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A quantitative assessment of the hydrogen storage capacity of the UK continental shelf

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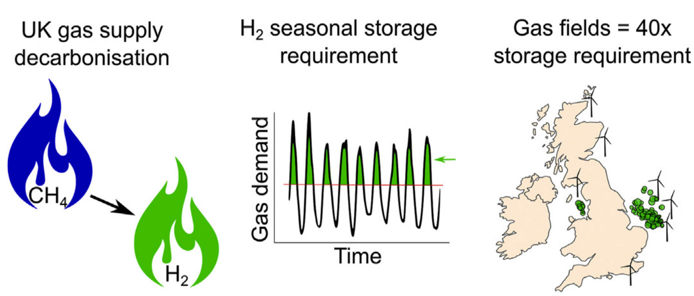
HIGHLIGHTS

- UK requires 150 TWh of seasonal hydrogen storage capacity to decarbonise gas.
- First quantification of hydrogen storage capacity in gas fields.
- 6900 TWh hydrogen working gas capacity in UK offshore gas fields.
- Low temperature/high pressure capacity storage sites are best.
- Offshore gas fields and wind could develop offshore hydrogen production.

GRAPHICAL ABSTRACT



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ABSTRACT

Increased penetration of renewable energy sources and decarbonisation of the UK's gas supply will require large-scale energy storage. Using hydrogen as an energy storage vector, we estimate that 150 TWh of seasonal storage is required to replace seasonal variations in natural gas production. Large-scale storage is best suited to porous rock reservoirs. We present a method to quantify the hydrogen storage capacity of gas fields and saline aquifers using data previously used to assess CO_2 storage potential. We calculate a P50 value of 6900 TWh of working gas capacity in gas fields and 2200 TWh in saline aquifers on the UK continental shelf, assuming a cushion gas requirement of 50%. Sensitivity analysis reveals low temperature storage sites with sealing rocks that can withstand high pressures are ideal sites. Gas fields in the Southern North Sea could utilise existing infrastructure and large offshore wind developments to develop large-scale offshore hydrogen production.

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Introduction

In 2018, fossil fuels accounted for 85% of global primary energy demand [1], resulting in the release of 33.1 billion tons of carbon dioxide into the atmosphere [2]. The Paris agreement, reached in December 2015 by 196 members of the United Nations Framework Convention on Climate Change (UNFCCC), aims to keep the increase in global average temperature to well below 2 °C above pre-industrial levels (preferably less than 1.5 °C) in order to substantially reduce the risks and effects of climate change [3]. Meeting these targets requires rapid decarbonisation of power generation, heating, industry, and transport.

Success in decarbonising the UK electricity sector has led to increased deployment of renewable energy sources such as wind and solar. Whilst this increase in renewable energy sources will reduce CO_2 emissions intensity, economic security of supply and grid balancing issues associated with variations in wind, solar and water energy production are likely to increase [4–7].

Decarbonising heating has proven to be more challenging. The UK relies heavily on natural gas for heating with 23 million homes connected to the existing gas grid [8]. Heating and hot water in buildings alone accounts for 20% of the UK's total greenhouse gas emissions [8]. The CCC (Committee on Climate Change) recommended a reduction in these specific emissions of 20% below 1990 levels by 2030 [8] and a target of 57% reduction for all emissions from 1990 levels by 2030 [9].

A major challenge is replacing the seasonal flexibility of the natural gas supply with a low carbon alternative that can match the peak winter demand. Currently production rates from UK gas fields, along with imports from Norway, are increased in the winter to match peak demand and satisfy 70% of UK gas demand [10]. The seasonal difference in gas demand between summer and winter is between 45 and 75 TWh (calculated from Ofgem data [10], 2009–2018).

The key to solving issues of intermittency is the coupling of low carbon energy sources with large-scale energy storage systems capable of storing several TWh across seasonal timescales [11]. Large-scale natural gas (CH_4) storage is a proven technology where subsurface stores are filled during periods of low demand (i.e. summer) and emptied during high demand periods in winter.

Large-scale hydrogen production coupled with storage in geological structures is a technically feasible method for seasonal energy balancing [11–13] and could play an important role in enabling a low carbon energy system. However, this requires a decarbonised source of hydrogen either through steam methane reforming of natural gas combined with carbon capture and storage, or electrolysis using low carbon energy sources, with both sources being the subject of investigation on the UK continental shelf [14–20].

With 8.4 GW of existing offshore wind capacity in the UK and a government commitment of increasing that figure to 40 GW by 2030 [21], large-scale production and storage of hydrogen on the UK continental shelf could provide interseasonal balancing of renewable energy production while making use of existing oil and gas infrastructure. 40 GW of offshore wind with a load factor of 60% and an electrolyser efficiency of 70% could produce 147.17 TWh of hydrogen per year. Supplying the whole UK gas demand of 877.51 TWh [22] would require around six times this amount of offshore wind. Steam methane reformation of natural gas is therefore the more likely source for hydrogen to replace natural gas, but hydrogen production via electrolysis could still play an important role in balancing renewable electricity generation.

Underground hydrogen storage

Similar to natural gas, hydrogen can be stored in subsurface salt caverns, providing energy densities around 100 times greater than compressed air energy storage [23]. Hydrogen storage in salt caverns has been implemented commercially for industrial feedstock in three caverns at Teeside (UK) since the 1970s [24] and in two at the US Gulf Coast since the 1980s [25]. Salt cavern natural gas storage is important for short term energy demand fluctuations as they allow multiple injection and withdrawal cycles per year. However, salt caverns currently contribute only 20% of the total worldwide gas storage capacity [26] and their availability is limited to areas with thick subsurface salt deposits.

Hydrogen can also be stored in the pore space within a geological structure, displacing formation waters or, in the case of depleted gas fields, residual gases, which offers a geographically more independent and flexible solution for large-scale hydrogen storage [27]. Leakage is prevented by the presence of a caprock with a high capillary entry pressure above the reservoir and a trap structure will prevent the hydrogen from migrating laterally to guarantee its reproduction [28]. To date, pure hydrogen has not been stored in porous rocks, however, hydrogen-rich town gas (typically ~50% by volume) has been stored in porous rocks in Germany, France, and the Czech Republic [29].

As of 2018 there are 46 billion cubic metres (bcm) of natural gas storage in 75 saline aquifer storage sites and 334 bcm in 492 depleted hydrocarbon fields worldwide [26]. Whilst no commercial projects currently store hydrogen in porous rocks, no physical or chemical barriers have been identified that could not be addressed using the knowledge gained from decades of experience in underground natural gas storage, and it was concluded early on that the physical and chemical challenges associated with hydrogen storage were manageable [12,13,30]. Several modelling studies investigate the cyclic injection and storage of hydrogen in geological formations using standard industry software and no major technical obstacles have been reported [31–33].

Recent work compared the possibility of hydrogen storage with natural gas storage at the Rough Gas Storage Facility [34], which at 3.3 bcm was the UK's largest porous rock gas store until it ceased to operate as a storage site in 2017. The hydrogen storage capacity (in terms of energy) was found to be approximately one third that of natural gas, due to its lower energy density [35]. The same study found that losses through dissolution and bacterial action would be negligible [34].

Replacement of natural gas in the UK gas grid will require large-scale storage and, to date, no large-scale quantitative assessment of the potential hydrogen storage capacity available in subsurface porous rock has been undertaken. Here, we estimate the hydrogen storage capacity of the porous rocks on the UK continental shelf using a database originally compiled for geological CO_2 storage. The methodology outlined here is directly applicable to other national databases for carbon storage where they exist, paving the way for the compilation of robust hydrogen storage capacities for other large sedimentary basins. Furthermore we also calculate the proximity to storage sites to existing and planned offshore wind developments on the UK continental shelf which could provide a source of low carbon hydrogen in the future and may require large-scale energy storage.

Hydrogen storage capacity requirements for the UK

Replacement of existing storage

The current total natural gas storage capacity for the UK is 16.56 TWh [36], which is equivalent to 6.89 days' average supply based on 2019 UK gas demand of 877.51 TWh [22]. This is spread across 1.50 billion cubic metres (bcm) of underground gas storage [37], 0.37 bcm of which is in porous rocks at Humbly Grove and Hatfield Moor [38]. This equates to a porous rock working gas capacity of 2.34 TWh for natural gas [39]. If the UK moves to a 100% hydrogen gas network, only one third of the energy can be stored in these porous rock sites, equivalent to 0.78 TWh (assuming a similar cushion gas requirement as per a study on the Rough Gas Storage Facility study [34]) due to the lower energy density of hydrogen [34]. This would require an extra 1.56 TWh of working gas capacity to be found.

Further to additional porous rock storage capacity, the natural gas that is stored within the gas network itself, known as linepack, also needs to be considered. The energy density of hydrogen at linepack pressures can be four times lower than that of natural gas [40], so replacement of natural gas with hydrogen would, in the worst case, result in four times less energy stored in the linepack. Currently the UK national transmissions system and local gas grids contain 4.88 TWh at their maximum and 3.84 TWh at their minimum, with an average of 4.41 TWh [41]. Assuming that energy needs to be accessible for grid functionality then a further 2.88 to 3.66 TWh of working gas capacity will be required.

This means that replacing natural gas with hydrogen in the UK grid will require 4.44 to 5.22 TWh of additional working gas capacity to compensate for hydrogen's lower energy density.

Estimates of inter-seasonal storage requirements

Estimates from demand

The H21 Leeds City Gate project produced by utility network provider Northern Gas Networks, focused on the provision of heat through a 100% hydrogen gas network for the Yorkshire city of Leeds in northern England, UK [42]. This was based on converting the existing natural gas network of the city entirely to hydrogen. The study calculated that the conversion of the city's natural gas network to hydrogen would require 40 days of maximum average daily demand for inter-seasonal storage [42]. Extrapolating this 40 day storage requirement to a national level using the maximum 3 hourly change in the gas network as peak demand of 251 GWh [41] (from data between January 2013 and March 2018) results in a maximum daily demand of 2.0 TWh which translates to a storage requirement of 80.3 TWh.

Using the same assumption of a 40 day requirement but using a peak demand figure of 170 GW calculated from household user data [43] (collected between May 2009 and July 2010) gives a maximum daily demand of 4.1 TWh. Multiplying this maximum daily demand by the 40 day requirement equates to a storage requirement of 163.2 TWh. Finally, using the 2018 UK gas demand of 881 TWh [44], 40 days of seasonal storage would equal 96.5 TWh.

Estimates from supply

Over 70% of UK gas demand is supplied by gas fields located within the UK continental shelf (UKCS) and Norway, with storage, LNG (liquefied natural gas) and pipeline imports making up the balance [10]. Fig. 1 shows the UK gas demand and supply source between October 2009 and October 2018 (data from Ofgem [10]). Negative values indicate exports and injection into storage. Over the past decade, seasonal variations in demand are increasingly accommodated by imports

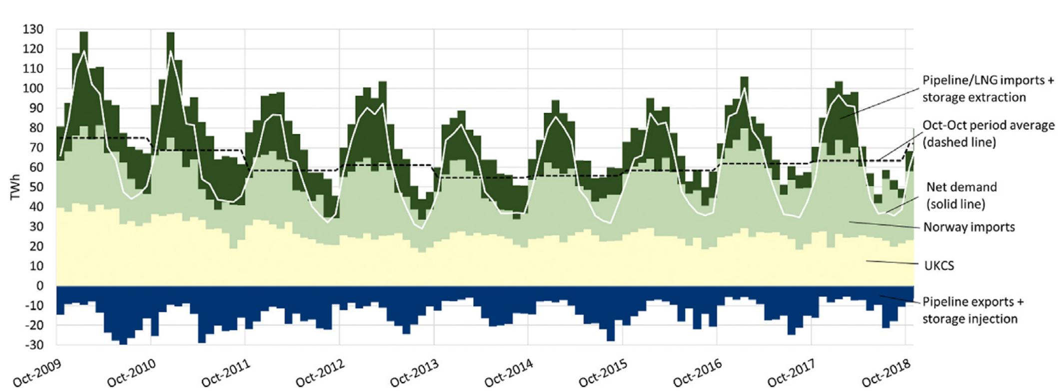

Fig. 1 – UK gas demand and supply source from October 2009 to October 2018 made using data from Ofgem [10]. Gas supplied from the UK continental shelf (UKCS) and Norway respectively makes up over 70% of demand. Negative values indicate injection into storage and pipeline exports. The dashed line is the yearly average from October to October, and the white line is the net demand.

from Norway and other pipelines from Europe due to a reduction in supplies from the UK continental shelf and LNG imports.

We have calculated the average monthly demand for each 12 month period from October to September in order to capture the full range of seasonal change in gas demand. The difference from this average for each month is shown in Fig. 2. In the winter period of 2017/18 total demand above the period average was 133.49 TWh. Assuming a constant hydrogen production rate of 63.35 TWh per month (the October 2017 to October 2018 average monthly demand) and no imports then the 133.49 TWh figure would be indicative of the level of working gas capacity required for seasonal storage of hydrogen. However, it is worth noting that this figure represents a maximum required working gas capacity as hydrogen production via steam methane reformation (SMR) could still utilise the seasonal variations in production rates of natural gas fields by building more capacity [45].

The Energy Research Partnership (ERP), a UK public-private partnership seeking to guide and accelerate innovation in the energy sector through enhancing dialogue and collaboration, investigated the potential role of hydrogen in the UK energy system [45]. This work found that if the full UK domestic heat and industrial demand of 424 TWh for the year 2013 was switched to hydrogen produced by SMR, as little as 54 GW of installed SMR capacity could be used (run continuously at a >90% load factor with 1 month downtime per year) if combined with 75 TWh of storage capacity (it is assumed that this figure is working gas capacity) [45]. Assuming the relationship between storage capacity and gas demand is linear, then the 2018 UK gas demand of 881 Twh [44] would require around double this amount of working gas capacity, ~150 TWh. This is consistent with the 133.5 TWh figure calculated previously from the 2008 to 2018 Ofgem data [10].

Methods and data

The CO_2 stored database

The CO_2 Stored database was developed by the UK Storage Appraisal Project, a consortium of Universities and the British Geological Survey (BGS), funded by the Energy Technologies Institute and published in 2012. It was developed to ascertain the geological storage capacity of the UK continental shelf for CO_2, and was maintained by the Crown Estate and BGS between 2013 and 2018 [46]. It is now maintained and developed solely by the BGS.

The database includes saline aquifers (porous rock formations saturated with saline, non-potable water), depleted and active hydrocarbon fields, and consists of some 574 entries. Information contained in the database includes porosity and permeability, areal extent, thickness, pore volume, pressure regime, location, and type of storage site. Entries are classified as either having identified structures/traps or not, and being open or closed pressure systems. Storage volumes in the database were calculated using Monte Carlo analysis and are provided in tonnes. However, calculations in this study are given in TWh to allow comparison between hydrogen and natural gas. P50 values (meaning that 50% of volumes exceed the P50 estimate and hence 50% of volumes are less than the P50 vol) for formation pore volumes in the CO_2 Stored database were used in this study and therefore all hydrogen storage capacities are also P50 values.

Methodology

The method used to calculate the hydrogen storage capacity of the UK continental shelf from the database comprised of three stages:

1) Filtering: The database was filtered for depth, reservoir quality, type (oil fields, gas fields, aquifers), along with removal of inappropriate entries.
2) Aquifer efficiency calculations: The calculation of storage efficiency to estimate useable pore volumes within saline aquifers with and without identified structures.
3) Hydrogen capacity calculation: Conversion of the available pore volume for hydrogen storage into hydrogen energy equivalent.

The stages were coded in “R” programming language [47] and run using the CO_2 Stored database as input. The code used is available in the supplementary information Appendix 2.

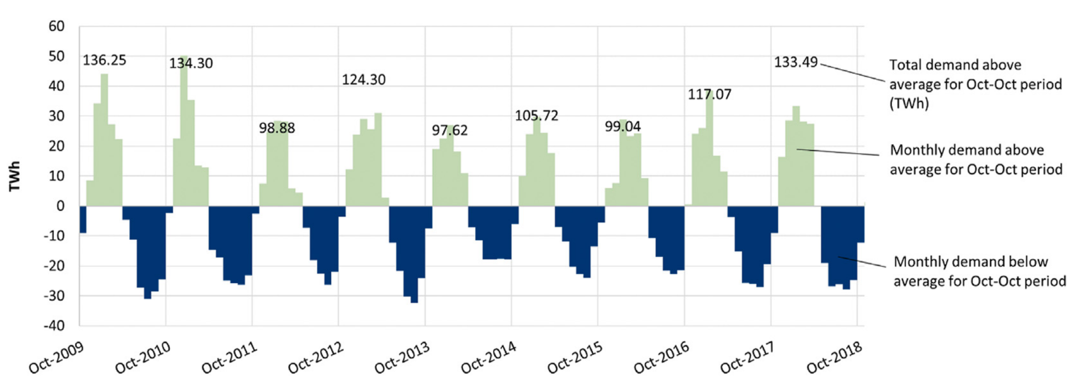

Fig. 2 – UK gas demand difference from yearly October to October average (see dashed line on Fig. 1). Positive values are supply above average and negative values are supply below average. This graph quantifies the seasonal changes in gas demand over each October–October period. The difference between winter peaks and summer lows are 45–75 TWh depending on the year.

Stage one: filtering

Site selection. Sites containing oil or gas condensates were considered unsuitable due to the potential for contamination of stored hydrogen. These were removed and only gas fields and saline aquifers were considered, bringing the total number of entries in the database down to 470.

Saline aquifers are far less well understood than hydrocarbon fields due their size and lack of discovered commercially exploitable hydrocarbon fields. However, they can contain traps that may be suitable for hydrogen storage. Whilst some of these traps have been studied during oil and gas exploration, there are likely to be many undiscovered or undocumented traps not present in the CO_2 Stored database, which relies heavily on hydrocarbon industry data. Hence, we deem saline aquifers to be suitable for hydrogen storage and include them in the hydrogen storage capacity estimate.

Reservoir quality filtering of saline aquifers. Gas fields are deemed to be highly suitable for hydrogen storage as they have trapped and stored buoyant natural gas for geological periods of time. Therefore, gas fields were not filtered for depth and other reservoir properties due to their proven ability to store gas over long time scales.

Saline aquifers were filtered for a minimum permeability of 100 mD and porosity of 10% based on CO_2 storage parameters [48]. However, hydrogen is a much smaller molecule and based on recent work on helium [49], it may be diverted into disconnected and dead-end pores not accessed by larger molecules. This means that lower porosities and permeabilities than those required for CO_2 storage may be acceptable, but further investigation is needed to verify this. Porous rock natural gas storage sites in the UK show average permeabilities of less than 100 mD. The Rough gas storage facility in the UKCS has well average permeabilities ranging between 2 mD – 184 mD [50], the average core permeabilities for the two wells at the UK Hatfield Moors gas storage facility are 38.4 and 248 mD [51], and the average permeability for the UK Humbly Grove gas storage facility is only 20 mD in the storage formation (Great Oolite Group) [52]. However, we apply the precautionary principle and filtering for reservoir quality reduced the number of entries to 325.

Depth filtering of saline aquifers. The saline aquifers were then filtered for depth, using a minimum value of 200 m TVDSS based on accepted compressed air storage guidance [53]. As hydrogen requires more work to compress than CO_2 or natural gas, having a shallow minimum depth would save on compression costs. This reduced the number of entries in the database considered in this study to 317.

A maximum depth filter of 2500 m TVDSS was applied to the mean depth of saline aquifers. This depth was chosen as porosity in sandstone reservoirs typically declines to less than 10% below these depths [54], meaning a lack of available effective pore space for storage. 2500 m is also the maximum depth cited for best practice in CO_2 storage [55]. This brought the number of entries considered down to 202.

Duplicate entries and missing data. Some sites were duplicated as result of subdivision of larger units. For example, the Bunter sandstone which has entries for the full extent, zones, and closures. The full extent and zones were filtered out as the closures had been identified as separate entries in the database. This brought the number of entries considered down to 191.

Not all entries in the CO_2 Stored database were complete, with some missing key data required for the hydrogen capacity calculation. These were filtered out bringing the number of entries in the database considered down to 177.

Stage two: efficiency calculations for saline aquifers

After the filtering stage, 82 saline aquifers remained. Of these 12 have no identified structures or traps. In order to store hydrogen in a porous rock formation we assume that, as with natural gas storage, a trap (a physical shape to the rock layers) is required to contain injected hydrogen within the areal extent that allows production wells to recover it. As there are no identified traps in these 12 saline aquifers we must estimate the likely pore volume of unidentified traps within them. Based on a method recently developed for compressed air energy storage [56] we determined that there were very low storage capacities in these saline aquifers. Combining this with the low confidence of location, and lack of data we do not consider these saline aquifers further. More details on these calculations and their results are provided for interest in appendices 1 and 3 in the supplementary information.

Estimating useable pore volumes in saline aquifers with identified structures and/or traps. A storage efficiency of 1% was applied to the 70 saline aquifers with identified structures and traps based on the conservative estimate of the proportion of pore volume available for CO_2 storage in the CO_2 Stored database [46]. This assumption was required as no information on trap geometries and their suitability for seasonal gas storage exists in the CO_2 Stored database.

Stage three: hydrogen capacity estimation

For depleted gas fields and saline aquifers, the estimated reservoir pore volumes were converted into hydrogen energy equivalent in TWh, allowing direct comparison to estimated energy storage requirements.

Pore volumes were converted to equivalent hydrogen volumes at STP using equation (1) adapted from the Rough Gas Storage Facility study [34].

$$V_{H(STP)} = \frac{V_{H2}(1 - S_{wi})P}{ZP_0}\frac{T_0}{T} \tag{1}$$

where $V_{H(STP)}$ is the volume of hydrogen at STP, V_{H2} is the volume of pore space suitable for hydrogen storage, S_{wi} is the irreducible water saturation (defined as the lowest water saturation that can be achieved by displacing the water with oil or gas and given in the CO_2 Stored database as 0.423), P_0 is pressure at STP, P is reservoir pressure (hydrostatic, calculated from depth), T_0 is temperature at STP, T is reservoir temperature, and Z is the compressibility factor of hydrogen which was linked to the temperature and pressure of the reservoir using an equation of state [57]. The irreducible water saturation in the CO_2 Stored database was used as a conservative estimate. We are currently aware of only one laboratory measurement of hydrogen-water relative permeability in sandstone from Yekta et al. [58] which gives a value of ~0.13. The calculation was also run using this value to see what effect it had on the hydrogen storage capacity. Eq. (1) was also subject to a sensitivity analysis to determine the influence of each variable.

Only a proportion of the total volume calculated using Eq. (1) comprises the working gas capacity (WGC) i.e. the gas that could be economically stored and removed each cycle. The gas required to keep reservoir pressure at a suitable level to allow efficient production of stored gas is called the cushion gas requirement (CGR). We assumed a cushion gas requirement of 50% based on the Rough Gas Storage Facility study [34]. Hydrogen volume was converted using density at STP to calculate mass using the Nobel-Abel equation of state [59] (Eq. (2)).

$$\rho = P/(RT + bP) \tag{2}$$

where ρ is density, P is pressure, R is the gas constant (4160 J/kg K for hydrogen [60]), T is temperature, and b is the co-volume (15.84 cm^3/mol for hydrogen [61]). Mass was converted to energy using the higher heating value (HHV) for hydrogen (39.41 kWh/kg [62]) to allow a comparison to energy demand in the UK.

Offshore wind development proximity calculation

After filtering and volumetric calculations were completed, the remaining gas field and saline aquifer data were tabulated and loaded into QGIS geographical information software [63]. Crown estate offshore wind installation data [64,65] was also loaded into the GIS software and a nearest neighbour analysis was performed to calculate how close each of the remaining gas fields and saline aquifers were to existing or planned offshore wind installations. For the locations of saline aquifers without identified structures the geographic centres given in the CO_2 Stored database were used.

Results

Using the methods outlined and the irreducible water saturation of 0.423 given in the CO_2 Stored database, 95 depleted gas fields and 82 saline aquifers were identified as suitable for hydrogen storage. Using an available pore space of 62.9 billion cubic metres, a total working gas capacity of 9100 TWh energy equivalent of hydrogen was calculated. A full list of sites and calculated capacities is available in the supplementary information, appendix 4.

Gas fields account for 6900 TWh of working gas capacity, saline aquifers with identified structures account for 2100 TWh of working gas capacity, and saline aquifers with no identified structures account for 70 TWh of working gas capacity (see Table 1). Calculated figures are given to 2 significant figures for gas fields and saline aquifers with identified structures, and 1 significant figure for saline aquifers with no identified structures based on the differing uncertainties associated with them. Table 1 also shows the capacity estimates where $S_{wi} = 0.13$ (from Yekta et al. [58]), an increase of 51% (see section on sensitivity analysis below).

Fig. 3 shows the location of all identified hydrogen storage sites and the location of active, under construction, and planned offshore wind developments.

Twenty-nine of the gas fields are 10 km or less from wind developments with the maximum distance being 46 km. Twenty-one of the saline aquifer storage sites with identified structures are 10 km or less from wind developments, with twenty-two sites at a distance of 100 km or greater, with the maximum distance being 186 km. Four of the saline aquifer storage sites with no identified structures are 10 km or less from wind developments with seven sites at a distance of 100 km or greater with the maximum distance being 189 km. As the distances for saline aquifers with no identified structures are measured from centroids rather than identified sites these hold little meaning.

85% of identified gas field storage capacity is located in the Southern North Sea (SNS) and the remaining 15% is located in the East Irish Sea (EIS). Fig. 4 shows the Southern North Sea gas fields and offshore wind developments. The Rough gas field (previously Rough gas storage facility) mentioned earlier is highlighted along with the largest gas field, Leman.

The majority of storage sites have a capacity between 1 and 100 TWh. Size distribution of storage sites by type and geographic area is given in Fig. 5.

Sensitivity analysis and factors affecting hydrogen storage capacity estimates

A base case scenario was created from average values in the CO_2 Stored database (with an arbitrary 1 bcm pore volume), along with high and low values for each variable based on extremes. This data is shown in Fig. 6 as a tornado plot, with the base case values shown in the middle of each bar and the extreme values on the ends (labelled high and low).

The variables that are least well known are the storage pressure (P), working gas capacity fraction (WGC), and

Table 1 – Filtering parameters, final number of entries from the CO_2 Stored database post-filtering, and storage capacities by site type and S_{wi} value used. Storage capacities given to 2 significant figures.

	Depth	Porosity & Permeability	No. of entries	Working gas capacity (TWh) $S_{wi} = 0.423$	Working gas capacity (TWh) $S_{wi} = 0.13$
Gas fields	n/a	n/a	95	6900	10,000
Saline aquifer with identified structure	>200 m <2500 m	≥10% ≥100mD	70	2100	3200
Saline aquifer with no identified structure	>200 m <2500 m	≥10% ≥100mD	12	70	100
Total			177	9100	14,000

irreducible water saturation (S_{wi}). All three will be site specific to some degree, affected by the geology of the storage site and in the case of WGC and pressure, economics of compression and storage. Irreducible water saturation is likely to be lower than the base case as evidenced by the work of Yekta et al. [58]. Z (compressibility factor) has relatively little effect as hydrogen compressibility does not change significantly across the temperature/pressure range encountered in the CO_2 Stored database.

A sensitivity analysis was performed to determine which of the variables in equation (1) had the biggest influence on working gas capacity estimates for hydrogen. Fig. 7 shows the influence of each variable in equation (1) on the output (working gas capacity) as they are varied by ±10%. Compressibility (Z) has the biggest influence with a change of −1.006% in output with every increase of 1%, however as this is directly linked to temperature and pressure, it is ultimately these variables that result in changes in compressibility. Irreducible water saturation (S_{wi}) has the smallest effect of −0.733% with every increase of 1%.

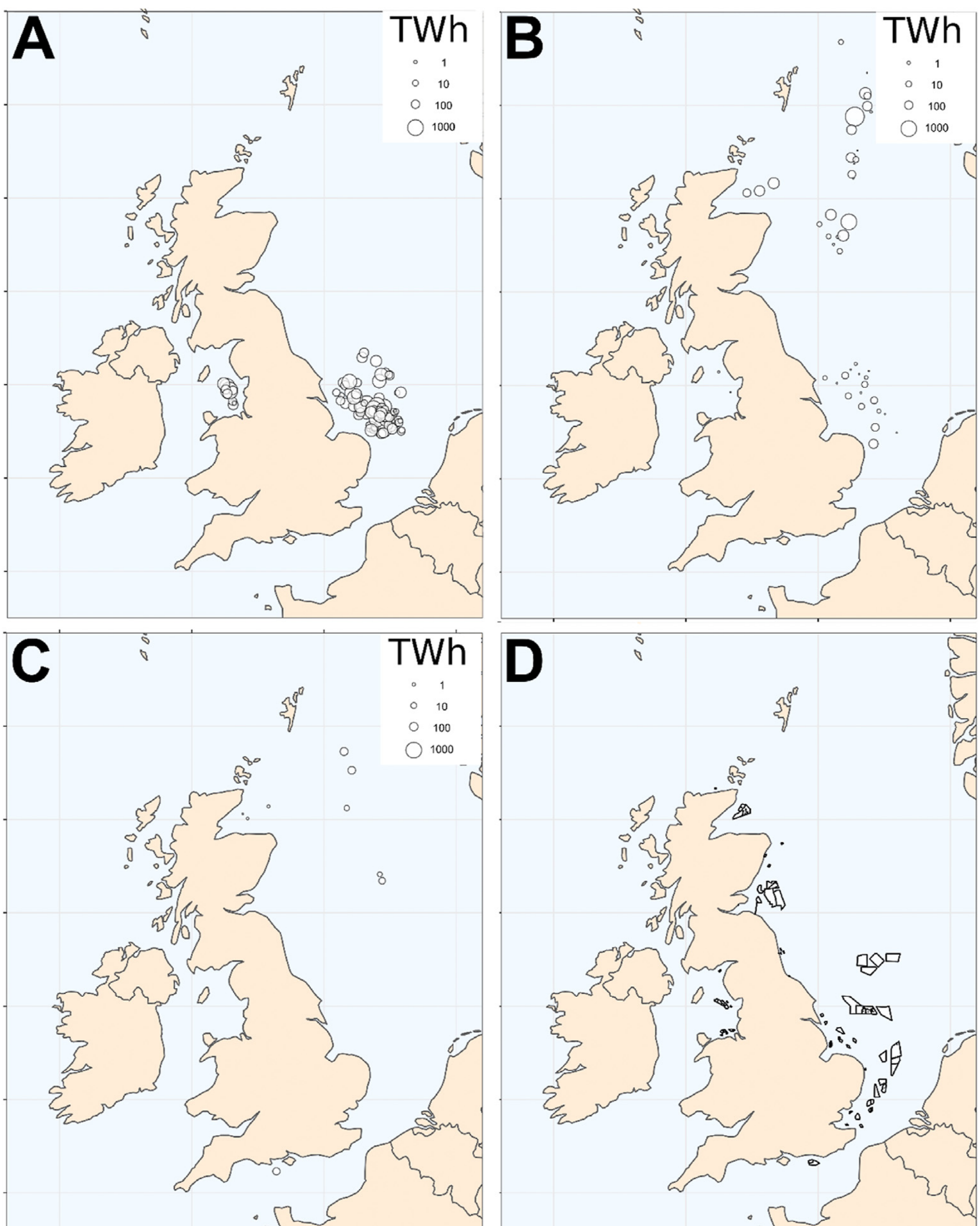

Fig. 3 – Location and relative sizes of different storage types and offshore wind on the UK continental shelf. A = Gas fields; B = Saline Aquifers with Identified Structures; C = Aquifers with no identified structures; D = location of existing and planned offshore wind developments. The majority of storage exists in the gas fields of the Southern North Sea, in close proximity to the majority of offshore wind developments. Figure generated in R using gplot2 [72].

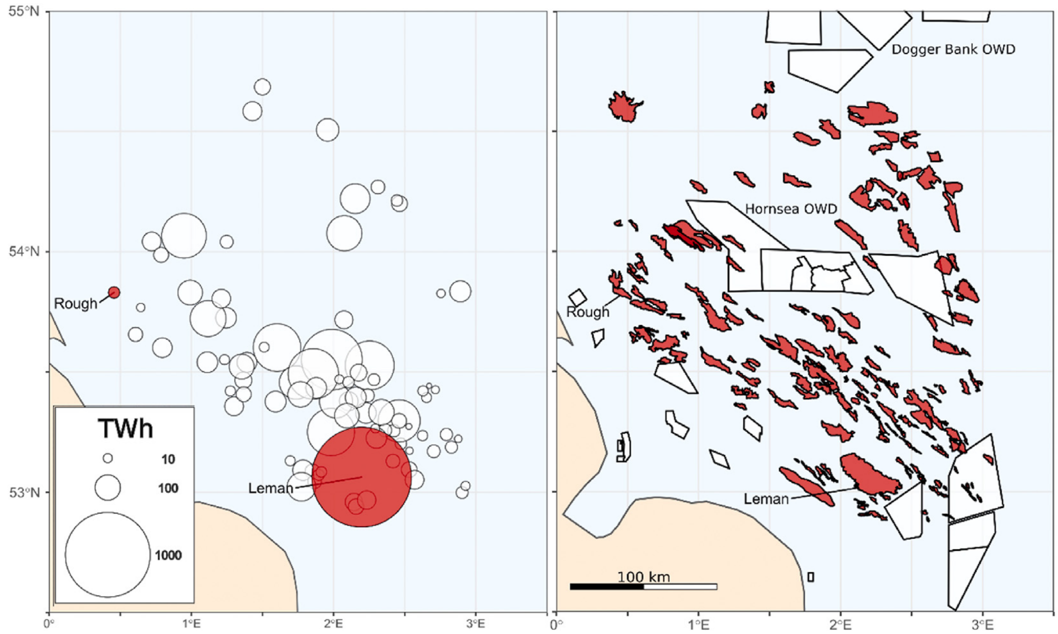

Fig. 4 – Detailed view of the Southern North Sea gas fields. Left panel shows gas fields and their relative storage capacities in TWh. Right panel shows the locations of the gas fields relative to planned and visiting offshore wind developments (OWD). The Rough (12 TWh) and Leman (1200 TWh) gas fields are highlighted in both panels.

Discussion

Our results show that there is a potential 6900 TWh of high confidence (P50) working gas capacity for hydrogen in gas fields in the Southern North Sea and East Irish Sea.

This is greater than any estimates of seasonal storage capacity requirements given earlier, the highest of which was ~150 TWh. The majority of this storage capacity is located in the Southern North Sea close to existing and planned large offshore wind developments which could be used to produce hydrogen that could be injected into seasonal energy stores in

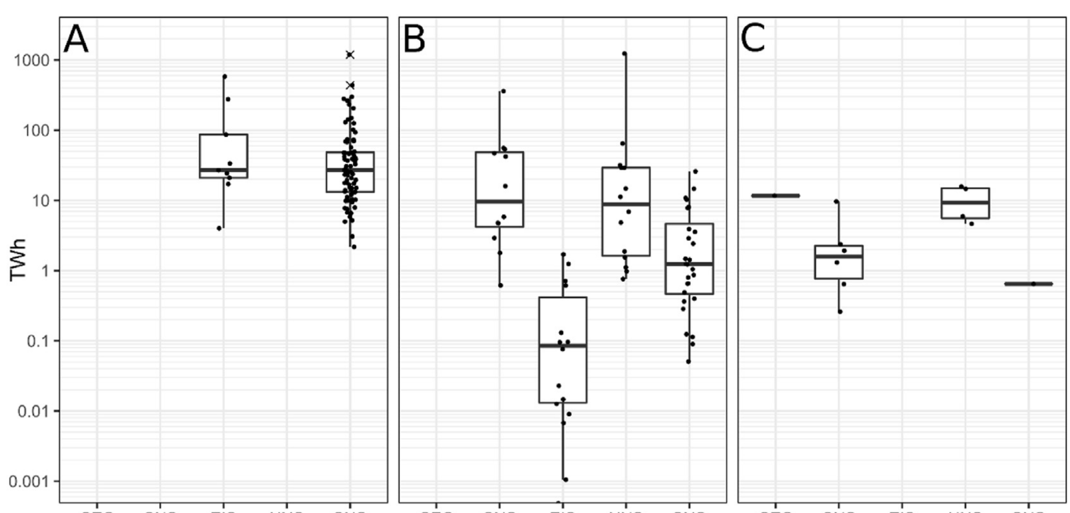

Fig. 5 – Boxplot diagram showing storage site size distribution by geographic region. A = Gas fields; B = Saline aquifers with identified structures; C = Saline aquifers with no identified structures. White boxes extend to the 25th and 75th percentiles, bold horizontal lines within boxes represent the median value, whiskers extend 1.5 times the distance between the first and third quartiles, crosses represent outliers and black points represent data points. CEC = Central English Channel; CNS = Central North Sea; EIS = East Irish Sea Basin; NNS = Northern North Sea; SNS = Southern North Sea. The SNS gas fields provide the largest number and diversity of site sizes.

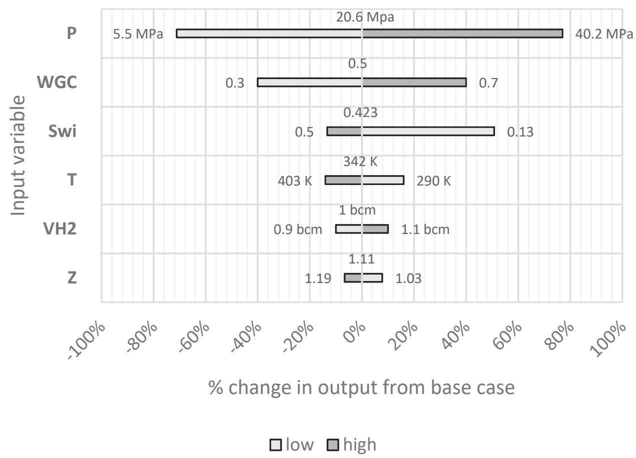

Fig. 6 – Tornado plot showing the base, high and low for variables in equation (1) and their effect on the output (hydrogen storage capacity). Uncertainty in P, WGC, and Swi have the biggest potential to change the storage capacity estimate P = reservoir pressure; WGC = the working gas capacity fraction; Swi = the irreducible water saturation; T = reservoir temperature; VH2 = the volume of pore space suitable for hydrogen storage; and Z = the compressibility factor of hydrogen.

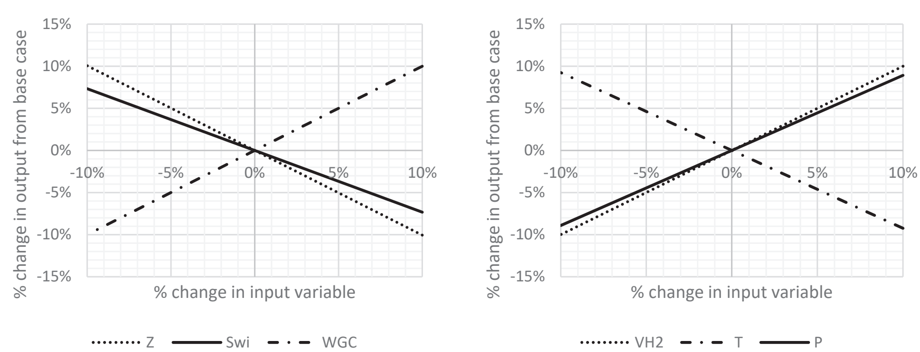

Fig. 7 – Sensitivity of variables in Eq. (1). All variables are positively correlated with changes in output except temperature, irreducible water saturation, and compressibility factor. P = reservoir pressure; WGC = the working gas capacity fraction; Swi = the irreducible water saturation; T = reservoir temperature; VH2 = the volume of pore space suitable for hydrogen storage; and Z = the compressibility factor of hydrogen.

the future. Individual gas fields offer a range of storage capacities between <10 TWh to >1000 TWh. Offshore hydrogen production is currently being investigated along with energy hubs which combine hydrogen and electricity production from offshore wind with existing oil and gas infrastructure [14–19].

We also show that there is a potential 2200 TWh of working gas capacity for hydrogen in saline aquifers, however there are considerable hurdles to providing accurate estimations of hydrogen storage capacity in saline aquifers in the CO_2 Stored database. This is due to the amount of uncertainty in the size and location of useable pore space within suitable structures, especially in aquifers with no identified structures, making this a low confidence estimate.

Sensitivity analysis of Eq. (1) and the tornado plot in Fig. 6 shows that the ideal storage sites in terms of capacity of hydrogen stored would be low temperature reservoirs capable of containing high pressure while allowing for a relatively high working gas capacity fraction i.e. a higher working gas capacity would make a storage site more economically viable. Further refinement of ideal storage site parameters for site selection would need to take this into account.

As the relative permeability of hydrogen in water is not well defined it is unclear as to whether viscous fingering would dominate over capillary limited flow. As viscous fingering can be controlled to some degree by injection rate it is not unlikely that the low irreducible water saturations demonstrated by Yekta et al. [58] could be achieved in real storage sites.

This high-level study sought to estimate total hydrogen storage capacity in the UK continental shelf. Further refinement would need to take into consideration the potential conflict with CO_2 storage sites, potential reactions between hydrogen and existing fluids in the gas fields such as natural gas, carbon dioxide, and hydrogen sulphide, and well integrity.

This methodology can also be applied to other carbon storage databases where they exist to provide an estimate of hydrogen storage capacity at a national level. Such databases currently exist in Australia [66], Brazil [67], China [68], Europe [69], Norway [70], and North America [71].

Conclusions

We present a methodology to estimate hydrogen storage capacity in porous rocks at a national level using a carbon dioxide storage database for the UK. We find a P50 estimate of 6900 TWh of hydrogen storage capacity in the gas fields of the UK continental shelf and a lower confidence estimate of 2200 TWh in saline aquifers. These figures are an order of magnitude greater than all known estimates for the seasonal storage requirement for the UK. This methodology can be applied to other national carbon dioxide storage databases where they exist to provide a high-level quantified estimate of hydrogen storage potential.

Declaration of competing interest

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 data to this article can be found online at https://doi.org/10.1016/j.ijhydene.2020.12.106.

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