

Verhallen, P. T. H. M., Oomen, L. J. P., van der Elsen, A. J. J. M., & Kruger, A. J., 1964. The diffusion coefficients of helium, hydrogen, oxygen and nitrogen in water determined from the permeability of a stagnant liquid layer in the quasi-steady state. *Chem. Eng. Sci.* 39: 1535–1541.

VicGSV, 2020. dbMap online database. http://geoscience-web.s3-website-ap-southeast-2.amazonaws.com/well/hyperlinkages.htm

Wells, A.T., 1980. Evaporites in Australia. Bureau of mineral resources, Dept of National Development & Energy, bulletin 198.

Wiebe, R., Gaddy, V. L., 1934. The Solubility of Hydrogen in Water at 0, 50, 75 and 100° from 25 to 1000 Atmospheres. *J. Am. Chem. Soc.* 56:76–79. https://doi.org/10.1021/ja01316a022

Wise, D. L., & Houghton, G., 1966. The diffusion coefficients of ten slightly soluble gases in water at 10-60°C. *Chem. Eng. Sci.* 21: 999–1010. https://doi.org/10.1016/0009-2509(66)85096-0

Wu, D., Wang, J. G., Hu, B., Yang, S., 2020. A Coupled Thermo-Hydro-Mechanical Model for Evaluating Air Leakage from an Unlined Compressed Air Energy Storage Cavern. *Renew. Energy* 146: 907–20. https://doi.org/10.1016/j.renene.2019.07.034

Xiao, M., Zhang,H., Zhang,G.,2010. High density of hydrogen storage materials reviewed. *J. Shenyang Normal Univ. (Nat. Sci. edition)* 28: 208–209.

Yang, C., Ogden, J., 2007. Determining the lowest-cost hydrogen delivery mode. *Int. J. Hydrogen Energy* 32: 268-286.

Yanze, Y., De Kok, J., Clemens, T., 2009. Optimised combined underground gas storage and enhanced oil recovery. *SPE EUROPEC/EAGE Conference and Exhibition, Amsterdam, The Netherlands, 8-11 June*, 1–9.

Yekta, A. E., Manceau, J. C., Gaboreau, S., Pichavant, M., Audigane, P., 2018a. Determination of Hydrogen–Water Relative Permeability and Capillary Pressure in Sandstone: Application to Underground Hydrogen Injection in Sedimentary Formations. *Trans. Porous Med.* 122:333–356. https://doi.org/10.1007/s11242-018-1004-7

Yekta, A. E., Pichavant, M., Audigane, P., 2018b. Evaluation of geochemical reactivity of hydrogen in sandstone: Application to geological storage. *Appl. Geochem.* 95:182–194. https://doi.org/10.1016/j.apgeochem.2018.05.021

Zgonnik, V., 2020. The occurrence and geoscience of natural hydrogen: A comprehensive review. *Earth Sci. Rev.* 203:103140. https://doi.org/10.1016/j.earscirev.2020.103140

Zhang, P., Ge, J., Luo, G., 2010. The characteristics of the metal hydride hydrogen storage device and its application. *Gas Sep.* 6:52.

Zhang, Q., Liu, Q., He, G., 2020. Reexamining the Necessity of Adding Water Curtain Borehole with Improved Understanding of Water Sealing Criterion. *Rock Mech. Rock Eng.* 53: 4623–38. https://doi.org/10.1007/s00603-020-02194-0

Zhao, X., Jin, H., 2019. Investigation of hydrogen diffusion in supercritical water: A molecular dynamics simulation study. *Int. J. Heat Mass Transfer* 133:718–728. https://doi.org/10.1016/j.ijheatmasstransfer.2018.12.164

Zhou, S., Xia, C., Zhou, Y., 2020. Long-Term Stability of a Lined Rock Cavern for Compressed Air Energy Storage: Thermo-Mechanical Damage Modeling. *Eur. J. Environ. Civil Eng.* 24:2070–93. https://doi.org/10.1080/19648189.2018.1499556

Zivar, D., Kumar, S., Foroozesh, J., 2021. Underground hydrogen storage: A comprehensive review. *Int. J. Hydrogen Energy* 46:23436-23462. https://doi.org/10.1016/j.ijhydene.2020.08.138

FUTURE FUELS CRC

Future Fuels CRC

Enabling the Decarbonisation of Australia’s Energy Networks

www.futurefuelscrc.com

info@futurefuelscrc.com

Australian Government
Department of Industry, Science, Energy and Resources

AusIndustry
Cooperative Research Centres Program