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Key considerations for evaluating Underground Hydrogen Storage (UHS) potential in five contrasting Australian basins

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ABSTRACT

Hydrogen gas can provide baseload energy as society decarbonizes through the energy transition. Underground Hydrogen Storage (UHS) will be secure, convenient and scalable to accommodate excess hydrogen production or compensate temporary shortfalls in energy supply. Hydrogen is a gas under all viable subsurface conditions, so is invasive, mobile and low-density. Methane and CO_2 are also stored underground but storage parameters differ for each, affecting the balance of geological storage risks. UHS in Australia is most likely to utilise conventional sedimentary reservoir rocks bound by conventional trapping closures. Hydrogen energy density will affect the competitiveness of UHS against purpose-built surface storage or solution-mined salt cavities. This study presents an overview of key considerations when screening for UHS opportunities and evaluates them for five Australian sedimentary basins. A threshold storage depth mapped across them reveals that the most prospective UHS basins will have to function as integrated energy fluid resource systems.

1. Introduction

For the world to meet the maximum global warming target of 1.5 °C set as part of the 2015 Paris Agreement [1], global fossil fuel consumption – and related carbon dioxide (CO_2) emissions – must significantly decrease. A recent study by Ref. [2] suggests that as much as 58% of all currently known oil, 59% of natural gas and up to 89% of coal resources would need to remain unextracted to meet this target. The need for the energy sector to transition into a low to zero carbon sector, therefore, is apparent more than ever, and one of the most discussed options to enable this transition is for hydrogen (H_2) gas to become one of the major energy sources/carriers/storage resources of the future (e.g. Refs. [3,4]).

In the search for carbon neutral energy resources, hydrogen accumulations have been reported to occur naturally across the globe in various locations [5–10]. These natural accumulations, however, are not widespread enough to contribute to a large-scale natural hydrogen production industry at present as the formal description of natural hydrogen generation, migration and accumulation systems remains highly uncertain [6,10]. The processes of generating hydrogen from feedstock resources more readily available, on the other hand, are well understood [11]. Globally, the majority of industrial hydrogen is generated by steam reforming of methane gas [12]. The National Hydrogen Roadmap suggests that most hydrogen generated in Australia will be produced by the electrolysis of water [13,14], a process that when powered by renewable energy (solar, wind and hydro-power) is said to generate green hydrogen [15].

Within this context, Australia is also aiming to position itself in the global hydrogen market by establishing a large-scale hydrogen export industry (e.g. Ref. [16]). As of January 2022, more than 40 hydrogen generation projects were in development in Australia [14]. Some of these projects are anticipated to have the potential to generate between 300 kt to 3 Mt (million tonnes) of hydrogen gas annually (project IDs 28 and 75 as per AusH2 [14]). The Hydrogen Energy Supply Chain demonstration project began early in 2022 to export supercooled hydrogen to the Japanese market from the Mornington Peninsula in Victoria by boat [17]. Even more recently, Fortescue and E.ON agreed for Australian green hydrogen to replace a third of the German methane gas shortfall imposed by international sanctions arising from the Ukraine crisis [18]. However, these current commitments do not account for the surplus in hydrogen gas generation that will exist in Australia. Thus, national study efforts have also highlighted the need to accelerate the identification of Underground Hydrogen Storage (UHS) opportunities and solutions [19].

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1.1. Framing considerations for UHS

Manufactured hydrogen is typically stored: as compressed gas under elevated pressure near or at the Earth's surface (typically 100–200 bars in stationary vessels [20]; up to 700 bars in fuel tanks feeding hydrogen fuel cells [21]); as liquid at low temperature (below its liquefying temperature of −252.9 °C [20,22]); adsorbed under elevated pressure to liquid or solid adsorbents requiring a less demanding temperature constraint (e.g. −196 °C in the case of liquid nitrogen, porous active carbons and metal-organic frameworks [20]); or as a molecular component of solid metal hydrides or fluid chemical hydrides like methanol or ammonia [20,21]. These modes of storage are challenging and therefore costly to maintain at scale owing to their high energy cost and particular engineering requirements, including constrained storage efficiency and thermodynamic control [20,21]. Another option is to store hydrogen gas deep within the subsurface either at ambient conditions or at the required elevated pressure above ambient pressure. The most proven method to date is storage in solution-mined cavities created within thick intervals of undisturbed natural halite buried over geological time [23,24].

Underground storage of hydrogen gas for general industrial purposes was introduced in 1957 (to 1974) at Beynes in France [25]. However, until recently there has been minimal investment and interest beyond this and a few other similar projects due to the cost and lack of necessity. Ensuring reliable baseload energy supply as our society decarbonises through the energy transition means that the purpose for large-scale hydrogen storage has now arrived. However, there are many factors to consider when defining the best conditions for UHS.

Storing hydrogen in its gaseous phase is the only storage option within the viable subsurface depth range (refer to Ref. [26]). Thus, the temperature and formation fluid pressure of the subsurface storage location are key factors in determining economic viability. The same is true regarding the potential of the geological containment system to induce hydrogen losses or contamination. For example, as hydrogen diffuses somewhat readily into fresh, oxygenated (meteoric) water (H_2O), it is an advantage that the host rock be absent of fresh water and rather be saturated with a saline (connate) brine [27]. Similarly, a warmer host rock is likely inoculated against the presence of hydrogen-consuming microbes, though chemical reaction rates may be enhanced [28–31].

These factors depend on the depth of the storage location, which will also affect the capacity of a geological containment system to withhold hydrogen gas [32]. Pressure of the stored hydrogen itself – which will be above the equivalent hydrostatic pressure at a particular depth owing to compression due to buoyancy pressure – also has implications for containment integrity. A large hydrogen column may pose a risk to the mechanical integrity of geological formations through the potential to induce microseismic strain events. These might occur within the storage reservoir rock by reducing effective stress towards failure or within the overlying sealing rock by increasing the vertical stress which, if parallel to the maximum principal stress (defining an extensional regime), could also induce failure [33,34]. The likely need for frequent, rapid injection and production of hydrogen may also induce microseismic events via the same geomechanical pathways [34].

For economic viability it is vital that the subsurface storage location is near to end-users (e.g. Ref. [35]) or existing energy delivery infrastructure [36] that can be adapted to transport and/or export hydrogen gas. The energy transition, in part, will therefore further depend on a widespread, robust, agile, distributed subsurface hydrogen storage and delivery network that can smooth out the peaks and troughs of supply and demand. These fluctuations are inherent at local temporal and spatial scales for the preferred modes for green hydrogen generation (PV-solar and wind turbine powered water hydrolysis) and for typical seasonal use patterns [28,37]. Constructed surface facilities would provide small and relatively fixed-scale, short-period injection-production storage options for hydrogen energy supply buffering. Geological storage systems could be more flexible and secure at a range of scales for short-, medium- and long-term storage-production cycles of hydrogen energy supply.

In this study we define a play-based set of considerations for identifying, assessing and evaluating UHS opportunities in conventional reservoir systems within sedimentary basins. We define a threshold depth for UHS on the basis of temperature, hydrogen density and nominal caprock sealing capacity criteria implied by the works [20,29,32]. We demonstrate a comparative ranking approach with a set of cases focusing on five Australian sedimentary basins that represent a range of suitability and settings, aspects of which will relate directly to basin cases outside Australia. In particular, we map our threshold depth criterion across these basins for use as a screening tool of prospective reservoir closure sites in future.

1.2. Basin analysis for hydrogen storage plays

Hydrogen will remain a gas under all viable conditions that might be considered for its storage within geological formations underground. As such, there are two comparable engineered subsurface fluid resource systems that can be considered when determining the scope and potential of UHS. Petroleum systems have been formed naturally by geological processes in sedimentary basins and provide a proof of concept for the accumulation of an immiscible buoyant fluid within a trapping structure enclosing the reservoir rock. The inherent concepts have informed and been broadened to define an array of viable geological systems for the permanent disposal of anthropogenic CO_2. Allied to traditional petroleum trapping systems, seasonal methane storage is undertaken in similar or sometimes the same geological structures in order to ameliorate imbalances between thermal gas supply and demand. UHS will function in the same way often utilising similar storage systems but with differing constraints related to the properties of hydrogen gas within the subsurface. Eventually, sedimentary basins will host all four types of energy resource fluid activities, in some cases as part of the same integrated energy supply operation (illustrated in Fig. 1).

As mentioned previously, the most familiar subsurface hydrogen gas storage play concept is the development and use of macro-cavities hollowed out by an artificial dissolution process within thick halite layers of sedimentary basin stratigraphy (a minimum thickness of 150 m – at least 65 m thicker than the proposed cavern height [24]). Such storage systems have been used successfully within the petrochemicals industry since the 1960's [28,38]. They take a variety of forms and have been developed for gas storage at a variety of depths [23]. A key aspect of the concept is use of a cushioning system whereby a denser gas [39] of significantly larger molecular size and higher wettability sits within the cavity (notionally below the hydrogen gas column) and becomes pressurised as hydrogen gas is injected [31]. This gas acts to maintain pressure and prevent water invasion whilst helping push hydrogen back out of the cavity during production cycles [31,38]. The contrast in wettability, gas molecular density and viscosity ensures that separation of the mixed gas product into pure hydrogen and cushion gas streams is straightforward at the surface prior to reinjection of the cushion gas and export of the hydrogen for use elsewhere [28,31,39].

Key advantages with using salt caverns as a subsurface storage container for hydrogen gas include the self-annealing nature of the plastic solid salt rheology (i.e. the cavity wall can self-repair), the ability to hollow specific container dimensions, the 100% storage volume efficiency of the cavity space (i.e. it is not a porous medium), the non-reactivity of the salt cavity walls with dehydrated gas streams and the absence of hydrogen-consuming bacteria [20,24,28]. However, because the distribution of thick, pure halite is sparse and stratigraphically sporadic (e.g. Ref. [40]), hydrogen gas storage in subsurface salt caverns – though argued to be the best economic option [41] – may not solely be relied upon to provide a distributed subsurface hydrogen gas storage network that bridges hydrogen generation precincts and major

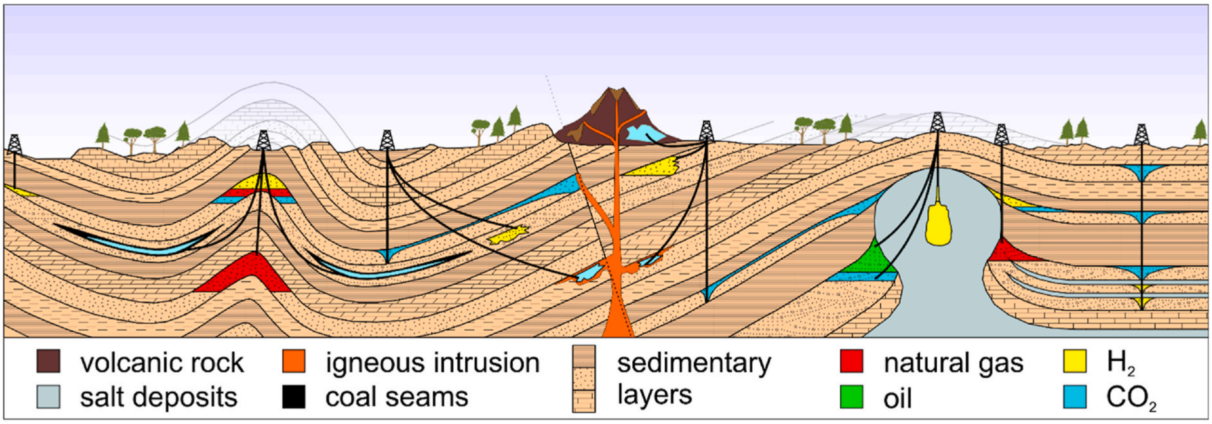

Fig. 1. Play types for subsurface energy fluid operations in sedimentary basins of the energy transition.

hydrogen use centres. This is especially so in Australia where viable stratigraphic intervals of salt are located away from major industrial and population centres but would otherwise dictate the distribution of onshore green hydrogen production precincts [41] without consideration of other land use sensitivities.

Other geological play concepts for short-term hydrogen gas storage and production are related to those of petroleum production, are similar to those of natural gas storage, and share some features with those of Geological CO_2 Sequestration (GCS). The concept for petroleum production concerns identification of a petroleum fluid accumulation hosted within a geological trapping closure. This trapping system comprises a porous and/or fractured, permeable reservoir rock compartment bound above by an impermeable sealing rock with possible lateral containment provide by impermeable rocks or structural features (by folds and faults; see Fig. 1). Accumulations form over millions of years but are produced economically through production wells to surface under natural or pumped pressure differential over years to decades. Key risks are permanent pore volume collapse and/or activation of geological faults due to depressurisation of the reservoir volume. The concept for methane gas storage is to charge such a trapping closure with methane via pumping wells from surface during periods of production surplus nearby, and to produce methane back from the closure during periods of demand surplus. Typically these systems run on an annual (seasonal) storage-production cycle (e.g. Refs. [40,41]). A key risk is seen to be geomechanical hysteresis in the strain response of the system to repeated depressurisation-pressurisation cycles.

GCS comprises a broader range of possible scenarios. Known geological trapping closures akin to those that have produced petroleum and/or those used for methane storage, can be used for permanent disposal of CO_2. However, much greater storage potential is thought to exist for disposal into so-called Deep Saline Formations/Aquifers [47] – reservoir rock units assessed to be without economic or environmental risk constraints, and without such clearly defined disposal volume. In this scenario, the reservoir rock unit is injected with CO_2 down-dip from a trapping closure (or even into a flat-lying layer of rock without defined closure) in order that it migrates under buoyancy towards the top of the reservoir, and towards the closure if applicable, whilst losing mass to residual saturation trapping in pore space along the way. Two key features distinguish GCS from other energy fluid storage systems. The obvious one is that CO_2 is intended for permanent disposal so its presence occludes useable pore volume and obscures surface-based monitoring of other storage operations located within or beneath the GCS volume. The second is that CO_2 is disposed of as a supercritical fluid in order to maximise volumetric sequestration efficiency. This means it must be sustained at a reservoir pressure of at least 7.38 MPa [48], equivalent to a hydrostatic column depth of ~752 m. This is often rounded with a margin of error to a minimum disposal depth of 800 m in most literature. A key risk concerns the (bio-)chemical reactivity between acidified formation water adjacent to the CO_2 plume and minerals that form the sealing rock to CO_2. Containment leakage from any of these systems could contaminate subsurface resources, operations or environmentally sensitive receptors lying above.

It is anticipated that storage-production cycles will be on the timescale of weeks to months [49,50], generally shorter than for natural gas storage. The most efficient and predictable system will be one that relies on a conventional reservoir unit with structural closure to retain buoyant hydrogen within a well-defined reservoir volume under a predictable fluid pressure regime [51]. An alternative scenario for shallow dip closures or truly open-ended porous reservoir systems would rely on use of a cushion gas such as those adopted for salt cavern storage that sits below the hydrogen in a compound gas column [28,31]. Priming pores of the deeper reservoir space with partial saturation of cushion gas limits the relative permeability to imbibition of formation water on production of hydrogen from the reservoir. Subsequent recharge acts to depress and compress the cushion gas column, storing potential energy for the next hydrogen production phase. Presence of the cushion gas thereby confines the highest hydrogen concentration to the vicinity of the injection-production well bore(s), optimising use of the storage volume and injectivity-productivity efficiency. Gas separation at the surface and reinjection of cushion gas would still be required following the hydrogen production phase [37].

Though non salt-based hydrogen storage systems will resemble methane gas storage systems, there will be the added complication of reactivity with water by reversible dissolution/decomposition reactions. This distinction is shared with GCS. The solubility of CO_2 is orders of magnitude greater than that of hydrogen gas meaning CO_2 is considered a far more reactive reagent when introduced into the subsurface [52]. It will also be in contact with formation water over a period of time that is 4–5 orders of magnitude longer than will be the case for free hydrogen gas as part of UHS (assuming substantial free supercritical CO_2 dissolution at ~1000 years [47]). However, for UHS there is also the consideration of catalysed reactions by hydrogenotrophic microbial biota (bacteria or archaea) that 'consume' hydrogen [28,31]. A small proportion of free gas contacting pore water dissociates according to a sequence of reversible reactions to form mild acids in the vicinity of the reaction front. Reaction rates are slow, but could be significant in producing reagents that interact with and modify some of the minerals comprising reservoir or sealing rock matrices (e.g. Refs. [29,53]). Consequences could be that storage reservoir and sealing/containment rock elements become geochemically and geomechanically dynamic so may vary in their performance over the course of operations. Stored gases may also become modified, for example by mixing with a pressure support cushion gas or by contamination due to microbial action [54], which would affect the purity of hydrogen when produced [39]. In addition, some reactions produce free water thereby increasing reservoir pressure [29]. GCS systems are intended to function indefinitely following injection operations, meaning modification of the storage system may become significant but possibly only beyond the operations lifespan. Hydrogen storage-production cycles will be short – weeks to months – so the risks posed to operational efficiencies, including those concerning modification of the hydrogen gas, are considered insignificant per cycle, though they may be significant when compounded over the operational lifetime of a storage field [29]. However, storage systems chosen as sites for both hydrogen storage and CO_2 disposal – for example, sites for storing blue hydrogen and its waste product – will have to be selected to minimise these effects.

The diffusivity of aqueous hydrogen is two to three times that of solutions formed from likely cushion gases, CO_2 or methane (CH_4), and is generally limiting for abiotic chemical reactions with reservoir or sealing rock unit minerals [29,31]. However, catalysed reactions mediated by hydrogenotrophic microbial biota make by far the major contribution to hydrogen consumption in reservoirs, especially by methanogenesis – anaerobic generation of methane as a microbial metabolite – in the presence of CO_2 [29,54]. Recent literature (e.g. Ref. [55]) provides examples of UHS projects in at least two depleted petroleum reservoirs and three saline aquifers within which microbial activity has led to loss of hydrogen, increase of methane and permeability changes in some cases. Previously, a temperature exceeding 80 °C was thus thought to be required in order for a reservoir to be biologically inactive [29] but in certain cases it is now thought a temperature exceeding 120 °C is required [30]. This would be particularly important in suppressing hydrogen contamination with H_2S gas by sulphate-reducing bacteria or archaea in reservoirs containing sulphurous minerals [54]. Thus, a screening depth criterion may be developed that is analogous to the threshold depth required to sustain supercritical CO_2 when screening for viable CO_2 storage reservoirs. A microbe inoculation depth criterion for hydrogen storage – the depth of the 120 °C temperature contour – can be determined from the geothermal gradient data acquired at existing petroleum exploration and production wells.

The reactivity of aqueous hydrogen with shales that seal the porous reservoir rock will be a key storage site screening and operational consideration. The clay minerals of shale seals are chemically reactive [29,53] and prone to dehydration in the presence of acidic formation water. This can reduce their volume to promote the formation of cracks that may cause mechanical degradation [56], thereby posing a containment risk over an extended period of time (as would apply for GCS) or under a repeated cushion gas partitioning if CO_2 is used. An offsetting effect under the same chemical regime might be subsequent salt precipitation that acts to fill and seal the cracks following dehydration and super-saturation of formation water brine [56]. Usually, the buoyant fluid column withholding capacity of the sealing rock is defined by the magnitude of the representative pore throat entry pressure of the sealing rock at its point of contact with the reservoir rock. Volume changes by dehydration at this interface would open cracks that move the point of withholding entry pressure further into the rock unit. In this way, an impermeable sealing rock may eventually become a 'rate seal' – a low permeability semi-seal that retards upward migration of the buoyant fluid rather than completely withholding it. Theoretical calculations based on latest available laboratory-determined parameters suggest that sealing rock withholding capacities with respect to hydrogen are similar to those determined for CH_4 [57,58]. A crucial distinction at viable storage sites might be a dynamic chemical-mechanical regime induced by fluid-rock interactions over time.

There are other niche geological storage reservoir systems that have been considered for methane production and/or storage, or CO_2 disposal, that may therefore have an application in UHS. They do not depend on the conventional arrangement of an impermeable cap rock sealing the porous reservoir rock vertically below and/or to its side. They include gas injection into the cleat system of subsurface coal seams and; reacting gas with the labile mafic minerals of basic igneous rocks, particularly basalt [59–61]. These possible options are not considered further in this study.

2. Materials and methods

2.1. Considerations when determining potential of UHS systems

An approach for identifying the most viable UHS options in a country, region, state, sedimentary basin or field area is presented by running through a series of high-level geological and non-geological considerations that can be brought together for semi-quantitative ranking of their suitability. The application of this approach will vary, depending on the purpose for which is it being undertaken. For example, the approach could be modified to guide a national-scale audit and ranking of sedimentary basins for UHS (as is done in this study) or used in a more targeted and higher-resolution evaluation of specific sub-basins, or applied to compare UHS stratigraphic and/or closure plays at the field scale. Not all data relevant at the basin scale will be relevant at the field scale, and vice versa.

The proposed approach is to be used in the initial stages of screening for the most prospective UHS opportunities. Economic considerations are evaluated separately from geological considerations but both aspects are brought together in the final semi-quantitative ranking table. Geological data are collated to cover the critical play elements of the notional or prospective storage system – reservoir units, sealing lithologies and capacities, trapping systems, geothermal gradient, and reservoir formation fluid pressure. The geological aspects applied in the current study are shown in Table 1.

An aspect missing from Table 1 that would be relevant when zooming in from basin scale is the consideration of viable trapping systems. For UHS within conventional reservoir rocks – nominally sedimentary rock with porosity ≥10% [62] and permeability ≥10 mD [63] – folded or faulted structural closures such as those hosting the majority of petroleum accumulations are most viable [51]. Once a trapping structure is identified, the hydrogen gas column withholding capacity of the sealing rock overlying the reservoir can be compared with the column height of the structural closure to understand how efficiently the structure can be utilised.

Stratigraphic closures are more likely to form shallow dip closures

Table 1
Summary of proposed Stage 1 screening steps for basin scale assessment.

PART 1 - Systems Approach (parameters of site)	
SEAL FM	Basin
Description	
Thickness	min - max (m)
Depth	MD (m)
Porosity	(%)
Permeability	(mD)
RESERVOIR FM	
Description	
Thickness	min - max (m)
Depth	MD (m)
Porosity	(%)
Permeability	(mD)
SUPPL. BASIN PARAMETERS	
Water Depth	(m)
Pressure	(psi)
	mean gradient (psi/km)
Temperature	(°C),
	mean gradient (°C/km)
80 °C	mean TVD (m)
	mean H_2 density (kg/m^3)
120 °C	mean TVD (m)
	mean H_2 density (kg/m^3)
Gas Production (Conventional)	Produced (PJ)
	Remaining (PJ)

with extensive containment footprints than more steeply sided structural closures, and may not be easily resolved by exploration data. They are therefore unlikely to be attractive targets for UHS. Storage in volcanic reservoir rocks may depend on conventional trapping systems (e.g. the rhyolitic domes of [64]) though storage in solution-mined salt cavities [24] will not. Neither are considered further in this study. Another aspect of storage systems not covered any further is consideration of the geomechanical performance of the hydrogen containment system over frequent injection-production cycles. This will involve detailed analysis and modelling only once a site for UHS has been selected for characterisation. The analysis in this study remains at the basin scale so in addition to summarising prospective reservoir and sealing rock potential for each of the basins analysed, a threshold UHS depth criterion was developed. The idea is that this criterion can be used to screen viable candidate stratigraphy or trapping structures identified in more detailed future studies. The depth criterion is defined first as an isotherm and modified, if necessary, in order to attain a threshold hydrogen gas density. The 120 °C isotherm was chosen initially in order to completely inhibit microbial consumption of hydrogen, as suggested by Ref. [30] but this was relaxed to the 80 °C isotherm [29] to admit more candidate reservoir-seal pairs identified in the basin summary analysis. In reality, a threshold isotherm should be identified that will eliminate hydrogenotrophic microbes present within stratigraphy at the nominated storage location. A lower or higher threshold may therefore be appropriate should formation sampling reveal the presence of particular microbial species. For a generalised basin-scale study such as this, 80 °C and 120 °C are convenient thresholds given their support in existing literature and their correspondence to formation fluid pressures within the candidate basins that would impose hydrogen storage densities of around or above 10 kg/m^3 and 15 kg/m^3 respectively, as determined using [26]. For further simplification we adopt 10 kg/m^3 to be a threshold storage density corresponding to a threshold depth that would: (a) guarantee the storage system operator a minimum or standardised storage density (e.g. Ref. [20]); (b) store H_2(g) at an energy density and deliverability that can match shallow methane gas reserves [54,50]; and (c) minimise H_2(g) losses to hydrogenotrophic microbes. Thus, in our analysis we adopt the 80 °C thermal depth criterion – which we assume to be sufficient to satisfy condition (c) above – and deepen from this, where required, in order to also satisfy conditions (a) & (b).

The final stage of our approach is a semi-quantitative, comparative ranking of all the data collated for various geological and non-geological aspects of each basin. This is done for the current study in a 'traffic light' style (though with four classes rather than three). Classes are defined either by boundary values recommended in published literature or by splitting the range of data values across the five Australian basins we analyse in a manner that differentiates them. In the case of data values we calculate – primarily the threshold depth for hydrogen storage and the hydrogen storage mass potential – the four classes are defined by the four quartile ranges of the distribution of data generated. We do not suggest that class boundary values we propose here will be suitable to use as global threshold values to decide the viability of various UHS system elements or other aspects of sedimentary basins relevant to UHS. Such values (or 'show-stoppers') will depend ultimately on the non-geological context of UHS in the region or basin, or at the field site concerned (e.g. local demand for UHS, economic conditions, regulatory constraints, socio-political appetite, competing resource operations). Our study is comparative – the best basin scores 1.0 and the worst scores zero – so our data value ranges are divided to maximise the spread of scores.

For any particular aspect of UHS under consideration, the best value for the purpose of UHS in the range of data will score four points and the worst scores one point, with the two classes between scoring three and two, from best to worst respectively. The best case would: have high population density nearby; be onshore; have large depleted capacity within existing petroleum field areas; have high nominal hydrogen gas sealing capacity and high cumulative reservoir thickness; have high reservoir porosity and permeability; have a relatively shallow threshold depth for hydrogen storage (that satisfies mass density, energy density and temperature criteria) though with high storage mass potential. A weighting system is used to modify point scores to emphasise particular geological aspects of storage performance. Nominal sealing capacity and cumulative reservoir thickness scores are tripled as these are integrated performance features at storage system scale that are generally well known. Reservoir porosity and permeability scores are doubled as these aspects are important to storage system performance but are often less well known (more uncertain) and/or have been acquired with spatial sampling bias. All other aspect are left as originally scored. Finally, the set of modified scores is summed and normalised using the range defined by maximum and minimum total scores calculated for all basins.

For further information, clarification and justification concerning our basin data ranking system, please refer to Appendices A and B.

3. Results

3.1. Application to five sedimentary basins in Australia

UHS potential for five Australian basins of varying age and setting is demonstrated by applying the above approach. From north-west to south-east across the continent, these basins are: Northern Carnarvon; Cooper, Otway, Surat, Sydney. A descriptive overview of these basins is summarised in Table 2. They were selected for analysis on the basis that they represent a range of contexts in terms of historical hydrocarbon production, physiographic setting (onshore, offshore, coastal, continental) proximity to prospective hydrogen generating areas and proximity to hydrogen energy end-users (population centres), as demonstrated economically by Ref. [41] and presented in Fig. 2.

Reservoir and seal pairs have been identified through the online Australian Stratigraphic Units database [65] and relevant strata within each basin are detailed in Table 3. The reservoir-seal pairs were selected owing to the availability of data, which itself is a reflection of their relevance to petroleum exploration and development. Other potentially viable reservoir and sealing formations may occur, for example, those pertaining to Deep Saline Formations as considered in screening for GCS. However, they do not form part of this analysis. The main economic consideration at this scale of analysis is to ensure UHS is not proposed any deeper than necessary. The shallowest examples of proven reservoir and seal pairs that are historically associated with natural gas production are included. The proven ability of sealing units to withhold a gas column, existing petroleum production infrastructure and the quantity of data already available ensure that these units are the most likely to become initial UHS targets.

The above approach applies for the traditional petroleum producing basins. However, the Sydney Basin is a different case as it does not have a history of producing conventional gas resources. It would be an unlikely prospect for UHS operations as community sensitivity to this type of operation is often high where there is no prior history of hosting them. As would be required for any area that does not have recent history of subsurface resource exploration and production, substantial investment in research, data collection and modelling would be necessary alongside extensive and ongoing community engagement (e.g. Ref. [85]). However, the Hawkesbury Sandstone is often discussed as an analogue for petroleum system reservoirs so the analysis was applied on the assumption that it could hypothetically perform as a storage reservoir rock. An overlying sealing unit known as the Wianamatta Group or the Wianamatta Shale, was identified through the online Australian Stratigraphic Units database and using published information on the stratigraphic column for the basin in this case [66,67].

3.2. Determining a UHS depth threshold across the five Australian basins

Formation fluid pressure and temperature data as presented in Table 3 were mined from the most recent edition of the CSIRO

Table 2
Overview of the five Australian sedimentary basins selected for the case studies presented. NSW – New South Wales, NT – Northern Territory, QLD – Queensland, SA – South Australia, TAS – Tasmania, WA – Western Australia.

Basin	Geographical			Geological			Industrial		References
	Basin area (km^2)[1]	Location[2]	Main Population Centre[3]	Basin Type[4]	Age[5]	Depositional Setting[6]	H_2 Scenario and Context	Existing Resources[7] – (largest fields)	
Cooper	127,000	QLD, SA	Brisbane (2.2 mil) Adelaide (1.2 mil)	Intracratonic	Late Carboniferous to Middle Triassic	Non-marine (fluvial, deltaic, shoreface sands)	Regional (*value chain*)	Gas (& oil) – (Gidgealpa)	[1,2] [77];[3] [78];[4,5,6,7] [79]
Northern Carnarvon	535,000	NT, WA	Darwin (129,062) Perth (1.9 mil)	Extension	Late Palaeozoic, Mesozoic and Cenozoic	Deltaic to marine sands, shelfal carbonates	Export	Oil, gas, condensate – (Barrow Island; North Rankin)	[1,2,4,5,6,7] [80];[3] [78]
Otway	155,000	SA, TAS, VIC	Adelaide (1.2 mil) Hobart (216,656) Melbourne (4.3 mil)	Rift and Drift	Jurassic to Late Cretaceous	Fluvial lacustrine, marginal marine, deep water marine	Supply & demand	Gas (CH_4 & CO_2) – (Thylacine)	[1,2] [81];[3] [78];[4,5,7] [82]
Surat	300,000	NSW, QLD	Sydney (4.6 mil) Brisbane (2.2 mil)	Intracratonic	Early Jurassic to Early Cretaceous	Fluviolacustrine (to coal swamp environment) to marine	Supply & demand	Coal, coal seam gas – (Fairview)	[1,2,4,5,6] [83];[3] [78];[7] [84]
Sydney	64,000	NSW	Sydney (4.6 mil)	Convergent margin foreland thrust loaded	Permian to Triassic	Shallow marine to fluvial sands	Population & industry non-petroleum	Minor oil & gas	[1,2,4,5,6] [73];[3] [78]

PressurePlot national database of formation fluid pressure and fluid sample data acquired when drilling petroleum wells (updated in 2019 [68]). Only test data rated 'A' to 'C' in quality [68] were admitted for analysis meaning very few outlier data required removal later. Representative basin surface temperatures were projected from the dominant basin geotherm trend as were True Vertical Depths (TVD) to the piezometric surface. This analysis revealed that the Cooper-Eromanga Basin succession – which is hydraulically coupled to the Great Artesian Basin recharge system in highland areas of Queensland to the east – has artesian formation fluid pressure projected at ground level along the dominant basin pressure trend, which itself has a gradient that is shallower than hydrostatic. Other basins project to atmospheric pressure below ground level (i.e. to the water table onshore) or to mean sea level (offshore).

For wells contributing data that lack either geothermal gradient or formation fluid pressure information, the modal basin gradient was adopted in either case. TVD was chosen as the depth reference scale rather than elevation, in order that formation fluid pressure could be related easily to depth, and to ensure that onshore and offshore areas could be compared equally and in a more intuitive way. In the case of offshore wells, TVD can be considered to begin just above mean sea level at whatever the elevation of the well depth reference datum happens to be (Kelly Bushing, KB, or Rotary Table, RT).

The geothermal gradient at wells was used to predict the 80 °C depth criterion. A polynomial function of temperature and pressure fitted to the hydrogen gas density results of [26] was used to predict the corresponding hydrogen gas density. This is to be considered a minimum density given that hydrogen gas pressure at the top of a hydrogen gas column would exceed that of incompressible formation fluid pressure at the same depth, the formation fluid pressure being that used to predict hydrogen gas density. If the predicted hydrogen gas density happened to be below the minimum threshold of 10 kg/m^3 imposed for this study, the same fitted polynomial function was used with the well temperature and pressure gradients to predict the minimum depth at which the required density would be attained. Thus for each modelled well, the two-step depth criterion – 80 °C or deeper to attain 10 kg/m^3 – is calculated and interpolated to produce the map presented in Fig. 3.

The depths shown in Fig. 3 correspond to a hydrogen gas density predicted by the local temperature and pressure conditions. However, a depth limit for viable storage is implied by Ref. [32] on the basis that the sealing capacity of conventional caprocks is reduced by the increasing water-rock-gas contact angle with depth to the point of neutral wettability (a contact angle of 90° [89]) at ~3663 m assuming typical temperature and (hydrostatic) pressure gradients. Our two-step depth criterion stays within this bound for all five Australian basins shown in Fig. 3. The study of [32] also suggests an optimum depth for storage on the basis of the countervailing effects of increasing hydrogen density and decreasing sealing capacity with depth. This is expressed in terms of a maximum capacity for the mass of hydrogen gas that can be stored within reservoir rock with 20% effective porosity over a notional 100 m × 100 m geographic storage footprint [32]. The study applies a multi-segmented empirical function of sealing capacity to hydrogen that predicts this depth to occur at 1100 m. Our calculation of typical hydrogen sealing capacity using their primary equation and made directly from their depth relations for fluid densities, fluid interfacial tension and water-rock-gas contact angle, predicts this optimum depth to occur at 1559 m, which falls within the range of our predicted two-step depth criterion across all five Australian basins shown in Fig. 3. This suggests an 80 °C depth or greater to attain a minimum hydrogen density of 10 kg/m^3 is a realistic two-step criterion to apply for viable UHS within conventional reservoir systems of these Australian basins. Fig. 4 shows the maximum capacity for the mass of hydrogen that can be stored on the basis of the predicted depths shown in Fig. 3, calculated according to the method of [32].

Figs. 3 and 4 were interpolated using the Natural Neighbour algorithm [90] to ensure that the mapped extent was constrained to the

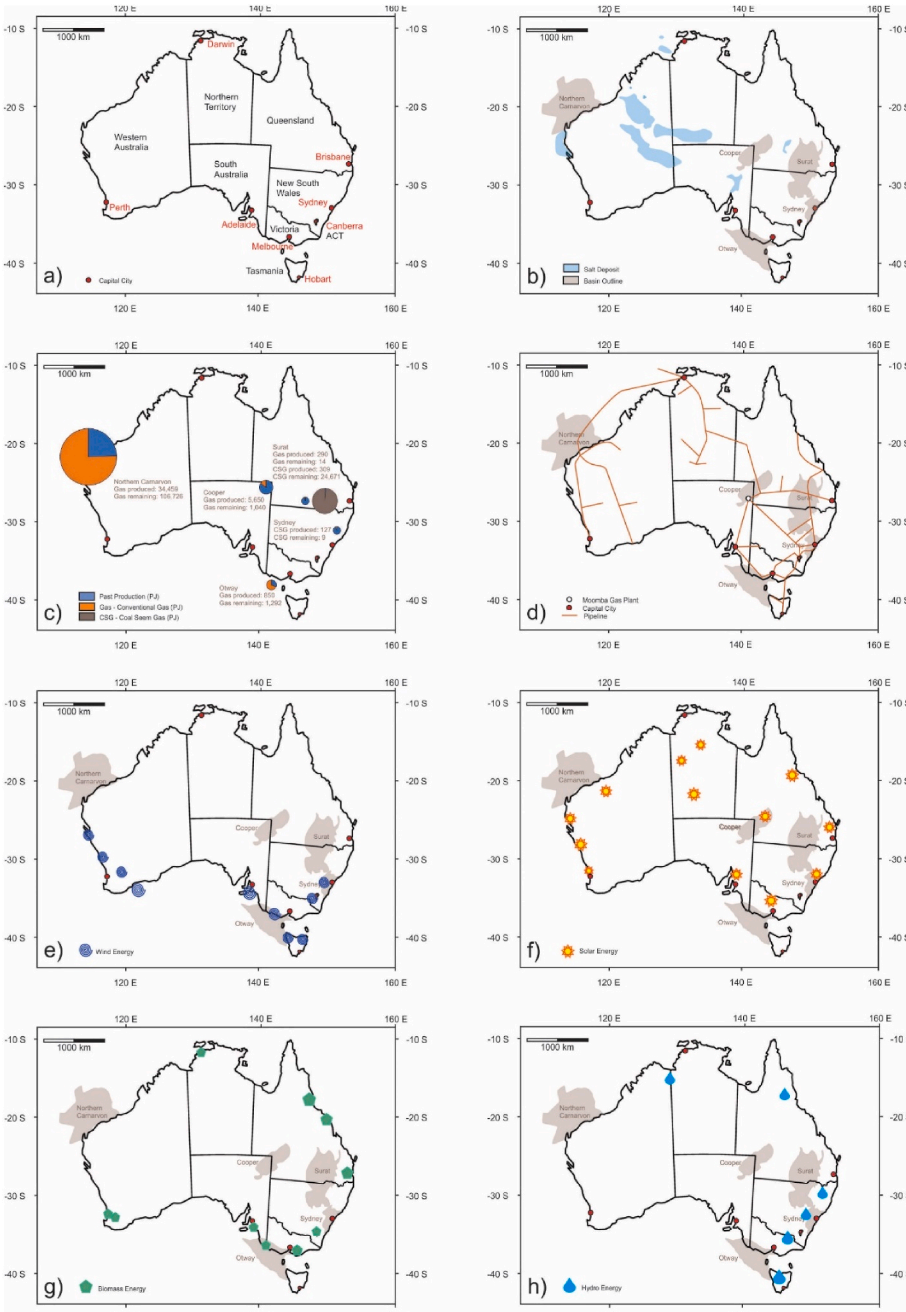

Fig. 2. Location of Australia's a) states, territories, and capital cities (ACT - Australian Capital Territory) b) oil and gas basins studied in this paper (after [42,43]), alongside thick onshore and offshore salt deposits potentially suitable for UHS [19,40]. Figure c) displays gas reserves (according to EnergyQuest in Refs. [44–46]), d) the gas pipeline infrastructure across Australia (after [19]), as well as the main locations for e) solar, f) bio and g) hydro energy production (after [19]).

convex hull enveloping the outlying well data locations and to ensure that no data values were mapped that exceed the data value range calculated at wells. Geostatistical data trends were not investigated at this stage so the spatial autocorrelation of data values was assumed to be isotropic – this is unlikely to be an accurate assumption given the ubiquity of geological fabrics in nature. Nevertheless, these maps represent the results of a first-pass hydrogen storage criterion at any mapped location within these sedimentary basins that can be used to screen viable trapping structures of viable reservoir and sealing units on the basis of their depth of occurrence.

4. Discussion

4.1. Basin ranking discussion

Each of the three historically active petroleum producing basins investigated in this study – Northern Carnarvon, Cooper and Otway – appear to be prospective basins for UHS. The landward portions of the Northern Carnarvon and Otway basins host their most prospective tracts while the Cooper Basin hosts storage conditions prescribed by our two-step criterion at the shallowest depth overall (Fig. 3). Storage depths within the majority of the Sydney Basin are higher than needed across much or most of the other basins. Hydrogen storage mass potential as defined by Ref. [32] is similar across most of each basin, the majority

Table 3a
Application of approach to the five Australian case studies/basins selected for this demonstration – Sealing Parameters.

PART 1 - Systems Approach (parameters of site)

	BASIN	Cooper		Northern Carnarvon	Otway		Surat	Sydney	References
SEAL FORMATION		Nappamerri Group	Murteree Shale	Muderong Shale	Laira	Belfast Mudstone	Birkhead	Wianamatta Group	
Description		red beds, mudstone, siltstone, sandstone, lithic sandstone	argillaceous siltstone, fine-grained sandstone, disseminated carbonaceous matter, fine-grained pyrite, and muscovite	siltstone, pyritic mudstone	shale, siltstone minor fine-grained sandstone	glauconitic mudstone	bioturbated siltstone and mudstone interbedded with fine- to medium-grained sandstone containing thin basal pebble lags, and thin laterally discontinuous coal seams	shale with minor thin-bedded lithic sandstone	[65]
Thickness	min - max (m)	na - 200	80–92	na - 266	na - 890	na - 1362	110–570	na - 300	[65]
Depth	MD (m)	1966–2859	2025–2909	606–2676	1995–2359	1402–2632	211–2239	0–198	[66–72]
Porosity	(%)	11.2 (171)	9.5 (59)	22.5 (169)	11.4 (38)	0.3 (35)	14.1 (882)	na	
Permeability	(mD)	4.0 (170)	0.4 (59)	6.8 (155)	1.5 (35)	2.8 (33)	KH 2.7 (809)/KV 1.0 (195)	na	

Table 3b
Application of approach to the five Australian case studies/basins selected for this demonstration – Reservoir Parameters.

BASIN		Cooper		Northern Carnarvon	Otway		Surat	Sydney	References
RESERVOIR FORMATION		Toolachee	Patchawarra	Mungaroo	Pretty Hill	Waarre	Hutton Sandstone	Hawkesbury Sandstone	
Description		basal conglomerate, sandstone, siltstone, mudstone, shale	sandstone, siltstone, mudestone, coal	sandstone, claystone, minor coal, limestone (at top)	mudstone, sandstone	bioturbated carbonacous sandstone	basal coarse to medium-grained feldspathic sandstone and fine-grained, well-sorted quartzose sandstone (at top)	quartz sandstone with minor shale and laminite lenses	[65]
Thickness	min - max (m)	25–190	50–680	380–6000	na - 5000	na - 636	40–290	na - 290	[65]
Depth	MD (m)	1867–3234	1764–3475	810–4909	1087–3117	1519–4130	21–2284	21–301	[67–72]
Porosity	(%)	12.2 (1928)	10.4 (5748)	16.8 (902)	12.0 (607)	10.4 (57)	16.2 (2258)	16.6 (4)	
Permeability	(mD)	3.2 (1904)	0.7 (5722)	40.3 (1186)	0.4 (606)	1.0 (7)	KH 21.4 (1993)/KV 11.3 (676)	25.0 (13)	

Table 3c
Application of approach to the five Australian case studies/basins selected for this demonstration – Supplementary Basin Parameters.

SUPPL. BASIN PARAMETERS							References
Water Depth	(m)	not applicable	50–4500	50–3000	not applicable	0–4000	[73–75]
Pressure	(psi)	1.06–1.14	1.44–1.99	1.12–1.61	1.22–1.64	1.26–1.66	[68,76]
	mean gradient (psi/km)	1.33	1.49	1.42	1.40	1.47	
Temperature	(°C),	23.2–50.9	15.1–40.7	18.1–52.7	17.6–56.9	23.8–54.0	
	mean gradient (°C/km)	33.8	28.4	34.0	32.4	25.1	
Salinity	NaCl equiv. min-mean-max (ppm)	1134–4240 – 16929	2100–36544 – 181500	1400–14512 – 36300	2850–2906 – 2925	1–37 – 132	
80 °C	mean TVD (m)	1703	2078	2054	2171	2363	
	mean H_2 density (kg/m^3)	10.1	11.6	11.9	12.6	14.3	
120 °C	mean TVD (m)	3074	3651	3460	3568	3865	
	mean H_2 density (kg/m^3)	15.2	19.3	18.0	18.5	21.1	
Gas Production	Produced (PJ)	5650	34459	850	290	0	[44–46]
(Conventional)	Remaining (PJ)	1040	106726	1292	14	0	

within each lying within the range 1.5–1.6 kilotonnes. The exception occurs across the Sydney Basin where the higher storage depth threshold ensures a higher water-rock-gas hydrogen wettability contact angle that reduces typical hydrogen gas column withholding capacity of the notional sealing caprock (Fig. 4). The same effect is seen locally where this applies within the other basins. The Cooper Basin is the only one showing a relatively consistent hydrogen storage depth, though its distribution of hydrogen storage mass is more variable owing to unusually low pressure gradients (underpressured reservoir intervals) at most wells and unusually high temperature gradients at some wells. This

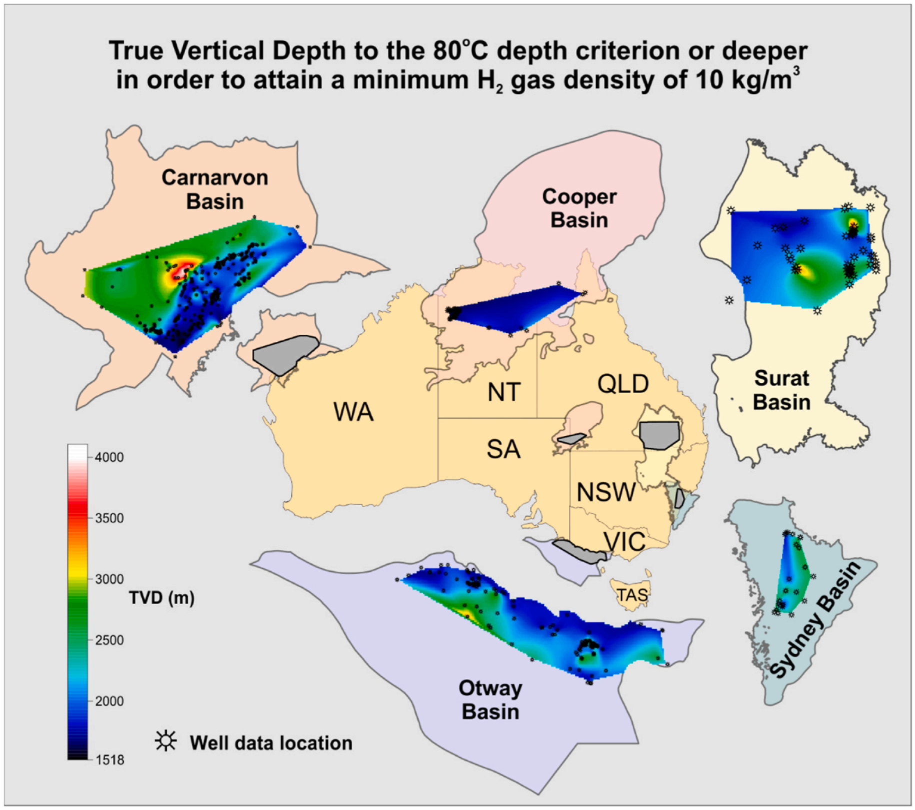

Fig. 3. True Vertical Depth to the 80 °C isothermal depth criterion of [29] or deeper in order to reach a formation fluid pressure resulting in a minimum stored hydrogen gas density of 10 kg/m^3. Well data locations provided the datasets for TVD mapping. All known oil & gas fields are shown on the expanded views of all basins bar that of the Sydney Basin (as determined from Refs. [81,86–88]).

results in deepening beyond the 80 °C isotherm in order to attain a 10 kg/m^3 hydrogen gas density for almost all wells (meaning a higher hydrogen wettability angle according to Ref. [32], which lowers the withholding capacity of the notional seal). It must also be borne in mind that the distribution of data sampling within this basin is the least evenly spread, with the vast majority of wells concentrated in and around the Gidgealpa Field in the west of the basin. Any outliers in the east therefore have a disproportionately strong influence on the appearance of anomalies across the mapped area and therefore an overweighted contribution to summary distributions of the variables mapped. Results in the Surat Basin are distorted by local outlier data values sitting in the transition between high and low spatial sampling densities. In the context of the depth ranges stated for identified reservoir-seal pairs (Table 3), the Sydney Basin can be considered inviable according to our mapped depth criterion (Fig. 3), while the other basins should present opportunities where the reservoirs occur in trapping compartments below the storage depth thresholds.

Table 4 presents the traffic light-style ranking of these and other aspects of UHS suitability using the scoring system shown in Table 5, with a normalised summary score provided for each basin. For two of the basins – the Cooper and Otway basins – the ranking system was applied for two particular reservoir-seal pairs. In the case of the Cooper Basin, these pairs are associated with the dominant petroleum systems of the basin. In the case of the Otway Basin, there is strong partitioning in the structural and stratigraphic evolution of the basin in western and eastern parts that roughly corresponds to the portions of the basin associated with the states of South Australia to the west and Victoria to the east. Thus the dominant petroleum system reservoir-seal pair is considered for each case separately (Pair 1 and Pair 2, respectively).

The ranking system shows that the Northern Carnarvon Basin and the Cooper Basin, specifically the deeper, older, more prolific petroleum reservoir-seal pair (Pair 2) of the latter, are the most prospective basin plays for UHS at this 'helicopter view' scale of analysis. These two basins also happen to be close to or at economic sweet spots for production and delivery of 'green' hydrogen to storage or export receptors [41]. The Northern Carnarvon Basin hosts hydrogen storage conditions satisfying our two-step depth criterion (80 °C isotherm, then hydrogen density of 10 kg/m^3) at some of the shallowest depths along its coastward tract, despite having only a moderate geothermal gradient. This should mean the 80 °C isotherm is deeper than within the Cooper Basin (as per [26]). However, the Cooper Basin 80 °C isotherm is calculated as being too shallow to attain hydrogen at the required density of 10 kg/m^3 so the criterion was deepened there but under a low formation fluid pressure gradient. The generally high formation fluid pressure gradient in the Northern Carnarvon Basin – reservoir intervals tested during exploration were generally above hydrostatic pressure, which is not likely to be the case today – ensures the 80 °C isotherm is not only at sufficient depth but at a depth where hydrogen gas density would exceed the minimum density requirement of 10 kg/m^3. This results in a relatively high hydrogen storage mass potential (Fig. 4) and therefore the highest dollar storage value for produced green hydrogen (Table 4) despite the lower average hydrogen column withholding capacity at the storage depth criterion (~72 m vs. ~78 m). The need to deepen from the 80 °C isotherm to satisfy the depth criterion within the Cooper Basin, sometimes significantly so owing to underpressured conditions, is another good reason to target the Pair 2 reservoir-seal system there.

A more detailed analysis might reverse the relative relationship of column heights between these two basins as hydrogen gas at the depth criterion is an average of ~1.6 kgm^{-3} denser in the Northern Carnarvon Basin. Assuming equal threshold pressures for respective sealing rocks, which is in fact not the case (Northern Carnarvon Basin sealing rocks generally having higher threshold pressures [89]), this variable alone would increase the column capacity in the Northern Carnarvon Basin relative to that of the Cooper Basin. However, the much higher salinity

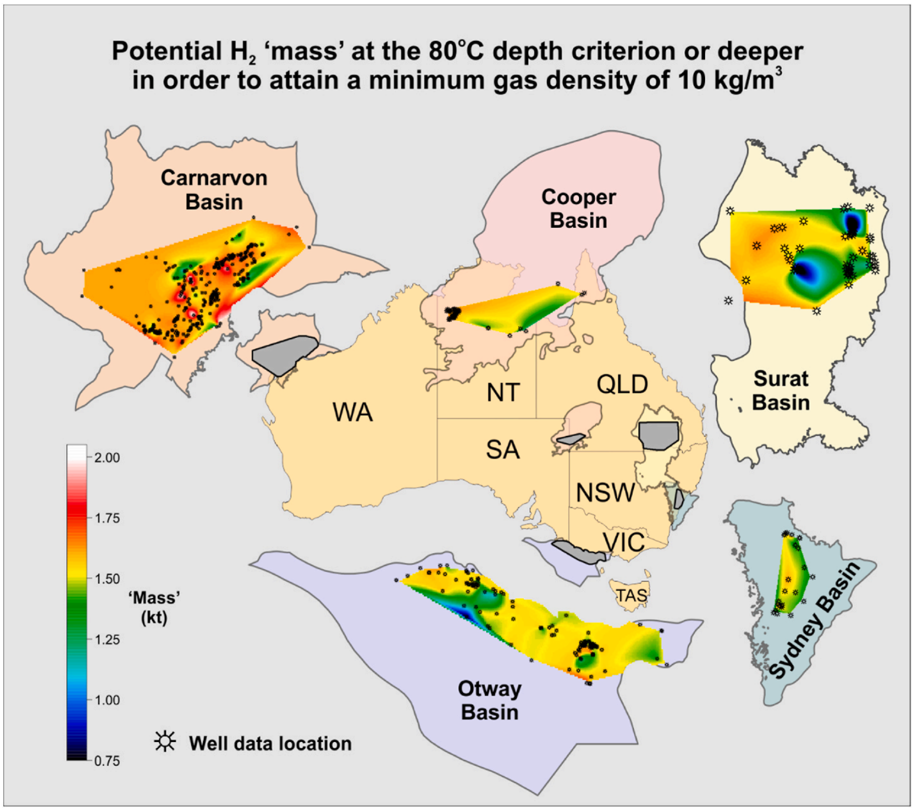

Fig. 4. Maximum potential 'mass' capacity for hydrogen storage according to a balance between of the typical hydrogen gas column withholding capacity of a conventional sealing rock [32] and hydrogen gas density within an underlying conventional reservoir rock at the 80 °C isothermal depth criterion of [29] or deeper in order to reach a formation fluid pressure resulting in a minimum hydrogen gas density of 10 kg/m3. Mass is calculated on the assumption that hydrogen gas completely sweeps conventional reservoir rock with 20% effective porosity over a 100 m × 100 m geographic storage area, in accordance with [32]. Actual storage potential will be governed by local lithostratigraphic architecture and the local distribution of reservoir properties. Well data locations provided the datasets for Mass mapping. All known oil & gas fields are shown on the expanded views of all basins bar that of the Sydney Basin (as determined from Refs. [81,86–88]).

formation water in the Northern Carnarvon Basin (Table 3c) should more than counter this effect so our simplified calculation of the difference may be representative of reality. The influence formation water salinity has on the interfacial tension of the H_2–H_2O binary fluid system (or the ternary system involving the cushion gas of choice) in contact with the sealing rock substrate [92] would also require consideration.

The Otway Basin, for comparison, shows poor hydrogen storage mass potential at shallow to moderate depths under hydrostatic formation fluid pressures and a relatively warm geothermal gradient. This basin scores poorly for reservoir permeability and depleted capacity onshore where production of many petroleum fields in the past lasted only a few years before becoming uneconomic. However, this area was economically high-graded by Ref. [41] for 'blue' hydrogen production and delivery to receptor. Both reservoir-seal plays of the Otway Basin score in the middle of the range. Finally, the Surat and Sydney basins both have very low overall ranking score, with very little between them in terms of scores gained across individual basin ranking aspects.

4.2. Australian sedimentary basins as mixed-use energy resources

A logistical challenge for UHS operations within the Cooper Basin is the large distance either to end users or to port facilities for hydrogen importation or onward international exportation. However, it is located in ideal territory for consistent solar energy supply capable of producing green hydrogen all year round. Hydrogen generation by electrolysis requires water as the feedstock, which would be the major resource constraint on hydrogen generation operations there. Blue hydrogen generation produced from a methane gas feedstock would produce CO_2 as a by-product. The Cooper Basin currently hosts a large field-scale demonstration of GCS at the Moomba field operated by Santos Ltd. This demonstration is the forerunner of widespread operations across the basin as Santos Ltd and other licence holders diversify their subsurface activities as the energy transition begins across Australia. The same readiness to accommodate blue hydrogen generation and associated GCS applies in the Northern Carnarvon Basin, which hosts the largest commercial-scale demonstration of GCS in the world. The Gorgon Joint Venture project operated by Chevron Australia Pty Ltd began with the aim to store 3.4–4.0 Mt of CO_2 per year beneath Barrow Island [93]. Though this is presently the highest methane gas producing basin in Australia [44,94], the GCS storage system of the Gorgon Project features large-scale water production in order to accommodate CO_2 within the disposal reservoir [93]. So the two main hydrogen feedstocks could be readily available in the Northern Carnarvon Basin to accommodate blended hydrogen generation there.

For a truly integrated process system, energy suppliers working in these basins could generate both green and blue hydrogen, disposing of by-product CO_2 in the case of the latter into other subsurface reservoir systems (e.g. Fig. 1), nominally at shallower depth [48]. Hydrogen reproduced from storage could be used to generate electricity by combustion *in situ* for onward transmission or for energy storage in some other form, thereby producing water as the by-product that could be recycled back into the process as a feedstock for green hydrogen generation. This would help minimise the impact on local water resources and limit local reliance on methane as a hydrogen feedstock, a closed cycle that would be particularly advantageous within the Cooper Basin.

The distribution of threshold depth for hydrogen storage calculated across all five of the sedimentary basins analysed in this study (Fig. 3) suggests that UHS in conventional reservoir systems will be undertaken

Table 4
Summary of basin ranking results. *H_2 Mass Values in millions of US dollars assume a generic discount factor of 50% (accounting for unknown trapping system geometries, Net Pay Ratios, etc) and adopt average levelised costs per kg for H_2 produced from methane gas (by steam reforming; denoted "Fossil H_2") and water (by electrolysis; denoted "Green H_2") of $2.00 and $5.50 respectively, according to Ref. [91]. Mass Potential is used in the overall ranking calculation but H_2 Mass Values are not.

Criteria		Basin						
		Cooper		Northern Carnarvon	Otway		Surat	Sydney
		Pair 1	Pair 2		Pair 1	Pair 2		
Economics								
Population Density (person/km^2)		1.62-2.50	1.62-2.50	0.16-0.89	1.62 (SA)	23.5 (VIC)	2.65-8.64	8.64
onshore/offshore		onshore	onshore	offshore	both (on)	both (on)	onshore	both (on)
Depleted Capacity (PJ)		5,650		34,359	850		290	0
Storage Performance								
Nominal H_2 Sealing Capacity (m)		78		72	65		60	52
Max Reservoir Thickness (m)		190	680	6000	5000	636	290	290
Reservoir Quality	Porosity (%)	12.2	10.4	16.8	12.0	10.4	16.2	16.6
	Permeability (mD)	3.2	0.7	40.3	0.4	1.0	11.3	25.0
H_2 Storage Prospects	Min Depth (km)	1.76		2.37	2.08		2.14	2.27
	Mass Potential (kt) or Fossil H_2 Mass Value ($M)*	1.52		1.60	1.48		1.45	1.48
	Green H_2 Mass Value ($M)*	4.18		4.40	4.07		3.99	4.07
Normalised Final Ranking Score		0.77	**1.00**	**1.00**	0.62	0.54	0.15	**0.00**

Table 5
Key to Table 4 – rows in this table correspond to those of Table 4 above for Economics and Storage Performance categories of consideration.

Data Source	Aspect Class Point Score 1	2	3	4	Point Score Factor
Economics					
Table 1 Table 3	<1 offshore <1000	1-5 both (off) 1,000-5,000	5-10 both (on) 5,000-10,000	>10 onshore >10,000	x1
Storage Performance					
N/A Table 3	<55 <100	55-64 100-500	65-74 500-1000	>75 >1000	x3
Table 3	<5 <25	5-10 25-50	10-15 50-100	>15 >100	x2
Figs 3 & 4	>2.56 <1.50	2.11-2.56 1.50-1.56	1.91-2.11 1.56-1.61	<1.91 >1.61	x1

slightly deeper on average than GCS when considering the multiple energy fluid operations of sedimentary basins outlined by Refs. [95,96]. Fig. 5 is adapted from this work with the viable hydrogen storage depth range 'balloon' in yellow defined by the full set of our results shown in Fig. 3 in proportion with the scale of mapped areas. This range is contingent on the two-step temperature and hydrogen density depth criterion we apply so should not be considered definitive in terms of physical or technical feasibility. A large majority of our calculated depth

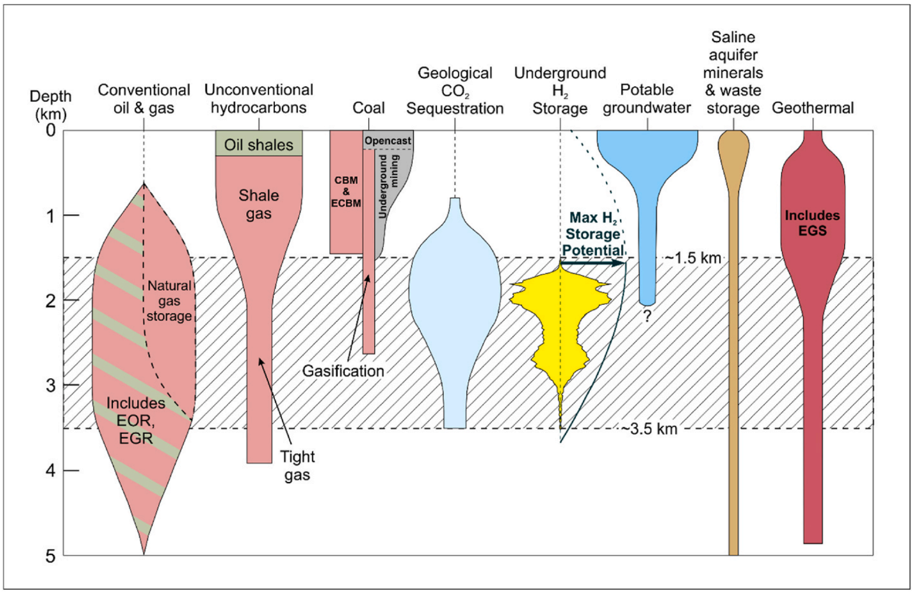

Fig. 5. Schematic diagram varied from Refs. [95,96] of the typical depth ranges of occurrence and activity for energy resources and other fluid resources within sedimentary basins. Polygon widths are varied conceptually to represent typical distributions for each resource or grouping, wider zones being those depth intervals that are more prevalent. No meaning is implied or intended by absolute widths in this figure so these polygons should not be taken as a means by which to compare the volumetric potential of different resources. The most prospective depth ranges for many of the resources are shown to overlap though several resource activities may co-occur within different depth ranges at the same geographic location provided their effects are isolated by geological compartmentalization (sealing rocks, faulting zones). The distribution of depth for Underground Hydrogen Storage has been added as a yellow polygon using the quantified results of threshold depth mapped for the five Australian sedimentary basins as shown in Fig. 3 of this study. The depth range for these data are shown by the line-shaded interval 1.5–3.5 km. The dark green curve illustrates the nominal decline profile for hydrogen storage mass potential (after [32]) from a maximum at the horizontal dark green arrow to zero just deeper than end of the range for threshold depth. EOR: Enhanced oil recovery; EGR: Enhanced gas recovery; CBM: Coal bed methane; ECBM: Enhanced coal bed methane; EGS: Enhanced geothermal systems. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

range lies below the 1800 m depth limit suggested by Ref. [19] for storage of hydrogen in solution-mined salt caverns, though a broader range than theirs for cavern storage is implied by Ref. [23]. The modal depth calculated and shown in Fig. 5 (~1974 m, though a second shallower peak occurs at ~1795 m) deviates from the suggested optimum storage depth and feasible range suggested by Ref. [32] that was determined assuming a segmented hydrogen gas withholding capacity profile and parameters assumed for a typical caprock that seals the reservoir rock below within a typical sedimentary basin with typical geotherm and formation fluid pressure profiles. Our study, by contrast, applies real-world geotherm and formation fluid pressure gradients calculated from test measurements made at petroleum exploration wells and applies a two-step depth criterion. In any case as mentioned previously, recalculation of the optimum depth of [32] assumed a standard hydrogen capacity profile predicted by their primary equation to produce an optimum storage depth within the range we calculate (though close to its shallow end). This is shown by the dark green arrow in Fig. 5. Ultimately, economic conditions and environmental regulations will dictate where UHS is affordable or allowable, the former being that which will control the feasible depth range at any location and at a particular time. Technical storage potential will be governed by local lithostratigraphic architecture, geomechanical constraints and the local distribution of reservoir properties.

5. Conclusions

In this paper, we present an approach for identifying, assessing and evaluating Underground Hydrogen Storage (UHS) opportunities in sedimentary basins, and apply this to five Australian basins. At this basin-scale of analysis, we suggest that the key parameters to determine a technically viable hydrogen storage opportunity are: (1) the presence of adequate conventional reservoir rock units; (2) the presence and style of structural and/or stratigraphic trapping systems typically predominant in hosting petroleum resources; (3) the presence of conventional sealing rock units with sealing capacity to hydrogen gas that exceeds the trapping closure column of prospective reservoirs units; (4) the relationship all these aspects have to an UHS threshold depth criterion, defined in this study first by the 80 °C isotherm depth, then if required by depth of the formation fluid pressure isobar ensuring a minimum hydrogen density of 10 kg/m^3.

After evaluating case study data for five Australian sedimentary basins at the basin scale, we determine that the Northern Carnarvon Basin and a deep and well-known reservoir-seal play within the Cooper Basin of central Australia, are the most readily viable opportunities for hosting UHS within conventional petroleum rock systems. These are both mature hydrocarbon production provinces with ample information available to characterise hydrogen storage system elements. They satisfy the temperature and hydrogen density depth criterion adopted here at relatively shallow depths producing high hydrogen storage mass potential. Other mature hydrocarbon producing opportunities remain viable, in particular the shallower reservoir-seal play of the Cooper Basin and plays in both the west and east of the Otway Basin. However the Surat Basin, another mature petroleum province, is shown to be far less promising and does not score much higher than the Sydney Basin, which we rate as inviable. However, at this ‘helicopter’ scale of analysis, storage system conditions may vary a great deal so all basins analysed probably have some high quality opportunities locally.

Though geological hydrogen storage conditions have now been defined for these basins at a high level, their ultimate viability as hydrogen storage hubs will be governed by economic conditions, regulatory requirements and socio-political considerations. A framework to formalise these important components of the overall decision-making process around hydrogen storage viability should be developed in parallel with field site screening studies. This should be followed by more detailed high-resolution investigations to characterise or predict components of geological storage system performance that have been touched upon in this study, before more detailed site selection, performance testing and planning can progress.

As when evaluating hydrocarbon exploration or GCS targets, there is no universal set of thresholds for criteria that will be used to identify the best locations for UHS. In some locations, a lower reservoir quality (porosity, permeability) may be selected if the reservoir volume is greater (Total Pore Volume; TPV). In addition, the current petrophysical definition for a 'good' conventional petroleum reservoir is probably unjustified for identifying adequate UHS reservoirs given the mobility of hydrogen in the subsurface. Ultimately, economic viability may relate more to existing infrastructure or physical location of supply/demand. Locations showing potential for hydrogen storage arising from initial screening studies should be demonstrated theoretically by geological and reservoir modelling to produce a suite of cost-benefit analyses based on simulations of future storage system performance. The overall approach will be like those undertaken for hydrocarbon exploration or GCS assessment, with a few new considerations driven by the fact that UHS systems will be under perhaps a continual and possibly variable injection-production cycle. These distinctions will include management of hydrogen supply/feedstock and cushion gas resources, control and monitoring of multiple gas streams at the surface and below ground, management of a dynamic, multi-scale, bidirectional hydrogen transportation infrastructure, and continual development of the dynamic model of geological storage properties and performance as the system operates.

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Declaration of interests

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix A. Supplementary data

Supplementary information to this article can be found online at https://doi.org/10.1016/j.ijhydene.2024.03.340.

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