Mapping geological hydrogen storage capacity and regional heating demands: An applied UK case study

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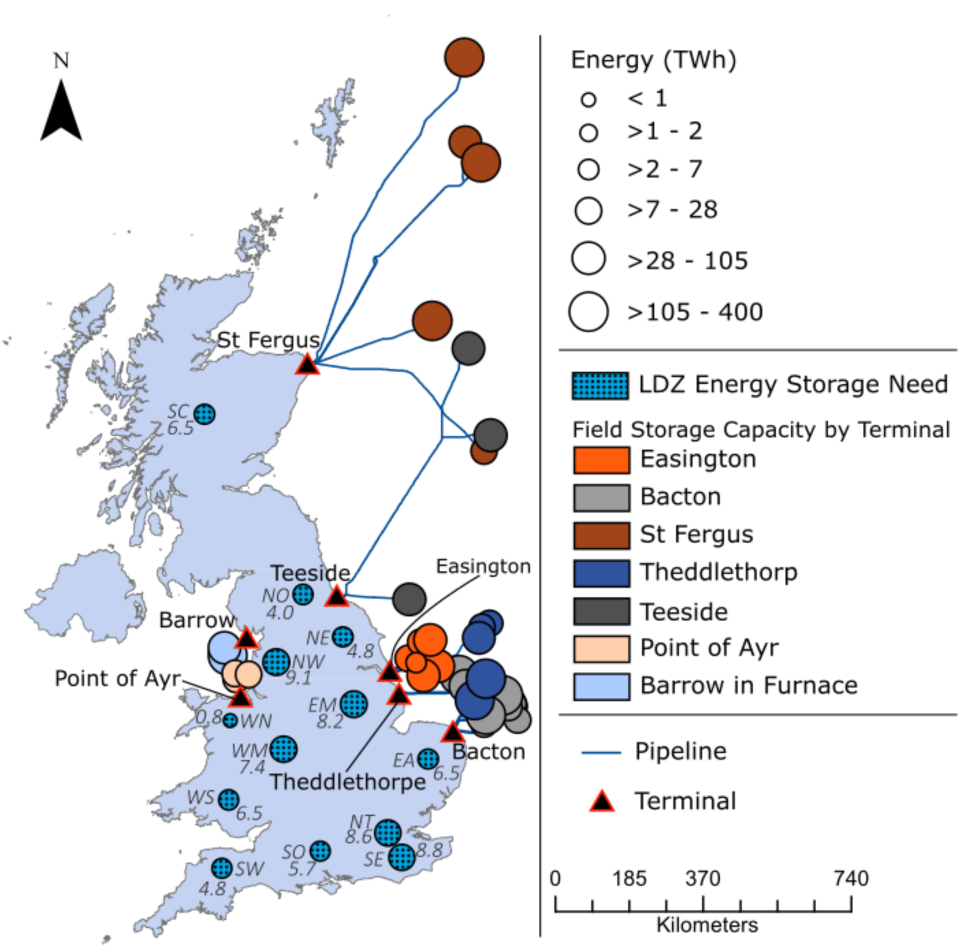
Graphical abstract



The map shows the centroids (geometric centres) of the local gas distribution zones (dotted circles), the offshore pipeline network connecting the potential hydrogen storage sites to the UK gas terminals. The scaling of the circles is logarithmic base ten, hence the energy storage need of LDZ is generally one or two orders of magnitude smaller than the storage capacity of individual storage sites. The LDZ are indicated in italic next to their matching centroid. Their storage need in TWh is also indicated. SC: Scotland, NO: Northern England, NE: North East England, NW: North West, EM: East Midlands, WM: West Midlands, WN: Wales North, WS: Wales South, SW: South West, SO: Southern England, SE: South East, NT: North Thames, EA: East Anglia.

Abstract

Hydrogen is considered as a low-carbon substitute for natural gas in the otherwise difficult to decarbonise domestic heating sector. This study presents for the first time, a globally applicable source to sink methodology and analysis that matches geological storage capacity with energy demand. As a case study, it is applied to the domestic heating system in the UK, with a focus on maintaining the existing gas distribution network. To balance the significant annual cyclicity in energy demand for heating, hydrogen could be stored in gas fields offshore and transported via offshore pipelines to the existing gas terminals into the gas network. The hydrogen energy storage demand in the UK is estimated to be ~77.9 terawatt-hour (TWh), which is approximately 25 % of the total energy from natural gas used for domestic heating. The total estimated storage capacity of the gas fields included in this study is 2,661.9 TWh. The study reveals that only a few offshore gas fields are required to store enough energy as hydrogen to balance the entire seasonal demand for UK domestic heating. It also demonstrates that as so few fields are required, hydrogen storage will not compete for the subsurface space required for other low-carbon subsurface applications, such as carbon storage or compressed air energy storage.

Keywords: Hydrogen, Energy Transition, Decarbonisation, Energy Storage

Highlights:

- A new method comparing geological storage capacity to storage need is presented.
- Geological hydrogen storage capacity exceeds UK heating seasonal storage needs.
- Offshore UK gas fields can potentially store 2,661.9 terawatt-hour of hydrogen.
- Hydrogen storage is unlikely to compete with other subsurface uses.
- Stores used with hydrogen, instead of natural gas, can store up to 75% less energy.

1 Introduction

It is widely recognised that climate change is having an adverse effect on our environment and societies. With greenhouse gas emissions identified as a key contributor to climate change, political momentum has gathered over the past 5 years to actively decarbonise our societies. The Paris Agreement on Climate Change, limiting global warming to 1.5°C above pre-industrial levels, initiated a transition from fossil fuels to low-carbon alternatives, primarily due to the recognition that CO_2 emissions from fossil fuel combustion accounts for around 74% of the total global greenhouse gas emissions [1]. Many countries have proposed robust long-term emission reduction goals for 2050, for example, the UK has committed to a target of Net Zero carbon emissions by 2050 [2]. While there has been progress towards net zero emissions through decarbonising electricity by means of improved energy efficiency, increase of renewables and nuclear power and switching from coal to natural gas fired power stations, the global emissions picture is more complex. One area which is particularly challenging to decarbonise is the use of heat in buildings [3]. Emissions associated with energy use in buildings make up 17.5% of the global emissions [4]. 7% of which are due to direct combustion of fuels in cookers and boilers. In many countries natural gas is a prime source of heat via direct combustion. For example, the UK (84%), the Netherlands (83 %), Italy (72 %) and Hungary (69 %) [5]. To achieve GHG emission reductions targets these countries need to find a way to decarbonise their heat provision to buildings.

On key challenge for decarbonising heat is the seasonal variation in demand [6]. Currently, most of the variation is accommodated by importing or producing natural gas as needed during the year. To decarbonise such a system requires a new balancing mechanism between winter and summer heat production. One such balancing mechanism, considered by many to be part of the solution, is to use Hydrogen as an energy vector [3,7-9] as it produces no CO_2 emission at the point of use (only water vapour). It can also be produced at scale using existing commercially mature technologies, such as alkaline electrolysers, or steam methane reformation (SMR) and auto-thermal reforming (ATR) [3]. These means of hydrogen production are ideal for two reasons; firstly, they allow a rapid transition based on methane derived hydrogen (along with carbon capture and storage) and they can repurpose the supply chain already in place for natural gas. Secondly, a long-term decarbonised production of hydrogen can be established using renewable energy sources (RES) and electrolysis of water, which does not release any CO_2 [10].

For RES produced hydrogen to be viable, TWh-scale hydrogen seasonal storage is required [11]. This storage capability would have the added benefits of facilitating the usage of renewable electricity generation [12] by balancing fluctuating supply and demand and increasing energy security [13]. Finding large-scale storage solutions for hydrogen is challenging because hydrogen has the lowest mass density of all known elements. The underground hydrogen storage in porous rock formations (UHS) considered in this study offer billions of cubic meters of storage within a naturally contained system [14].

Because ongoing, industry led, hydrogen demonstration projects are relatively small scale (e.g. 'Hydrogen 100' in Scotland, aiming to deliver hydrogen-for-heat to 300 customers by early 2020s)[15] such large storage solutions are not currently required, and more expensive surface alternatives are being used. Although these pilot projects are essential to develop the value chain and increase customer acceptability, they fail to address the large-scale storage element which is essential for a wider uptake of hydrogen [14].

In this study we address this gap by identifying where large-scale underground hydrogen storage (UHS) can be found relative to the existing natural gas infrastructure, and developing a new storage capacity assessment methodology to determine how much hydrogen storage capacity is available. These findings are useful for the following reasons: (1) to enable industry to assess their UHS assets in relation to the whole hydrogen supply chain; (2) to support policy makers in understanding the UHS resource available nationally or regionally to develop appropriate strategies to transition from demonstration hydrogen projects to wider national and regional decarbonised solutions (such as hydrogen clusters) [15]; (3) provides a new set of potential UHS locations in the UK to inform energy network modelling efforts. We present a novel hydrogen storage capacity assessment method and apply it to the UK as a case study, because the UK has a significant reliance on natural gas for heating. This work is a timely contribution to ensure large-scale and long-term hydrogen storage solutions are identified in the near future to support the growing demand for decarbonised heat.

2 Underground Hydrogen Storage: An overview

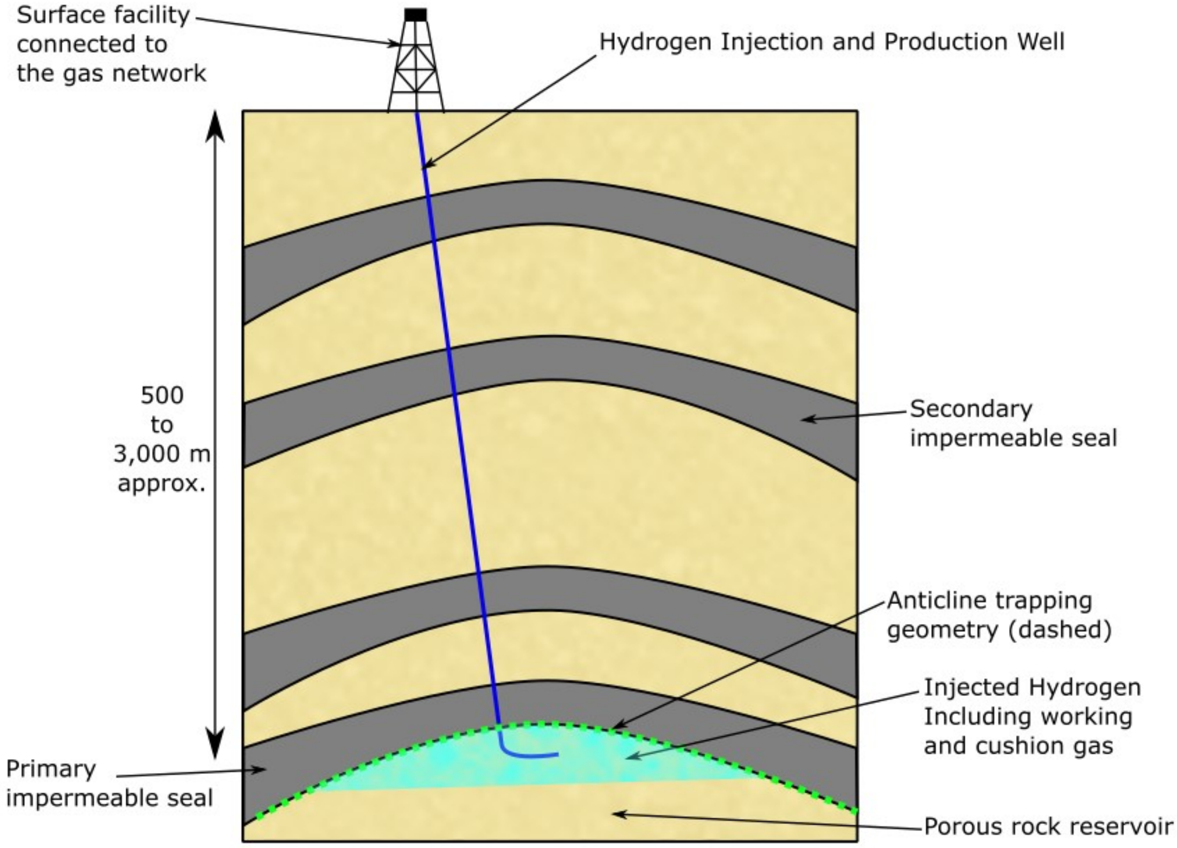


Figure 1: Conceptual diagram of underground hydrogen storage in a porous rock reservoir. The key element to ensure the safe operation of the system are (1) a porous and permeable reservoir formation in which the hydrogen can be stored. (2) An impermeable sealing formation to prevent the hydrogen migrating vertically due to buoyancy. (3) A trap structure, such as an anticline, which prevents the hydrogen migrating laterally away from the well.

Hydrogen, like any other buoyant fluid, can be stored in a subsurface store consisting of a porous and permeable geological reservoir, an impermeable barrier seal and a trap structure located many 100s of meters below the ground (Figure 1) [16]. These UHS systems are formed over millions of years via the deposition and compaction of sands and muds. The hydrogen injected via a wellbore will displace the in-situ fluids located in the pores of the reservoir rock, usually brine or hydrocarbons, and collect underneath the impermeable seal. A trap structure, for example an anticline, will prevent the hydrogen from escaping laterally and keep the hydrogen in place to enable its recovery. In order to maintain an operational pressure and to minimise water extraction during hydrogen production, a share of the injected gas, referred to as 'cushion gas' to distinguish it from the extractable 'working gas', will remain in the reservoir. To avoid semantic confusion between the field of reservoir engineering and hydrogen generation, the term 'extraction' will be used to describe the recovery of fluids from the subsurface, and the term 'production' will refer to the making of hydrogen.

Large-scale underground storage of natural gas has been practised successfully for many decades, with a global total of 413 billion standard cubic meters (BSCM) of natural gas storage accommodated in depleted gas fields (80%), underground aquifers (12%) and engineered salt caverns (8%) [14]. Practical experience of the geological storage of pure hydrogen is limited to storage in salt caverns such as at Teesside in the UK and Clements Dome and Moss Bluff in the US [17]. Additional experience was gained through the storage of town gas produced from the gasification of coal with variable amounts of hydrogen, carbon monoxide, methane, CO_2 and nitrogen in depleted reservoirs and aquifers in Germany (Kirchhielingen and Ketzin), Czech Republic (Lobodice) and France (Beynes) [18]. As well as the more recent "Underground Sun Conversion" pilot projects where hydrogen was added to the natural gas injection stream [19]. Experience from operating these town gas sites over many decades e.g. Ketzin, Lobodice and Beynes has proved tightness and integrity of caprock and well cements with no safety issues reported [22].

Natural gas supply systems have the advantage of being highly flexible with storage facilities available at a range of scales, from large depleted gas fields through smaller salt caverns, to surface tanks and line packing. When converting the natural gas supply to hydrogen, not only will the large UHS facilities be required, but the hydrogen supply systems will also have to offer flexibility in order to respond very quickly to fluctuations in demand through the use of multiple sources of hydrogen from different production and storage facilities. To achieve this flexibility, hydrogen will require a wide range of storage scales and locations including large and small depleted gas fields and salt caverns to ensure that the regional domestic gas demands and delivery can be optimised. As existing natural gas storage and supply systems are distributed across different gas network regions with direct connections to the pipeline transmission network or gas terminals, hydrogen storage sites will also have to deliver this flexibility. Additionally, the offshore storage facilities will require connections to the nearest gas terminal via offshore pipeline, with many studies concluding that the existing gas supply network could be repurposed for hydrogen transport [21][22].

This study presents a new a source to sink methodology and analysis that matches geological storage capacity with energy demand, which is applied to the domestic heating system in the UK. The methodology has a focus on maintaining the existing gas distribution network [23], as the re-use of infrastructure in-place could reduce up-front costs significantly [24]. This study focusses on the hydrogen storage required to balance the seasonal supply and demand of heat. The analysis consists of two steps, firstly potential storage sites in suitable locations around the UK are analysed in terms of their capacity for hydrogen storage; and secondly, a demand scenario for the gas distribution zones in the UK is established. In this study, depleted offshore gas fields are considered as potential hydrogen storage site candidates, because of their large magnitude storage capacity, existing infrastructure, availability of geological data to reduce the uncertainty in the storage operations, and their capability to securely store gas is already established [25].

3 Case study: The United Kingdom

The UK was chosen as a case study because its gas demand pattern is highly seasonal (Figure 2), and the UK offshore regions offer suitable UHS facilities. In the UK, 84 % of households are reliant on natural gas for heat [26]. Natural gas is also a prime source of heat in other European countries such as the Netherlands (83 %), Italy (72 %) and Hungary (69 %) [5]. Domestic heat presents the greatest seasonal fluctuations within the UK energy supply system and it is apparent that the variation in natural gas demand on a seasonal basis is strongly correlated to domestic heating needs (Figure 2). In this study, the natural gas consumption data from non-daily metered demand is used as a proxy for the energy need associated with domestic heat [6]. Domestic heat demand fluctuates between a minimum of 0.4 TWh per day in the summer and up to 3.5 TWh per day on particularly cold winter days, which is approximately seven times higher than a typical summer day [6]. Future electrification of heat and energy efficiency improvements will not be sufficient to flatten the variability in domestic heat demand [27], therefore low carbon hydrogen is a promising option to ensure security of supply for domestic heating throughout the year. In this study we assume that the production of hydrogen will be achieved using RES. As highlighted in the introduction, this is the scenario in which TWh-scale inter-seasonal storage needs to be developed [3]. The UK has a large offshore wind resource which is being considered for the long-term production of hydrogen to decarbonise heat [10].

Prior to the retirement of the Rough Gas Storage facility in 2017 [28], the UK had approximately 53 TWh of natural gas storage. Although not all this gas would be used to accommodate domestic heat demand, it represents about 17 % of the 309 TWh of total UK domestic gas demand in 2018 [29]. Estimates by the H21 project for the decarbonisation of industry and heating in Leeds (UK) state that about 8 TWh of inter-seasonal storage, in about 56 salt caverns, would be required to complement a total hydrogen production of 75 TWh [30]. This indicates the large storage requirements relative to the total hydrogen production required to decarbonise UK heat, and highlights the need for larger scale UHS capacity in large offshore depleted gas fields. It is important to note that salt caverns would still be needed as intermediate scale storage to provide fast response time for uses such as power generation and daily peak demand.

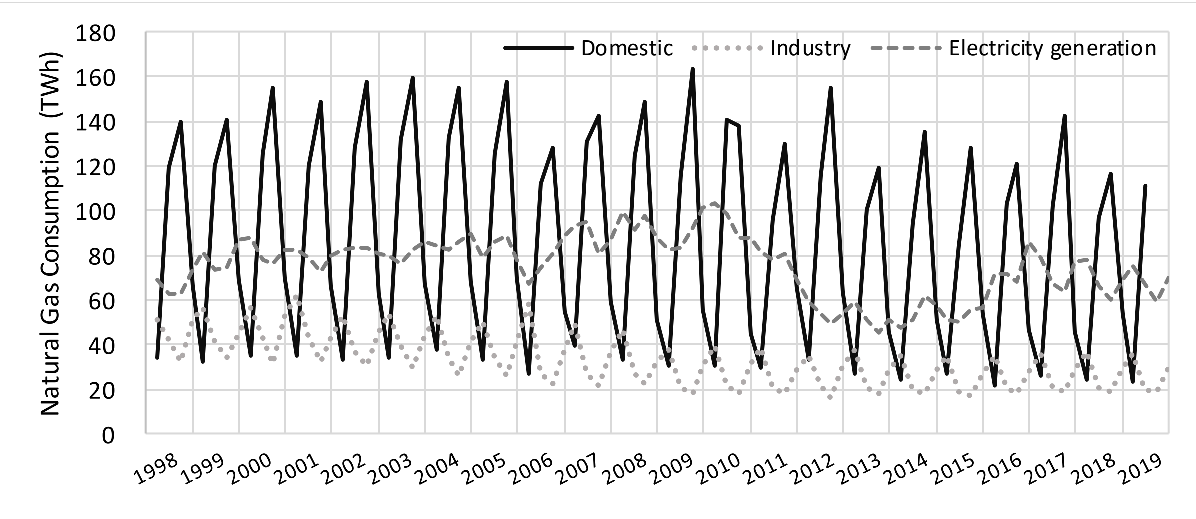


Figure 2: This figure shows the quaterly UK natural gas demands from 1998 to 2019 for industrial and domestic consumption as well as power generation. The demand profile with the greatest fluctuations is the domestic gas demand, which is primarily used for heating. Similarly, some of the seasonal variations observed in the electricity generation could be due to the relatively small portion of electricity used for domestic heating compared to gas heating in the UK. (data from [31])

4 Methods

The methodology will be presented in three steps. Firstly, the selection procedure of the geological sites, including an overview of the geological data; secondly, the calculations for the hydrogen storage capacity of depleted gas fields will be described; and thirdly, the procedure to estimate the hydrogen storage requirement will be presented, along with the associated data used for the calculations.

4.1 Geological Site Selection

It is generally accepted that deep geological formations, such as depleted gas fields or aquifers, have large capacity storage potential, whether for CO_2 [32], compressed air [33], or hydrogen [34]. Gas fields currently in operation are often dismissed as it is considered that interference with active gas 'extraction' operations should be avoided. However, in this study we added operational gas fields into our capacity calculations because many established fields will soon be considered depleted. Declining 'extraction' rates combined with low gas prices may stop gas 'extraction' from some gas fields, or future net-zero policy and economic incentives may drive conversion of 'extracting' gas fields to energy storage sites from 2040 onwards [35], as the percentage of electricity generation from variable amounts of renewable energy increases above 80% [36].

For this study of offshore UHS candidate sites, only gas fields were considered. This is because oil fields are likely to have more complex multiphase fluid flow interactions with hydrogen resulting in lower occupancy of the pore space and higher storage costs, plus they do not have the added benefit of a cushion gas already in place.

The UK offshore gas fields chosen for this study are situated in four locations, the Southern North Sea Basin, the Central Graben, the Viking Graben and the East Irish Sea, each of which serves particular gas terminals. The Southern North Sea Basin hosts the majority of the UK's gas fields with reservoir formations of predominantly Carboniferous and Permian age and important discoveries such as Leman, Indefatigable and Hewett [37]. Fields in the Central North Sea and the Viking Graben mainly contain oil and condensate with occasionally gas in reservoirs formations of predominantly Mesozoic and Tertiary age, with important discoveries being Frigg and the Britannia [37]. The gas and oil-bearing Jurassic Fulmar and Brent field were also included, due to a lack of gas fields in this area and the fact they have significant gas caps enabling hydrogen storage exclusively within this zone [37]. Gas fields in the East Irish Sea are predominantly of Triassic age with the Hamilton and Morecambe fields the most prominent gas fields [37]. Overall, 41 fields were selected due to their location, size, connection to the UK gas terminals via pipelines and data availability.

Using the oil and gas data authority website [38], offshore gas fields were selected that were either directly connected to the primary gas terminal supply pipeline, or one spur off the main gas supply pipeline. By doing so, this study effectively utilises the storage potential of sites connected to the existing gas supply infrastructure including the onshore gas terminal, which in turn is directly connected to the national transmission system (NTS), as this study is focused on the replacement of natural gas with hydrogen for heating. The gas field data were obtained from the United Kingdom oil and gas fields' Commemorative millennium volume from the London Geological Society [37]. Fields without suitable data availability were excluded from the study. For gas supply into the St Fergus terminal this meant selecting gas condensate or oil fields with a gas cap that have a dedicated gas supply network, as there are very few gas only fields in this area.

4.2 Hydrogen Storage Capacity Estimate

A volumetric approach based on the original gas volume in place has been used to calculate the hydrogen storage capacity. Dynamic studies using numerical simulators are more accurate for specific scenarios at specific sites and allow the storage efficiency to be determined. However most regional estimates for gas storage use volumetric approaches for preliminary estimates [e.g. 39]. The hydrogen storage capacity estimations calculated from this methodology are for the volume of working gas, the hydrogen gas that is used as the energy source. Cushion gas and working gas can theoretically be chemically different and can account for a significant capital expenditure at the beginning of any storage project. For offshore gas reservoirs the in-situ natural gas is expected to be reusable as cushion gas [34].

The methodology utilises both the original gas volume in place (OGIP) and the recoverable volume of gas (RG) to calculate the total field volume available for storage. The values are reported with a standard cubic meter accuracy. OGIP is a function of the volume of the reservoir, porosity, water saturation and depth and as such is an excellent proxy for estimating the static pore space in the reservoir. RG is the proven volume of gas that can be technically and economically recovered and is based on the reservoir 'extraction' history and as such is an excellent proxy for estimating the dynamic recovery capacity of hydrogen in the reservoir. The OGIP and RG data for the gas fields were primarily obtained from the United Kingdom oil and gas fields' Commemorative millennium volume from the London Geological Society [37]. The advantage of using OGIP and RG estimates is that the gas volumes reported are based on 'extraction' data and provide a comprehensive assessment of the amount of gas that can be stored in the subsurface. For example, the residual water saturation that cannot be removed from the store pore space is accounted for. The data also provides an indication of the residual volumes of natural gas remaining in the reservoir that could contribute to the cushion gas volume estimation. Using the temperature and pressure of the gas field at its discovery, hydrogen and methane volumes were calculated for storage conditions using the Open-Source Thermophysical Property Library implemented in Python [40]. The pressure and temperature of field are reported with 0.1 MPa, and degree Celsius accuracy, respectively.

The reservoir hydrogen storage capacity is calculated by substituting the gas field volume occupied by recoverable natural gas with hydrogen using equation 1, assuming that the reservoir natural gas has the properties of methane:

$$E_H = HHV_H \times \rho_{H,s} \times OGIP \times \frac{\rho_{CH4,stp}}{\rho_{CH4,s}} \times UG \qquad \textit{Eq. 1}$$

Where, E_H is the amount of energy stored as hydrogen in the working gas, HHV_H is the higher heating value of hydrogen (MWh/kg with 4 significant digit accuracy), ρ_H,s is the hydrogen density at the pressure and temperature when the store is full, OGIP is the original gas in place in the store expressed as a volume at standard temperature and pressure (STP), *RG* is the recoverable amount of gas also expressed as a volume at STP. $\rho_{CH4,stp}$ is the natural gas density at STP, $\rho_{\mathrm{CH4,s}}$ is the natural gas density at the pressure and temperature when the store is full. The ratio $\frac{\rho_{CH4,stp}}{\rho_{CH4,s}}$ is used to convert gas volumes at STP to gas volume at storage conditions. UG is the fraction of the storage volume which can be used for working gas and is described in Equation 2.

$$UG = \frac{WGV}{CGV + WGV} = \min\left[0.5, 0.8\left(\frac{RG}{\mathrm{OGIP}}\right)\right] \qquad \textit{Eq. 2}$$

Where, WGV, is the working gas volume which describes the portion of volume occupied by hydrogen gas which is cycled in and out of the reservoir. CGV is the cushion gas volume, that is the storage volume occupied by a mixture of hydrogen and natural gas which is permanently stored.

Therefore, the ratio of the working gas volume to the total storage volume (CGV + WGV) is the usable fraction of the storage volume for working gas (UG).

The value of UG in the literature varies. Flanigan recommends a value between 0.7 and 0.3 [41]. A study investigating the repurposing of the Rough Gas field for hydrogen storage at an inter-seasonal scale finds a value of 0.55 to 0.45, and this study uses 0.5 according to the Rough study [42]. However, another constraint has to be accounted for as we are considering a system where a portion of the cushion gas is not the gas being cycled (i.e. natural gas). The working gas type (i.e. hydrogen) has to account for at least 20 % of the cushion gas (i.e. for a hydrogen store, at least 20 % of the cushion gas has to be hydrogen) [43]. This constraint is accounted for by the 0.8 factor in equation 3. When gas fields have a recoverable gas volume over 62.5% of the OGIP, this study assumes a storage scenario where the hydrogen working gas accounts for 50 % of the original gas volume in place, based on studies considering natural gas storage [41], hydrogen storage [44], and hydrogen storage with mixed cushion gas [43] (first term of the minimum statement in Eq 3.). However, if less than 62.5 % of the OGIP is recoverable from the reservoir, that recoverable fraction multiplied by 0.8 is used as the working gas volume and the remainder as cushion gas (second term of the minimum statement in Eq 3.).

$$UG = \min\left[0.5, 0.8\left(\frac{RG}{\mathrm{OGIP}}\right)\right] \qquad \textit{Eq. 3}$$

The 'heating value' (or 'calorific value') of hydrogen is defined as the amount of heat released during combustion of a given amount of hydrogen. This study uses the higher heating value (gross energy or gross calorific value) which takes into account the latent heat of vaporisation in the combustion and assumes water is in its liquid state at the end of combustion. This is the value used to calculate the UK's gas demand national statistics [45]. A higher heating value of 39.4 kWh/kg for hydrogen is used to convert from mass of hydrogen to energy [46].

4.3 Hydrogen Storage Need Estimate

Finally, the hydrogen storage needed to balance the seasonal supply and demand of heating in a hydrogen-based net zero landscape was estimated. The UK gas consumption data were collected from the National Grid's Data Item Explorer [47] from December 2015 to December 2019 (Figure 3). The data has a daily granularity and is distributed across Local Distribution Zones (LDZs) in space. It is provided by National Grid with a KWh accuracy. The UK mainland is divided into 13 LDZs (Figure). The gas distribution networks in these zones are operated by four different Distribution Network operators. The zones offer an approximate geospatial division of the UK gas demand, which can easily be rationalised across the existing gas network infrastructure, the network models and the gas market, which makes the findings of this study applicable to economic and energy network models. Only the non-daily metered data were used in this study as they exclude large industrial users and power plants, and represents instead domestic, small businesses, and a share of commercial and public administration usage, which is the focus of this study [6].

The hydrogen storage need is calculated in way that ensures the hydrogen production facility usage can be maximised throughout the year. This is achieved by aggregating the non-daily metered gas demand difference between the winter and summer months: December, January, February and June, July, August, respectively. The storage need is taken as half that difference for each of the local distribution zones (Figure 3). This operation is repeated for each of the years between 2015 and 2020. The maximum value is used to capture the annual variation in storage needs. This provides the required hydrogen storage volume which would fill the storage reservoir during the summer and be 'extracted' during the winter, while ensuring that the required green hydrogen production facilities continue to operate at a maintained constant load.

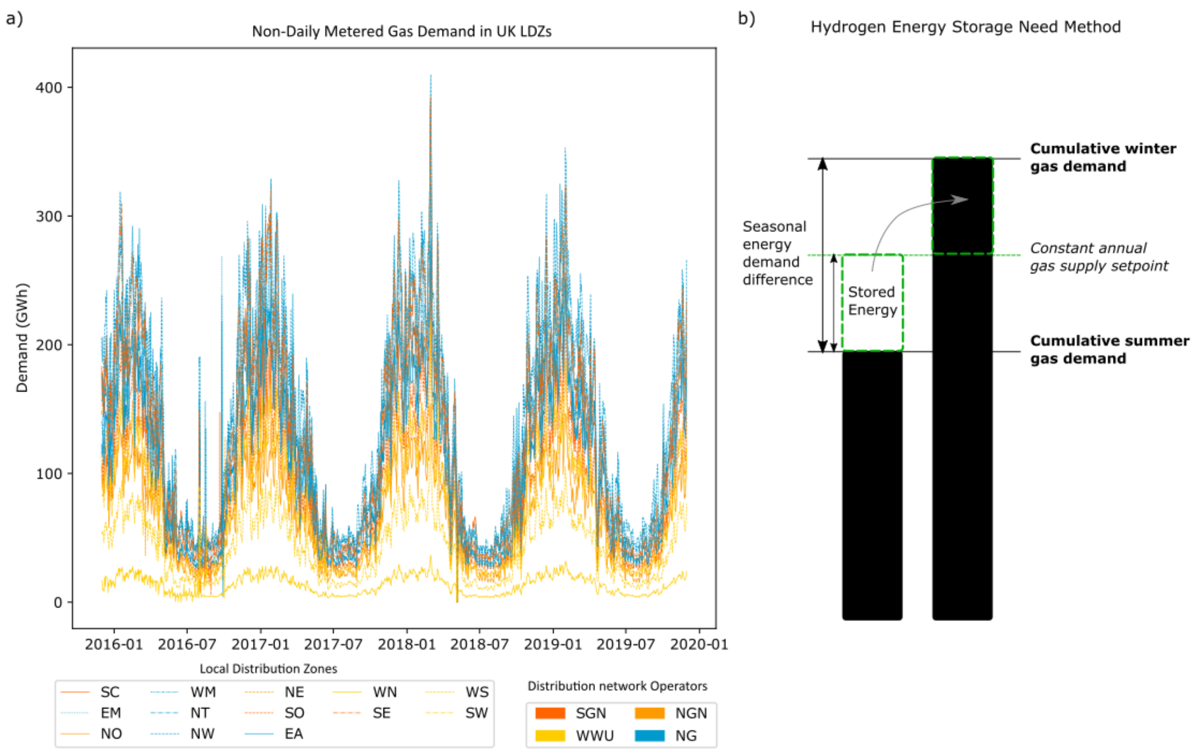


Figure 3: a) Non-daily metered gas demand data for the UK's 13 local distribution zones (LDZ) [47]. The LDZs are indicated in italic in Figure 7. Colours correspond to the four difference distribution network operators in the UK: SGN (dark orange), Northern Gas Networks (orange), Wales and West Utilities (yellow), and National Grid Distribution (blue). SC: Scotland, NO: Northern England, NE: North East England, NW: North West, EM: East Midlands, WM: West Midlands, WN: Wales North, WS: Wales South, SW: South West, SO: Southern England, SE: South East, NT: North Thames, EA: East Anglia. b) Represents the method used to determine the storage need in each LDZ (dashed green box) based on the data displayed in a). For b) Assumptions are in italic, data is in bold, resulting terms are in normal font.

5 Results

5.1 Gas field storage capacity

The storage capacities reported here are for the working gas. The cushion gas is composed of a mixture of residual natural gas and hydrogen and is not part of the fill and withdraw cycles. The exact proportions are not reported here, as only the working gas is of use to the energy system during the operational phase of the storage facility. The total estimated storage capacity across all the gas fields included in this study is 2,661.9 TWh. To put that into context, the total hydrogen energy storage demand for the whole of the UK is estimated to be 77.9 TWh (see section 4.2).

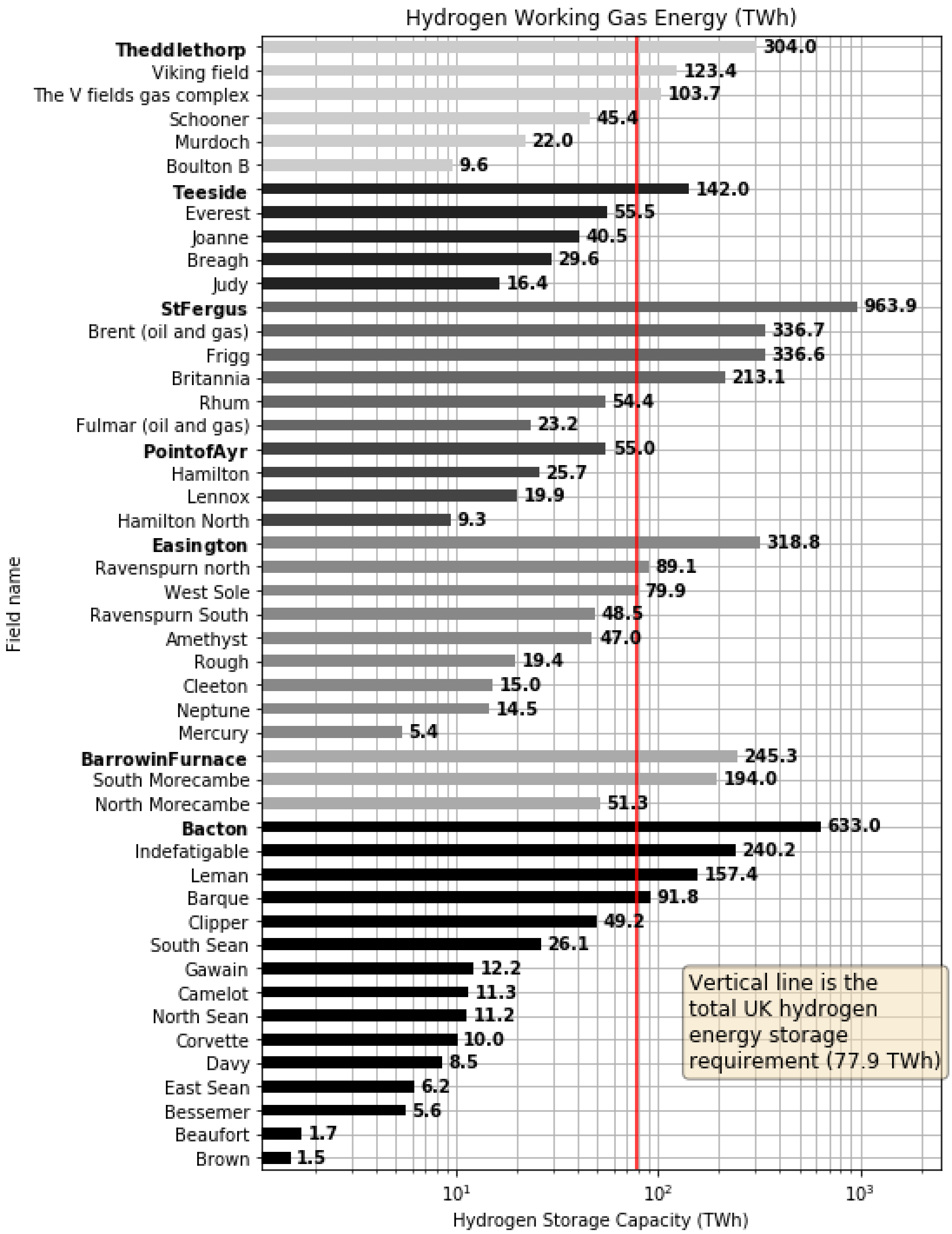


Figure 4: The hydrogen storage capacity of the analysed hydrocarbon fields calculated based on the original gas in place data. The capacities are in working gas energy content. The data is sorted according to the gas terminal they are connected to. Also shown is the cumulative working gas capacity connected to each terminal.

Figure 4 shows the calculated hydrogen working gas energy for each gas field used in the study. The greatest capacities can be accessed through the St Fergus and Bacton gas terminals, which account for 35 % and 25 % percent of the total assessed energy storage capacity, respectively. The smallest capacities are accessed by Point of Ayr and Teeside, with 2 % and 5 %, respectively. The three remaining terminals have access to roughly 10 % of the total energy storage capacity. Only the Point of Ayr gas terminal and associated storage sites are not capable of storing and delivering the 77.9 TWh of total hydrogen energy storage demand for the whole of the UK.

One of the most important outcomes of this study is that it demonstrates that the required working hydrogen gas demand for the UK, (77.9 TWh) can be stored in a single gas field. As highlighted in Figure 4, at least twelve of the fields analysed in this study are large enough to hold the entire annual UK hydrogen energy storage requirement and these are distributed across most of the UK gas terminals. Indeed, six of the twelve have a capacity at least twice as large as required, with two fields, Frigg and Brent located in the Viking Graben, having a capacity four times that required. The overall working gas capacity of the investigated fields is 2,661.9 TWh, which is approximately 35 times the total storage capacity required for the UK.

The St Fergus and Bacton gas terminals are connected to the greatest amounts of cumulative storage capacity, 972 TWh and 692 TWh, respectively. The storage capacity of the fields studied span orders of magnitude storage from 1.5 TWh for the Brown field to 342 TWh the Frigg field.

The ratio of the energy storage capacity of hydrogen, relative to methane, uniformly lies between 0.25 and 0.30 for the geological stores studied. The exception is the Rhum field, which is significantly deeper (4.6 km) and has a ratio of 0.35. Due to the thermodynamic properties of hydrogen and methane at those depth, namely their energy volumetric density, the energy penalty from operating the site as a hydrogen store rather than a natural gas store decreases with depth. Typically, temperature and pressure increase with depth leading to a hydrogen density increase.

5.2 Regional demand distribution

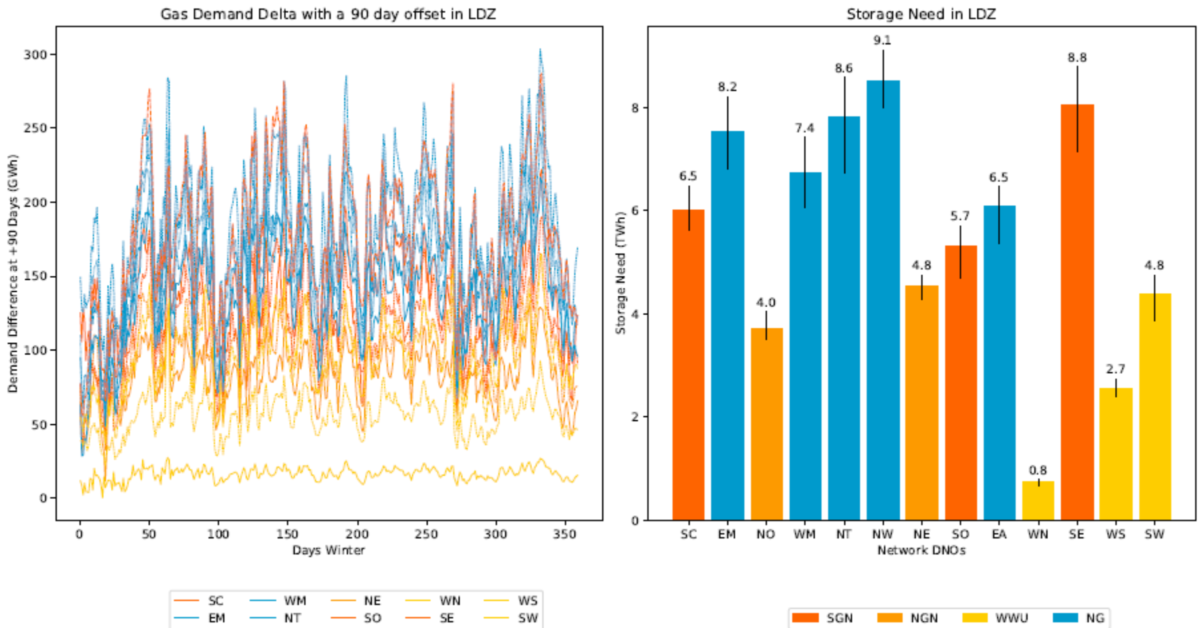


Figure 5: (left) Difference in non-metered gas demand between winter and summer days for UK LDZs at a 90 day offset (i.e. difference between a winter day and a summer day 90 days later). (right) The hydrogen storage need of individual LDZs required to be able to meet its seasonal heat demand fluctuations whilst maximising the use of hydrogen production facilities. (Colours correspond to the four difference distribution network operators in the UK: SGN (dark orange), Northern Gas Networks (orange), Wales and West Utilities (yellow), and National Grid Distribution (blue).) SC: Scotland, NO: Northern England, NE: North East England, NW: North West, EM: East Midlands, WM: West Midlands, WN: Wales North, WS: Wales South, SW: South West, SO: Southern England, SE: South East, NT: North Thames, EA: East Anglia.

Figure 5 shows the difference between winter and summer gas demand and the hydrogen energy requirements of the individual LDZs required to decarbonise heat. Large daily variations are experienced in the non-metered gas demand difference between winter and summery days occurs (Figure 5, left). Variations also occur on an annual basis, as shown by the error bars on Figure 5 (right) showing the maximum and minimum values over the years studied. The values considered for this assessment and indicated above each bar in Figure 5 (right) are the maximum storage values over the period 2015-2019. As previously discussed, the overall energy to be required to store is ~77.9 TWh. However this is not equally distributed across all of the LDZs, where distribution is dominated by the higher population density areas of the North-West of England (NW) including the cities of Manchester and Liverpool, the South-East of England (SE), North Thames (NT) and the East Midlands (EM).

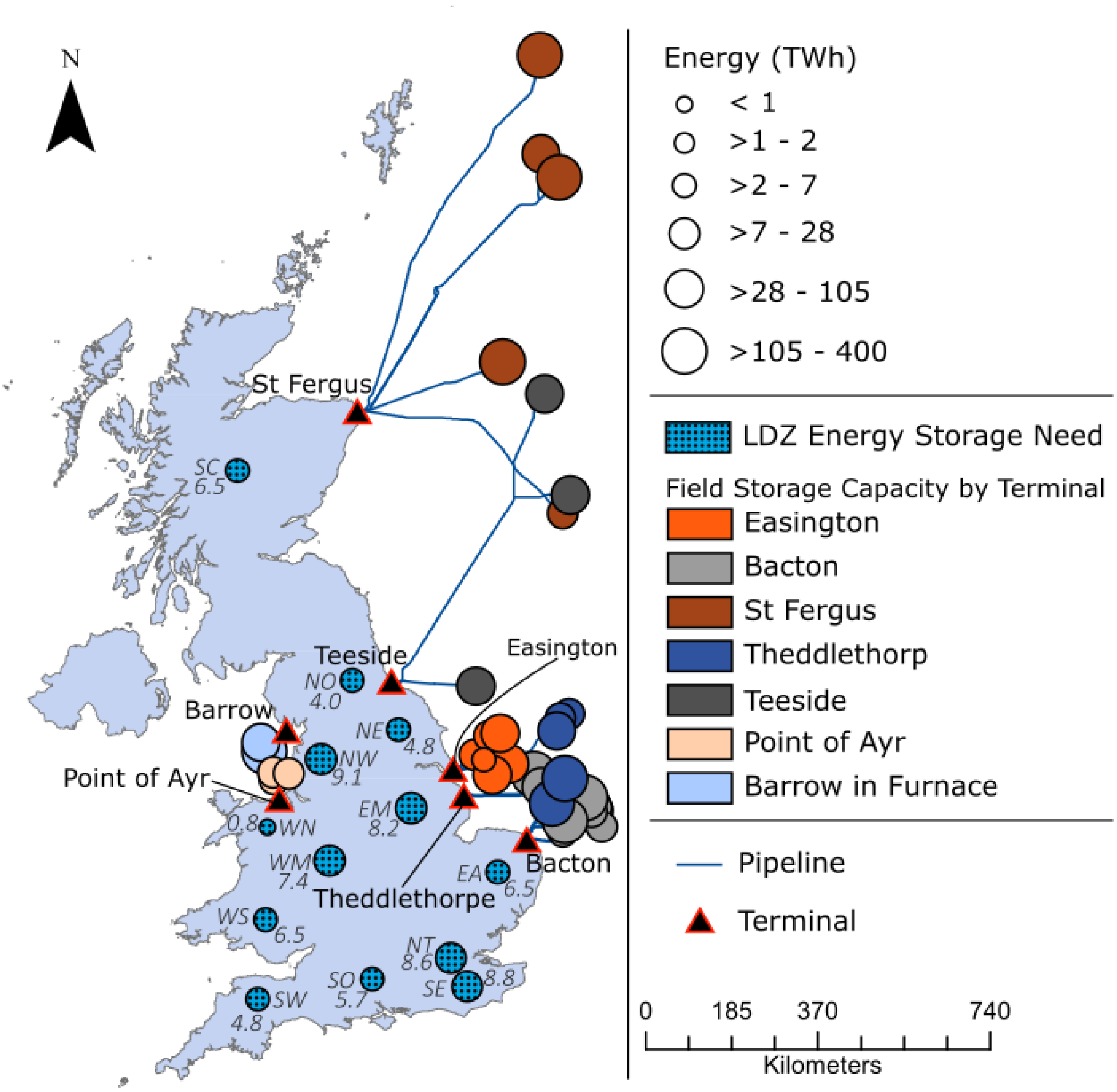


Figure 6: The map shows the centroids (geometric centres) of the local gas distribution zones (dotted circles), the offshore pipeline network connecting the potential hydrogen storage sites to the UK gas terminals. The scaling of the circles is logarithmic base ten, hence the energy storage need of LDZ is generally one or two orders of magnitude smaller than the storage capacity of individual storage sites. The LDZ are indicated in italic next to their matching centroid. Their storage need in TWh is also indicated. SC: Scotland, NO: Northern England, NE: North East England, NW: North West, EM: East Midlands, WM: West Midlands, WN: Wales North, WS: Wales South, SW: South West, SO: Southern England, SE: South East, NT: North Thames, EA: East Anglia.

The connection between the storage sites as hydrogen sources and the LDZs, as hydrogen sinks, are the gas terminals (Figure 6). According to this analysis, all terminals except Point of Ayr and Teeside, are connected to at least one field that has the capacity greater than 77.9 TWh and can act as a storage site for the entire UK. In other words, no matter how the LDZs are interconnected, there will be sufficient hydrogen offshore capacity accessible. For example, the Point of Ayr gas terminal is connected to the Hamilton Field which has a storage capacity of 25.7 TWh. While this is not enough capacity for the entire UK, the Hamilton field alone can store the hydrogen for the entire west of England, namely the LDZs of Wales, the North and the South West and the West Midlands. Only 5 of the analysed gas fields (East Sean, Mercury, Beaufort, Bessemer, Brown and Davy) are too small to meet the storage demand of any individual LDZs and all but Beaufort and Brown, could provide at least 50 % of the storage need for any individual LDZs. Furthermore, even these small fields do not to represent a severe limitation to the storage potential of a region as all gas terminals are directly connect to multiple sites large enough to meet the energy storage need of nearby LDZs.

6 Discussion

An important result of this study is that there is more than enough hydrogen storage capacity in gas fields around the UK. Considering the capacity data only, most combinations of only 2 of the gas field included in this study would be able to supply all the UK's hydrogen storage requirements. This is important, not only to develop confidence that only a few gas fields will be needed to store all of the UK's hydrogen, but also that accommodating hydrogen storage in the subsurface will not create additional problems when considering the competing subsurface usage strategies to decarbonise energy and industry, such as natural gas storage, geothermal, compressed air storage and CO_2 sequestration.

As hydrogen storage has not been conducted on a commercial scale to support the gas network, an accurate estimation of hydrogen storage capacity within all types of porous media has not been fully defined. This study proposes gas fields as suitable storage sites due to the fact that their capacity can be more accurately assessed because of the existing OGIP data, rather than in saline aquifers, which may have a greater storage capacity, but their storage capacities have a higher uncertainty. It is also important to consider that while these capacity estimates are accurate, it is not yet known if hydrogen can be injected and extracted from the store in a similar way to natural gas, as such, the actual hydrogen storage capacity estimates of the gas fields remains unproven. Further dynamic assessments of the proposed storage sites will reveal if and how seasonal hydrogen injection and withdrawal can be performed.

The results show that the hydrogen storage capacity for the Rough field is estimated at 20 TWh, which is about 48 % of the natural gas working gas capacity it held when it was being used as the main UK seasonal natural gas store until its decommissioning in 2017[48]. This estimate is in line with the findings from [42] which estimated that the Rough gas field could store 42 % of its methane energy capacity as hydrogen. This provides confidence that the applied method provides estimates comparable with previous literature for the same gas field.

Using the natural gas working volume for Rough provided by the operator [48] and comparing it to the literature we can determine that our chosen usability fraction (UG) is indeed valid. According to the operator, the working gas volume was 16 % of the original gas in place. This is lower than the original Rough gas field recovery factor obtained from literature sources, which was estimated at 82 % when the field was used to 'extract' gas instead of storing it. This implies that a UG fraction of 50 % [42] is within a realistic range. It also indicates that the Rough storage site was not operated to its full 'storage capacity'.

Another study on the conversion of underground natural gas stores to hydrogen indicates that the shift to hydrogen from natural gas results in a reduction in the storage capacity of any given reservoir of 75 % to 78 % [35]. This is in line with the findings of this study which shows a reduction in energy capacity of between 65 % and 75 % when natural gas fields are converted to hydrogen, depending on their depth. This highlights the need for further identification and optimisation of multiple new underground storage sites across the UK and globally, particularly the identification of deeper fields as the energy penalty from operating the site as a hydrogen store rather than a natural gas store decreases with depth.

As previously mentioned, the advantage of gas storage in depleted gas fields include increased confidence levels in a functioning sealing caprock and a great deal of knowledge about the store due to operational experience and geophysical investigations including well and seismic data. This increased knowledge however comes at a price, as abandoned wells can pose a major threat for containment failure. As an example, for CO_2 storage, several studies have concluded that leakage along abandoned wells is considered as the greatest risk of containment loss, [49 and references therein]. As abandoned wells are a major source of leakage risk, particularly in well-developed hydrocarbon provinces such as the North Sea [50], the status and quality of the wells must also be taken into consideration as a part of a storage site risk assessment in hydrocarbon provinces [49]. In order to avoid stored hydrogen migrating towards abandoned wells, an accurate storage plan informed by dynamic modelling must be undertaken. This is also true for geological leakage of hydrogen along faults that may be sealing to methane, but their hydrogen sealing is unknown. The use of dynamic simulations is essential as a mitigation strategy and can hel p to forward predict the development of the gas plume and to identify suitable injection locations with [51] or without residual hydrocarbons[52]. Both a vigorous risk analysis for abandoned wells and faults and a detailed dynamic simulation of the hydroge n storage operation can decrease the risk of hydrogen loss along potentially leaky abandoned wells and faults significantly.

The use of the remaining natural gas in the storage fields as the cushion gas for the storage operation may offer a cost efficient opportunity and could reduce the amount of injected hydrogen cushion gas required. The cushion gas is regarded as an economic investment because it cannot be fully recovered until the storage site is abandoned [18]. However, mixing between the natural gas and the injected hydrogen gas is inevitable and the impact on the storage operation remains to be investigated. Both in terms of physical mixing [53] and thermodynamic properties of gas mixtures [54]. Modelling studies with nitrogen as cushion gas and hydrogen as working gas have shown a relatively efficient storage cycle strongly dependant on the hydrogen and nitrogen ratio in the storage site, with a more effective hydrogen ‘extraction’ cycle in scenarios when additional hydrogen remains alongside the initial nitrogen cushion gas [55]. Despite the risk of impurities during ‘extraction’, there is the additional advantage of natural gas providing a mobility “cushion” where the natural gas could help to reduce the extremely sharp mobility contrast between the hydrogen and the formation water and as such prevent an unstable displacement front [56].

The demand analysis undertaken in this study is based on the gas demand for different distribution zones across the UK. Each of these exhibit a geographic variation in demand, and as such show an uneven gas demand from the gas terminals. The analysis of the offshore storage sites indicate that the storage needs of the different distribution zones can be accommodated using a gas field directly offshore of the associated gas terminal. This would reduce the need for transportation on the transmission network and would make the system more flexible and secure.

This study does not explicitly model the hydrogen transmission from the gas terminals to the distribution zones. This is because the method focuses on the elements of the system which are likely to endure. Indeed, the geological stores are, at the timescales of interest, static and permanent. Equally, 80-90% of the housing stock currently in use in developed countries will still be in use by 2050 [57]. Finally, large industrial complexes such as Gas Terminal, are also likely to remain as key installations transporting gas onto the mainland.

The future of the high-pressure gas transmission network is currently uncertain. Both a phased transition of portions of the network to hydrogen [30], and the widespread use of natural gas and hydrogen blending [58], are being considered in the UK. The blending approach offers benefits such as reducing the risks from steel embrittlement caused by hydrogen and enabling an upscaling in hydrogen production facilities. Hydrogen permeation is greater than natural gas in plastic polyethylene pipes of distribution networks (although still very low relative to the transported amounts) [23], and has not been highlighted as a significant risk for steel transmission networks [23]. Another, consideration here, is that the strategy adopted for the UK gas network might not be the same in other parts of the world. This study presents a method to derive the storage and demand estimates to support further work into the gas network conversion to decarbonised heat. In the case of the UK, our study provides the data to achieve this.

7 Conclusion

This study presents a new source to sink methodology and analysis that matches underground hydrogen storage capacity with energy demand and is applied to the domestic heating system in the UK, with a focus on maintaining the existing gas distribution network and the re-use of infrastructure in-place.

The key findings of the analysis are:

- The total hydrogen storage capacity in selected gas fields offshore of the UK is 2,661.9 TWh. This amount is much greater than the ~ 77.9 TWh of seasonal storage need for a hydrogen-based UK domestic heating scenario.

- Only a few sites are required to store enough energy to balance the seasonal variations in the UK heating needs. As such hydrogen storage will not cause a significant issue when considering the competing low-carbon subsurface requirements due to the limited number of sites needed for hydrogen storage.

- Considering all porous rock subsurface storage options, gas fields are the best place to start as data has already been gathered and their ability to trap and contain gas is proven. Natural gas should be investigated as a useful and cost-efficient cushion gas for hydrogen storage.

- For LDZs connected to a gas terminal, more than enough storage capacity can be provided from offshore sites via the terminal. Hence the whole hydrogen energy supply system would have flexibility and security.

- Gas fields used to store hydrogen have a working gas volume containing up to 75% less energy than for an equivalent working gas volume of natural gas, therefore optimisation of multiple new underground storage sites across the UK and globally is important.

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9 Data Availability

The dataset produced in this study are available as supplementary information.

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