A QUANTITATIVE ASSESSMENT OF THE HYDROGEN STORAGE CAPACITY OF THE UK CONTINENTAL SHELF

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1 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.

2 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 inter-seasonal 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.

3 Hydrogen storage capacity requirements for the UK

3.1 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.

3.2 Estimates of Inter-seasonal storage requirements

3.2.1 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.

3.2.2 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

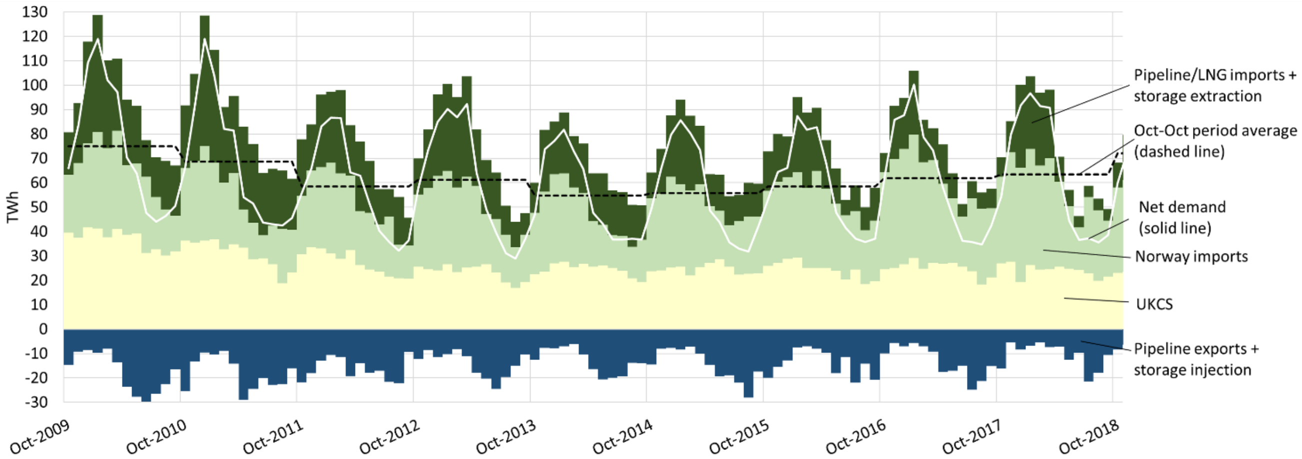

Figure 1: UK gas demand and supply source from October 2009 to October 2018 made using data from Ofgem[10]. Gas supplied from the UK continental shelf (UKCS) and Norway respectively makes up over 70% of demand. Negative values indicate injection into storage and pipeline exports. The dashed line is the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

up the balance[10]. Figure 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 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 Figure 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].

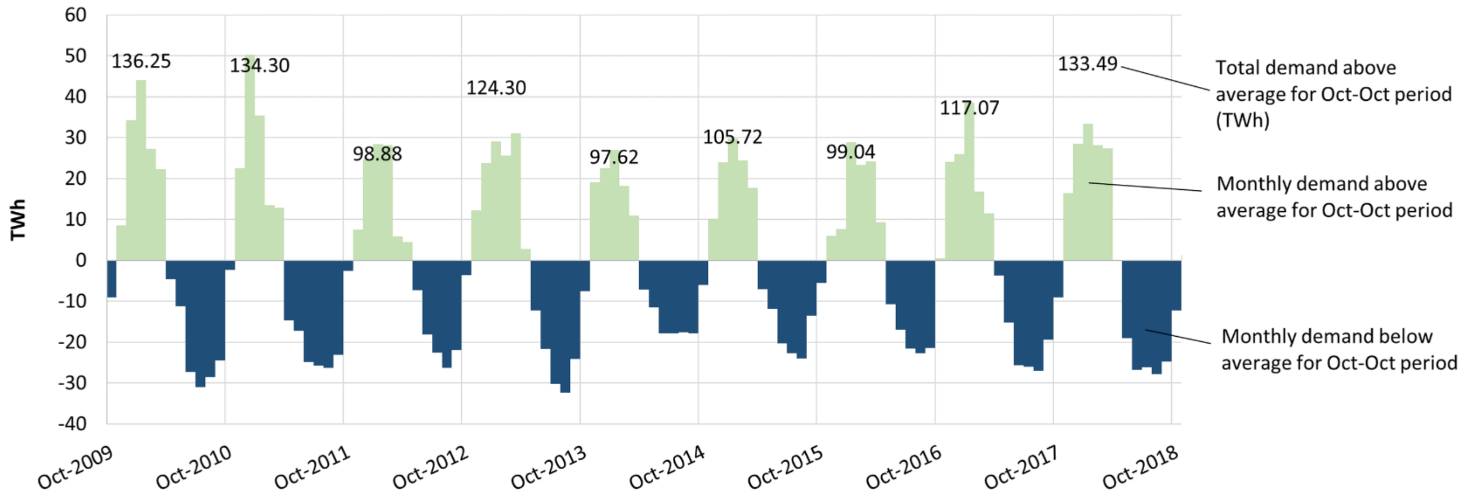

Figure 2: UK gas demand difference from yearly October to October average (see dashed line on Figure 1). Positive values are supply above average and negative values are supply below average. This graph quantifies the seasonal changes in gas demand over each October-October period. The difference between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

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].

4 Methods and Data

4.1 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 volume) 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.

4.2 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 usable 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.

4.2.1 Stage One: Filtering

4.2.1.1 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.

4.2.1.2 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.

4.2.1.3 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.

4.2.1.4 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.

4.2.2 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.

4.2.2.1 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.

4.2.3 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].

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

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. Equation 1 was also subject to a sensitivity analysis to determine the influence of each variable.

Only a proportion of the total volume calculated using equation 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] (equation 2).

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

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.

4.2.4 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.

5 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 6,900 TWh of working gas capacity, saline aquifers with identified structures account for 2,100 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).

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	6,900	10,000
Saline aquifer with identified structure	>200m <2500m	≥10% ≥100mD	70	2,100	3,200
Saline aquifer with no identified structure	>200m <2500m	≥10% ≥100mD	12	70	100
Total			177	9,100	14,000

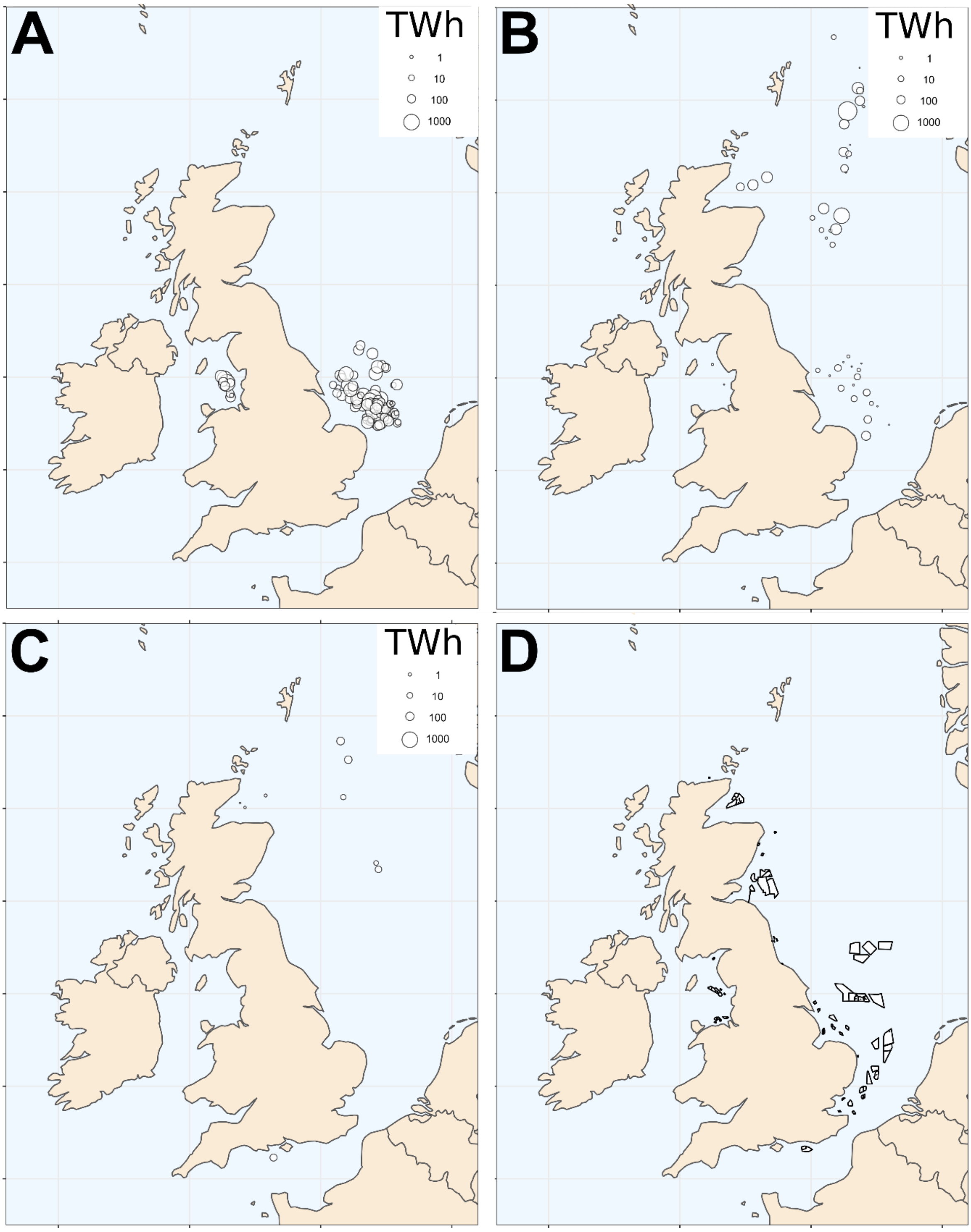

Figure 3: Location and relative sizes of different storage types and offshore wind on the UK continental shelf. A = Gas fields; B = Saline Aquifers with Identified Structures; C = Aquifers with no identified structures; D = location of existing and planned offshore wind developments. The majority of 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].

Figure 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

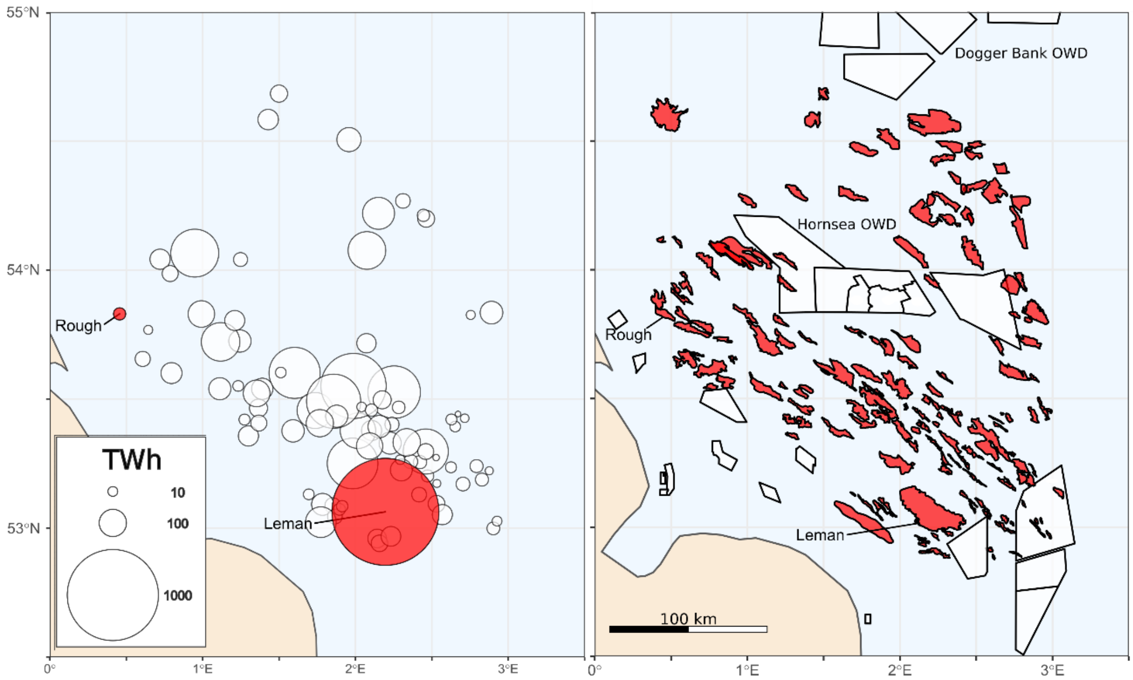

Figure 4: Detailed view of the Southern North Sea gas fields. Left panel shows gas fields and their relative storage capacities in TWh. Right panel shows the locations of the gas fields relative to planned and visiting offshore wind developments (OWD). The Rough (12 TWh) and Leman (1200 TWh) gas fields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

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). Figure 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 Figure 5.

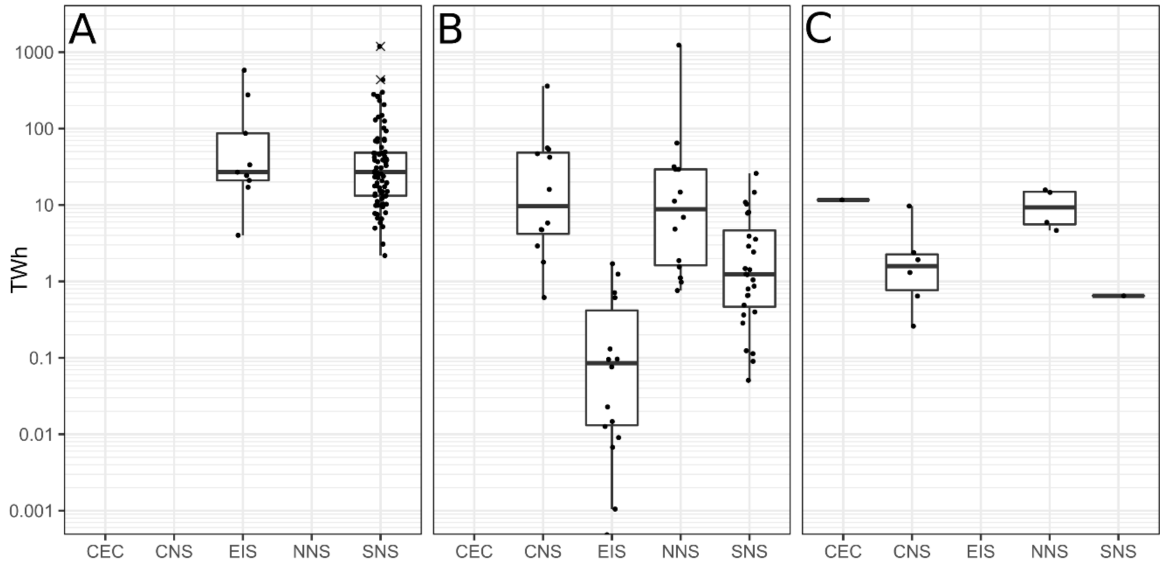

Figure 5: Boxplot diagram showing storage site size distribution by geographic region. A = Gas fields; B = Saline aquifers with identified structures; C = Saline aquifers with no identified structures. White boxes extend to the 25th and 75th percentiles, bold horizontal lines within boxes represent the 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.

6 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 Figure 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

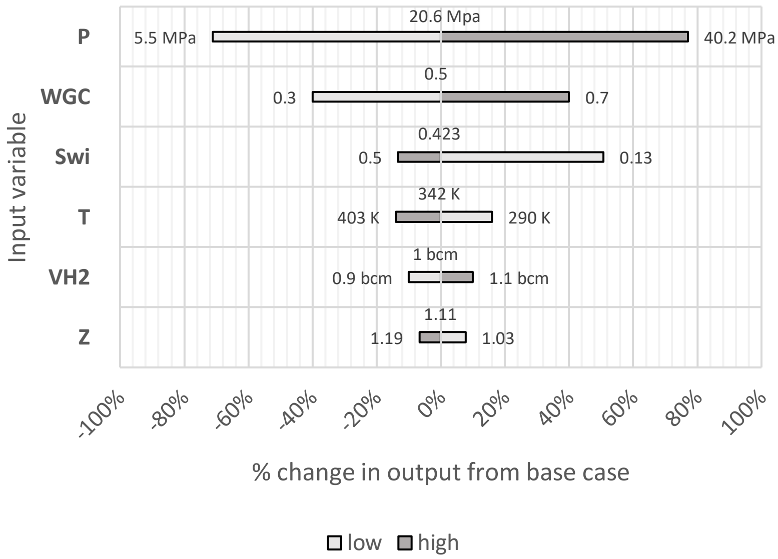

Figure 6: Tornado plot showing the base, high and low for variables in equation 1 and their effect on the output (hydrogen storage capacity). Uncertainty in P, WGC, and Swi have the biggest potential to change the storage capacity estimate P = reservoir pressure; WGC = the working gas capacity fraction; 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

fraction (WGC), and 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. Figure 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%.

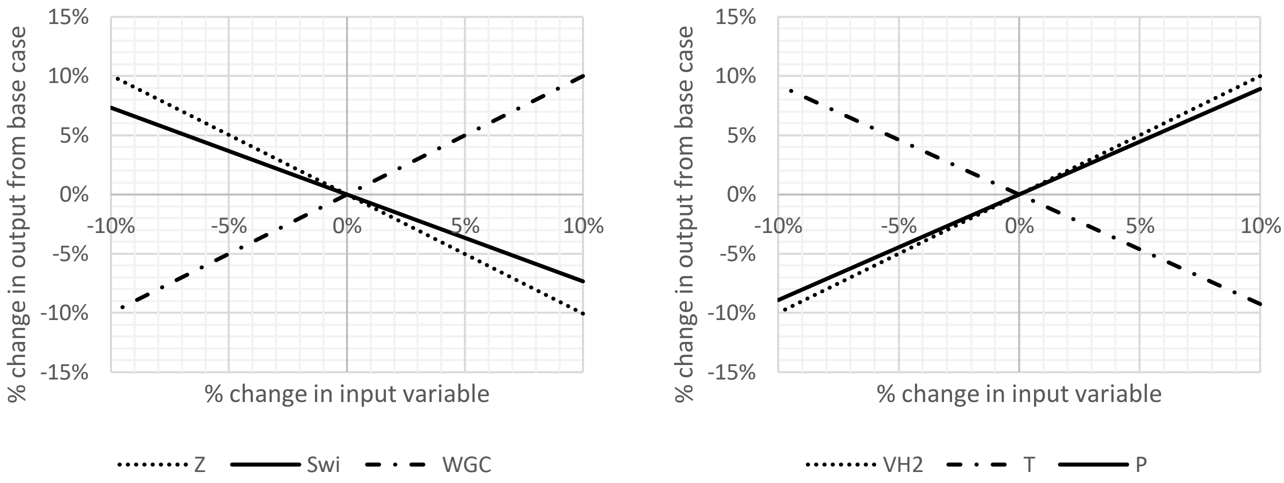

Figure 7: Sensitivity of variables in equation 1. All variables are positively correlated with changes in output except temperature, irreducible water saturation, and compressibility factor. P = reservoir pressure; WGC = the working gas capacity fraction; Swi = the irreducible water saturation; T = reservoir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

7 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 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 equation 1 and the tornado plot in Figure 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].

8 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.

9 Conflicts of interest

There are no conflicts to declare.

10 Acknowledgements

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A quantative assessment of the hydrogen storage capacity of the UK continental shelf – supplementary information

Appendix 1 –

Estimating useable pore volumes in saline aquifers without identified structures or traps

The methodology used to estimate pore volume in saline aquifers without identified structures or traps was adapted from a compressed air energy storage capacity study[1]. This combined hydrocarbon exploration well success rates and oil field production data in order to estimate the likely volumes of pore space within traps that are suitable for fluid storage.

It was assumed that all hydrocarbon exploration wells are drilled into some form of trap within an aquifer, identified by exploration techniques such as seismic interpretation. Since the success rate of hydrocarbon exploration wells from 1963 to 2002 is 30%[2], the relationship between the volume of hydrocarbons produced from these structures and the average success rate of hydrocarbon exploration wells provides an estimate of the total volume of effective fluid traps[3].

Using this total volume, an estimate of the proportion suitable for hydrogen storage can be made, using the difference between the proportion of traps suitable for fluid storage and the proportion of traps that contain hydrocarbons. This provides the volume of traps that do not contain hydrocarbons and are therefore suitable for hydrogen storage. This process is visualised in Figure 1.

It is unknown if the successful exploration wells found gas or oil or both so the entire 30% of the total volume was assumed to contain oil and therefore considered unsuitable for hydrogen storage. However, traps with wells which found gas are accounted for separately in the calculation for depleted gas fields based on data from the CO_2 database. Where available, oil production figures were taken from Oil & Gas Authority data[4] for each oilfield in the list. Formation volume factors (FVF, the volume change upon bringing fluids from a reservoir to the surface) are from Gluyas and Hichens (2003)[5] and from Evans et al. (eds) (2003)[6]. As there was little to no available data on FVF for most North Sea fields, an average was used, calculated from the available data. This data and calculation is given in spreadsheet form in appendix 3.

The volume of the traps was calculated from the oil production and FVF data and compared with that given in the database for a given saline aquifer to provide an estimate of the proportion of pore volume suitable for hydrogen storage. This proportion is known as the storage efficiency and was averaged using the available data and applied to all saline aquifers with no identified structures/traps, resulting in a storage efficiency of 0.1 % ± 0.04 % $\sigma_{\bar{x}}$.

Equation (1)[3] was used to estimate the pore volume of useable structures within a single aquifer.

$$(1)\ V_{H2} = (V_{oil(STP)} * FVF/R_{ow}) * S_{H2}$$

Where V_{H2} is the volume of pore space suitable for hydrogen storage, $V_{oil(STP)}$ is the total volume of produced oil at STP (standard temperature and pressure), *FVF* is the average formation volume factor (1.28 ± 0.04 $\sigma_{\bar{x}}$), R_{ow} is the success rate of oil wells, and S_{H2} is the proportion of structures suitable for hydrogen storage. The latter is estimated from the proportion of total traps in an aquifer that are suitable for fluid storage where drilling has penetrated sealing/reservoir formation pairs[2] (49 ± 8%; this includes structures containing oil). The success rate of exploration wells is 30%[2] and as structures that contain oil are deemed unsuitable for hydrogen storage these are subtracted. This leaves a figure of 19 ± 8% of structures suitable for hydrogen storage. A visual representation of this method is shown in Figure 1.

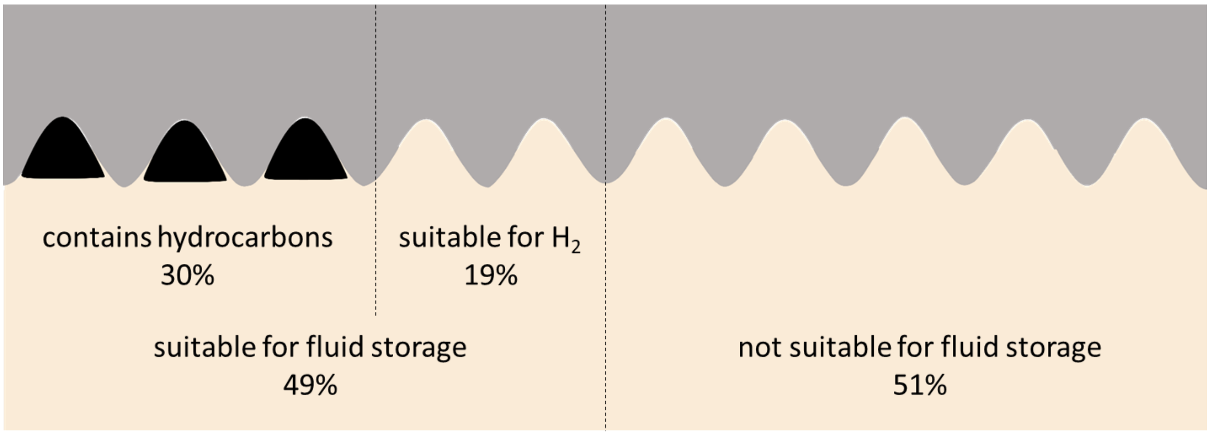

Figure 8: Schematic saline aquifer and seal to visualise the variables in the efficiency calculation. The grey area represents the sealing formation above the saline aquifer (pale yellow area). Small structures exist at the top of the saline aquifer, 30% of which contain hydrocarbons represented by black fill. The 51% of structures on the right are not suitable for fluid storage (e.g. due to poor reservoir quality or compartmentalisation) which leaves the 19% structures in the middle which are suitable for fluid storage but do not contain hydrocarbons available for hydrogen storage. Dashed lines represent the boundaries between the various portions of the saline aquifer. NB this schematic is not to scale nor is it intended to be a realistic representation of an actual saline aquifer. It merely visualises the logic of the calculation.

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Appendix 2 –

Hydrogen storage capacity calculator code for R

h2_cap_calculator.R

Jonathan Scafidi

2019-08-15

```
# load co2stored database
CO2STORED_for_use_in_R <- read.csv("R:/CO2STORED_for_use_in_R.csv")

# set hydrogen values
gasdensitystp <- 0.0899  #kg/m3
h2energydensity <- 120  #Mj/m3
MJ2kWh <- 0.277778  #kwh/Mj
twhperkg <- 3.941e-08  #twh/kg HHV
h2gasconstant <- 4160  #R: j/kg K from engineering science page 88
h2covol <- 1.58e-05  #b: m3/mol

# constants
stpp <- 0.101325  #MPa@stp
stpt <- 273.15  #kelvin@stp
iws <- 0.423  #irreducible water sat from database
```

```
wgc <- 0.5  #working gas capacity

#conversions
MMtom <- 1e+06  #millions cubic metres to cubic metres
MPatopa <- 1e+06  #megapascals to pascals

#####################################################################################
#
# STAGE 1 : FILTERING
#
#####################################################################################
# filter so only saline aquifers and gas sites (s.a. = 1, gas = 2, gas condensate = 3, oil
& gas = 4)

h2store <- subset(CO2STORED_for_use_in_R, CO2STORED_for_use_in_R$unitdesignate_trans < 3)

# H2 compressibility factor for each reservoir (cons & formula from Lemmon et al 2008)
cons <- read.csv("R:/cons.csv", T)

for (i in 1:nrow(h2store)) {
  h2store$Z[i] <- 1 + sum(cons$ai * (100/h2store$formationtempml_Kelvin[i])^cons$bi * (h2st
ore$Hydrostatic_pressure_Mpa[i]/1)^cons$ci)
}

filter1 <- nrow(h2store)

# POROPERM

# storage parameter filter for permeability
h2store <- subset(h2store, !(h2store$unitdesignate_trans == 1 & h2store$storagepermeability
ml_md < 100))

filter2 <- nrow(h2store)

# storage paramter filter for porosity
h2store <- subset(h2store, !(h2store$unitdesignate_trans == 1 & h2store$porosityml_frac < 0
.1))

filter3 <- nrow(h2store)

# all code above working fine

# filter for min depth based on min CAES
h2store <- subset(h2store, !(h2store$unitdesignate_trans == 1 & h2store$shallowestdepthml_m
TVDSS < 200))

filter4 <- nrow(h2store)

# max depth from chadwick 2008
h2store <- subset(h2store, !(h2store$unitdesignate_trans == 1 & h2store$meandepthml_mTVDSS
> 2500))

filter5 <- nrow(h2store)


# number of sites left
n_saline <- sum(with(h2store, unitdesignate_trans == 1))
n_gas <- sum(with(h2store, unitdesignate_trans == 2))

# remove all identified unsuitable saline aquifers: Bunter zones and extent as closures ide
ntified, Ormskirk Zones
# as closures identified, Leman extent as fields identified.

tomatch <- list(128, 138, 139, 141, 153, 154, 225, 226, 227, 228, 229, 230, 231, 248, 256,
```

```r
257, 258, 259, 260, 303,
                304, 306, 307)
h2store <- h2store[!h2store$code %in% tomatch, ]

filter6 <- nrow(h2store)

# remove na values

cols <- c(17, 21, 28)
h2store <- h2store[complete.cases(h2store[, cols]), ]

filter7 <- nrow(h2store)

#####################################################################################
#
# STAGE 2 : EFFICIENCY CALCULATION FOR SALINE AQUIFERS
#
#####################################################################################

# no identified structure as per paper section
for (i in 1:length(h2store$unitdesignate_trans)) {
  if (h2store$storage_unit_type_trans[i] == 1 && h2store$unitdesignate_trans[i] == 1) {
    h2store$porevolume_10E6m_3[i] <- h2store$porevolume_10E6m_3[i] * 0.001
  }
}

# identified structure 1% as per CO2Stored database minimum efficiency
# conservative estimate based on lack of data

for (i in 1:length(h2store$unitdesignate_trans)) {
  if (h2store$storage_unit_type_trans[i] != 1 && h2store$unitdesignate_trans[i] == 1) {
    h2store$porevolume_10E6m_3[i] <- h2store$porevolume_10E6m_3[i] * 0.01
  }
}

#####################################################################################
#
# STAGE 3 : HYDROGEN CAPACITY CALCULATION
#
#####################################################################################

# equation 2 from paper
h2store$capacity_m3 <- ((h2store$porevolume_10E6m_3 * MMtom) * (1 - iws) * h2store$Hydrosta
tic_pressure_Mpa * stpt)/(h2store$Z *

stpp * h2store$formationtempml_Kelvin)

# working gas capacity

h2store$capacity_m3 <- h2store$capacity_m3 * wgc

# density at reservoir conditions

h2store$density <- (h2store$Hydrostatic_pressure_Mpa * MPatopa)/(h2gasconstant * h2store$fo
rmationtempml_Kelvin + h2covol *
                                                                    (h2store$Hydrostatic_pre
ssure_Mpa * MPatopa))

# density at stp

h2densstp <- (stpp * MPatopa)/(h2gasconstant * stpt + h2covol * (stpp * MPatopa))

h2store$h2mass_kg <- h2store$capacity_m3 * h2densstp
```

```
# conversion to TWh

h2store$twh <- h2store$h2mass_kg * twhperkg

# tabulate results

# GRAND TOTAL
grandtotaltwh <- colSums(h2store["twh"], na.rm = TRUE, dims = 1)

# saline aquifer TOTAL
aquifers <- subset(h2store, h2store$unitdesignate_trans == 1)

nostructure_aquiferstoretwh <- subset(aquifers, aquifers$storage_unit_type_trans == 1)
withstructure_aquiferstoretwh <- subset(aquifers, !(aquifers$storage_unit_type_trans == 1))

withstructure_aquifertotaltwh <- colSums(withstructure_aquiferstoretwh["twh"], na.rm = TRUE
, dims = 1)
nostructure_aquifertotaltwh <- colSums(nostructure_aquiferstoretwh["twh"], na.rm = TRUE, di
ms = 1)

# gas field TOTAL

gasfieldstoretwh <- subset(h2store, h2store$unitdesignate_trans == 2)
gasfieldtotaltwh <- colSums(gasfieldstoretwh["twh"], na.rm = TRUE, dims = 1)

# numbersleft after everything
ngas <- nrow(gasfieldstoretwh)
nsa_ns <- nrow(nostructure_aquiferstoretwh)
nsa_ws <- nrow(withstructure_aquiferstoretwh)

post_n_saline <- sum(with(h2store, unitdesignate_trans == 1))
post_n_gas <- sum(with(h2store, unitdesignate_trans == 2))

# make table of results
Results_twh_h2 <- c(gasfieldtotaltwh, withstructure_aquifertotaltwh, nostructure_aquifertot
altwh, grandtotaltwh)

# label results
names(Results_twh_h2) <- c("Gas field capacity/twh", "Saline aquifer with id structure capa
city/twh", "Saline aquifer no id structure capacity/twh",
                           "Total capacity/twh")

# export data to GIS for visualisation

write.csv(h2store, "R:/PhD/h2store_offshore_resources/h2store_r_processed_update", row.name
s = TRUE)  #open excel, open file, save as .csv


filters <- c(filter1, filter2, filter3, filter4, filter5, filter6, filter7)

filters

## [1] 470 326 325 317 202 191 177

Results_twh_h2

##                          Gas field capacity/twh
##                                      6926.24340
## Saline aquifer with id structure capacity/twh
##                                      2141.62187
##   Saline aquifer no id structure capacity/twh
##                                        69.41263
##                              Total capacity/twh
##                                      9137.27790
```

```
final_numbers <- c(ngas, nsa_ns, nsa_ws)

final_numbers

## [1] 95 12 70
```

APPENDIX 3					
Data used to calculate average efficiency for saline aquifers with no identified structures					
from: Scafidi, J., Wilkinson, M., Gilfillan, S. M. V., Heinemann, N., & Haszeldine, R. S. (2020). *A quantative assessment of the hydrogen storage capacity of the UK continental shelf*					
Formation	Total oil produced [10E06 m3]	Total oil produced * FVF [10E06 m3]	CO2 Stored porespace figure [10E06 m3]	Equation 1 (Mouli-Castillo, 2018)	Efficiency
Mey	140.029841	179.0873951	1235869	113.4	0.009%
Maureen	45.369756	58.02442794	550143	36.7	0.007%
Burns/Ettrick	4.292823	5.4901904	245783	3.5	0.001%
Tor/Ekofisk	1367	1748.287846	280552	1107.2	0.395%
Forties	658.425544	842.0756227	252389	533.3	0.211%
Captain	67.196	85.93851508	52402	54.4	0.104%
Carr	28.080134	35.91233138	10601	22.7	0.215%
				Average efficiency	**0.1%**
Global average FVF	1.28				
Formation	Field	oil produced [m3]	source (production)	FVF	source (FVF)
Mey	Andrew	26805499	Oil & Gas Authority (2020)		Gluyas & Hichens (2003)
Mey	Balmoral	18679864	Oil & Gas Authority (2020)	1.256	Evans et al. (2003)
Mey	Banff	8667688	Oil & Gas Authority (2020)	1.31	Gluyas & Hichens (2003)
Mey	Bladon	704108	Oil & Gas Authority (2020)		Gluyas & Hichens (2003)
Mey	Blair	30907	Oil & Gas Authority (2020)		Gluyas & Hichens (2003)
Mey	Blenheim	3241475	Oil & Gas Authority (2020)		Gluyas & Hichens (2003)
Mey	Cyrus	4248581	Oil & Gas Authority (2020)	1.19	Gluyas & Hichens (2003)
Mey	Donan	1003445	Oil & Gas Authority (2020)		Gluyas & Hichens (2003)
Mey	Everest	5785028	Oil & Gas Authority (2020)		Gluyas & Hichens (2003)
Mey	Gannet A	14583583	Oil & Gas Authority (2020)		Gluyas & Hichens (2003)
Mey	Gannet B	1556311	Oil & Gas Authority (2020)		Gluyas & Hichens (2003)
Mey	Gannet C	1511094	Oil & Gas Authority (2020)		Gluyas & Hichens (2003)
Mey	Gannet D	7380001	Oil & Gas Authority (2020)		Gluyas & Hichens (2003)
Mey	Gannet E	5530502	Oil & Gas Authority (2020)		Gluyas & Hichens (2003)
Mey	Gannet F	4971440	Oil & Gas Authority (2020)		Gluyas & Hichens (2003)
Mey	Gannet G	3129081	Oil & Gas Authority (2020)		Gluyas & Hichens (2003)

Mey	Joanne	9542880	Oil & Gas Authority (2020)		Gluyas & Hichens (2003)
Mey	Macculloch	18844093	Oil & Gas Authority (2020)	1.2	Gluyas & Hichens (2003)
Mey	Orion	3814261	Oil & Gas Authority (2020)		Gluyas & Hichens (2003)
Maureen	Everest	5785028	Oil & Gas Authority (2020)		Gluyas & Hichens (2003)
Maureen	Fleming	5195776	Oil & Gas Authority (2020)		Gluyas & Hichens (2003)
Maureen	Maureen	34388952	Oil & Gas Authority (2020)	1.29	Gluyas & Hichens (2003)
Burns/Ettrick	Ettrick	4292823	Oil & Gas Authority (2020)		Gluyas & Hichens (2003)
Tor/Ekofisk	ALBUSKJELL	7400000	Evans et al. (2003)		Gluyas & Hichens (2003)
Tor/Ekofisk	BANFF (UK)	7900000	Evans et al. (2003)	1.31	Gluyas & Hichens (2003)
Tor/Ekofisk	DAGMAR	1000000	Evans et al. (2003)		Gluyas & Hichens (2003)
Tor/Ekofisk	DAN	105000000	Evans et al. (2003)		Gluyas & Hichens (2003)
Tor/Ekofisk	EDDA	4800000	Evans et al. (2003)		Gluyas & Hichens (2003)
Tor/Ekofisk	EKOFISK	478500000	Evans et al. (2003)		Gluyas & Hichens (2003)
Tor/Ekofisk	ELDFISK	108500000	Evans et al. (2003)		Gluyas & Hichens (2003)
Tor/Ekofisk	GORM	52000000	Evans et al. (2003)		Gluyas & Hichens (2003)
Tor/Ekofisk	HALFDAN	42000000	Evans et al. (2003)		Gluyas & Hichens (2003)
Tor/Ekofisk	HARALD EAST	9000000	Evans et al. (2003)		Gluyas & Hichens (2003)
Tor/Ekofisk	HOD	7800000	Evans et al. (2003)		Gluyas & Hichens (2003)
Tor/Ekofisk	KRAKA	6000000	Evans et al. (2003)		Gluyas & Hichens (2003)
Tor/Ekofisk	KYLE	3500000	Evans et al. (2003)		Gluyas & Hichens (2003)
Tor/Ekofisk	MACHAR	233000000	Evans et al. (2003)		Gluyas & Hichens (2003)
Tor/Ekofisk	REGNAR	1000000	Evans et al. (2003)		Gluyas & Hichens (2003)
Tor/Ekofisk	ROLF	5000000	Evans et al. (2003)		Gluyas & Hichens (2003)
Tor/Ekofisk	SKJOLD	44000000	Evans et al. (2003)		Gluyas & Hichens (2003)
Tor/Ekofisk	SOUTH ARNE	35000000	Evans et al. (2003)		Gluyas & Hichens (2003)
Tor/Ekofisk	SVEND	5000000	Evans et al. (2003)		Gluyas & Hichens (2003)
Tor/Ekofisk	TOMMELITEN GAMMA	3900000	Evans et al. (2003)		Gluyas & Hichens (2003)
Tor/Ekofisk	TOR	25800000	Evans et al. (2003)		Gluyas & Hichens (2003)
Tor/Ekofisk	VALDEMAR	2000000	Evans et al. (2003)		Gluyas & Hichens (2003)
Tor/Ekofisk	VALHALL	166700000	Evans et al. (2003)		Gluyas & Hichens (2003)
Tor/Ekofisk	VEST EKOFISK	12200000	Evans et al. (2003)		Gluyas & Hichens (2003)

Forties	ARBROATH	24175024	Oil & Gas Authority (2020)	1.327	Evans et al. (2003)
Forties	ARKWRIGHT	3661080	Oil & Gas Authority (2020)	1.456	Gluyas & Hichens (2003)
Forties	EVEREST	5785028	Oil & Gas Authority (2020)		Gluyas & Hichens (2003)
Forties	FORTIES	438382145	Oil & Gas Authority (2020)	1.28	Evans et al. (2003)
Forties	GANNET B	1556311	Oil & Gas Authority (2020)		Gluyas & Hichens (2003)
Forties	GANNET C	1511094	Oil & Gas Authority (2020)		Gluyas & Hichens (2003)
Forties	GANNET D	7380001	Oil & Gas Authority (2020)		Gluyas & Hichens (2003)
Forties	GANNET E	5530502	Oil & Gas Authority (2020)		Gluyas & Hichens (2003)
Forties	GANNET F	4971440	Oil & Gas Authority (2020)		Gluyas & Hichens (2003)
Forties	GANNETG	3129081	Oil & Gas Authority (2020)		Gluyas & Hichens (2003)
Forties	KYLE	4259965	Oil & Gas Authority (2020)		Gluyas & Hichens (2003)
Forties	MACHAR	18246821	Oil & Gas Authority (2020)		Gluyas & Hichens (2003)
Forties	MONAN	1561942	Oil & Gas Authority (2020)		Gluyas & Hichens (2003)
Forties	MONTROSE	14417567	Oil & Gas Authority (2020)	1.5	Evans et al. (2003)
Forties	MUNGO	27451817	Oil & Gas Authority (2020)		Gluyas & Hichens (2003)
Forties	NELSON	74470429	Oil & Gas Authority (2020)	1.357	Gluyas & Hichens (2003)
Forties	PIERCE	18430547	Oil & Gas Authority (2020)		Gluyas & Hichens (2003)
Forties	LOMOND	3504750	Oil & Gas Authority (2020)		Gluyas & Hichens (2003)
Captain	BLAKE	17034193	Oil & Gas Authority (2020)		Gluyas & Hichens (2003)
Captain	CAPTAIN	48513724	Oil & Gas Authority (2020)	1.06	Evans et al. (2003)
Captain	ATLANTIC	230493	Oil & Gas Authority (2020)		Gluyas & Hichens (2003)
Captain	HANNAY	1417590	Oil & Gas Authority (2020)		Gluyas & Hichens (2003)
Carr	BEATRICE	27102958	Oil & Gas Authority (2020)	1.09	Evans et al. (2003)
Carr	JACKY	961597	Oil & Gas Authority (2020)		Gluyas & Hichens (2003)
Carr	LYBSTER	15579	Oil & Gas Authority (2020)		Gluyas & Hichens (2003)

APPENDIX 4: RESULTS						
name	**lat**	**lon**	**unit_type**	**working_gas_capacity/twh**	**closest_res_infrastructure**	**distance_km**
Esmond	54.583221	1.428973	gas field	39.946	Z3 Creyke Beck A OFTO	19.7
Forbes	54.683773	1.499463	gas field	27.538	Z3 Creyke Beck A OFTO	9.2
Gordon	54.505503	1.957469	gas field	56.730	Z3 Creyke Beck A	17.2
Caister_B	54.19862	2.463122	gas field	26.599	Hornsea Project Three (HOW03)	24.2
Leman	53.062638	2.196042	gas field	1188.686	East Anglia North Tranche One West (Norfolk Vanguard West)	15.9
Barque	53.601201	1.601773	gas field	265.570	Hornsea Project 1 Transmission Asset (OFTO)	17.6
Amethyst_East	53.600446	0.795735	gas field	42.116	Hornsea Project 1 Transmission Asset (OFTO)	0.1
Camelot_North	52.959285	2.142056	gas field	32.776	East Anglia North Tranche One West (Norfolk Vanguard West)	11.5
Camelot_Central_South	52.940538	2.157195	gas field	25.594	East Anglia North Tranche One West (Norfolk Vanguard West)	10.2
Camelot__Northeast	52.967641	2.232372	gas field	36.849	East Anglia North Tranche One West (Norfolk Vanguard West)	6.3
Cleeton	54.041875	0.721038	gas field	38.942	Hornsea Project Four (HOW04)	20.0
Clipper_North	53.455531	1.736011	gas field	129.832	Dudgeon	28.5
Corvette	53.235392	2.625324	gas field	10.230	East Anglia North Tranche 2 (Norfolk Boreas)	16.3
Davy	52.998409	2.902582	gas field	14.328	East Anglia North Tranche 2 (Norfolk Boreas)	0.0
Bessemer	53.20185	2.472358	gas field	12.986	East Anglia North Tranche One West (Norfolk Vanguard West)	18.8
Beaufort	53.172681	2.532864	gas field	4.981	East Anglia North Tranche One West (Norfolk Vanguard West)	14.6
Brown	53.026738	2.92691	gas field	7.920	East Anglia North Tranche 2 (Norfolk Boreas)	0.0
Gawain	53.17035	2.703799	gas field	16.829	East Anglia North Tranche 2 (Norfolk Boreas)	7.9
Guinevere	53.42024	1.273852	gas field	10.300	Dudgeon	12.5
Deborah	53.086962	1.851217	gas field	22.812	Dudgeon	31.4

Big_Dotty	53.091643	1.784571	gas field	46.369	Dudgeon	27.2
Little_Dotty_(Leman_Sdst)	53.04442	1.865417	gas field	19.578	East Anglia North Tranche 2 (Norfolk Boreas)	26.9
Della	53.07218	1.895105	gas field	12.106	East Anglia North Tranche 2 (Norfolk Boreas)	30.2
Dawn	53.130539	1.694635	gas field	9.902	Dudgeon	19.8
Delilah	53.084599	1.913129	gas field	11.140	East Anglia North Tranche One West (Norfolk Vanguard West)	31.3
Indefatigable	53.296441	2.460179	gas field	205.305	East Anglia North Tranche One West (Norfolk Vanguard West)	29.1
Johnston	54.040604	1.247792	gas field	17.363	Hornsea Project Four (HOW04)	0.0
Malory	53.550605	1.232497	gas field	9.852	Hornsea Project 1 Transmission Asset (OFTO)	14.6
Mercury	53.767896	0.643787	gas field	6.574	Hornsea Project 2 OFTO	18.8
Neptune	53.986194	0.787381	gas field	23.802	Hornsea Project Four (HOW04)	20.6
Pickerill	53.539872	1.11212	gas field	47.037	Hornsea Project 1 Transmission Asset (OFTO)	11.9
North_Sean	53.239903	2.79265	gas field	15.034	East Anglia North Tranche 2 (Norfolk Boreas)	9.8
South_Sean	53.187541	2.827992	gas field	14.918	East Anglia North Tranche 2 (Norfolk Boreas)	3.6
East_Sean	53.221801	2.875965	gas field	5.197	East Anglia North Tranche 2 (Norfolk Boreas)	5.0
Vanguard	53.378	2.105641	gas field	38.566	Dudgeon	45.6
Vulcan	53.250026	1.981406	gas field	261.054	Dudgeon	35.8
North_Valiants	53.377162	2.016299	gas field	125.554	Dudgeon	39.9
Vikings	53.526552	2.253237	gas field	280.494	Hornsea Project 1 Transmission Asset (OFTO)	31.6
Anglia	53.376415	1.591555	gas field	48.111	Dudgeon	15.5
Ann	53.716145	2.072232	gas field	35.479	Hornsea Project 1 Transmission Asset (OFTO)	10.3
Audrey	53.550552	1.987359	gas field	435.516	Hornsea Project 1 Transmission Asset (OFTO)	28.9
Baird	53.272899	2.528135	gas field	3.080	East Anglia North Tranche 2 (Norfolk Boreas)	23.9
Waveney	53.356853	1.299396	gas field	38.873	Dudgeon	5.4

Bell	53.255268	2.422808	gas field	15.467	East Anglia North Tranche One West (Norfolk Vanguard West)	25.6
Callisto	53.257401	2.361244	gas field	17.717	East Anglia North Tranche One West (Norfolk Vanguard West)	27.7
Europa	53.224839	2.300154	gas field	45.819	East Anglia North Tranche One West (Norfolk Vanguard West)	26.9
Excalibur	53.464615	1.365214	gas field	30.639	Dudgeon	16.7
Galahad	53.539587	1.389982	gas field	43.286	Hornsea Project 1 Transmission Asset (OFTO)	20.4
Galleon	53.491337	1.856954	gas field	299.061	Hornsea Project 1 Transmission Asset (OFTO)	33.7
Ganymede	53.32906	2.226863	gas field	46.973	East Anglia North Tranche One West (Norfolk Vanguard West)	39.2
Hyde	53.829514	0.991344	gas field	69.033	Hornsea Project Four (HOW04)	14.4
Lancelot	53.406662	1.367423	gas field	23.711	Dudgeon	10.3
Mordred	53.521873	1.353082	gas field	69.855	Hornsea Project 1 Transmission Asset (OFTO)	21.4
Newsham	53.724659	1.243678	gas field	47.829	Hornsea Project 2 OFTO	0.9
Ravenspurn	54.065469	0.948175	gas field	232.632	Hornsea Project Four (HOW04)	7.0
Sinope	53.264778	2.29308	gas field	7.748	East Anglia North Tranche One West (Norfolk Vanguard West)	30.8
Skiff	53.433243	1.877184	gas field	47.527	Dudgeon	34.1
Thames	53.093842	2.530741	gas field	26.037	East Anglia North Tranche One West (Norfolk Vanguard West)	6.2
Victor	53.332015	2.335615	gas field	73.995	East Anglia North Tranche One West (Norfolk Vanguard West)	35.8
Vixen	53.401741	2.239164	gas field	17.982	Hornsea Project 1 Transmission Asset (OFTO)	45.2
West_Sole	53.721458	1.117158	gas field	148.876	Hornsea Project 2 OFTO	3.3
Windermere	53.825977	2.754488	gas field	6.726	Hornsea Project Three (HOW03)	0.6
Alison	53.49683	2.175066	gas field	30.593	Hornsea Project 1 Transmission Asset (OFTO)	34.4
Amethyst_West	53.655426	0.60749	gas field	20.769	Hornsea Project 2 OFTO	9.6

Barque_South	53.602825	1.511394	gas field	9.495	Hornsea Project 1 Transmission Asset (OFTO)	16.1
Bure	53.129283	2.416744	gas field	19.354	East Anglia North Tranche One West (Norfolk Vanguard West)	13.7
Clipper_South	53.406266	1.767085	gas field	72.951	Dudgeon	26.4
Indefatigiable_South_West	53.29644	2.46018	gas field	23.326	East Anglia North Tranche One West (Norfolk Vanguard West)	29.1
Rough	53.829899	0.456151	gas field	13.046	Westermost Rough	16.4
Yare	53.051765	2.568526	gas field	38.763	East Anglia North Tranche One West (Norfolk Vanguard West)	0.9
Markham	53.834911	2.890449	gas field	49.599	Hornsea Project Three (HOW03)	9.6
Vampire	53.469246	2.040144	gas field	7.538	Hornsea Project 1 Transmission Asset (OFTO)	37.8
Valkyrie	53.456959	2.105176	gas field	13.186	Hornsea Project 1 Transmission Asset (OFTO)	38.8
Victoria	53.467546	2.283344	gas field	14.025	Hornsea Project Three (HOW03)	37.5
Viscount	53.393005	2.155652	gas field	48.355	Hornsea Project 1 Transmission Asset (OFTO)	45.9
Valiant_South	53.317707	2.0926	gas field	67.540	East Anglia North Tranche One West (Norfolk Vanguard West)	43.3
Hoton	53.804363	1.209999	gas field	38.071	Hornsea Project Four (HOW04)	3.2
Brigantine_A	53.393234	2.653017	gas field	9.487	East Anglia North Tranche 2 (Norfolk Boreas)	29.2
Brigantine_B	53.420746	2.628058	gas field	10.154	Hornsea Project Three (HOW03)	31.9
Brigantine_C	53.425451	2.715192	gas field	5.844	East Anglia North Tranche 2 (Norfolk Boreas)	29.8
Brigantine_D	53.441868	2.671291	gas field	2.176	Hornsea Project Three (HOW03)	28.7
Hamilton	53.568347	-3.450813	gas field	33.538	Burbo Bank Extension	8.8
Hamilton_North	53.645936	-3.47204	gas field	17.082	Burbo Bank Extension	17.2
North_Morecambe	53.964246	-3.673617	gas field	275.747	Walney Extension Transmission Asset	4.5
South_Morecambe	53.872332	-3.598405	gas field	580.194	Walney Extension Transmission Asset	9.0

Hamilton_East	53.603283	-3.407324	gas field	4.018	Burbo Bank Extension	11.4
Millom	54.017144	-3.808132	gas field	86.682	Walney Extension Transmission Asset	4.8
Bains	53.875693	-3.463778	gas field	20.983	Walney Extension Transmission Asset	5.7
Dalton	53.897447	-3.728957	gas field	24.311	Walney Extension Transmission Asset	12.0
Calder	53.806281	-3.665614	gas field	26.890	Walney Extension Transmission Asset	17.5
Hewett	53.022614	1.773482	gas field	93.102	East Anglia North Tranche 2 (Norfolk Boreas)	24.1
Murdoch	54.267967	2.311171	gas field	19.411	Hornsea Project Three (HOW03)	31.4
Schooner	54.075801	2.075275	gas field	142.000	Hornsea Project Two (HOW02)	9.2
Boulton	54.219636	2.151279	gas field	101.356	Hornsea Project Three (HOW03)	25.8
Caister_C	54.211971	2.445023	gas field	13.280	Hornsea Project Three (HOW03)	25.6
Fulmar_028_05	56.877812	0.821726	Saline aquifer with identified structure	5.815	Hywind (Scotland) Ltd	145.6
Fulmar_021_28	57.023636	0.586666	Saline aquifer with identified structure	1.785	Hywind (Scotland) Ltd	125.5
Fulmar_021_29	57.182104	0.753223	Saline aquifer with identified structure	2.911	Hywind (Scotland) Ltd	128.8
Fulmar_021_23	57.193361	0.39953	Saline aquifer with identified structure	4.773	Hywind (Scotland) Ltd	108.0
Fulmar_021_18	57.358078	0.449926	Saline aquifer with identified structure	0.616	Hywind (Scotland) Ltd	106.7

Fulmar_021_16	57.457633	0.052782	Saline aquifer with identified structure	4.733	Hywind (Scotland) Ltd	81.9
Bunter_Closure_1	54.0251	1.76661	Saline aquifer with identified structure	7.973	Hornsea Project 2 OFTO	2.6
Bunter_Closure_4	54.384764	1.623913	Saline aquifer with identified structure	0.113	Hornsea Project Four (HOW04)	32.5
Bunter_Closure_5	54.466272	1.421954	Saline aquifer with identified structure	2.425	Hornsea Project Four (HOW04)	32.3
Bunter_Closure_7	54.101063	0.98824	Saline aquifer with identified structure	0.124	Hornsea Project Four (HOW04)	2.3
Bunter_Closure_35	54.215727	1.027245	Saline aquifer with identified structure	10.261	Hornsea Project Four (HOW04)	0.7
Bunter_Closure_38	54.311859	1.920562	Saline aquifer with identified structure	0.797	Hornsea Project 2 OFTO	34.9
Bunter_Closure_39	54.173271	1.821028	Saline aquifer with identified structure	2.890	Hornsea Project 2 OFTO	19.2
Bunter_Closure_40	54.248415	1.551506	Saline aquifer with identified structure	1.228	Hornsea Project Four (HOW04)	17.7

Bunter_Closure_41	54.341867	1.235258	Saline aquifer with identified structure	1.245	Hornsea Project Four (HOW04)	15.4
Bunter_Closure_42	54.408695	1.084344	Saline aquifer with identified structure	0.652	Hornsea Project Four (HOW04)	22.3
Bunter_Closure_46	54.049356	0.712246	Saline aquifer with identified structure	1.422	Hornsea Project Four (HOW04)	20.1
Bunter_Closure_32	53.978083	0.417206	Saline aquifer with identified structure	0.364	Z3 Creyke Beck A OFTO	22.0
Rannoch_210_25	61.363752	0.866452	Saline aquifer with identified structure	4.841	Nova Innovation Ltd	124.2
Carr_012_22	58.127854	-2.691303	Saline aquifer with identified structure	16.004	MacColl Offshore Windfarm Ltd	0.0
Punt_012_24	58.172	-2.213	Saline aquifer with identified structure	42.143	Moray Offshore Wind Farm (East	21.0
Captain_013_17	58.337	-1.677	Saline aquifer with identified structure	53.364	MacColl Offshore Windfarm Ltd	54.1
Bunter_Closure_29	54.164407	0.259956	Saline aquifer with identified structure	3.914	Z3 Creyke Beck A OFTO	0.0

Bunter_Closure_18	52.955722	2.143609	Saline aquifer with identified structure	0.490	East Anglia North Tranche One West (Norfolk Vanguard West)	11.4
Bunter_Closure_2	53.778113	1.145496	Saline aquifer with identified structure	8.072	Hornsea Project Four (HOW04)	7.5
Bunter_Closure_21	53.551834	1.642516	Saline aquifer with identified structure	7.800	Hornsea Project 1 Transmission Asset (OFTO)	23.6
Bunter_Closure_22	53.595038	1.356559	Saline aquifer with identified structure	0.399	Hornsea Project 1 Transmission Asset (OFTO)	13.9
Bunter_Closure_23	53.476887	1.563445	Saline aquifer with identified structure	0.090	Dudgeon	23.2
Bunter_Closure_24	53.464106	1.355361	Saline aquifer with identified structure	0.659	Dudgeon	16.6
Bunter_Closure_25	53.538117	1.208355	Saline aquifer with identified structure	0.285	Hornsea Project 1 Transmission Asset (OFTO)	15.0
Bunter_Closure_26	53.846642	1.620278	Saline aquifer with identified structure	1.473	Hornsea Project 2 OFTO	0.0
Bunter_Closure_9	53.103944	2.162435	Saline aquifer with identified structure	14.657	East Anglia North Tranche One West (Norfolk Vanguard West)	21.0

Bunter_Closure_17	53.387944	2.530687	Saline aquifer with identified structure	1.048	East Anglia North Tranche 2 (Norfolk Boreas)	33.3
Bunter_Closure_20	53.178646	2.698508	Saline aquifer with identified structure	0.051	East Anglia North Tranche 2 (Norfolk Boreas)	8.6
Bunter_Closure_28	53.68426	2.121505	Saline aquifer with identified structure	10.834	Hornsea Project 1 Transmission Asset (OFTO)	13.4
Bunter_Closure_3	53.451501	2.301575	Saline aquifer with identified structure	3.564	Hornsea Project Three (HOW03)	38.5
Frigg_Sandstone_Member	60.262987	1.788166	Saline aquifer with identified structure	64.661	Nova Innovation Ltd	159.8
Heimdal_Sandstone_Member	59.764412	1.391094	Saline aquifer with identified structure	1234.401	P/f SHEFA	144.0
Tay_Sandstone_Member	57.214001	0.95326	Saline aquifer with identified structure	55.733	Hywind (Scotland) Ltd	139.6
Cromarty_Sandstone_Member	57.66	0.484214	Saline aquifer with identified structure	46.852	Hywind (Scotland) Ltd	109.2
Flugga_Sandstone_Member	58.884766	1.244936	Saline aquifer with identified structure	29.343	P/f SHEFA	155.6

Hermod_Sandstone_Member	59.863137	2.005782	Saline aquifer with identified structure	1.872	P/f SHEFA	177.6
Skadan_Sandstone_Member	58.842275	1.431641	Saline aquifer with identified structure	6.904	P/f SHEFA	167.4
Teal_Sandstone_Member	59.987419	1.863455	Saline aquifer with identified structure	29.236	P/f SHEFA	169.5
Skroo_Sandstone_Member_1	59.036395	1.491254	Saline aquifer with identified structure	0.759	P/f SHEFA	162.4
Skroo_Sandstone_Member_2	58.75416	1.365673	Saline aquifer with identified structure	0.978	P/f SHEFA	168.5
Skroo_Sandstone_Member_3	58.446585	1.328304	Saline aquifer with identified structure	1.549	P/f SHEFA	186.0
Ormskirk_closure_1	53.527505	-3.757251	Saline aquifer with identified structure	0.000	Gwynt y Mor	8.5
Ormskirk_Closure_2	53.492623	-3.758859	Saline aquifer with identified structure	0.001	Gwynt y Mor	6.2
Ormskirk_closure_3	53.474974	-3.674108	Saline aquifer with identified structure	0.009	Gwynt y Mor	0.6

Ormskirk_closure_4	53.459 49	- 3.6515 25	Saline aquifer with identifi ed structu re	0.096	Gwynt y Mor	0.0
Ormskirk_closure_5	53.662 459	- 3.7502 53	Saline aquifer with identifi ed structu re	0.131	Gwynt y Mor	21.2
Ormskirk_closure_6	53.444 253	- 3.5872 88	Saline aquifer with identifi ed structu re	0.712	Gwynt y Mor	0.0
Ormskirk_closure_7	53.747 504	- 3.1986 78	Saline aquifer with identifi ed structu re	0.614	Walney 2 OFTO	16.7
Ormskirk_closure_8	53.779 9	- 3.1813 89	Saline aquifer with identifi ed structu re	0.015	Walney 2 OFTO	13.0
Ormskirk_closure_9	53.860 054	- 3.3135 29	Saline aquifer with identifi ed structu re	1.244	Walney Extension Transmission Asset	5.8
Ormskirk_closure_10	54.022 795	- 3.3353 28	Saline aquifer with identifi ed structu re	0.013	Walney 1 OFTO	0.0
Ormskirk_closure_11	54.104 443	- 3.3668 52	Saline aquifer with identifi ed structu re	0.007	Ormonde	3.2
Ormskirk_closure_12	54.104 782	- 3.4164 83	Saline aquifer with identifi ed structu re	0.076	Ormonde	1.0

Ormskirk_closure_13	54.142195	-3.380432	Saline aquifer with identified structure	0.023	Ormonde	5.6
Ormskirk_closure_14	54.212677	-3.468196	Saline aquifer with identified structure	0.001	Ormonde	11.7
Ormskirk_closure_15	54.146463	-3.541296	Saline aquifer with identified structure	0.095	Walney 2	5.5
Ormskirk_closure_16	54.291616	-3.756797	Saline aquifer with identified structure	1.704	Walney Extension 3	15.5
Balder_Sandstone_Member_1	59.482459	1.265716	Saline aquifer with identified structure	31.598	BT Openreach	140.5
Balder_Sandstone_Member_2	58.526197	1.275758	Saline aquifer with identified structure	14.733	P/f SHEFA	178.1
Balder_Formation_Sandstone_Member_3	60.207579	1.867762	Saline aquifer with identified structure	11.234	Nova Innovation Ltd	166.0
Balder_Formation_Sandstone_Member_4	60.70069	1.851479	Saline aquifer with identified structure	1.111	Nova Innovation Ltd	154.7
Hewett_Sandstone_Bed	52.750845	2.097506	Saline aquifer with identified structure	25.915	East Anglia North Tranche 2 (Norfolk Boreas)	0.4

Spilsby_Sandstone_Formation_2	52.990776	2.973943	Saline aquifer with identified structure	0.867	East Anglia North Tranche 2 (Norfolk Boreas)	0.0
Forties_5	57.506401	1.16623	Saline aquifer with identified structure	359.322	Hywind (Scotland) Ltd	148.6
Mains_012_26	58.020657	-2.882098	Saline aquifer with no identified structure	1.922	Moray Offshore Windfarm (West)	5.3
Orrin_012_26	58.117854	-3.067867	Saline aquifer with no identified structure	1.307	Moray Offshore Windfarm (West)	0.0
Louise_012_22	58.141262	-2.836619	Saline aquifer with no identified structure	0.643	Moray Offshore Windfarm (West)	0.0
Coracle_012_20	58.279	-2.093	Saline aquifer with no identified structure	2.382	MacColl Offshore Windfarm Ltd	28.8
Mousa_Formation_1	59.052561	1.055292	Saline aquifer with no identified structure	14.618	P/f SHEFA	138.2
Otter_Sandstone_Formation	50.457417	-1.795488	Saline aquifer with no identified structure	11.654	Rampion (Southern Array)	104.4

Spilsby_Sandstone_Formation_3	52.506911	2.842884	Saline aquifer with no identified structure	0.647	Z5 East Anglia Three OFTO	2.0
Mousa_Formation_2	58.270479	0.170599	Saline aquifer with no identified structure	0.260	Hywind (Scotland) Ltd	123.8
Dornoch_Formation	59.455341	0.762061	Saline aquifer with no identified structure	15.723	P/f SHEFA	112.6
Grid_Sandstone_Member	58.244087	0.863274	Saline aquifer with no identified structure	5.928	Hywind (Scotland) Ltd	154.3
Mey_1	56.68334	2.20503	Saline aquifer with no identified structure	9.684	Z3 Teesside (Lackenby) B	173.0
Maureen_1	56.821499	2.11464	Saline aquifer with no identified structure	4.644	Z3 Teesside (Lackenby) B	188.5