Assessing the Regional Demand for Geological Hydrogen Storage

Building a Strategic Case for Investment in the East Coast Cluster

February 2024

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Assessing the East Coast Cluster's Demand for Geological Hydrogen Storage:

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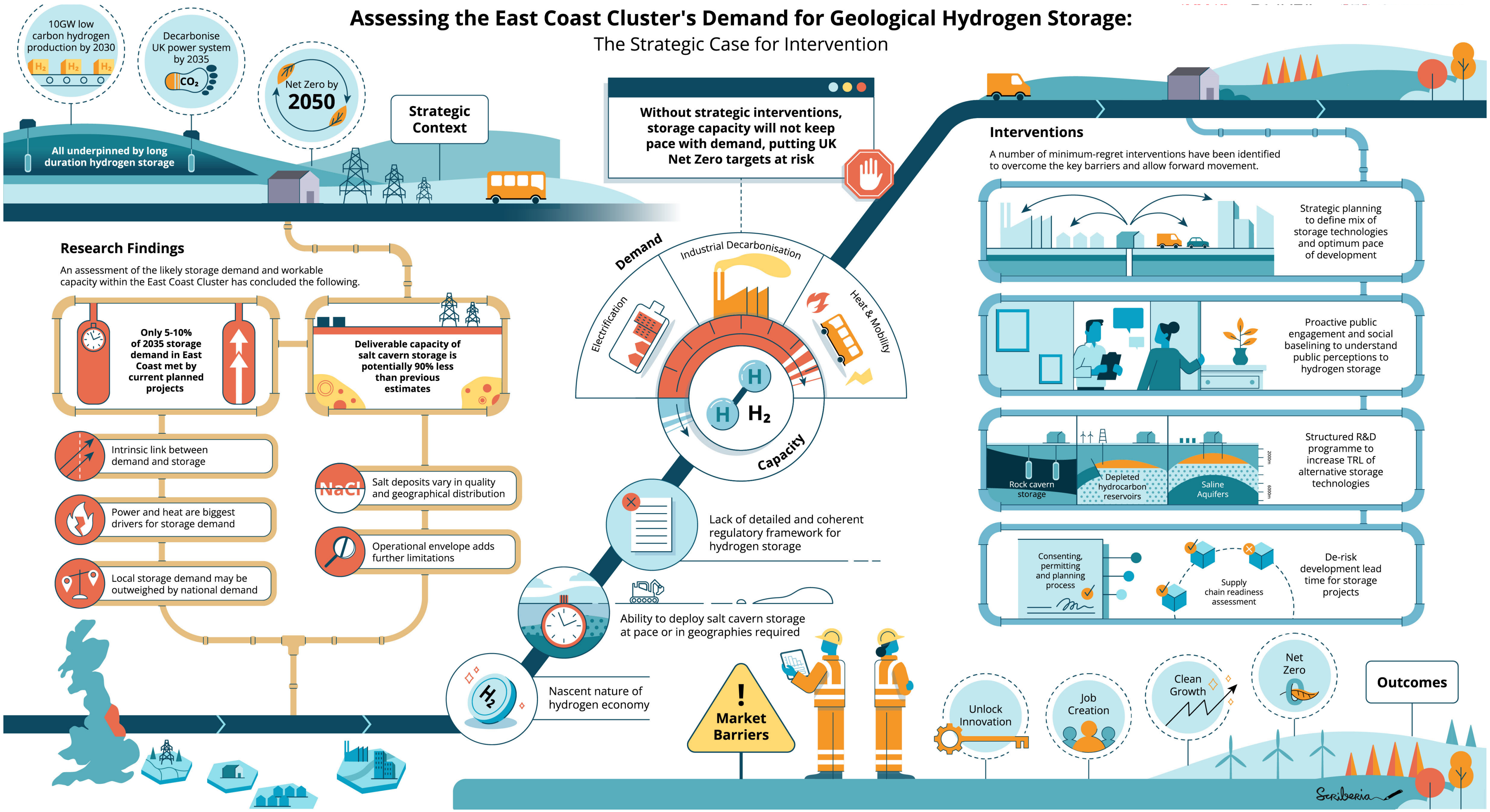
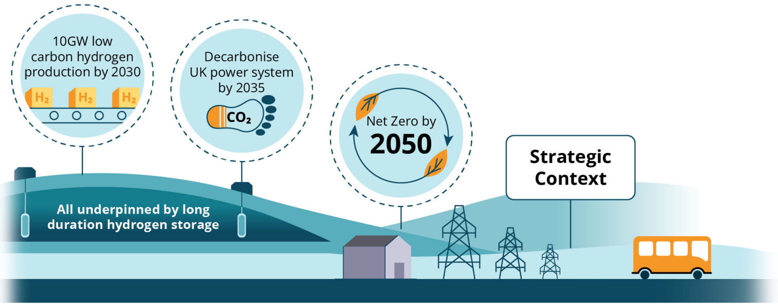


Strategic Context

Hydrogen storage is a key component of the UK's decarbonisation plans, as it unlocks the ability to hold the significant reserves needed to meet growing energy demands throughout an energy system transition. Without government intervention, the hydrogen storage market will not be able to deliver the necessary storage at pace with demand, thereby threatening the delivery of the government's 2030 and 2035 goals on the path to Net Zero by 2050.

For almost two decades, the UK has been a global leader in climate protection, recently moving forward its already ambitious goals by committing to a 78% reduction in emissions by 2035 (from 1990 levels) as an interim milestone towards Net Zero by 2050.



While the detailed roadmap to achieve these legally binding commitments is still in development, it is widely accepted that low carbon hydrogen will play a critical role in any future decarbonisation energy system, helping to bring down emissions in vital UK industrial sectors and providing flexible energy for power, heat and transport.

While the scale of hydrogen's role is still to be determined, analysis by the department for Carbon Budget 6 suggests 250-460 TWh of hydrogen could be needed in 2050, making up 20-35% of UK final energy consumption. [1]

The East Coast is a strategically important area for production. To date the UK has announced over 20GW of hydrogen production with 11.6GW potentially being located in the East Coast Cluster.

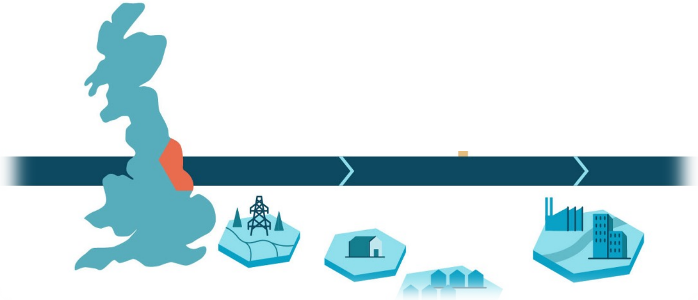
The criticality of hydrogen lies in its ability to be stored at significant scale and duration. This makes it a versatile replacement for high-carbon fuels used today and allows it to underpin an energy system comprised of other energy sources without the same capability.

It is widely acknowledged that it will take a diverse portfolio of technologies to reach Net Zero, diversification being the foundation to a strong, secure, and resilient investment strategy.

Hydrogen storage is a critical building block of the hydrogen network with its ability to deliver the scale and duration of low carbon hydrogen demand expected.

It is likely that hydrogen storage will be required for the following roles:

- Providing capacity to allow hydrogen producers and end-users to reduce supply risks resulting from demand and production mismatch, particularly for electrolytic hydrogen.
- Supporting the decarbonisation of the power system by 2035 through avoiding curtailment of renewables and supporting dispatchable power generation through hydrogen-fuelled powerplants.
- Supporting the need for strategic storage to underpin a resilient and secure energy system as the UK shifts to energy independence.



Strategic Context

Setting the strategic context for further investment in critical storage infrastructure

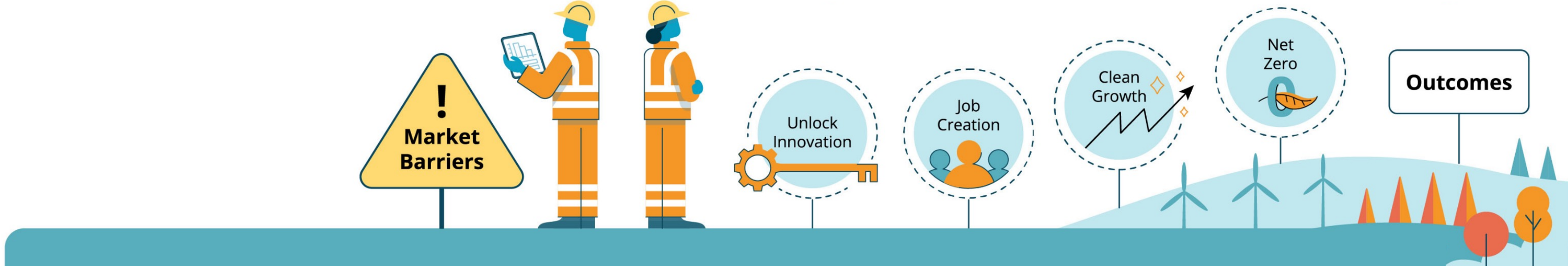
There are a variety of estimates of hydrogen storage requirements in published literature, which are revised and updated as the evidence base grows and uncertainty is removed. The requirement for storage is intrinsically linked to demand for hydrogen, and the ultimate end use of hydrogen. The uncertainty associated with the demand mix for hydrogen explains the large ranges for storage requirements that are reported.

At present, the only proven technology for storing large volumes of pure hydrogen is within underground salt caverns formed through solution mining of suitable geology. The UK currently has 0.025 TWh of salt cavern hydrogen storage, with two notable projects in development, namely HyKeuper and Aldbrough, that will add a further 1TWh and 0.5TWh storage capacity, respectively. Whilst the UK is fortunate to have a significant amount of suitable geology to support salt cavern storage development, the technology has limitations that challenge its ability to deliver the scale of hydrogen storage at pace to match modelled demand requirements.

Beyond the challenges of (1) total workable capacity of the salt considering surface and subsurface constraints and (2) the location of suitable salt deposits in relation to the producers and end-users, the most significant obstacle is the time required to develop and deliver large-scale salt cavern projects.

Given the barriers to the development of large-scale hydrogen storage within salt caverns, further compounded by immaturity of alternative technologies, it is considered by the authors of this report that there is a risk of market failure associated with the ability of the UK to deliver the necessary hydrogen storage within the required time frames. Put simply, without action, our assessment has indicated that we will not be able to develop enough storage at pace with demand – the delay in the delivery of this critical infrastructure could threaten the government's ambition to have 10 GW of low carbon production capacity by 2030, a decarbonised power system by 2035, and ultimately our legally binding Net Zero target.

This report builds on work done to date within the hydrogen storage field, conducting a first-of-a-kind cluster specific hydrogen storage assessment alongside an innovative approach for a more realistic estimate of available capacity for underground storage. The findings have allowed us to progress beyond theoretical to illustrate that the above market failure is a very real possibility, and set out the case for change to ensure storage requirements are met in a sustainable and resilient way.



Research Findings: Demand Modelling for the East Coast Cluster

A granular, sector-based assessment of storage requirements of the East Coast Cluster

This report presents a scenario-based, regional-scale assessment of the temporal demand for large-scale hydrogen storage across the East Coast Cluster. The underlying approach involves daily temporal hydrogen production and demand matching, over an annual period, based on comprehensive analyses of forecasted industry, heat, power generation and transport sector hydrogen demands.

Total hydrogen storage demand forecasts for the East Coast Cluster were derived by examining all ‘low’ hydrogen demand scenarios across all sectors and, separately, all ‘high’ hydrogen demand scenarios across all sectors, to give the full range of capacity requirements. All values represent minimum working gas capacity requirements.

The assessment, which has been completed for the East Coast Cluster specifically, informs the following conclusions:

- There is an intrinsic link between hydrogen demand and storage, the more hydrogen used, the more storage will be required.
- The assumptions over how hydrogen will be used in our future energy system are creating significant uncertainty, resulting in large ranges in the estimates of storage required, and with an absence of clear decision on policy, will cause delays to investment and uptake.
- Heat and power sector are biggest drivers for storage demand. Conversely, our assessment has shown that other end-users with more steady demand requirements require less hydrogen storage. The heat and power sectors have some of the greatest uncertainties for hydrogen uptake; with key decisions from UK government on the role of hydrogen for heat due in 2026, and a number of other technologies that can act as balancing mechanisms for the electricity network for power generation.
- The 2035 targets for decarbonising the power system and the government milestone for heat pumps are key drivers for medium to short-term hydrogen storage demand.
- Local demand for hydrogen storage may be outweighed by national demand, with an expectation that those areas with proven salt resources will serve the storage of production clusters without natural storage.
- This assessment provided demonstrates that irrespective of which end of the range is selected, there is a significant short-term demand for long duration hydrogen storage.

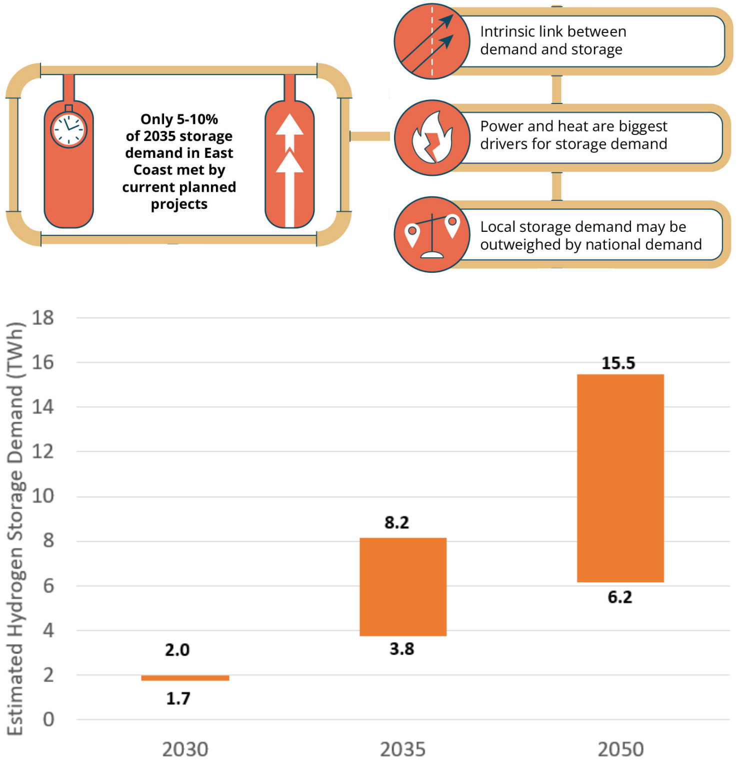


Figure 1: Forecasted hydrogen storage requirements for the East Coast region with data tables highlighting the illustrative hydrogen storage demand proportions for each individual sector Note: While hydrogen storage demands for each sector have been reported individually for illustrative purposes, this does not suggest that hydrogen storage will be developed for the individual sectors in isolation. See main report for more detail.

Research Findings: Demand Modelling for the East Coast Cluster

Going beyond hypothetical numbers of actual storage, an assessment of the capacity of salt cavern storage in the East Coast Cluster.

The East Coast cluster, comprising Teesside and Humber, has been identified as one of three geographies in the UK for hydrogen storage investment due to the abundance of suitable salt basins for salt cavern development, alongside Cheshire and Wessex. Previous work has estimated theoretical storage capacities within these regions. This report presents the re-assessment of 'workable' capacity of the salt deposits beneath the East Coast cluster, building upon previously published numbers.

A detailed geological assessment of publicly available information has been presented alongside an assessment of surface and development constraints. This data, presented in an interactive heat map, has been used to assess the likely workable capacity of the salt deposits for the development of large-scale underground hydrogen storage. Based on the methodology presented in this report, we have estimated the total workable capacity of dry operated storage caverns in the onshore Fordon Evaporite Formation under the East Coast Cluster as 22 – 48 TWh of Hydrogen Storage. Storage estimates are based on the Lower Heating Value (LHV).

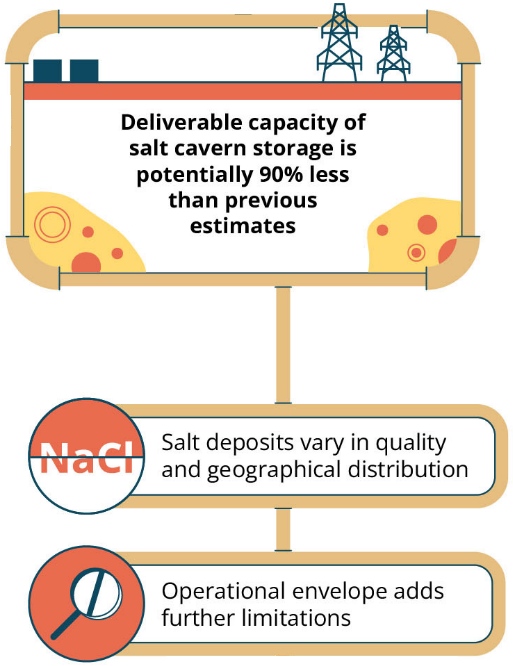
	East Coast Region IDRIC Study, 2024	No. of East Coast Region caverns required to be developed
3 x cavern radius	48 TWh	2200
5 x cavern radius	22 TWh	1000

Table 1: Total theoretical salt cavern storage and required number of caverns.

This assessment informs the following conclusions:

- Previously published assumptions about the capacity of the salt caverns for hydrogen storage are overstated. The workable capacity resulting from the re-assessment presented in this report, building on previously published work, represent approximately 70-90% reduction on published estimates.
- All salt is not equal and even within the constraints of the study area, there is significant variability in the salt deposits which significantly impacts the capacity for underground hydrogen storage.
- Based on the assumptions made within the report, the capacity within the East Coast Cluster is sufficient to meet the short-term demands of 2030 and 2035, subject to deliverability requirements. However, long-term storage requirements will exceed the available capacity.
- The operational envelope of underground hydrogen storage, needed to meet the demands of end-users, is an important and often overlooked consideration when assessing the capacity of large-scale storage to meet demand. Total capacity may not be the limiting factor, with other operational requirements such as withdrawal rates and cycling, becoming key in the assessment of storage development requirements.

This report concludes that the ability to deploy storage at the pace required is a significant risk given development timescales. As noted, the UK has 0.025 TWh of underground hydrogen storage in operation with a further 1.0-1.5TWh in development. Timescales to bring on the additional required capacity is unlikely to be delivered ahead of 2030 and 2035 requirements.



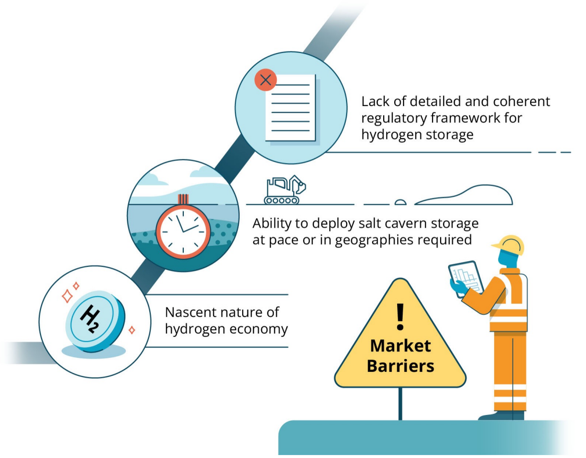
Market Barriers

Establishing the case for change, recognising the market barriers associated with the deployment of large-scale hydrogen storage.

This report has demonstrated that there is significant near-term demand for large-scale hydrogen storage, and the capacity to meet this demand in the salt located near the East Coast Cluster is severely limited by a number of barriers:

Nascent nature of hydrogen economy

There is uncertainty around how and when storage will be needed and the optimum mix of storage technologies. This is impacting the development and deployment of storage technologies, including alternative technologies, in turn resulting in an overreliance on a limited capacity of salt cavern storage projects.



Ability to deploy salt cavern storage at pace or in the geographies requiring storage

Large salt cavern storage facilities can take over a decade to build, and are required to follow a complex development process, including permitting, planning and consenting. Given these lead times, projects will need to be developed in parallel, increasing CAPEX and putting strain on supply chains. Salt is geographically constrained, meaning that salt cavern storage is not a viable technology for demand outside of those areas. This is further compounded by the impact of surface constraints that impact land availability for this technology.

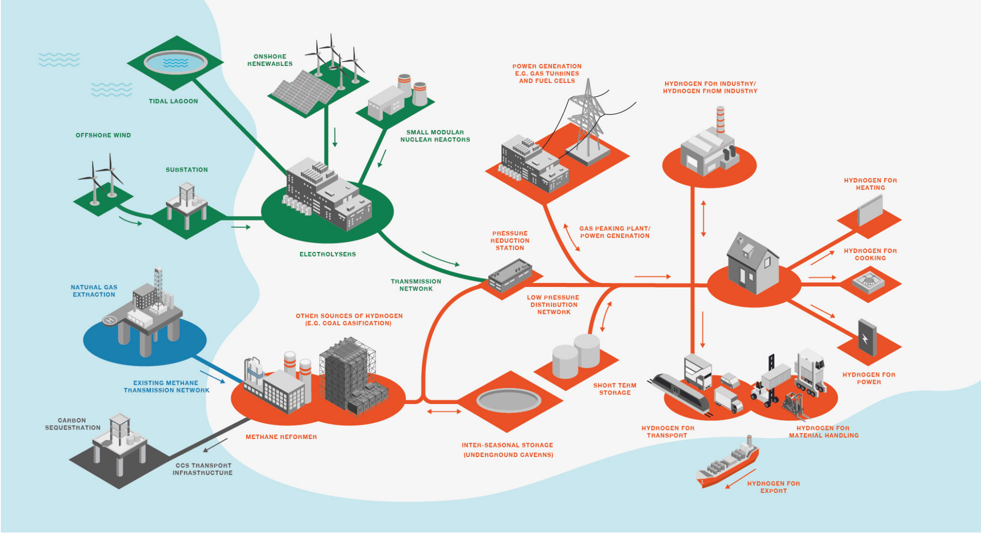


Figure 2: Establishing A Hydrogen Economy - The Future of Energy 2035.
Source: Establishing a Hydrogen Economy, Arup [2]

Lack of a detailed and coherent regulatory framework for hydrogen storage

Hydrogen storage is a critical component within the hydrogen economy and will require significant levels of up-front investment, far ahead of demand, to meet development timeframes. Lack of a clear regulatory framework is a barrier to economic investment and challenges timescales.

Interventions

Further government intervention is required to overcome barriers to support of UK Government's Net Zero ambitions.

This report concludes that further government intervention is required, alongside industry and academia, to overcome barriers and with clear outcomes in support of key government strategic objectives associated with Net Zero. The support to be provided by the preliminary proposal for a Hydrogen Storage Transport & Storage Business Model is a good start but needs to be more ambitious. This report has identified a number of minimum-regret interventions, to be implemented over the next six to twelve months, that will overcome these key barriers and allow forward movement.

Define the mix of storage technologies required and the optimum pace of development through strategic planning.

- We recommend that a detailed assessment for storage demand for remaining clusters in the UK is undertaken to understand the mix of technologies alongside the optimum pace of delivery to meet demand. Recognising the uncertainty associated with the nascent hydrogen economy, boundary conditions should be applied to ensure a consistent approach.

Implement a structured R&D programme for the development of storage technologies.

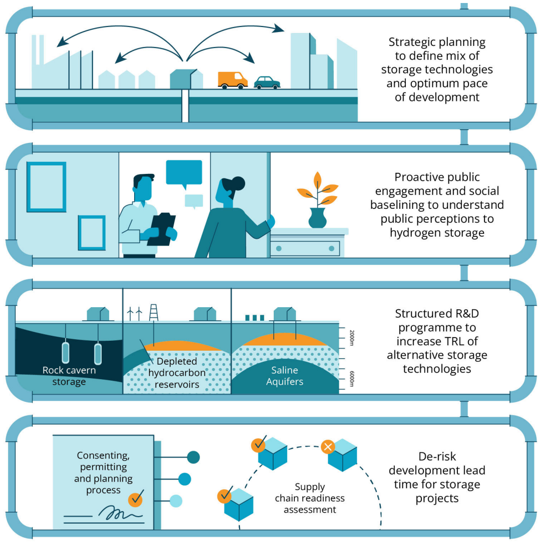
- Alternative large scale hydrogen storage technologies will be required to meet the pace and quantity of storage demand by 2035 and 2050, and existing technologies will need to be optimised. Therefore, this report recommends that a structured R&D programme is put in place to provide support to the development and deployment of the key alternative technologies including depleted reservoirs and line rock shafts/ caverns, and to optimisation of existing technologies such as fast cycle salt cavern storage.
- Alongside research and innovation delivered through UK institutions, the private sector should have access to support through development stage funding for demonstration and pilot storage projects, similar to the Net Zero Hydrogen Fund | Strand 1 Development Funding.

Undertake proactive public engagement and social baselining to understand public perceptions to large scale hydrogen storage.

- We recommend initiating a proactive approach towards public engagement and social baselining to gain a comprehensive understanding of public perceptions regarding large-scale hydrogen storage.
- By actively involving the community in the decision-making process, the aim is to assess their attitudes, concerns, and preferences related to this technology. Through social baselining, a systematic analysis of the current social and cultural context will be conducted, providing insights into potential challenges and opportunities. This proactive strategy seeks to foster transparency, build trust, and address any misconceptions or reservations that the public may have, ultimately promoting informed decision-making and facilitating the successful implementation of large-scale hydrogen storage initiatives.

Targeted interventions to de-risk the development lead time for storage projects.

- The report recommends that a number of interventions are undertaken to de-risk the development and delivery process through which large scale storage will follow. A key area of focus is recommended to the consenting, permitting and planning process, where projects will benefit from better defined processes and timelines. We also recommend undertaking a supply chain readiness assessment to identify possible bottlenecks and to allow proactive action to be taken to address these.



Section 2:

Introduction

Introduction

The University of Edinburgh and Arup have partnered, with support from BGS, to conduct a pioneering, cluster-specific assessment of hydrogen storage demand and capacity in the East Coast Cluster.

The climate emergency reverberates globally, impacting populations through rising temperatures, extreme weather events, and the disruption of critical ecosystems. The effects disproportionately burden vulnerable communities, exacerbating food and water insecurity, displacement, and health risks. Urgent action is imperative. Responding to this is the UK's legally binding commitment as enshrined in the Climate Change Act, making the UK the first major economy in the world to pass laws aimed at ending its contribution to global warming by 2050.

In the Build Back Greener Strategy, the UK Government identifies a number of key strategic areas in which decarbonisation efforts will be focused, including:

- Deliver 10 GW of hydrogen production capacity by 2030, whilst halving emissions from oil and gas.
- Fully decarbonise our power system by 2035.
- Set a path to all new heating appliances in homes and workplaces being low carbon from 2035.
- Remove all road emissions at the tailpipe and kickstart zero emissions international travel.

Hydrogen is poised to play a central role in the UK's journey towards achieving net-zero emissions due to its versatility and potential to decarbonise multiple sectors. As a clean energy carrier, hydrogen can be produced through various low-carbon methods, including electrolysis powered by renewable energy, offering a pathway to decarbonise sectors that are difficult to electrify such as heavy industry. Furthermore, hydrogen may provide grid flexibility through energy storage, allowing for a resilient decarbonised power system. Embracing hydrogen technology at scale holds the promise of reducing carbon emissions, driving economic growth and fostering innovation in the UK's green energy sector.

Despite its potential, hydrogen faces significant barriers on its path to widespread adoption in the UK's journey to Net Zero. One major challenge lies in the high cost of producing low-carbon hydrogen, particularly through electrolysis, which requires substantial investment in renewable energy infrastructure. Additionally, the current lack of a comprehensive hydrogen infrastructure, including storage and distribution networks, hampers its scalability and accessibility. Storage, in particular, presents a significant obstacle, as efficient and cost-effective methods for large-scale hydrogen storage are still in development.

Addressing these barriers will require concerted efforts from policymakers, industry stakeholders, and researchers to overcome technological, economic, and regulatory hurdles and unlock hydrogen's full potential as a cornerstone of the UK's Net Zero ambitions.

The University of Edinburgh (UoE) and Arup have partnered, with support from the British Geological Survey to prepare a pioneering, cluster-specific assessment of hydrogen storage demand and capacity, as presented in this report. The East Coast Cluster (ECC) has been selected for assessment given the relatively mature understanding of hydrogen production and demand. The region also offers large-scale existing and potential geological salt deposit storage sites. Through a first-of-a-kind analysis of likely hydrogen demand and storage requirements in the ECC, and an assessment of capacity offered by existing salt cavern storage technologies, the analysis in this report provides a significant evidence base to support the case for change associated with long-duration energy storage to meet the likely demand requirements. In demonstrating the case for change to meet the storage requirements in the ECC, where the situation appears to be most optimistic, the findings of the report should be viewed in the context of the even greater challenge of ensuring a national long-duration energy storage capacity, delivered at the scale and pace required to meet demand associated with our net-zero milestones.

There are significant challenges for industrial decarbonisation ahead, but it is hoped that this report will contribute to further investment in long-duration energy storage solutions that will accelerate industrial decarbonisation with deployment at scale required within the next decade, securing the UK's position as an innovation leader, creating green jobs, and ultimately supporting the transition to Net Zero by 2050.

Katriona Edlmann, University of Edinburgh

James Todd, Arup Project Director

Section 3:

Strategic Context

UK Decarbonisation Timeline: Hydrogen's role in the pathway to 2050

It is widely accepted that low carbon hydrogen will play a critical role in any future decarbonisation energy system, helping to bring down emissions in vital UK industrial sectors and providing flexible energy for power, heat and transport.

The Climate Change Act 2008 marked a pivotal moment in the global fight against climate change. The enactment committed the UK to ambitious targets aimed at reducing greenhouse gas emissions and transitioning towards a low-carbon economy by 2050. The groundbreaking legislation not only established legally binding emission reduction targets but also laid the groundwork for long-term planning and adaptation strategies.

Definition of the path to 2050 is further detailed in legally binding 'carbon budgets' that act as milestones towards the 2050 target. These budgets represent a cap on the amount of greenhouses gases the UK can emit over a given period, and include recommendations regarding policy and activities required by policy makers, businesses and individuals. The most recent Carbon Budget 6 (CB6) provides a blueprint for a fully decarbonised UK, with a recommended pathway to achieve a 78% reduction in UK territorial emissions between 1990 and 2035.

Central to CB6 is the take-up of low carbon solutions and the expansion of low carbon energy supplies. Low carbon hydrogen is seen as playing a pivotal role in both areas, with an expectation that industry must adapt technologies that use electricity or hydrogen instead of fossil fuels, and that low-carbon hydrogen is to be used to decarbonise areas less suited to electrification, particularly shipping and parts of industry, and is vital in providing flexibility to deal with intermittency in the power system.

Importantly, analysis by the Department for Business, Energy and Industrial Strategy (BEIS) for CB6 suggests 250-460 TWh of hydrogen could be needed in 2050 (See Figure 3), making up 20-35% of UK final energy consumption.

The UK's Hydrogen Strategy (2021), provides further detail of the role of hydrogen in meeting net zero by 2050, specifically in a complementary and enabling role alongside clean electricity in decarbonising the UK's energy system. The strategy includes important targets for hydrogen production and uptake, namely for the production of 10GW of electrolytic (green) hydrogen by 2030. The strategy recognises that hydrogen will play an important role in decarbonisation of the power system by 2035, both as low carbon back-up generation and in providing long-duration storage to manage intermittency of renewable energy supply.

With virtually no low carbon hydrogen produced or used currently, particularly to supply energy, the strategy recognises this will require rapid and significant scale up from where we are today – the Climate Change Committee (CCC) report, 'Delivering a reliable decarbonised power system', from March 2023 [8], includes a conclusion that:

'delays in the delivery of hydrogen infrastructure could limit the role for hydrogen in the 2035 energy system, including its role to provide low-carbon back-up capacity'.

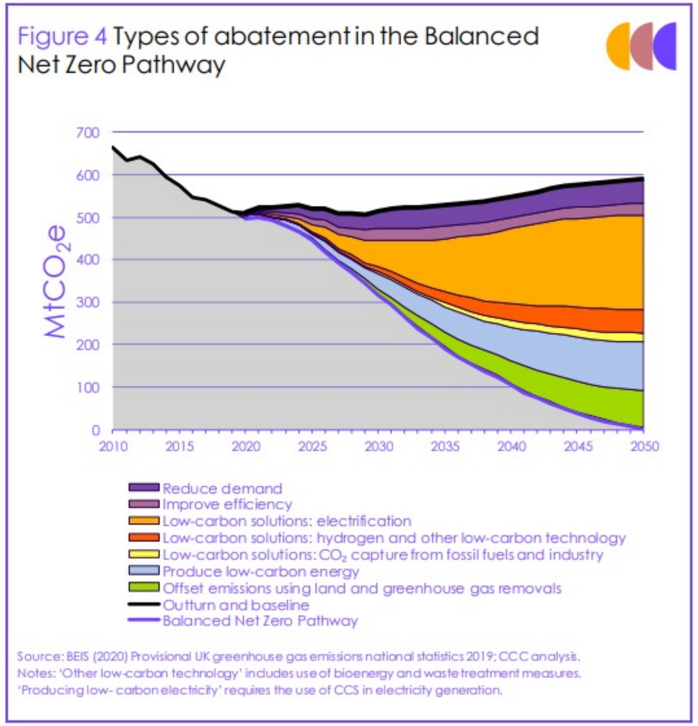


Figure 3: Types of Abatement in the Balanced Net Zero Pathway.
Source: BEIS Provisional UK greenhouse gas emissions national statistics 2019; CCC analysis (2020). [3]

Demand and Capacity: The role of long duration storage in the Hydrogen Economy

There are a variety of estimates based on currently held assumptions regarding the demand and capacity of hydrogen storage

Hydrogen storage will be a critical component within the future hydrogen system and will play a vital role in the hydrogen economy and wider energy systems. The recently published Hydrogen Transport and Storage Infrastructure: Minded to Positions [4] details the expected roles that hydrogen storage may play in supporting the wider hydrogen economy and path to net zero:

- Managing within-day network balance in the event of an imbalance between entry and exit volumes of hydrogen networks.
- Providing capacity to allow hydrogen producers and end-users to reduce supply risks resulting from demand and production mismatch, particularly for electrolytic hydrogen.
- Providing a means of long duration energy storage, supporting the decarbonisation of the power system by 2035 through avoiding curtailment of renewables and supporting dispatchable power generation through hydrogen-fuelled powerplants.
- Possibly reducing the overall hydrogen production capacity requirements by maximising supply and allowing producers to optimise their outputs, irrespective of demand.
- Figure 4 summarises the storage capacity and discharge durations of the various proven storage technologies, this demonstrates the role hydrogen may play in providing high capacity, long duration energy.

There are a variety of estimates of storage requirements which are revised and updated as the evidence base grows. The large range of storage capacity required results from different use-case assumptions built into each assessment.

Notable figures include the following:

- The Royal Commission Large-Scale Electricity Storage report (Sept 2023) concludes that some 100 TWh of hydrogen storage will be required to support a model in which all of the UK's future electricity demand is met by wind, solar and hydrogen provides a benchmark for comparison with other cases [5]. This would require wind and solar supply averaging around 760 TWh/year.
- The National Grid Future Energy Scenario assessment estimates a maximum of 56 TWh in their System Transformation scenario [6]. This scenario assumes a high use of Hydrogen for heating, with inter-seasonal storage required in addition to storage for system balancing.
- AFRY, commissioned by BEIS, estimated hydrogen storage requirement for long duration storage to be between 11.4 TWh and 17.2 TWh and concluded that oversizing seasonal hydrogen storage would be a low regret decision, with some utilised at a low rate of cycling [7].
- The Climate Change Committee has stated that 2.1-2.8 TWh of hydrogen storage is deployed by 2030, 3.3-5.2 TWh by 2035, and 7.1- 11.6 TWh by 2050 [8].
- In an initial high-level assessment, Hydrogen UK estimates that 3.4 TWh of large-scale storage capacity is required to be operational by 2030. To support the rapid development of the hydrogen economy, the storage volume could need to be expanded to 9.8 TWh by 2035 [9].

Whilst there are a range of required storage volumes presented in literature, it is recognised that given the limited proven long duration storage technologies available in the market, either end of the scale will pose significant challenges to be overcome.

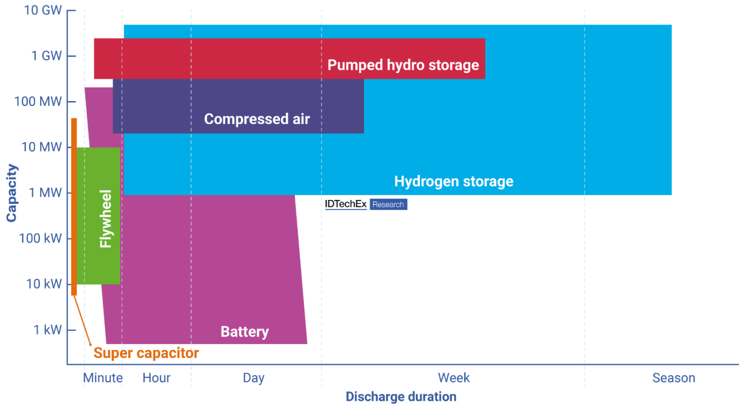


Figure 4: Storage capacity and discharge durations of proven storage technologies.
Source: IEA Energy Technology Roadmap Hydrogen and Fuel Cells, JRC Scientific and Policy Report 2013. [10]

Long-duration Hydrogen Storage technologies

Salt caverns are the only 'proven' technology for storing hydrogen at scale and therefore the only technology mature enough to meet UK Government's requirements for investment

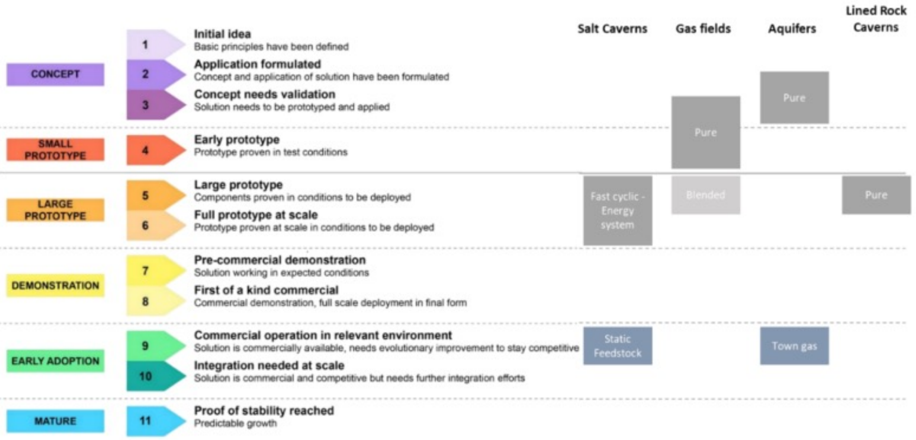
Storing hydrogen at scale presents several challenges due to its physical and chemical properties, namely its low energy density, the ability to diffuse, the absorption of hydrogen into material, including metals, and the temperature and pressure requirements.

Small volumes may be met with above ground hydrogen storage solutions, centred around pressure vessels and pipe storage, which are common methods for storing hydrogen and non-hydrogen gas at the surface. Above ground facilities face several challenges for large-scale hydrogen storage (typically 30 to 50 te and greater), due to factors such as cost, land footprint and technical feasibility.

The only 'proven' option for storing hydrogen at scale is geological storage. Salt caverns represent one of the most mature methods of underground gas storage. In the UK, salt caverns in Teesside have been commercially operated (Technology Readiness Level, Stage 9) as static feedstock (constant pressure operation) for non-hydrogen and hydrogen gas for many decades. Two notable projects are in development, namely HyKeuper and Aldbrough, that will add a further 1TWh and 0.5TWh storage capacity respectively. It is recognised that there are significant limitations with this technology, namely the location of suitable salt deposits in relation to producers and end-users, and the time taken to develop these storage sites at scale.

Given the barriers associated with the development of large-scale hydrogen storage within salt caverns, other geological storage options that will provide high-capacity long duration storage are being assessed globally.

- Depleted gas fields: Storage capacity defined by the pore space in a (once) gas-bearing rock formation. Capacity typically exists within sandstone and carbonate bearing strata. Storage volumes are a result of prior hydrocarbon extraction. Fields are often sealed by an impermeable caprock such as mudstones, rock salt or structural, fault bound strata. Tests to determine hydrogen seal integrity are undergoing.
- Aquifers: Storage capacity defined by porous, water bearing rock formations. The presence of a secure and gas-tight seal must generally be proven by geological investigations, exploration drilling and injection tests.
- Lined rock caverns and shafts: Man-made caverns and shafts constructed in suitable geology. Secure gas containment is achieved by lining the cavern or shafts.



A recent report by the Hydrogen Technology Collaboration Programme (TCP) provides a comprehensive assessment of underground storage technologies for hydrogen, a graphical summary is provided in Figure 5.

It is noted that the recent minded position for the Storage and Transportation business models includes the requirement for applicant projects to demonstrate storage technologies above Technology Readiness Level (TRL) 7 [4]. As per Figure 5, it is likely that this is limited to salt cavern storage.

The position recognises the challenges associated with the development of salt cavern storage at scale and is explicit in the need to develop an optimum technology mix, including research and innovation to improve the readiness levels of alternative, relatively immature technologies.

Figure 5: Overview of Technical Readiness Levels for different UHS technologies according to the IEA TRL framework.
Source: Hydrogen Technology Collaboration Programme (TCP) – Task 42 Underground Hydrogen Storage, Technology Monitor Report 2023. [11]

Section 4:

Research Outputs

Research Outputs:

Demand Modelling in the East Coast Cluster

Executive Summary

This analysis combines demand forecasts for the industry, heat, power generation and transport sectors with localised data for the East Coast. The approach can be easily replicated to better understand the future hydrogen supply and demand balance across key regions.

This work package estimates the hydrogen storage demand for the UK East Coast region, focusing on near-term (2030 and 2035) and long-term (2050) requirements. By aggregating fluctuating demand profiles for hydrogen use in industry, heat, power generation and transport* sectors, this analysis involves daily temporal matching of overall forecasted hydrogen demand and hydrogen production across the East Coast; the resulting energy balance used to inform the estimation of regional inter-seasonal hydrogen storage demand requirements.

Forecasted sectoral hydrogen demands are estimated for ‘low’ and ‘high’ hydrogen demand scenarios to develop lower and upper bounded estimates of the total regional hydrogen storage capacity requirements. The system boundary of the demand assessment comprises the Northern, Northeastern and East Midlands regions of the UK, aligning with the UK Local Distribution Zones (LDZs) as defined by National Gas [12] and building on recent work such as that outlined in the East Coast Hydrogen (ECH_2) Delivery Plan [13]. The following overarching approach was applied:

1. Establish ‘low’ and ‘high’ hydrogen demand requirements and associated demand profiles for each sector in the East Coast region.
2. Engage with subject matter experts and project partners to understand future hydrogen storage needs and refine model assumptions.
3. Daily temporal matching to understand the energy balance between hydrogen production and demand to estimate the total hydrogen storage demand for the East Coast.

Due to the uncertainty of announced hydrogen production capacity in the region, mostly concentrated around the Teesside and Humber industrial clusters, the base case assesses a constant hydrogen production profile, with annual production equal to annual average demand. Sensitivity analyses were undertaken to investigate the impact of electrolytic hydrogen production fluctuations and seasonality; an extended system boundary to include the Southeast of England; and oversizing hydrogen production capacity for additional energy system flexibility.

This work package provides forecasted demand for hydrogen salt cavern storage in the East Coast region for the years 2030, 2035 and 2050. WP2 provides an estimate for the available “supply” of hydrogen salt cavern storage in the East Coast region, based on real world constraints. The outputs are then combined in WP3 to assess the likelihood of bottlenecks in salt cavern storage development, e.g. if/when demand for hydrogen salt cavern storage will exceed available supply in the East Coast region between 2030 and 2050.

The analysis can be easily replicated for other regions to better understand potential future hydrogen supply and demand balances across key regions in the UK. This can help build the full picture of the requirements of hydrogen storage to meet future demand.

**For the transport sector, an assumed demand based on the days of storage needed for maritime and aviation operations was used instead of a temporal profile – see Appendix A for more details.*

Figure 6: System boundary of storage demand modelling assessment, chosen to align with East Coast Hydrogen Delivery Plan system boundary with additionality to include full Northern LDZ region (as outlined in red). [12][13]

Context: Hydrogen Production in the UK East Coast Region

The announced hydrogen production projects in the East Coast region will see up to 11.6 GW of low-carbon hydrogen production capacity by 2037, with 10.8 GW by 2030. This places the East Coast well to make up a significant proportion of the UK's 2030 10 GW hydrogen production target.

The East Coast region is set to become a key producer of low-carbon hydrogen with up to 11.6 GW of planned capacity to be operational by 2037, representing around 58% of the UK's total announced capacity of over 20 GW [13]. Teesside and Humber are set to account for 33.1% and 60.2% of this total regional capacity, respectively, highlighting the significance of the East Coast Cluster in developing the UK hydrogen industry.

	Total announced production by 2037 (GW)
East Coast Region	11.6
CCUS-Enabled	6.3 [54.5% of ECR total]
Electrolytic	5.2 [45.1% of ECR total]
Teesside	3.8
CCUS-Enabled	2.0 [52.4% of Teesside total; 2 sites]
Electrolytic	1.8 [47.6% of Teesside total; 5 sites]
Humber	7.0
CCUS-Enabled	4.3 [61.7% of Humber total; 4 sites]
Electrolytic	2.7 [38.3% of Humber total; 7 sites]

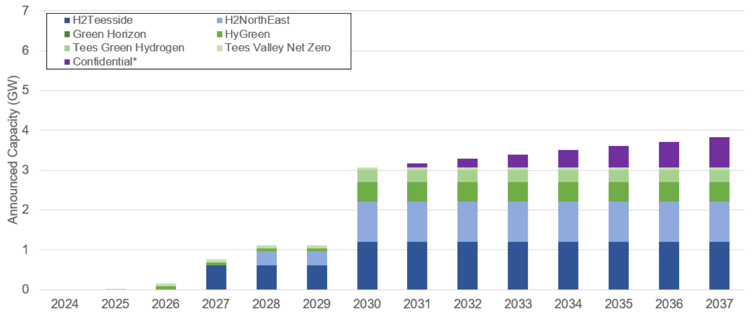
Table 2: Total announced low-carbon hydrogen production capacity in the East Coast region by 2037.

The growth of hydrogen production capacity is expected to accelerate in the mid-2020s, with large gigawatt-scale CCUS-enabled (Carbon Capture, Utilisation & Storage) hydrogen projects leading the way and electrolytic capacity mostly contributing from 2030. However, the majority of the announced 11.6 GW of production is pre final investment decision and at the pre-planning or pre-FEED (front-end-engineering-design) stage. It is likely that only a fraction of this will convert into commissioned projects by 2030 [13]. Especially given early hydrogen production projects require public support to enable a viable business model and UK national targets have set a 10 GW of hydrogen production nationally by 2030. (Only a fraction of the 10 GW will be in the East Coast)

During the early stages of adoption, production sites will be matched to specific customers with individual supply between CCUS-enabled or electrolytic hydrogen plants, that align with their schedules. Later on, if hydrogen infrastructure is rolled out at scale it will be possible for production points to feed hydrogen into the grid with no specific customer, as is done with natural gas, on the National gas grid today.

The impact of a greater influence of wind variability on the increased electrolytic hydrogen production capacity from 2030 is assessed in the seasonality of hydrogen production sensitivity analysis.

(a) Teesside



(b) Humber

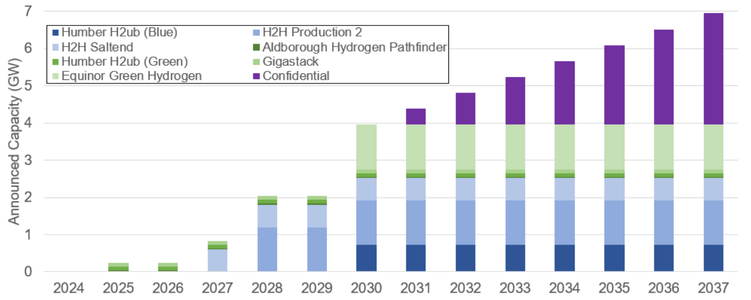


Figure 7: Total capacity profile of announced hydrogen production projects in (a) Teesside and (b) Humber Sum of CCUS-enabled capacity and electrolytic capacity not aligned to 10.8 GW from East Coast Hydrogen plan, as only specific projects are plotted, with publicly announced capacities – *other confidential projects included as one in purple, and show an indicative linear growth from 2030 to 2037 to illustrate the full scale of ambitions for the East Coast.

Methodology: Summary of Sectoral Hydrogen Demand Analysis

Several data sources and assumptions have been applied throughout the study to develop a unique assessment of hydrogen demand across the East Coast region, in alignment with local developments and UK Government targets.

<table>
<tr><th>Sector</th><th>Industry</th><th>Heat</th><th>Power Generation</th><th>Transport</th></tr>
<tr><td>Data</td><td>Representative quarterly hydrogen demand profile assumed, aligning with average 2020-22 quarterly UK industrial natural gas demand proportions.
Total annual regional hydrogen demand forecasts averaged using East Coast Hydrogen Delivery Plan and CCC modelling data.</td><td colspan="2">Heat and power, use the same data sources.
2019 data from the National Gas portal, the East Coast, assumed to be NE (Northeast), NO (North) and EM (East Midlands) LDZ (Local demand zones) – used for the profile.
UK government heat pump installations targets and forecasted H_2 demands, use to estimate uptake of domestic heat pumps and H_2 boilers between 2030 and 2050.</td><td>National UK hydrogen forecasts for maritime and aviation sector
Airport specific-aircraft movement data.
Port-specific freight movement data.</td></tr>
<tr><td>Key Assumptions</td><td>Low and high hydrogen demand scenarios between 2030 and 2050 determined using UK Government confidence interval ranges.
Localisation of data to East Coast region by applying representative quarterly demand profile to hydrogen demand forecasts.</td><td>Home energy efficiency (insulation) provide a domestic heat demand reduction between 2030 and 2050.
All homes will use either a heat pump or a hydrogen boiler. District heat networks, will be powered by large – scale heat pumps.
Off-gas grid homes not included in National-Gas demand data.</td><td>Long duration energy storage for the power sector will require hydrogen.
Domestic power consumptions will have the same shaped profile as domestic heat consumptions once heat is electrified.</td><td>Each airport and port will require hydrogen storage equivalent to a number of days demand to support its operations.
Hydrogen demands are scaled geographically proportionally with aircraft movements and freight movements.</td></tr>
</table>

Methodology: Hydrogen Storage Demand Model Construction

The model is designed to balance demand profiles from all sectors with hydrogen production to output the required storage capacity. Initially a constant hydrogen production rate is assumed throughout the year. This is explored as a sensitivity.

The model calculates the requirements to balance hydrogen production with demand profile across all sectors in the East Coast. Initially a constant production profile has been used. This assumes there is no variation in annual hydrogen production. Hydrogen production has therefore been sized to the annual hydrogen demand, so there is no accumulation of hydrogen in storage across multiple years. Under this assumption, storage will be the only mechanism of balancing hydrogen production and demands but in reality this may not be the case:

- Production could be oversized, with increased capacity to produce more in peak winter periods, rather than solely relying on storage. This means production would be ramped down during summer. In theory if production was sized to the maximum daily demand, then there would be no requirement for storage for balancing inter-seasonal swings. However, this would not be cost-effective as there would a very low utilisation of production plants and large capital investment. Equally, system costs can be saved by a smaller oversizing of production reducing storage requirements. Thus, the optimal point from a cost perspective will be between the two extremes of production sized to average demand and production sized to maximum demand. As system costs and estimating hydrogen production capacities are out of scope of this study this has not been considered in detail. An indicative oversizing is considered as a sensitivity to illustrate the relative impacts on storage.
- The East Coast is assumed to be a closed boundary. However, the East Coast may be a net importer or exporter of hydrogen with the rest of the UK, meaning production and demand do not necessarily have to match.
- Renewable generation sees a seasonal variation, which will be explored as a sensitivity.

East Coast storage forecasting model diagram

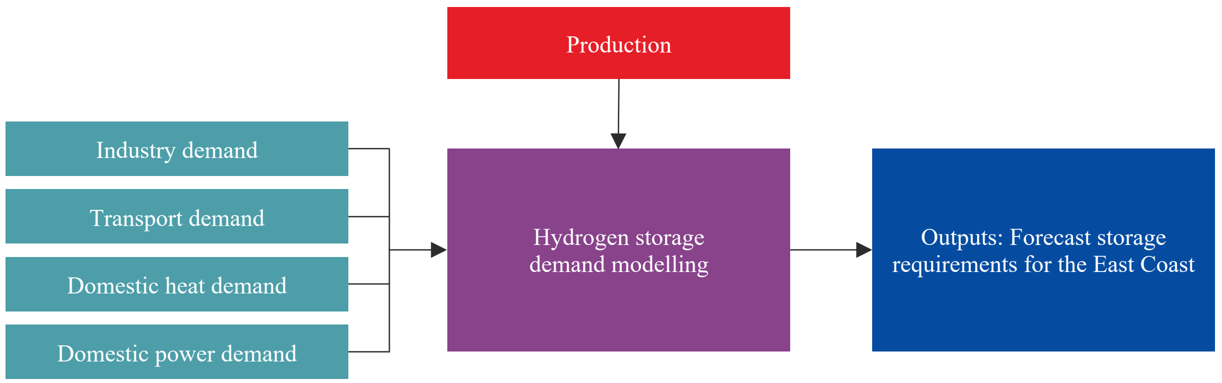


Figure 8: Block diagram, of hydrogen storage demand model.

Summary of Modelled Sectoral Hydrogen Demands

Industry is forecasted to have the greatest uptake in hydrogen demand across all sectors. This aligns with the plans of industrial sites, largely split between the Teesside and Humber industrial clusters, to decarbonise their operations by fuel-switching to low-carbon hydrogen.

The ‘low’ and ‘high’ sectoral hydrogen demand scenario-based analysis was undertaken to model the uncertainty of future hydrogen uptake. Based on the study assumptions, the industry, heat and power generation sectors were modelled using daily hydrogen demand profiles.

- The industry sector follows a constant daily profile over each quarter, assuming average quarterly industrial natural gas demand proportions (due to data availability). This quarterly profile has been applied to reported total industrial hydrogen demand forecasts for the East Coast region, which account for the proportion of industrial customers switching to hydrogen based on direct stakeholder engagement with a variety of customers.
- The heat and power generation sectors follow a variable daily profile with an inter-seasonal trend, assuming forecasted uptake rates of hydrogen boilers and heat pumps aligned to UK government targets. These have then been applied to natural gas LDZ data for the East Coast region. Power sector demands were estimated by assuming hydrogen-to-power generation required to accommodate increased future power demands due to the uptake of heat pumps.

The total annual hydrogen demand for industry is estimated to significantly outweigh other sectors in the near-term (2030 and 2035), with the exception of the high hydrogen demand scenario in 2035 where the heating sector is estimated to have a similar annual demand. This is due to industry being an early adopter of hydrogen, with many of the largescale projects in the East Coast being developed within industrial clusters, which have early demand needs driven by 2040 decarbonisation targets [14,15].

In 2050, hydrogen demand for the power sector is estimated to represent a greater proportion in the low hydrogen demand scenario, due to the forecasted widespread residential heat decarbonisation with the uptake of heat pumps. Total hydrogen demands for the low and high hydrogen demand scenarios for the three sectors across the East Coast region in 2050 were estimated to be 19.5 TWh and 78.7 TWh, respectively.

Table 3: Forecasted annual low and high sectoral hydrogen demands (TWh) for the East Coast region.

Forecast Year	Industry	Heat	Power Generation	Total*
Low hydrogen demand scenario				
2030	7.1	0.0	2.0	9.1
2035	9.9	0.0	5.2	15.1
2050	9.9	0.0	9.6	19.5
High hydrogen demand scenario				
2030	11.6	1.0	1.3	13.4
2035	11.6	19.5	2.7	44.0
2050	11.6	34.4	7.0	78.7

**An annual demand profile was not determined for the transport sector due to the assumed requirement for hydrogen storage to provide a minimum capacity for the aviation and maritime sub-sectors (i.e. based on 0-4 days of supply, depending on scenario) rather than for demand matching purposes, see subsection later.*

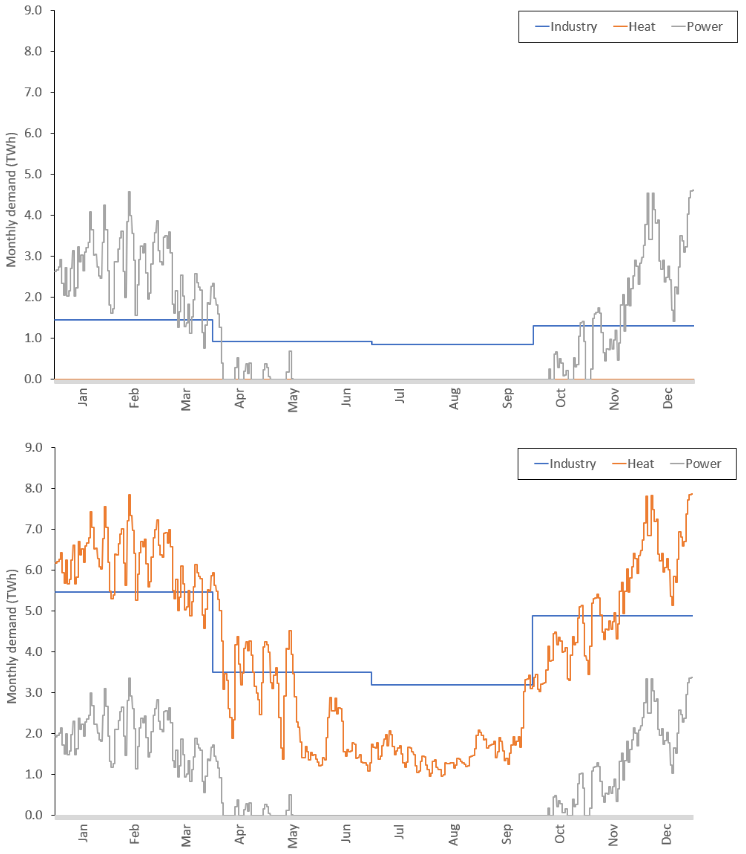


Figure 9: Assumed 2050 daily sector hydrogen demand profiles used for hydrogen storage demand modelling in the East Coast region (a) low hydrogen scenario above (b) high hydrogen scenario below, Transport not included as a temporal profile was not used.

Key Findings: Annual Hydrogen Storage Demand Forecasts

Despite industry having the greatest hydrogen demand, the use of hydrogen in the heat and power sectors are the greatest drivers of hydrogen storage capacity. This highlights the importance of hydrogen storage to balance the misalignment between production and highly variable, inter-seasonal demand for power and heating sectors.

The following total hydrogen storage demand forecasts for the East Coast region were estimated by assuming simultaneous occurrences of all 'low' hydrogen demand scenarios across all sectors and, separately, all 'high' hydrogen demand scenarios across all sectors, to give the full range of possibilities. All values represent minimum working gas capacity requirements.

- 2030: 1.7 – 2.0 TWh.
- 2035: 3.8 – 8.2 TWh.
- 2050: 6.2 – 15.5 TWh.

Across all scenarios, transport sector demand is forecasted to have a minimal impact on the overall hydrogen storage demand due to the static 0-4 days security of supply storage assumption.

For the low hydrogen storage demand forecasts, the power sector is observed to require the greatest capacity of hydrogen storage across all sectors. This is due to the highly variable and inter-seasonal nature of the forecasted power sector demand, with large peak demands in the winter requiring additional storage to meet these peaks. In contrast, despite industry having greater annual hydrogen demands, the reduced variability and seasonality of the industry demand profile means production will be more closely matched to demand. This highlights an important feature of storage demand forecasting; storage demand is driven by both scale of demand and variability with respect to production.

For the high hydrogen storage demand forecasts, hydrogen storage demand is even more driven by the industry, heat and power sectors, with industry requiring the greatest storage capacity in 2030 and the heat sector representing the majority in 2035 and 2050. This highlights the greater need for hydrogen storage to support the industry sector in 2030 due to an earlier expected transition to hydrogen. In the later years, the heating sector has a greater influence on the hydrogen storage demand, from the scale up to the assumed 35% of homes using hydrogen boilers in the region in 2050. This consequently reduces power sector demand with fewer heat pumps installed in this scenario. This storage is within the large range of other UK-scale assessments, but there is a great range in other studies forecasting to net zero in 2050:

- National grid FES 2050: 19 to 55 TWh [16]
- AFRY Long duration Energy storage for BEIS,: 11.2 to 17.4 TWh [17]
- Royal Society, Large Scale Electricity storage: 60 to 100 TWh [18]

Forecasted hydrogen storage demands for 2050 are explored further in the following slides to highlight the key characteristics and test assumptions in the developed model estimations. Similar conclusions can be made when analyzing the 2030/2035 time periods for the low and high hydrogen scenarios.

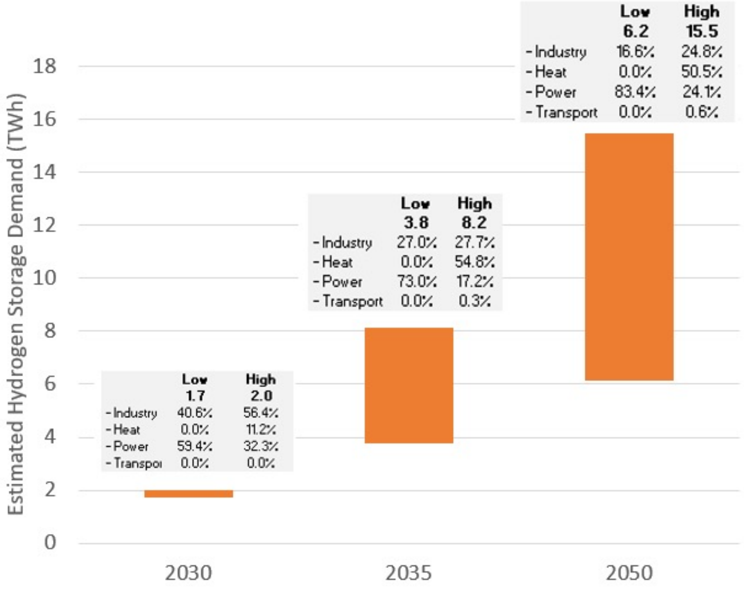


Figure 10: Forecasted hydrogen storage requirements for the East Coast region with data tables highlighting the illustrative hydrogen storage demand proportions for each individual sector.

**Note: While hydrogen storage demands for each sector have been reported individually for illustrative purposes, this does not suggest that hydrogen storage will be developed for the individual sectors in isolation. Data has been represented in this way to highlight the key drivers for the hydrogen storage demand estimates. The heat and power sector demands can also be considered in combination to represent an 'overall heating sector demand', representing hydrogen's potential use for gas (hydrogen boilers) and electrified heating (heat pumps), respectively.*

Key Findings: Forecasted 2050 Daily Temporal Demand and Supply Balancing

The aggregated sectoral demand profile highlights the daily variability and inter-seasonal nature of hydrogen demand. The net balance between the constant production profile and the variable demand highlights the need for hydrogen storage to provide additional capacity in winter months.

Figure 11 shows the hydrogen injection and withdrawal pattern that modelling has forecasted. Hydrogen is injected during the summer months between April and October and withdrawn in winter months between November and March.

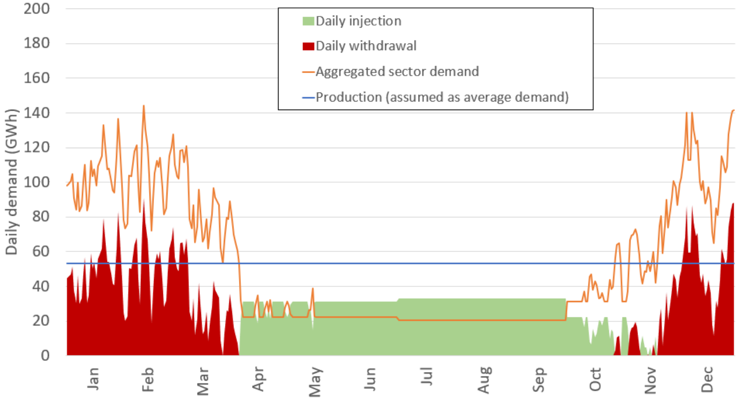
For both low and high hydrogen demand scenarios, an aggregated demand profile with daily variability and an inter-seasonal trend is observed. The daily variation is largely driven by the forecasted heat and power sector demands, with all three sectors contributing to the inter-seasonal trend, albeit to different degrees. By plotting daily annual demand with respect to average production, the area between the two profiles (i.e. the accumulated net difference between production and demand at daily intervals) provides an indication of the scale and duration of injection and withdrawal periods.

Maximum and minimum daily aggregated demands of the low and high hydrogen demand scenarios provides an indication of the minimum daily injection and withdrawal capacities required to prevent any unmet loads occurring throughout the year. The net difference of values greater than average daily production represent a daily minimum storage withdrawal capacity, whereas the net difference of values below the average daily production represent a daily minimum storage injection capacity.

This study only considers total capacity requirements (TWh) for hydrogen. However there will be significant infrastructure required to enable hydrogen to be injected into and withdrawn from storage at the required rate. The maximum withdrawal capacity varies from 33 to 116 GWh per day. Components such as compressors and dehydration plants will be needed. This type of infrastructure requirement has not been considered in detail in this study but should be considered when planning for hydrogen storage and the role it will play in the energy system.

Parameter	Low Hydrogen Demand Scenario	High Hydrogen Demand Scenario
Minimum daily aggregated demand	48 GWh/day	296 GWh/day
Maximum daily aggregated demand	172 GWh/day	596 GWh/day
Daily average production	81 GWh/day	412 GWh/day
Minimum daily storage withdrawal capacity	91 GWh/day	184 GWh/day
Minimum daily storage injection capacity	33 GWh/day	116 GWh/day

Table 4: Forecasted hydrogen storage demand modelling parameters for the 2050 low and high hydrogen demand scenarios.



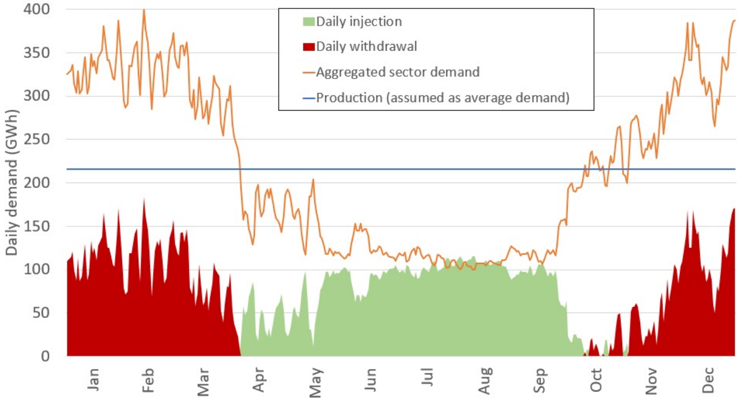


Figure 11: Aggregated 2050 daily demand profiles of the industry, heat and power sectors against production at average demand, with highlighted periods of injection and withdrawal (a) low hydrogen demand scenario above (b) high hydrogen demand scenario below – Graphs have different y-axes.

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Key Findings: Forecasted 2050 Hydrogen Storage Demand for Seasonal Balancing

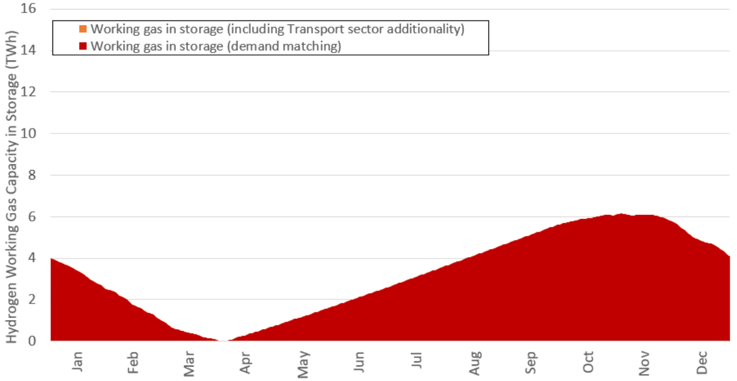
The developed profile of minimum daily hydrogen working gas capacity highlights the inter-seasonal balancing benefit of hydrogen storage. In 2050, a minimum hydrogen storage working capacity demand of 6.2 – 15.5 TWh was forecasted.

A profile of minimum daily hydrogen working gas capacity in storage was developed by accumulating the net difference between production and demand across the full year and assuming an initial working gas inventory such that the minimum value of the analysis returns a zero value for working gas. For each scenario this ensures the most significant withdrawal period doesn't fully deplete the entire working gas capacity available, thus providing an estimation of the minimum working gas capacity requirement for seasonal balancing as indicated by the maximum value of the profile.

- For the low hydrogen demand scenario, a minimum working gas capacity requirement of 6.2 TWh was determined. This scenario assumes there is zero additional storage demand from the Transport sector due to the 0-day storage assumption for the hydrogen- and e-kerosene-fuelled aviation and maritime sub-sectors.
- For the high hydrogen demand scenario, a minimum working gas capacity requirement of 15.5 TWh was determined. This estimate accounts for a small minimum storage additionality of 0.1 TWh from the transport sector, based on the 4-day storage assumption for hydrogen-fuelled aviation and the 2-day storage assumption for e-kerosene-fuelled aviation and the maritime sub-sectors.

The profile highlights the inter-seasonal energy system balancing opportunity of large-scale hydrogen storage at the regional level – hydrogen is withdrawn from storage during the winter months and is then injected into storage over summer. A smooth curve is observed from daily demand modelling, however in reality, increased intraday variability between injection and withdrawal is likely to occur creating more frequent demand fluctuations. Additionally, non-constant production will also increase variability of injection and withdrawal patterns. More frequent demand fluctuations will not strongly influence the total capacity required to balance inter-seasonal demands. Given the focus of this study on total capacity constraints, these higher frequency fluctuations have not been explored further (There are also additional complexities of whether hydrogen salt cavern should be the technology of choice for providing storage to balance higher frequency fluctuations).

It is important to reiterate that the hydrogen storage demand forecasts represent a working gas capacity. When designing storage systems and/or determining available hydrogen storage capacities to accommodate the hydrogen storage demand, cushion gas requirements and specific geometries of individual caverns will need to be considered. This is explored further in WP2 when assessing the surface and subsurface constraints to hydrogen storage development.



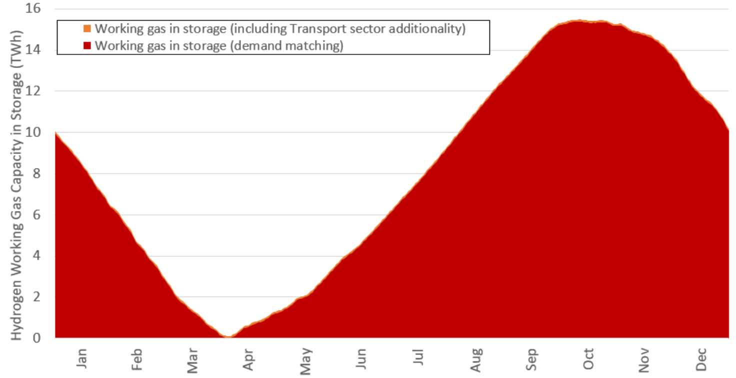


Figure 12: Minimum daily hydrogen working gas capacity requirement in storage (a) low hydrogen demand scenario above (b) high hydrogen demand scenario below – Additional demand for transport in orange is very small and so challenging to see when plotted to scale.

Conclusions: Hydrogen Storage Demand Modelling for the East Coast Cluster

The 6.2 – 16.0 TWh hydrogen storage requirement in 2050 highlights the significant opportunity for storage site developers and investors to focus efforts within the East Coast region. Storage projects can support up to 10.8 GW of announced low-carbon hydrogen production capacity by 2030.

The hydrogen storage demands estimated in this work package highlight the critical need for localised strategic planning and policy-led interventions to drive hydrogen storage infrastructure investment. Low-carbon hydrogen will play a crucial role in the UK. However, uncertainty remains around the scale and speed of uptake of demand across the industry, heat, power generation and transport sectors. This uncertainty creates high risk for first-mover hydrogen storage projects, making it difficult for storage site developers and investors to focus efforts. The study was localised to the East Coast, a region of key hydrogen activity and with an abundance of suitable salt basins for salt cavern development. This makes the East Coast a relatively low-risk region for initial hydrogen storage investment, with constraints facing the development of salt cavern capacity explored in WP2. In combination with WP2 outcomes, the following insights underpin the WP3 strategic case for hydrogen storage investment which aims to remove market barriers and improve investor confidence.

- High forecasted hydrogen demands highlight the need for hydrogen storage to improve energy system resilience.

The base case estimates that 6.2 – 15.5 TWh of WGC hydrogen storage demand is required to support the total aggregated sectoral hydrogen demand of 19.5 – 78.7 TWh for the East Coast alone in 2050. The UK has relatively low quantities of natural gas storage (approximately 16 TWh in salt caverns [19]*) so it will be challenging to convert natural gas caverns to hydrogen in the near term, given the importance of security of energy supply. Hydrogen salt cavern storage is proven in the UK at Teesside, but capacities are mall, approximately 25 GWh. Given newly developed salt cavern sites can have development lead times of up to 15 years, accelerated development is critical and there is a need to act now.

- The use of hydrogen in the heat and power sectors are the greatest drivers of hydrogen storage demand.

Despite industry forecasted to have the greatest hydrogen demand across all sectors, the heat and power sectors are observed to have a greater influence on hydrogen storage capacity requirements due to their highly variable and inter-seasonal demand profiles. In the low hydrogen demand scenario, the power sector is forecasted to account for around 83.4% of the 6.2 TWh hydrogen storage demand in 2050 despite having a similar hydrogen demand to the industry sector. In the high hydrogen demand scenario, the heat sector is forecasted to require around 52.1% of the 16.0 TWh hydrogen storage demand in 2050, aligning with a government decision in favour of hydrogen for heating in 2026.

- Medium-term government targets are driving a large hydrogen storage demand in 2035.

The analysis localises UK-wide government targets to the East Coast, such as decarbonising the heat sector by assuming the same uptake of hydrogen boilers and heat pumps in the heat and power sector analyses in the East Coast as UK wide. Hydrogen storage demands become significant in 2035 as the variable demand of these sectors begins to ramp up significantly. This is driven by modelling assuming key UK government targets are met in 2035; a decarbonised electricity grid, and 1.9 million heat pump installations per year [20]. This will see significant portions of the inter-seasonal swing in residential heating shifted from the gas network to the electricity network, consequently increasing requirements for storage to balance a future power sector, than is unable to rely on unabated CCGT generation for flexibility.

Forecast Year	Industry	Heat	Power Generation	Transport	Total
Low hydrogen demand scenario – Demand, TWh [proportion of demand (%)]					
2030	7.1 [40.5%]	0.0 [0.0%]	2.1 [59.6%]	0.0 [0.0%]	9.2
2035	9.9 [26.8%]	0.0 [0.0%]	5.5 [73.2%]	0.0 [0.0%]	15.4
2050	9.9 [16.6%]	0.0 [0.0%]	10.2 [83.4%]	0.0 [0.0%]	20.1
High hydrogen demand scenario					
2030	11.2 [55.8%]	1.1 [11.9%]	1.3 [32.2%]	0.0 [0.01%]	13.5
2035	21.8 [26.6%]	20.4 [56.4%]	2.8 [16.7%]	0.03 [0.3%]	45.0
2050	37.3 [23.9%]	35.8 [52.1%]	7.5 [23.4%]	0.1 [0.6%]	80.7

Table 5: Summary of forecasted sectoral hydrogen demands (TWh) for the East Coast region [with illustrative hydrogen storage demand proportions highlighted].

Forecast Scenario	2030	2035	2050
Base case	1.8 – 2.0	3.8 – 8.4	6.2 – 16.0
Hydrogen storage to support the Southeast of England	n/a	7.0 – 16.6	14 – 32.3
Oversizing production	1.3 – 1.4	3.2 – 6.2	5.4 – 12.0
Seasonality of hydrogen production	1.5 – 1.6	3.4 – 7.0	5.6 – 13.4

Table 6: Summary of forecasted hydrogen storage demands (TWh) for the East Coast region, including base case and sensitivity analysis scenarios. *When converting natural gas salt caverns to hydrogen, hydrogen will only have 25 to 30% the storage capacity, depending on storage pressure, due to a lower volumetric energy density.

Research Outputs:

Capacity Modelling in the East Coast Cluster

Executive Summary

A spatial analysis has been undertaken to determine a revised hydrogen storage potential of salt caverns in the East Coast region. It combines geographical occurrence of halite-bearing strata with land-based constraints to development. The methodology can be easily replicated to better understand the hydrogen storage potential in salt caverns across other key regions.

This work package provides a storage capacity assessment of salt caverns in the onshore East Coast Region by developing:

- A comprehensive theoretical storage volume, referred to as "resource potential" (Figure B1), accounting for geological and some social and environmental limitations.
- A dynamic multi-criteria assessment of viable host geology and above-ground constraints provided as an interactive tool to support decision making by developers, end-users and offtakers.

The purpose of this study is to the appraise and integrate existing public datasets to develop an estimate of the resource potential. The aim is to better inform decision makers on the ability of the East Coast region to meet future storage demand and challenge current assumptions on the timescales to deploy salt cavern storage.

Below-ground and above-ground constraints are integrated through spatial mapping techniques to derive revised storage estimates. Boulby Halite Formation and Fordon Evaporite Formation provide the host geology for salt cavern development in the East Coast region. The extent, purity, thickness and depth of these halite formations govern the size and scale of energy storage.

Above-ground constraints which limit surface development include existing and planned civil, social and industrial land use and environmentally sensitive sites.

A dynamic, spatially-driven model enables the user to visualize and analyse this data, allowing a weighted multi-criteria assessment of feasible host geology and above-ground constraints.

It is found that current assumptions on resource capacity of salt caverns for hydrogen storage are many levels removed from the feasible workable storage volume i.e., realisable potential. Existing published work [B1][B2] has appraised only the reserve potential of salt cavern storage in the East Coast region. This study has rationalised previous work to a resource potential by refining development requirements and development constraints.

In doing, this study has reduced the previous best estimates of storage capacity by c.95%. Storage capacity in the East Coast region is still significant, at least 22 TWh, however, significant barriers exist which limit the ability to deploy salt cavern storage to realise storage potential by 2050. These barriers include timescales for developing and commissioning new salt cavern storage assets at the scale which is required; approximately 1000 caverns are required to achieve 22 TWh of storage.

The analysis can be easily replicated for other UK saltfields to understand potential storage capacity and development considerations.

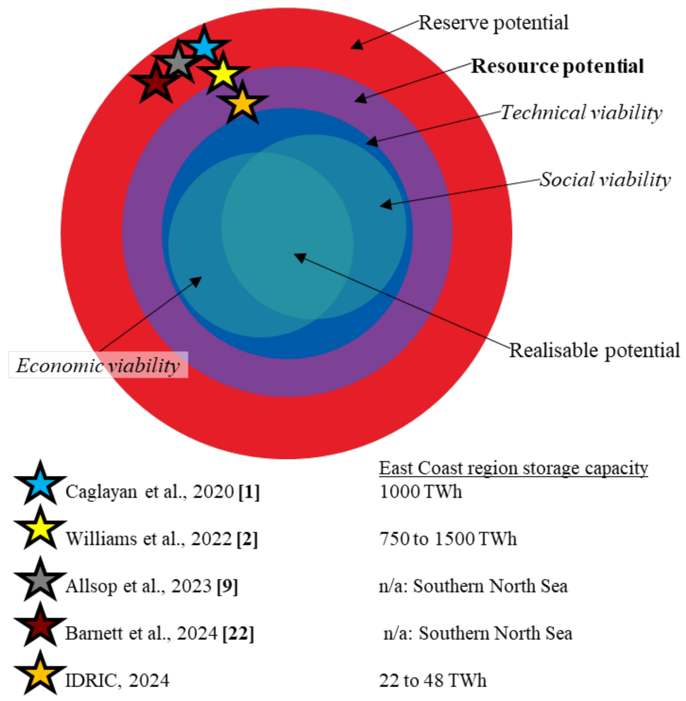


Figure 13. Concept of "potential", adapted from [B1][B3]. Where "realisable potential" is the refinement of "resource potential" based on technical, social and economic viability. Annotated are published studies of East Coast region storage capacity [B1][B2].

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Literature Review: UK East Coast region saltfield storage capacity

A number of studies have been published which have estimated the salt cavern storage potential of the UK and East Coast region.

Host geology

Storage in the East Coast region is focussed on two halite-bearing formations, Boulby Halite (BHF) and Fordon Evaporite Formation (FEH) and are both currently utilised for small scale natural gas and hydrogen storage. Evans and Holloway (2009) [26] and ETI & Foster-Wheeler (2013) [27] indicate that both salt formations have potential for storage cavern development for hydrogen. The BHF has been mined at Teesside where it is typically between 350 m and 650 m deep and between 30 m to 50 m thick. The FEH occurs below the BHF, separated by 10’s m of non-halite beds, and is typically between 1200 m and 1900 m depth and between 150 m to 200 m thick.

Cavern depth

There is a recognised sweet spot between 600 m and 1700 m depth for locating gas storage caverns (Figure 14; [24]). Storing gas at depth benefits from high lithostatic pressures, however caverns which are too deep may suffer from costly development, operation and maintenance costs, including balancing the pressure differential between surface infrastructure (pipeline) and storage caverns, and may suffer from salt creep (volume loss).

Existing capacity assessments

Storage capacities have previously been assessed for onshore UK: Caglayan et al. [21] suggests total capacity is around 1000 TWh, and most recently, Williams et al. [22] indicates a “potential capacity” of up to c. 2100 TWh. The latter goes on to conclude that the East Coast region provides the majority of the UK’s capacity, accounting for c. 1500 TWh (Table 7).

Figure 15 presents a map which indicates variability in storage capacity across the region.

The most recent assessment [22] accounts for storage in the Fordon Evaporite Formation only, and where viable thickness of it occurs, cavern locations have been screened out based on proximity to the following:

- Surface infrastructure, including roads, railways and urban settings
- Environmentally sensitive areas
- Geographic features including waterways and coastlines
- Wet rockhead (where halite is present at rockhead)
- Geological faults

Cavern pillar widths were assumed to be no less than 3x maximum cavern radius and a spatial buffer of 150 m was applied to all spatial features.

The study undertaken in this work package presents a continuation of the research from Williams et al. [22], by challenging the assumptions and further refinement of development sites, geological and surface constraints.

In addition to providing a refined energy capacity assessment across the East Coast region, this study evaluates the relative “attractiveness” of a development site based on the perceived criticality of multiple criteria. It is the ambition of this study that both aspects can be iterated over to establish realistic salt cavern development opportunities.

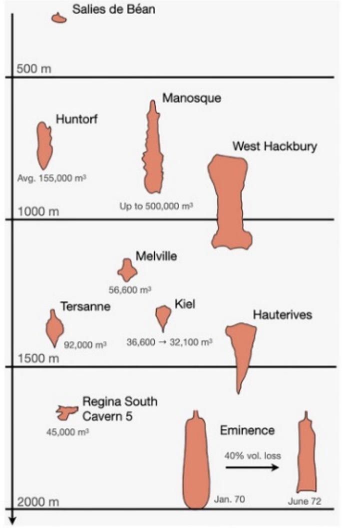


Figure 14: Distribution of salt caverns used for gas storage around the world. [24]

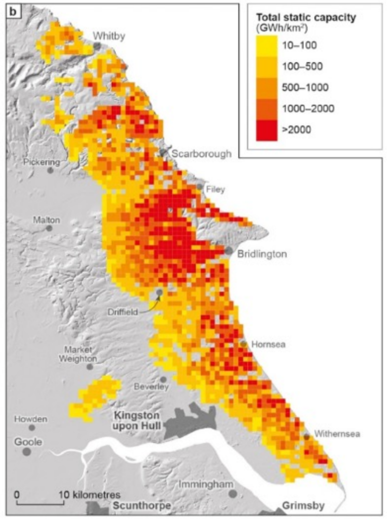


Figure 15: Total static capacity of hydrogen in salt caverns in East Yorkshire. [22]

Theoretical H_2 storage potential in new dedicated caverns (TWh)			
Cheshire	East Yorkshire	Wessex	UK Capacity
128.8	1464.9	556.6	2150

Table 7: Theoretical salt cavern storage capacity. [22]

Methodology: Overarching Approach

A comprehensive site selection methodology has been established to derive storage "resource potential".
It is based on previous publications and accounts for subsurface and surface constraints for cavern development.
Spatial analysis underpins the identification and evaluation of suitable development sites.

A summary of the methodology and approach is provided below:

Model pre-requisites and development

Geological model development ●

- Identification and characterisation of salt formations.
- Geo-referencing of ground data.
- Digitalisation and rasterisation of ground model (extent, thickness and depth).
- Scoring of rasters based on sub-surface constraints.

Surface criteria assessment ●

- Identification of datasets relevant to constrain surface development.
- Establishment of exclusion and evaluation criteria.
- Rasterisation of datasets and scoring of rasters based on proximity to surface constraints.
- Mapping of rasters to hexagonal grid.

Geometrical assessment ●

- Geometrical configuration of cavern by deriving viable height and diameter of cavern. Consideration of geometrical differences for wet and dry operated caverns.
- Cavern placement based on assumptions of cavern spacing.

Site selection

Multi-criteria assessment ●

- Exclude hexagons from hexagonal grid based on surface constraints and geological model (i.e., geological viability of cavern development).
- (Optional: Evaluate the score of selected hexagons against the evaluation criteria and determine most attractive sites to develop.)

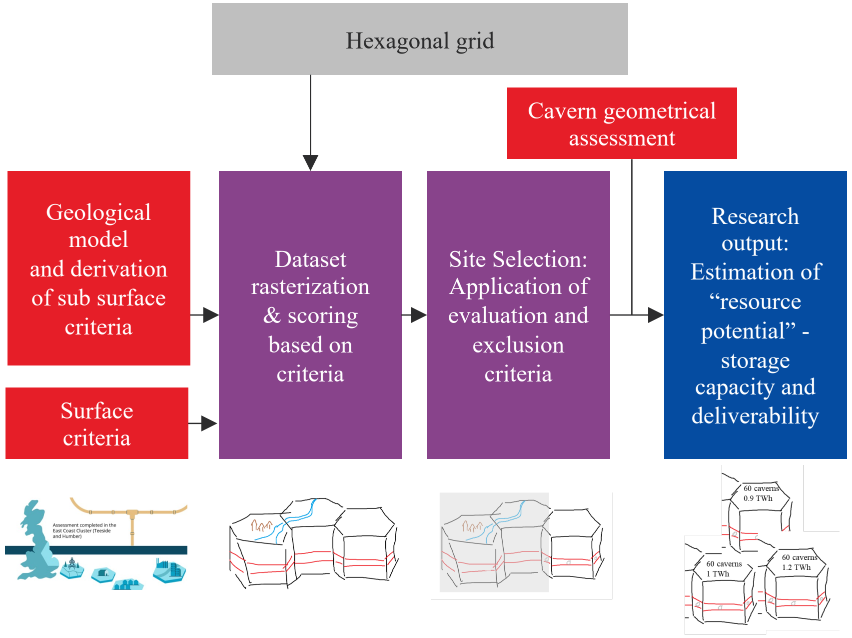
Research output ●

Storage cavern capacity, deliverability and estimated development programme

- Calculate the resultant energy capacity and flow rate for the selected development sites.
- Approximate the development programme to commission caverns to achieve the desired energy capacity.

Assumptions adopted throughout the study and limitations and opportunities for the future stages of analysis are provided in subsequent sections.

East Coast storage capacity development
(click each box to navigate to relevant section)



Key Findings: Capacity

A "resource potential" for hydrogen storage in salt caverns has been determined for the East Coast region. The storage potential ranges from 22 TWh to 48 TWh, up to 95% lower than previous estimates.

WP2 estimates the theoretical resource potential for storage to be at least 22 TWh, equivalent to c.1000 caverns of 20 m radius (Table 8).

Table 9 compares key parameters from the peer-reviewed publication by Williams et al (2022) [22] to this study and the results are compared in Table 10.

A key differentiator between the studies include:

- The evaluation of the Fordon Evaporite Formation for salt cavern development. In this study only the halite member has been identified as suitable for salt caverns, typically up to 100 m thick, in contrast to the assumption from Williams et al., that most of the (up to) 300 m thickness of Fordon Evaporites could be exploited.
- This study assumes a uniform cavern radius of 20 m, in comparison to Williams et al. [22], which assumes a cavern radius of 50 m.
- The assessment of storage capacity is undertaken on a grid basis, where each grid is approximately 2.5 km2. This removes the possibility of having isolated single caverns prone to becoming "stranded assets".
- Note that as highlighted in the methodology, both studies have employed similar logic to assessing the impact of surface constraints and excludes any development site which intersects the exclusion zone of a mapped constraint.

Storage capacity findings from this study are an order of magnitude lower than previously determined; 750 TWh compared to a revised estimate of 22 TWh. From an assessment of the viable regions in the UK for salt cavern storage of hydrogen, Williams et al. [22], estimates that the UK East Coast region represents approximately 70% of the UK's storage capacity. The findings of this study can be extrapolated to derive an approximation of the UK's total revised resource potential for salt cavern storage of approximately 35 TWh, which is provided in Table 10.

Mean deliverability of hydrogen per cavern has also been calculated as part of this study. A mean withdrawal rate of 1.2 GWh/ day per cavern is provided in Table B6 and represents the rate as limited by a 10 bar/ day pressure drop inside the storage cavern [28][29][30][31]. Note that the delivery rate is unlikely to scale linearly for many caverns; for a cavern cluster (10 – 20 caverns) the rate will largely be limited by topside infrastructure such as decompressors and dehydrators.

This study has co-developed an interactive site selection tool for the development of a salt cavern facility (a cluster of salt caverns).

A sensitivity analysis on the overall capacity of a selected site can be undertaken by altering:

- Cavern radius
- Cavern pillar width
- Withdrawal rate

	Resource potential of salt cavern storage	Caverns required to be developed	Mean deliverability rate per cavern
3 x cavern radius	48 TWh	2200	1.2 GWh/ day
5 x cavern radius	22 TWh	1000	

Table 8: IDRIC estimate for salt cavern storage capacity and deliverability.

	Williams et al., 2022	IDRIC Study, 2024
Cavern casing shoe depth [m]	747 – 1800	650 – 1800
Cavern height [m]	20 – 300	Up to 88
Cavern operating pressure [MPa]	14 – 34	12 - 32
Working hydrogen mass range [te]	486 – 13239	700 - 1500
Equivalent energy storage range [GWh]	16 - 441	23 – 49

Table 9: Key parameters for modelled caverns. Williams et al., [22] uses R=50m; IDRIC Study uses R=20m.

	Williams et al., 2022		IDRIC Study, 2024	
	East Coast Region	UK Capacity	East Coast Region	UK Capacity
3 x cavern radius	1500 TWh	2150 TWh	48 TWh	68 TWh
5 x cavern radius	750 TWh	1100 TWh	22 TWh	35 TWh

Table 10: IDRIC estimate of salt cavern storage in comparison to Williams et al. [22]

Key Findings: Programme

Development timescales for caverns are long and will require a robust supply chain and concurrent development of cavern clusters to realise the storage capacity potential by 2050.

A literature review supports the general understanding that it can take around 15 years to develop one cavern facility (nominally up to 20 caverns) (Figure 16), assuming there is an accepting local population, a robust, mature and available supply chain and a mature and efficient pathway through regulations and permitting.

This study has found that a lower-end resource potential of 22 TWh of storage capacity could be achieved in the East Coast region. The figure assumes a uniform cavern radius of 20 m and cavern to cavern pillar width of 5x cavern radius.

Due largely to geological constraints, notably the form of the bedded halite, approximately 1000 caverns are required to achieve 22 TWh and 2200 caverns for 48 TWh of storage capacity.

This is in agreement with literature estimates from Williams et al., [22] and The Royal Society [32], which estimate that 3000 caverns are required to achieve up to 100 TWh.

The findings therefore indicate that to achieve an additional 22 TWh of storage capacity in salt caverns by 2050 (in 25 years), 50 cavern clusters of 20 caverns each will need to be constructed. Many cavern clusters will also need to be developed concurrently to achieve the storage capacity by 2050. The challenge becomes greater for any larger storage capacity requirement.

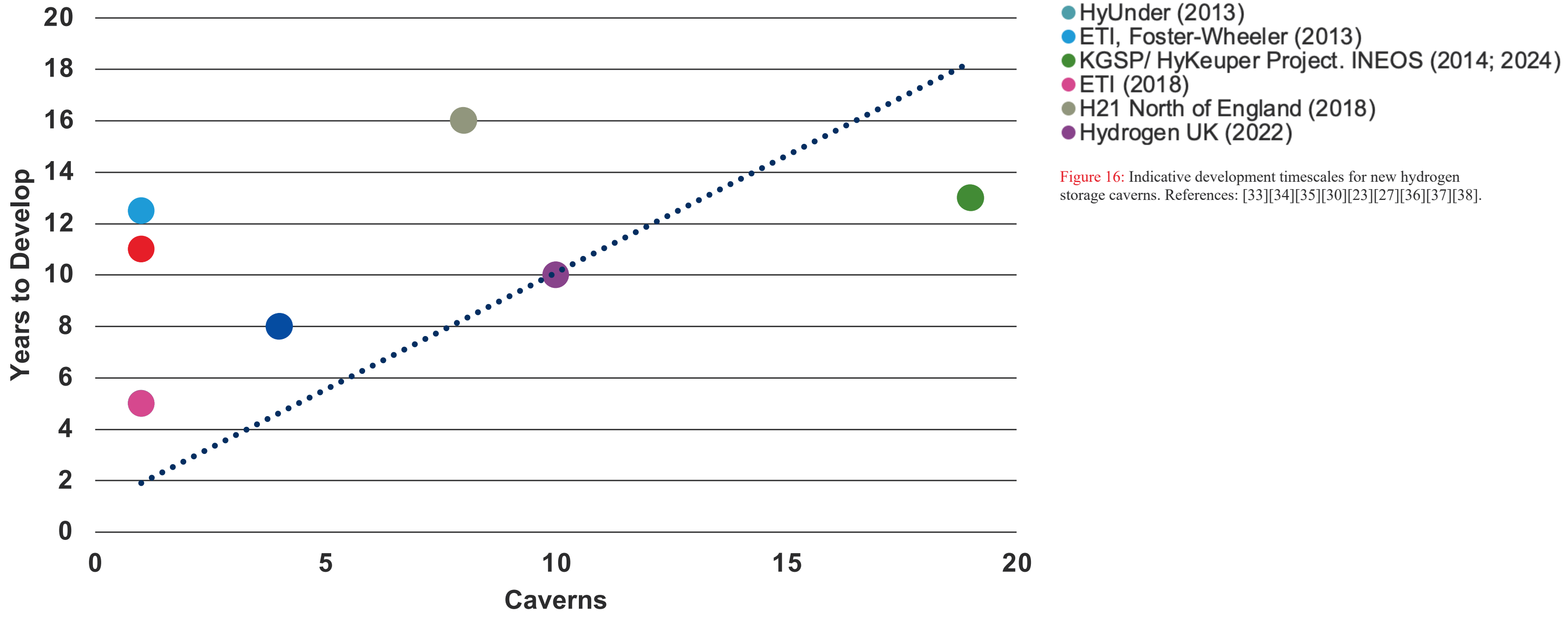


Figure 16: Indicative development timescales for new hydrogen storage caverns. References: [33][34][35][30][23][27][36][37][38].

Key development activities and approximate duration for the development of a single cavern are provided below:

1. Site selection & consultations | 1.5 – 2 years
2. Planning & permitting | 1.5 – 2 years
3. Detailed design & procurement | 2 to 2.5 years
4. Construction & commissioning | 2 to 3.5 years

Note that for the development of a cavern cluster the programme will largely benefit from optimised phasing of "Detailed design & procurement" and "Construction & commissioning" activities for multiple caverns e.g., phased development of 3 to 5 caverns at a time, which benefits from already mobilised resources such as solution mining equipment.

Conclusion: Current assumptions around capacity of caverns are overstated and the ability to deploy within the required timeframe is challenging

Current assumptions on resource capacity of salt caverns for hydrogen storage are many levels removed from the feasible workable storage volume; this study has rationalised the workable volume towards a "realisable potential" and in doing so has reduced the previous best estimates of storage capacity by c.95%. Storage capacity is still large, at least 22 TWh, however, significant barriers exist which limit the ability to deploy salt cavern storage to realise storage potential by 2050.

Salt caverns for hydrogen storage is a mature technology (TRL Stage 9) having existed in the UK for over 50 years, albeit at relatively small scale compared to future requirements by 2035 and 2050.

Current rhetoric from national policy documents and published literature assumes that large-scale hydrogen storage in salt caverns is readily available within the timescales for the Net Zero pathway.

The purpose of this study is to challenge the current assumptions and begin to rationalise the theoretical onshore storage capacity in the East Coast region towards a realisable potential.

This study finds that a resource potential (Figure B20) estimate of storage capacity is between 22 TWh and 48 TWh, based on the following assumptions on constraints:

- Development is specific to the Fordon Evaporite Formation only.
- A uniform cavern radius of 20 m.
- Development cannot occur within any defined surface constraint boundary.

An adequate estimation of realisable potential will require additional consideration of technical, social and economic viability, and is beyond the scope of this study but is recommended for future research.

Development of salt cavern storage is found to be strongly limited by:

- Geographical and geological limitations of the halite-bearing strata, and surface and subsurface constraints.
- The time required to develop at scale, including inefficiencies of a nascent supply chain.
- The location of suitable salt deposits in relation to the producers and end-users.

Three principal conclusions have been drawn from this work package:

1. Not all salt can host large caverns

The UK is host to bedded halite, typically limited to formations of interbedded halite and non-halite up to 300 m thick. Note that once allowances are made for suitable thicknesses of halite above and below the cavern, and presence of impurities/ non-halite geology within the formation, the thickness of workable halite is a fraction of the overall formation thickness.

For example, in the Netherlands, salt caverns are located in a salt diapir up to 1500 m thick. Owing to the geological nature there is a higher halite purity, and owing to its thickness caverns have been constructed to larger sizes and volumes than in the UK.

Therefore, many more caverns are required to be constructed in bedded halite to achieve the same storage capacity and deliverability rate. To achieve up to 22 TWh of hydrogen storage, c.1000 caverns are required to be constructed.

2. Operational capacity of the salt cavern is often overlooked and not considered

Volume capacity and rate of withdrawal of hydrogen from the storage vessel, is critical for end-users and offtakers.

Rate of withdrawal is constrained by stability requirements in the salt cavern, this differs depending on the operation mode (wet vs dry) of the salt cavern.

This study has incorporated an approximation of total deliverability, which can be used to support the developer's analysis on how storage and supply requirements can be met.

3. Salt cavern development timeline is long and challenging

For example, to achieve the lower-end storage potential identified in this study of 22 TWh, c.1000 new caverns are required. Based on a comprehensive literature review and stakeholder engagement, it is estimated that the delivery programme to deliver cavern clusters of 10-20 caverns is approximately 15 years.

To achieve this storage capability in the East Coast region before 2050, multiple concurrent developments (up to 50) are required. This assumes the supply chain is mature and has sufficient capacity.

Conclusion: Current assumptions around capacity of caverns are overstated and the ability to deploy within the required timeframe is challenging

Current assumptions on resource capacity of salt caverns for hydrogen storage are many levels removed from the feasible workable storage volume; this study has rationalised the workable volume towards a "realisable potential" and in doing so has reduced the previous best estimates of storage capacity by c.95%. Storage capacity is still large, at least 22 TWh, however, significant barriers exist which limit the ability to deploy salt cavern storage to realise storage potential by 2050.

Case Example: HyKeuper, Cheshire

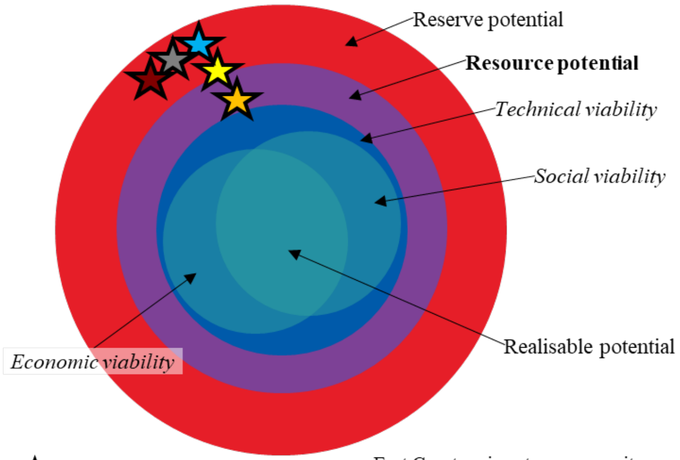
Development of 19 new hydrogen storage caverns, providing 1.3 TWh energy storage and up to 6 GW power deliverability.

The project is adjacent to current gas storage sites, hence represents an optimist case example given public acceptance and well understood ground conditions and mature FEED plans.

Nevertheless, pre-construction lead in-time, accounting for activities for planning application submission (DCO) was 3 years. Construction to commissioning of all 19 caverns is forecast to run over 10 years, hence 13 years from inception to delivery.

Key limitations to the scale of development (i.e., 19 caverns) include water availability for solution mining, brine discharge limits and dispersal rates, material and skill availability for topside development and well construction.

For a new cavern cluster in a greenfield site, the development timeline is anticipated to be much longer, largely due to protracted pre-planning and construction activities. If many cavern clusters are concurrently developed in the UK, there is likely to be a significant constraint on material and skill availability which is controlled by national and international market conditions.



	East Coast region storage capacity
Caglayan et al., 2020 **[1]**	1000 TWh
Williams et al., 2022 **[2]**	750 to 1500 TWh
Allsop et al., 2023 **[9]**	n/a: Southern North Sea
Barnett et al., 2024 **[22]**	n/a: Southern North Sea
IDRIC, 2024	22 to 48 TWh

Figure 13. Concept of "potential", adapted from [21][23]. Where "realisable potential" is the refinement of "resource potential" based on technical, social and economic viability.

Given the challenges facing the development and commissioning of adequate salt cavern storage for the UK's Net Zero ambitions, it is clear that there is a need for a diverse portfolio of energy storage options. Included in this will be salt caverns, alongside lined rock caverns, depleted oil and gas fields and saline aquifers.

Conclusion: Salt Cavern Capacity & Development Appraisal Tool

A new tool allows the user to estimate salt cavern storage potential and development programme for selected sites in the East Coast region.

Purpose

This study has co-developed an interactive site selection tool for the development of a salt cavern facility (a cluster of salt caverns).

The tool allows the user to identify suitable sites for development (hexagonal grids) based on a suite of constraining criteria. Storage capacity and deliverability is calculated for the sites and an indicative development programme can be reviewed.

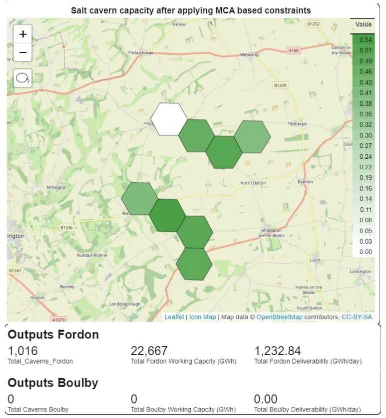
User control

- The user can influence the relative rank of each site for development by reviewing a comprehensive set of constraining criteria. It includes spatial occurrence of halite-bearing geology (in plan extent and depth), and land-based features which may hinder surface and subsurface development. The lower the rank, the poorer the hexagon scores and the least attractive it is as a site for salt cavern development e.g., this may be due to close proximity to existing infrastructure or sensitive natural environments.
- The user also has control on which halite-bearing geology to develop e.g., Boubly Halite and/ or Fordon Evaporite Formation, the radius and spacing of the caverns.
- An indicative programme is provided which the user can adopt based on the perceived timescale for each activity from pre-planning to commissioning.

The 'Hydrogen Storage Salt Cavern Development & Capacity Tool – East Coast Region' online platform and user manual are provided at the links below:

- Online Platform / User Manual

a) Selected development sites



b) Total development time required (years)

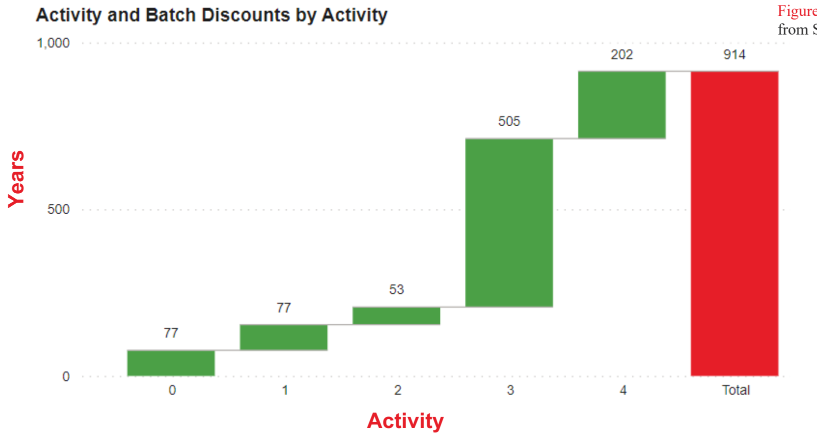
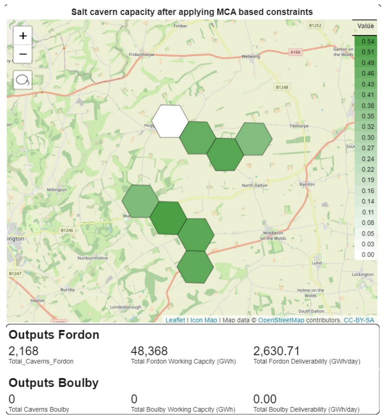


Figure 17. Lower end capacity estimate – extract from Salt Cavern Capacity & Development tool.

a) Selected development sites



b) Total development time required (years)

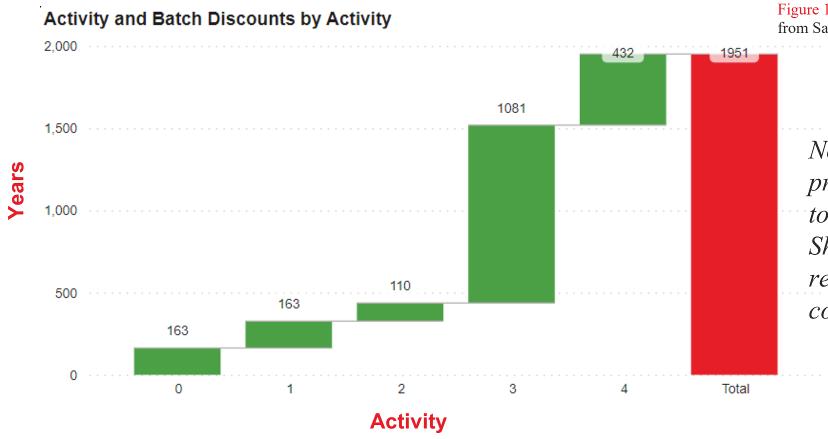


Figure 18. Upper end capacity estimate – extract from Salt Cavern Capacity & Development tool.

Note, the tool is in the process of being migrated to a publicly accessible SharePoint site; links in report to be updated once complete.

Section 5:

Market Barriers

Nascent Nature of Hydrogen Economy

There is uncertainty regarding how hydrogen storage will fit within the future Net Zero energy system, and consequently how much storage will be needed and the optimum mix of storage technologies. Without a clear end goal, it is difficult for a forward pathway to be defined.

While the overarching deliverable of Net Zero is clear, the exact makeup of the future decarbonised energy system is still in development. Therefore, there is uncertainty regarding what role hydrogen will play, and what percentage of our overall energy demand it will contribute. The challenge for the growth of the hydrogen economy is that it is inherently difficult to build a market around an uncertain demand. Hydrogen storage is a key component of the wider system architecture of the hydrogen network and is therefore impacted by this challenge, which the UK Government acknowledged in their minded to response to their consultation on business model designs and regulatory arrangements for hydrogen transport and storage infrastructure [4]:

'Understanding the mix of storage technologies required and the optimum pace of development [is a challenge]. Since the hydrogen economy is nascent, there is uncertainty around how and when demand for hydrogen storage will grow, what type of storage infrastructure will be needed in which locations, and the role it might play in providing energy security and resilience.'

This has the following impacts:

- Disjointed value chain: The complex ecosystem of the hydrogen economy is made up of 4 key components (Production, Storage, Supply & Distribution, and End Use) that represent dozens of stakeholders; see Figure 19 for a visual representation of the hydrogen economy and where storage sits within it. Without clarity of the future of the market, there can be hesitancy for stakeholders to make commitments and partnerships. There is risk in 'taking the first step' in a nascent market.

In the past few years, the UK Government has acknowledged the importance of its involvement in the nascent hydrogen economy, taking significant steps in rolling out the Hydrogen Production Business Model (HPBM) and announcing the first successful projects from its Hydrogen Allocation Round 1 (HAR1). While these are important steps, they do not go far enough in relieving the market uncertainty to support the significant uptick needed for the hydrogen economy to develop at the scale needed in the next decade. Notably, much of the involvement from the Government thus far has been to support or provide structure for other parts of the hydrogen market value chain.

'The new [Hydrogen Transport & Storage] business models will establish the principles of UK Government's support for hydrogen T&S projects. It is critical that the new business models provide the right incentives for investment.' [4]

While valuable, more focus needs to be put on hydrogen storage itself, which is potentially the longest lead item of the network (if salt caverns are used) - therefor actions is needed now.

East Coast Hydrogen is a consortium made up of stakeholders throughout the hydrogen value chain, with the ambition to create a hydrogen network utilising natural gas pipework throughout the East Coast region. In their East Coast Hydrogen Delivery Plan [13], they stressed the importance of establishing the structure needed in the hydrogen storage market:

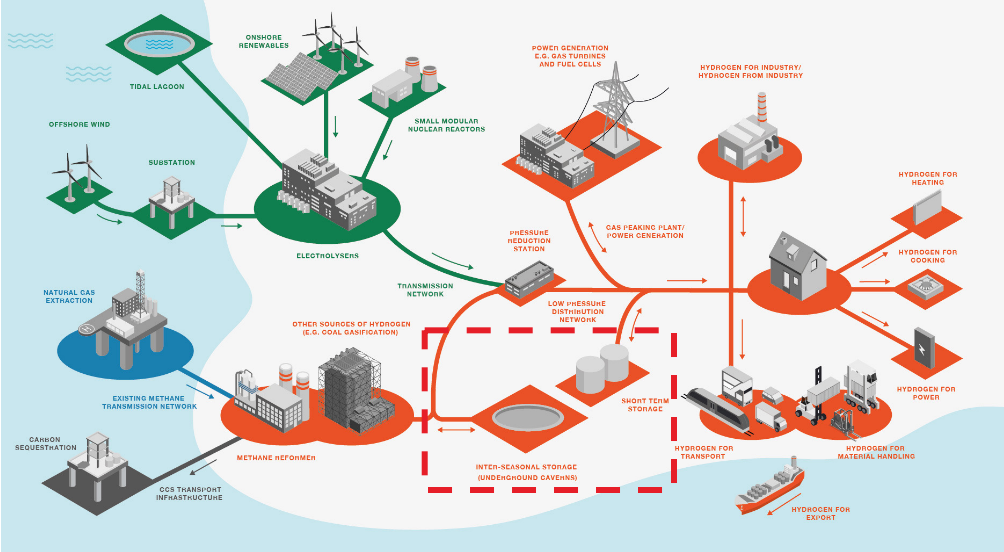


Figure 2: Establishing A Hydrogen Economy - The Future of Energy 2035.
Source: Establishing a Hydrogen Economy, Arup [2]

Ability to deploy salt cavern storage at pace

Large salt cavern storage facilities can take over a decade to build, and are required to follow a complex development process, including permitting, planning and consenting. Given these lead times, projects will need to be developed in parallel, increasing capex and putting strain on supply chains.

The current preferred option for storing hydrogen at scale is in salt caverns, in large part due to this being the only storage solution that currently meets the technology maturity level requirements (TRL 7) of the UK Government's Hydrogen Storage Business Model. However, while this report shows that there is a potential for 25-48 TWh of salt cavern storage for the East Coast region, capacity is not the only constraint that needs to be considered.

Constraint - Length of project development: It is well established that infrastructure projects, from rail to highways to wind farms, take a significant amount of time from conception to commissioning. This is due to myriad factors, notably that infrastructure projects involve a long series of dependent activities from public engagement to site selection to detailed design, all before shovels are put in the ground. See Figure 19, a high-level schedule for a typical project in this field, spanning a minimum of 8 years. According to the Energy Technologies Institute, 'the estimated duration…from the start of exploration and planning activities through to a fully functional storage cavern is 10 years.', [39] and can extend up to 15 years for a cavern cluster of c. 20 caverns in an established gas storage region [40].

Constraint - Flexibility/Strength of Supply Chain: Delivering multiple projects of a similar nature and timeframe within a single region, would strain even a mature supply chain. The supply chain for salt cavern storage is relatively young and untested with regards to delivering at the scale this report has defined is necessary within the next two decades.

Constraint – Capital Expenditure (CAPEX) costs: Noting commercial sensitivities and the large range of estimated costs for large-scale salt cavern storage, it is widely acknowledged that salt cavern storage requires significant up-front funding (CAPEX). These investment costs are then impacted by the other constraints, increasing due to shifting project timelines or procurement issues.

Constraint – Decarbonisation Targets: Finally, the overarching constraint in this market is the decarbonisation targets outlined by the UK Govt for 2030, 2035 and 2050. While we can shorten project development timelines, strengthen supply chain and take additional measures, the deadlines are fixed, as they fit into a wider global picture. The UK has ≈6, 11, and 26 years, respectively, to hit those goals.

Project Delivery Needed by 2035 and 2050

There is currently 0.025 TWh amount of working salt cavern storage in the East Coast region. There are 2 projects in advance stages of planning which will deliver an additional national capacity of 1 – 1.5 TWh storage by roughly 2030.

By 2035: With demand increasing to 3.8 – 8.4 TWh (as this report has shown) that leaves a deficit of at least ≈2.3 TWh of storage to build in 11 years, to meet the low end of demand. Based on the salt cavern capacity assumptions used in Appendix 2's research, ≈100 caverns are needed to deliver this deficit. Assuming a typical facility of 10-20 caverns, at least x5 salt cavern facilities need to be simultaneously delivered within the next 11 years, with immediate deployment.

By 2050: Beyond 2035, this report shows that demand increases to 6.2 – 16 TWh by 2050, indicating an additional ≈ 2.4 TWh of capacity needed to meet the low end of demand. In other words, an additional 110 caverns and a further x6 simultaneous facilities to be delivered in the following 15 years. This represents a total of 10+ projects delivered over the next 25 years just to meet the lowest end of the storage requirements scale.

It is important to note that this represents the least amount of project delivery needed, to meet the low end of demand. If using the high end of demand, x15 facilities need to be built by 2035 and an additional x25 facilities by 2050.

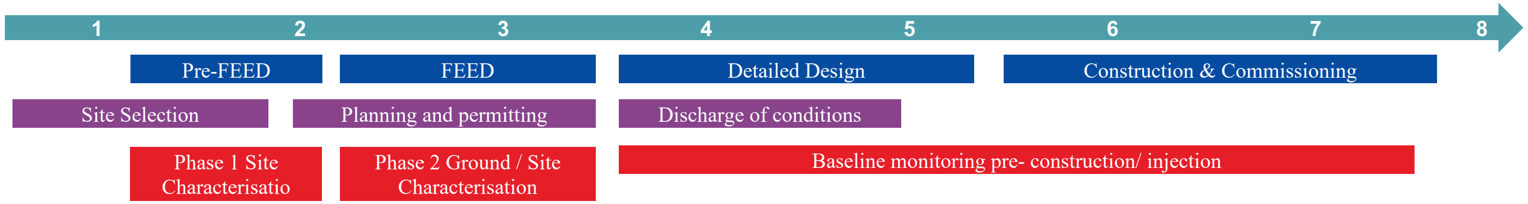


Figure 19: Development timeline for a typical infrastructure project, similar to that of a salt cavern facility.

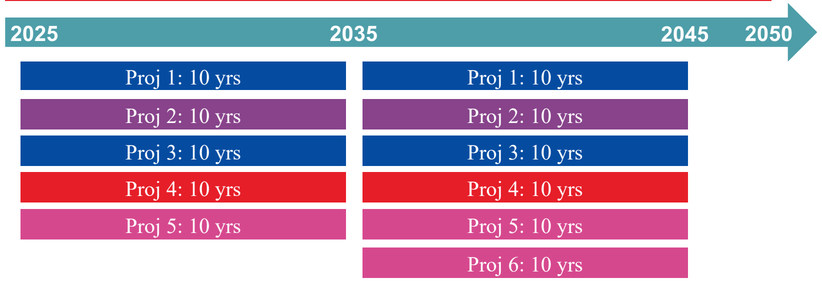


Figure 20: Concurrent projects needed to deliver low end of demand.

Lack of a detailed and coherent regulatory framework for hydrogen storage

Hydrogen storage is a critical component within the hydrogen economy and will require significant levels of up-front investment, far ahead of demand, to meet development timeframes. Lack of a clear regulatory framework is a barrier to economic investment and challenges timescales.

Hydrogen storage projects have a significant development timeframe, in part due to the planning, permitting, and licensing requirements. Projects of this scale and impact need to work within a regulatory framework structured by the government to ensure best practice and market equity. However, when there is not a clear 'set of rules' guiding projects in a particular sector, significant challenges arise:

- Increased cost and uncertainty for private sector actors
- Uncertainty in key factors such as operational requirements or safety practices drives up insurance costs
- Longer lead times as projects move through untested processes
- Low-levels of public acceptability, reducing confidence in the projects or technologies

Effectively, if it is not clear what set of requirements need to be followed, projects will take longer and cost more, compounding the other market barriers that have been noted, and disincentivizing investment. The UK Government acknowledged that the hydrogen network is facing these exact challenges, in their consultation on business model designs and regulatory arrangements for hydrogen transport and storage infrastructure, '…lengthy development lead times, high capital costs and uncertain financial investment returns in a nascent market mean this [transport & storage] infrastructure is unlikely to materialise without a supportive policy framework.'

At present, there is little legislation that applies specifically to hydrogen. As hydrogen falls under the category of 'gas' per the 1986 Gas Act, it sits within the same legislative landscape as other gases. In the Government's minded to position following the consultation, it agreed with the clear response from industry that the current economic and non-economic regulatory framework is restrictive at best.

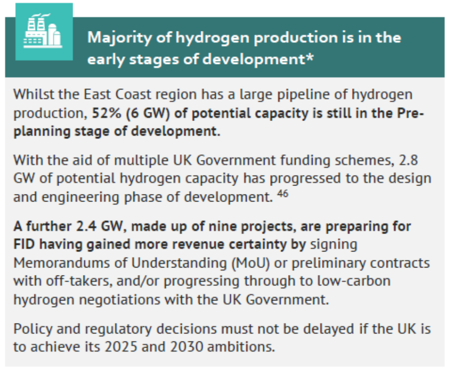
In their consultation response, the industry stressed that this current framework is …'suboptimal for supporting the development of hydrogen transportation and/or storage infrastructure'. [4].

Figure 21, from East Coast Hydrogen's recent strategic planning document, East Coast Hydrogen Delivery Plan [13], notes the number of projects already preparing for Financial Investment Decision (FID) and progressing through development. The report notes the criticality of policy and regulatory decisions to ensure these projects remain on track. This is reflected across the hydrogen network, where the number of projects is rising quickly to connect the producers to the end users to meet demand in coming years. With its long lead times, hydrogen storage projects lie on the Critical Path of the overarching programme to deliver the hydrogen economy. Delays to delivery of storage projects due to regulatory requirements could have knock on effects for dependent projects, or a push to the right of the whole network delivery schedule.

For the hydrogen network to develop at the exponential rate required to meet climate protection goals, it is fundamental that policy and regulatory decisions are made swiftly. This will ensure funding can be sourced and appropriate investment made keep up the pace.

While the Government's Hydrogen Strategy Update published in late 2023 outlines forward movement in the regulatory standards in other parts of the hydrogen network, storage lags behind, with the Transport & Storage specific Business Model not being deployed until 2025.

It is important to note that alternative storage solutions such as repurposing oil and gas fields, would not face the same challenges once the technology is mature enough.



Majority of hydrogen production is in the early stages of development*

Whilst the East Coast region has a large pipeline of hydrogen production, **52% (6 GW) of potential capacity is still in the Pre-planning stage of development.**

With the aid of multiple UK Government funding schemes, 2.8 GW of potential hydrogen capacity has progressed to the design and engineering phase of development. 46

A further 2.4 GW, made up of nine projects, are preparing for FID having gained more revenue certainty by signing Memorandums of Understanding (MoU) or preliminary contracts with off-takers, and/or progressing through to low-carbon hydrogen negotiations with the UK Government.

Policy and regulatory decisions must not be delayed if the UK is to achieve its 2025 and 2030 ambitions.

Figure 21: East Coast Hydrogen Delivery Plan. Source: East Coast Hydrogen Delivery Plan. [13]

A clear framework would have additional benefits in giving confidence to stakeholders -

- It would underpin a connection between the different parts of the hydrogen network value chain. Without a clear landscape for the different stakeholders, division of market responsibilities can be challenging and a joined up approach is difficult. Creating clear pathways for development would foster growth and collaboration between stakeholders. A blueprint setting out the cluster-specific conditions and challenges associated with developing hydrogen storage could be built.
- It would give credibility and legitimacy to hydrogen storage projects and therefore support the building of a social license to operate (SLO), i.e. level of public support and trust for hydrogen storage projects and technologies. At present, stakeholders are cautious about souring public perception of hydrogen storage due to the uncertainties and lack of SLO.

Section 6:

Interventions

Define the mix of storage technologies required and the optimum pace of development through strategic planning

We recommend that a comprehensive national strategic plan for hydrogen storage is developed, based on detailed assessments of the remaining UK clusters.

We recommend that a detailed assessment for storage demand for remaining clusters in the UK is undertaken to understand the mix of technologies needed alongside the optimum pace of delivery to meet demand. Recognising the uncertainty associated with the nascent hydrogen economy, boundary conditions should be applied to ensure a consistent approach.

Through our research, we have recognised that there are significant variations in the ranges of storage volumes that will be required, the timeframes over which these will be required to be deployed and the operational envelopes that will need to be met. Notwithstanding this, this report finds that the need for long-term storage has been seriously underestimated and that there has been an overcomplacency that storage needs will be met through existing technologies.

Our assessment has identified a significant barrier that is preventing the development of storage at scale is the nascent nature of the market and a lack of clear planning, strategy and direction on the optimum mix of storage technologies required and the timeframes over which these need to be deployed. Our report recommends that this is redressed as a matter of priority, with strategic planning and definition of T&S requirements.

Strategic Planning

We recognise and support the government's minded position that strategic planning, combined with elements of market-led development, is necessary to enable the efficient, cost-effective and timely roll-out of transport and storage infrastructure. It is recognised that forthcoming, the Future System Operator (FSO), (now National Energy System Operator, NESO) will provide centrally coordinated strategic planning integrated across energy and considers wider system interactions, with the minded position that this will include hydrogen and transportation.

In the short-term, immediate action is needed to provide clarity from government on the strategic approach to the development of hydrogen transport and storage infrastructure, especially in relation to uncertainty over location and optimum location and pace for storage solutions.

Cluster Specific Assessments

We note the government's minded position that early strategic planning is required in advance of the FSO coming online. In support of this we note the need to develop and assess the evidence for T&S requirements in the hydrogen economy to identify early strategically significant needs. In line with this we recommend that cluster specific assessments, following a similar methodology as laid out in this report, should be undertaken to better define the individual needs of each key cluster. Additionally, a more refined national capacity assessment needs to be undertaken. This should be done through extensive consultation with key stakeholders including producers and offtakers, storage asset operators, gas network operators and local / national governmental bodies.

Monitoring and Evaluation

This report recommends that mechanisms are adopted to monitor the progress of storage technology development and deployment, track key performance indicators, and evaluate the effectiveness of government policies and programs. This feedback loop allows for adjustments to be made based on changing market conditions and technological advancements that will feed into updates to strategic planning.

We encourage the government to publish a pathway for the strategic planning of hydrogen networks to set out in more detail some of the early strategic priorities for storage infrastructure and how they will be identified & supported, as well as looking forward to future strategic planning objectives.

Implement a structured Research & Development (R&D) programme for the development of storage technologies

This report recommends that a structured R&D programme is put in place to provide support to the development and deployment of the key alternative technologies including depleted reservoirs and line rock shafts/ caverns, and to optimisation of existing technologies such as fast cycle salt cavern storage.

Our assessment has shown that current mature storage technologies will not be enough to meet future demand.

Therefore, alternative large scale hydrogen storage technologies will be required to meet the pace and quantity of storage demand by 2035 and 2050, and existing technologies will need to be optimised.

This report recommends that a structured R&D programme is put in place to provide support to the development and deployment of the key alternative technologies including storage in depleted hydrocarbon reservoirs and line rock shafts/ caverns, and to the optimisation of existing technologies such as fast cycle salt cavern storage.

Alongside research and innovation delivered through UK institutions, private sector should have access to support through development stage funding for demonstration and pilot storage projects, as has been done under the Longer Duration Energy Storage Demonstration Programme Stream 2.

By linking R&D priorities to strategic planning objectives, government can effectively allocate resources to the most promising technologies, foster innovation, and facilitate the commercialisation and deployment of underground hydrogen storage solutions on a larger scale and at a quicker pace, contributing to a more resilient, flexible, and sustainable energy infrastructure.

This report highlights an example as the 2013 Nuclear Energy Research and Development Roadmap [41], which set out research and development activities needed for up to 75 gigawatts (GW) of nuclear energy in the UK.

Structured R&D programme

We note and support the statement within the storage consultation documents for government to support geological hydrogen storage technologies that do not yet have a TRL of 7 and the commitment to continue to work across government to make this kind of support available to projects that need it.

There are a range of innovation funding mechanisms available to support the ongoing development of technologies, including the Longer Duration Energy Storage Demonstration (LODES). However, it is noted that no long duration, high-capacity hydrogen storage technologies had access to Phase 2 funding. This report recommends a more structured approach is taken to research and development of hydrogen storage technologies, linked to strategic planning priorities.

Demonstrators and pilots

Within the structured R&D programme, this report recommends that demonstrators and full-field pilot projects are developed to demonstrate emerging technology that will feature in a future storage mix. There are currently several of demonstrator projects either in operation or the advanced stage of planning across Europe; these facilities will test specific tools and techniques associated with hydrogen storage, with the findings specific to the storage medium in which the trials are being developed.

This report recommends that the UK follows suit with the development of several field scale demonstrators and supports pilot projects to demonstrate technology readiness. These pilot programmes will help identify barriers to deployment, promote innovation and inform future policy decisions.

Case Example: Nuclear Energy Research and Development Roadmap

The Nuclear Energy Research and Development Roadmap [42] sets out R&D activities and illustrative timelines which would support implementation of future nuclear technology pathways. Recommendations were based on scenarios that were established given the uncertainty around how nuclear energy would be used in the future. It is recommended a similar approach is considered for long duration, high-capacity energy storage, including hydrogen.

Undertake proactive public engagement and social baselining to understand public perceptions to large scale hydrogen storage

We recommend initiating a proactive approach towards public engagement to gain a comprehensive understanding of public perceptions regarding large-scale hydrogen storage. By actively involving the community in the decision-making process, the aim is to assess their attitudes, concerns, and preferences related to this technology.

Positive public perception can facilitate smooth project implementation by garnering support from communities, policymakers, and investors. Conversely, negative perceptions can lead to opposition, regulatory hurdles, and delays in the deployment of projects. With hydrogen storage, public perception will be influenced by factors such as safety concerns, environmental impacts, and the perceived benefits of hydrogen as an energy carrier.

Addressing these concerns through transparent communication, robust safety protocols, and environmental stewardship measures is essential for building trust and acceptance. Additionally, public education and engagement efforts will help dispel misconceptions and highlight the potential benefits of hydrogen storage, such as enabling renewable energy integration, decarbonising industries, and in meeting net zero milestones.

The perspectives of those living near current or proposed energy developments are particularly critical because these residents may have a strong interest in the project and their opinions could influence the siting of the technology. Current hydrogen storage projects benefit from being in existing industrial areas or remote from population centres. However, this is unlikely to be the case going forward, as additional facilities will be required in areas outside of existing industrial clusters.

Proactively engaging with the public may guide the development of more effective communication strategies and hydrogen storage policy development.

Social Baselining

This report recommends undertaking a Social Baselining Assessment that would provide the following outputs:

- Increase understanding of public attitudes to underground hydrogen storage. To contribute to a wider public understanding of hydrogen and hydrogen storage and have the potential to shape attitudes and behaviours in the future.
- Inform public engagement initiatives for future large CCS research infrastructure projects and have potential to align with future scientific research.
- Form the basis for future similar studies in order to track evolving attitudes and support the development of specific projects and initiatives.

Understanding public attitudes and the issues that may impact support or opposition for hydrogen storage will be key to supporting the development and deployment of this technology at scale and pace.

Proactive Public Engagement

Stakeholder engagement and proactive public perception are important factors in supporting timely project development.

The Working Paper SCCS 2010-08, Towards a Public Communication and Engagement Strategy for CO2 Capture and Storage projects (2010) [42], concluded that successful engagement strategies have maintained a civil dialogue between publics / stakeholders and developers, have often involved independent expert and stakeholder endorsement, and have created transparent, participative processes for decision making.

Therefore, this report recommends that consideration is given to forming a Joint Industry, Government and Academic Working Party, to develop comprehensive social baselining methodologies, which involve assessing the existing social, cultural, and economic contexts of communities near proposed storage sites.

The JWP will collaborate on designing effective public engagement strategies tailored to local contexts, ensuring that stakeholders are informed, consulted, and involved throughout the project lifecycle.

Lastly, the working party could collaborate on monitoring and evaluating the effectiveness of public engagement efforts, using feedback mechanisms to continuously improve communication strategies and ensure that community perspectives are adequately considered in decision-making processes related to underground hydrogen storage projects.

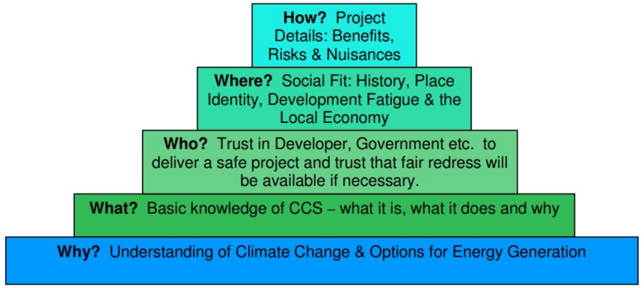


Figure 22: Taken from SCCS 2010-08, Towards a Public Communication and Engagement Strategy for CO2 Capture and Storage projects (Scottish CCTS Development Study, Work Package 4, 2010). [42]

Targeted interventions to de-risk the development lead time for storage projects

This report recommends that a number of interventions are undertaken to de-risk the development and delivery process through which large scale storage will follow. A key area of focus is the consenting, permitting and planning process, where projects will benefit from a better-defined process and timeline. We also recommend undertaking a supply chain readiness assessment to identify possible bottlenecks and to allow proactive action to be taken to address these.

A key constraint in the ability for proven technologies to meet the storage demands that underpin our 2050 net zero targets, is the ability to deploy at pace. Large scale salt cavern storage facilities can take over a decade to develop, with site characterisation, planning, permitting and cavern formation identified as long-lead activities that can constrain delivery programmes. Stakeholder engagement undertaken as part of this research has identified significant bottlenecks, in addition to those above, that need to be addressed to help facilitate more timely deployment of storage at scale.

Measures to streamline the planning and permitting for energy storage infrastructure development and project construction would aid in reducing project lead times. Supply chain risks need to be better understood and proactively addressed; there is real risk of skills and material shortages undermining the ability to deliver the scale and pace of project development required. These activities should not be undertaken in isolation; constraints impacting the deployment of underground hydrogen storage overlap with other technologies in the energy sector. Therefore, a more integrated approach is likely to be beneficial.

Notwithstanding the above, immediate development of hydrogen storage projects will be vital to guarantee energy independence. It is therefore imperative that the UK sees large-scale storage investments prior to the Government's design of business models in 2025, and that minimum regret actions to de-risk project delivery are implemented as a matter of urgency.

Planning and Permitting Guidelines

Considering the urgency imposed by the necessity for numerous storage projects within a limited timeframe, it becomes imperative to streamline engagement processes with critical stakeholders such as Natural England, the Environment Agency, and Health and Safety Executive (HSE). By establishing consensus on key principles, assessment methodologies, and permitting approaches across the industry, the scoping and assessment phases of the consenting process can be significantly expedited.

This proactive measure would facilitate smoother coordination and may also mitigate the risk of program delays arising from resource constraints within the consulted agencies.

Ultimately, such streamlined processes may enhance efficiency, reduce bureaucratic bottlenecks, and contribute to the timely execution of storage projects critical for meeting energy demands.

Supply Chain Readiness Assessment

Consideration should be given to undertaking a Supply Chain Readiness Assessment to estimate the readiness of the UK skills, manufacturing and fabrication supply chain to service the dramatic expected growth in long-duration hydrogen storage technologies.

An initial desktop assessment should be undertaken, including extensive stakeholder engagement, to provide skills, technical and manufacturing supply chain capability assessments of selected systems from within a generic hydrogen storage project.

As part of this assessment, an understanding of the key skills and components needs to be better developed, including an assessment of technology readiness. This will underpin the development and delivery of hydrogen storage technologies.

Case Example: CCUS supply chain intervention strategy

The Supply Chain Working Group of the CCUS Council was set up in September 2021 and quickly concluded that there was a need to assess the readiness of potential supply chains in the UK to make the most of potential opportunities. An initial sprint review was funded by Nuclear AMRC (part of the High Value Manufacturing Catapult. The assessment was carried out over four months and provided valuable insights and key pointers on next steps.

The report [43] confirmed a significant opportunity for the UK, leveraging its established strength and global capability in serving the oil and gas industries. However, it also emphasized the need for the UK to swiftly establish this capacity in its domestic market before advancing to secure a position within the global supply chain for CCUS.

Section 7:

Conclusions and Next Steps

Conclusions

It is hoped that this report, and our ongoing dissemination, will contribute to further investment in hydrogen storage solutions that will accelerate industrial decarbonisation with deployment at scale required within the next decade, securing the UK's position as an innovation leader, creating green jobs, and ultimately supporting the transition to net-zero by 2050.

This report presents a unique cluster specific assessment of the temporal demand for underground hydrogen storage alongside a calculation of the available and developable salt cavern storage capacity. The overarching conclusion from this assessment is that without immediate action and targeted inventions, storage capacity will not keep pace with demand, potentially hindering ability to reach milestones associated with the UK's journey to net zero by 2050.

It has been demonstrated that long duration energy storage, and specifically hydrogen storage, will underpin key milestones associated with net zero by 2050, namely 10 GW of electrolytic hydrogen by 2030 and a decarbonised power system by 2035. Underground storage will provide the required capacity and duration needed, and currently salt cavern storage is the only proven technology. However, other alternative technologies exist but at a lower Technology Readiness Level, hindering investment and deployment.

Previous estimates for the capacity of salt cavern storage have been in the 1000s TWh, far in excess of any demand scenario. However, the assessment provided in this report has further refined capacity estimates, using publicly available information to layer in subsurface and surface constraints. The results presented in this report represent a >90% reduction on previous estimates of salt cavern capacity.

The demand assessment presented in this report, that builds on published decarbonisation scenarios, has concluded that there is likely to be a significant demand for hydrogen storage in the east coast cluster (and nationally). The storage demand is intrinsically linked to the hydrogen demand, with electrification, industrial decarbonisation and heating assessed to be the biggest drivers for storage demand.

The UK currently has only 0.025 TWh of underground storage, in Teesside. Projects in advance stages of planning will offer an additional capacity of between 1 - 1.5 TWh, with only a fraction of this local to the East Coast region. Therefore, the 'planned' capacity will only be around 5-10% of calculated East Coast Cluster's demand. Salt cavern storage facilities can take over a decade to develop, constrained by site characterisation, planning, consenting and construction.

The technology will also be constrained geographically, to areas underlain by salt deposits. The market appetite to invest in the development and deployment of alternative technologies is constrained by the nascent nature of the hydrogen economy and the lack of strategic planning and a regulatory framework for storage.

'As the hydrogen economy develops, there will be times when the supply of hydrogen will not align with demand from offtakers which will result in periods of a surplus or scarcity of hydrogen, creating security of supply risks. Storage infrastructure will be key to address imbalances in hydrogen production and demand.' [4]

The Government has recently announced plans to launch the first round of business model allocation specially focused at hydrogen storage – recognising the need to support the deployment of storage at scale . This is a great first step, with the minded position to offer support to two storage projects in the first round of allocation. However, based on the assessment presented in this report, the report concludes that further action is required as a matter of urgency. A series of minimum regret interventions are recommended to address market uncertainty, to optimise current technologies, to support the development of alternative technologies, and to de-risk the delivery of storage projects.

The report has been delivered with support from a range of key stakeholders ranging from policy makers to storage operators and end users. We thank those who have contributed for their time and insights, that have supported our assessments. It is clear that there is a broad consensus of the significant challenges for industrial decarbonisation ahead. It is hoped that this report, and our ongoing dissemination, will contribute to further investment in long-duration energy storage solutions that will accelerate industrial decarbonisation with deployment at scale required within the next decade, securing the UK's position as an innovation leader, creating green jobs, and ultimately supporting the transition to net-zero by 2050.

Moving Forward

To expand on the work done to date in this report, next steps have been identified.

Demand modelling opportunities

- Regional analysis of other key regions for hydrogen storage (e.g. Cheshire, South of England, etc.) with consideration to key demand centres (e.g. HyNet, Acorn/The Scottish Cluster Solent, etc.) – whole UK energy system modelling.
- Increased granularity of temporal data. Refinement of data by engagement with key stakeholders, e.g. daily demand profiles of real projects to develop a bottom-up analysis of the industry sector rather than assuming constant quarterly hydrogen demand. Include current residential power demands, in addition to future residential power demands from electrified heat.
- Increased granularity of spatial supply and demand matching. Current assumption is that supply and demand of the whole East Coast Region are aggregated. Can improve granularity of e.g. large H_2 production projects in Teesside supplying demand centres outside of Teesside. Additionally test future scenarios where the East Cost is a net import or exporter of hydrogen, rather than all hydrogen demands being satisfied solely by local production. This will prompt questions of how the network is developed and how storage will need to connect to large demand centres.
- Increase the parameters within the analysis to quantify the benefit over other technologies e.g. cost, emissions, etc. This will lead to a more detailed analysis of other long duration energy storage or system balancing technologies such as interconnectors of power-CCS (carbon capture storage).
- A more comprehensive analysis can be developed using Energy System modelling software / Python to include further constraints to the analysis (also Monte Carlo analysis to test impact of varying input variables to understand weighting of key drivers to the demand modelling outcome).

Storage modelling opportunities

- Refine geological model. Incorporate additional ground data such as BGS GeoIndex boreholes and geophysics sections to better constrain the extent, depth and thickness of salt horizons.
- Refine workable volume insoluble content. A uniform value of 25% of non-halite geology is considered for the workable volume of Boulby Halite and Fordon Evaporite Formation. This should be refined to capture lithological and mineralogical heterogeneity.
- Communicate uncertainty in the geological model. This could be through statistical analysis of ground data and/ or incorporation of an uncertainty factor to the outputs.
- Refine topography model to reflect true land elevations. Currently the regional topography is defined as constant 0 mOD. This can result in over-conservative estimates of capacity where there is significant positive elevation.
- Refine potential capacity model. Incorporate extents of existing subsurface developments e.g., historical mining (e.g., coal), mine extraction limits (underground storage sites, Boulby Mine and Woodsmith Mine extraction limits), underground infrastructure (Boulby Mine shafts and associated developments and Woodsmith Mineral Transport System and other associated developments)
- Industry engagement. Refine and develop the tool based on industry requirements. This will set the scene for subsequent revisions.
- An adequate estimation of realisable potential will require additional consideration of technical, social and economic viability, and is beyond the scope of this study and should be considered at the next stage.
- Understand the geomechanical viability of hydrogen storage. This will include geological modelling for cavern responsiveness to hydrogen cycling.
- Extend methodology to refine offshore storage estimates in the Fordon Evaporite Formation and Boulby Halite Formation.
- Economic analysis of CAPEX required to meet UK's hydrogen storage demand.

Appendix A:

Hydrogen Storage Demand Modelling for the East Coast Cluster

Executive Summary

This analysis combines demand forecasts for the industry, heat, power generation and transport sectors with localised data for the East Coast. The approach can be easily replicated to better understand the future hydrogen supply and demand balance across key regions.

This work package estimates the hydrogen storage demand for the UK East Coast region, focusing on near-term (2030 and 2035) and long-term (2050) requirements. By aggregating fluctuating demand profiles for hydrogen use in industry, heat, power generation and transport* sectors, this analysis involves daily temporal matching of overall forecasted hydrogen demand and hydrogen production across the East Coast; the resulting energy balance used to inform the estimation of regional inter-seasonal hydrogen storage demand requirements.

Forecasted sectoral hydrogen demands are estimated for ‘low’ and ‘high’ hydrogen demand scenarios to develop lower and upper bounded estimates of the total regional hydrogen storage capacity requirements. The system boundary of the demand assessment comprises the Northern, Northeastern and East Midlands regions of the UK, aligning with the UK Local Distribution Zones (LDZs) as defined by National Gas [12] and building on recent work such as that outlined in the East Coast Hydrogen (ECH_2) Delivery Plan [13]. The following overarching approach was applied:

1. Establish ‘low’ and ‘high’ hydrogen demand requirements and associated demand profiles for each sector in the East Coast region.
2. Engage with subject matter experts and project partners to understand future hydrogen storage needs and refine model assumptions.
3. Daily temporal matching to understand the energy balance between hydrogen production and demand to estimate the total hydrogen storage demand for the East Coast.

Due to the uncertainty of announced hydrogen production capacity in the region, mostly concentrated around the Teesside and Humber industrial clusters, the base case assesses a constant hydrogen production profile, with annual production equal to annual average demand. Sensitivity analyses were undertaken to investigate the impact of electrolytic hydrogen production fluctuations and seasonality; an extended system boundary to include the Southeast of England; and oversizing hydrogen production capacity for additional energy system flexibility.

This work package provides forecasted demand for hydrogen salt cavern storage in the East Coast region for the years 2030, 2035 and 2050. WP2 provides an estimate for the available “supply” of hydrogen salt cavern storage in the East Coast region, based on real world constraints. The outputs are then combined in WP3 to assess the likelihood of bottlenecks in salt cavern storage development, e.g. if/when demand for hydrogen salt cavern storage will exceed available supply in the East Coast region between 2030 and 2050.

The analysis can be easily replicated for other regions to better understand potential future hydrogen supply and demand balances across key regions in the UK. This can help build the full picture of the requirements of hydrogen storage to meet future demand.

**For the transport sector, an assumed demand based on the days of storage needed for maritime and aviation operations was used instead of a temporal profile – see Appendix A for more details.*

Figure A1: System boundary of storage demand modelling assessment, chosen to align with East Coast Hydrogen Delivery Plan system boundary with additionality to include full Northern LDZ region (as outlined in red). [12][13]

Methodology

Use-Cases for Low-Carbon Hydrogen: While future demand remains uncertain, the analysis considers the most likely use cases of hydrogen. Hydrogen has been identified as critical to net zero, however it will face competition from other zero emission technologies in all sectors.

A comprehensive analysis of the most likely use cases of hydrogen has been undertaken to inform the hydrogen storage demand study. In the short- to medium-term it is generally accepted that hydrogen will be used to address hard-to-abate applications, such as the chemical, steel, fertiliser, aviation and shipping sectors, with other use cases such as a fuel source for high-temperature heat and as an energy vector for long duration energy storage becoming attractive in the longer term.

While hydrogen has been identified as a promising solution for these applications, it is important to note the following hierarchical approach to developing effective decarbonisation solutions, succinctly summarised in Figure A2 [A9].

1. Reduce overall energy demand with an emphasis on eliminating or limiting energy-intensive activities.
2. Optimisation by enhancing energy efficiency and refining existing systems.
3. Electrification.
4. Green fuels (including hydrogen, e-fuels, and biofuels).
5. Further measures, such as carbon capture and storage (CCS) or other removal technologies.

The various identified use cases, competing technology solutions and low current level of adoption of hydrogen highlights the complex, multi-factorial challenge of region-wide hydrogen storage demand modelling. In the context of this study, hydrogen storage has been considered as a solution for long duration energy storage, considering forecasted hydrogen demands for key overarching end-use sectors.

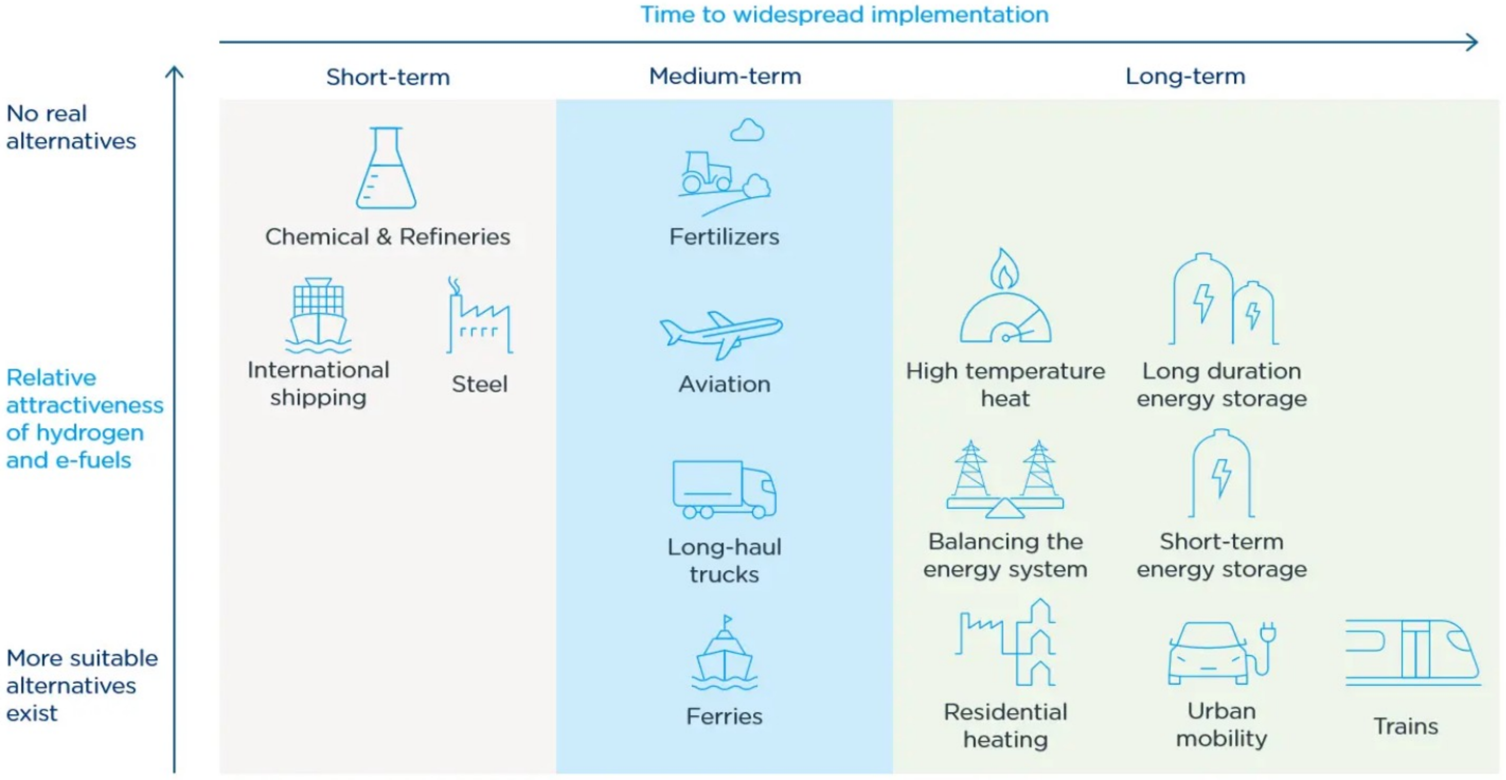


Figure A2: Hierarchy of relative attractiveness of hydrogen and e-fuels with respect to time for widespread implementation.
Source: The Green Hydrogen Hierarchy (Jan 2024). [A9] [Figure A2]

Methodology

End-use sectors considered in the analysis: The industry, residential & commercial heat, power generation and transport sectors have been considered in this hydrogen storage demand modelling study. Analysing these overarching end-use sectors provides a holistic assessment of regional hydrogen storage demand.

To estimate hydrogen storage demands, hydrogen uptake forecasts have been modelled for the following sectors.

- Industry: Large industrial users that currently use hydrogen as a chemical feedstock or are expected to fuel-switch their industrial process energy usages from fossil fuels to hydrogen.
- Heat*: Consumers analogous to those currently connected to gas distribution networks for natural gas, including residential and commercial buildings, that will use hydrogen boilers for heating.
- Power Generation*: Hydrogen-to-power sites that can operate flexibly to provide dispatchable low-carbon power capacity to complement intermittent renewable generation.
- Transport: Bunkering for hard-to-decarbonise transport applications that will use hydrogen as part of their energy transition, such as aviation and shipping. Road transport has been excluded within this study as hydrogen demand in this sector remains uncertain with a high expected uptake of battery electric vehicles.

Future supply from different low carbon hydrogen production technologies has also been considered:

- Electrolytic: Splitting of water via electrolysis, using low-carbon power.
- CCUS-enabled: Reforming of methane, with carbon capture and storage, to sequester produced CO2.

*Heat and power generation have been analysed as very closely interlinked sectors. Currently, the majority of heat sector energy consumption comprises natural gas for heating. However, a substantial proportion of gas heating demands are expected to transition into power demands as electrification increases due to widespread adoption of technologies such a s heat pumps. This is particularly true for lower temperature heat demands, such as for residential and commercial heating. Demands for the two sectors have thus been forecasted using the same input data of current natural gas network demand, however different assumption sets of rate of uptake of appliances (i.e. hydrogen boilers vs. heat pumps) have been applied.

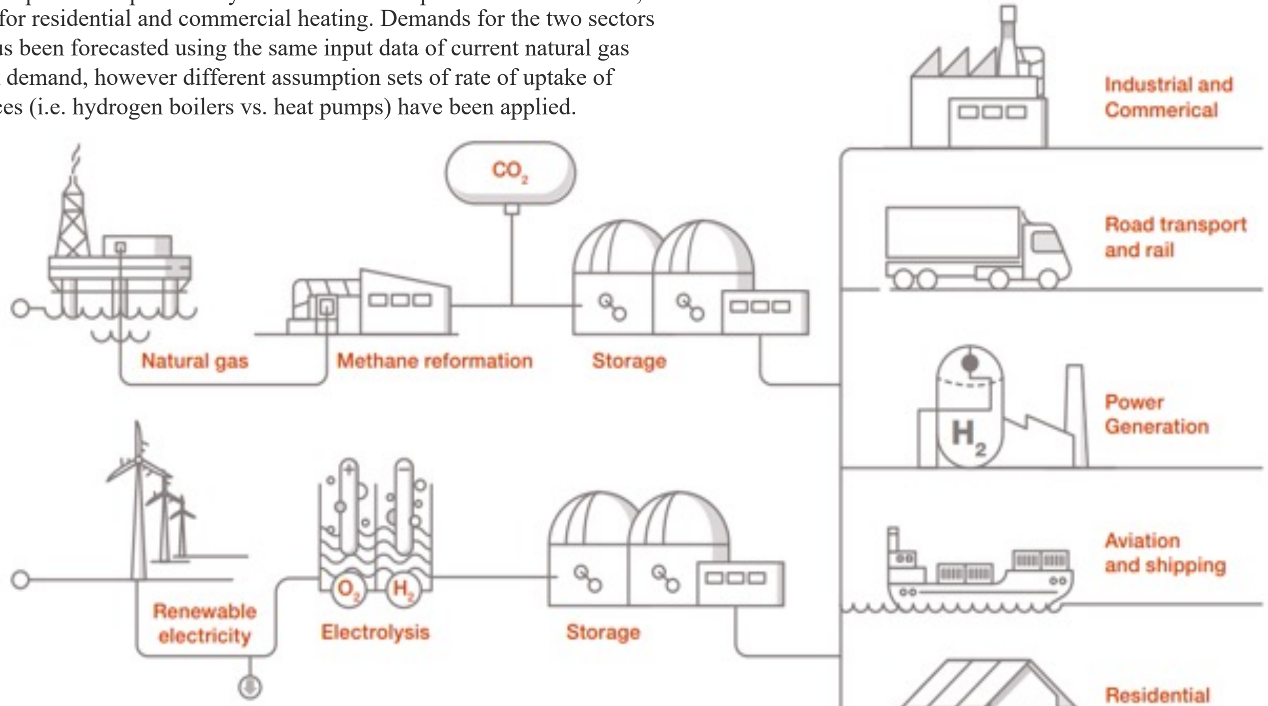


Figure A3: Low-carbon hydrogen end use sectors considered in the hydrogen storage demand analysis.
Source: National Grid ESO Future Energy Scenarios 2023. [A5]

Methodology

High and Low Hydrogen Demand Scenario-Based Analysis: While hydrogen demands are forecasted to increase in the East Coast region, both the rate and scale of uptake remain uncertain. A scenario-based analysis has thus been used to explore the impacts of both low and high hydrogen demand on required hydrogen storage capacities.

The uncertainty of hydrogen uptake in each sector is reflected in recent government publications, such as that outlined in the forecasted hydrogen demand ranges in the UK Hydrogen Transport and Storage Networks Pathway [Figure A4] [A10].

- Industry: Likely to become one of the main users of hydrogen and an important early adopter. This is supported by evidence of projects currently in development, including those in the first Hydrogen Allocation Round [HAR].
- Heat: Observed to have the greatest uncertainty in demand across all forecasted years, aligning with the current uncertainty regarding the formal government decision on the role of hydrogen for heating to be taken in 2026.
- Power: Hydrogen demand remains relatively uncertain, driven by uncertainty in overall and peak electricity demand levels, the mix of electricity generation technologies, and the relative costs and advantages of hydrogen compared to other low-carbon flexible capacity.
- Transport: Expected to make up a small proportion of demand in 2030, led by the potential use of hydrogen in buses and HGVs, with demand expected to grow rapidly, predominantly driven by uptake in the maritime and aviation sectors.

To account for this uncertainty in the analysis, two scenarios have been assumed for each sector:

- High hydrogen demand scenario: This represents an upper bound for hydrogen demand in the East Coast region, assuming development of hydrogen projects and supporting infrastructure at scale.
- Low hydrogen demand scenario: This represents a lower bound for hydrogen demand in the East Coast region, assuming a less pronounced uptake of hydrogen.

The scenarios have been developed by applying sector-specific assumptions to localised East Coast region data and/or announced government targets. While the scenarios capture uncertainty in future hydrogen demands, further uncertainty in the hydrogen storage requirements for each sector remain. The applied assumptions to determine the hydrogen storage demand for each sector have thus been tested through sensitivity analysis.

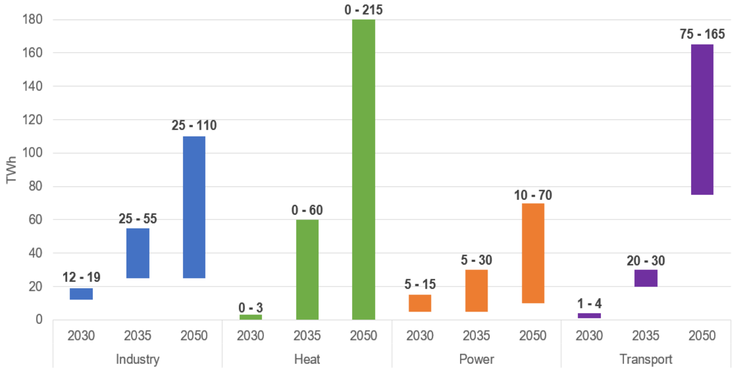


Figure A4: Forecasted UK hydrogen demands by sector in 2030, 2035 and 2050.
Source: Hydrogen Transport and Storage Networks Pathway (Dec 2023). [Figure A4]

Year	Industry	Heat	Power	Transport
2030	+/-22.6%	+/-100.0%	+/-50.0%	+/-60.0%
2035	+/-37.5%	+/-100.0%	+/-71.4%	+/-20.0%
2050	+/-63.0%	+/-100.0%	+/-75.0%	+/-37.5%

Table A1: Deviation of maximum and minimum forecasted sectoral hydrogen demands from mean values.
Source: Analysis of Hydrogen Transport and Storage Networks Pathway data. [Table A1]

Industrial Hydrogen Demand: Introduction

The use of hydrogen in industry represents a significant demand across future hydrogen demand scenarios, both as a fuel source and chemical feedstock. Large-scale hydrogen storage can be developed as a solution to mitigate security of supply risks and improve operational resilience of industrial sites.

Industry is forecasted to have the greatest certainty of hydrogen uptake across all sectors in the near-term, and likely the greatest demand. Hydrogen has already been used for decades as a chemical feedstock and reducing agent in industrial processes, with current global consumption split between the following conventional applications (based on a 2019 IEA hydrogen value chain analysis) [A11]:

- Petroleum recovery and refining where hydrogen is used for the cracking of heavier oils into lighter oils to produce petroleum and petroleum products.
- Ammonia production where hydrogen is combined with nitrogen as part of the Haber-Bosch process.
- Methanol production where syngas (a mixture of CO, CO2 and H_2) is produced, typically using natural gas or coal and prior to conversion to methanol.
- Iron and steel manufacturing where iron ore is reduced using hydrogen to produce direct reduced iron (DRI), in preparation for the production of steel.
- Other applications, including transport, glass making, other chemicals and the production of heat when mixed with other gases.

Understanding the current industry sector split is important, given the widely agreed priority for new low-carbon hydrogen to replace existing carbon-intensive hydrogen. In 2016 UK hydrogen production is estimated at around 27 TWh per year across 15 sites, with 96% as grey and brown/black hydrogen (49% and 47%, respectively). [A12*].

However, given the UK Government's ambition to scale up industrial fuel-switching from fossil fuels to hydrogen, both the scale of low-carbon hydrogen demand (i.e. up to 110 TWh in 2050) and variation of demand profiles will increase.

Refining, ammonia production, iron and steel manufacturing, glass making, and other chemicals production are current industrial hydrogen demands in the East Coast region, predominantly split across Teesside and Humberside. In addition to the transition of existing hydrogen users to low-carbon hydrogen, many new hydrogen users are expected in the future. Some industrial applications - such as certain high-temperature direct-heating processes - will see an increasingly prominent role for hydrogen, with many industrial users viewing hydrogen as their only viable decarbonisation solution. New hydrogen heating technologies are becoming available as industrial users are advancing plans to use hydrogen in the future, whereas many lower-grade heating applications are likely to be electrified.

With growth in hydrogen demand and the stringent contractual supply obligations of producers to customers, hydrogen storage will be required to act as an energy buffer to improve security of supply and operational resilience across industry.

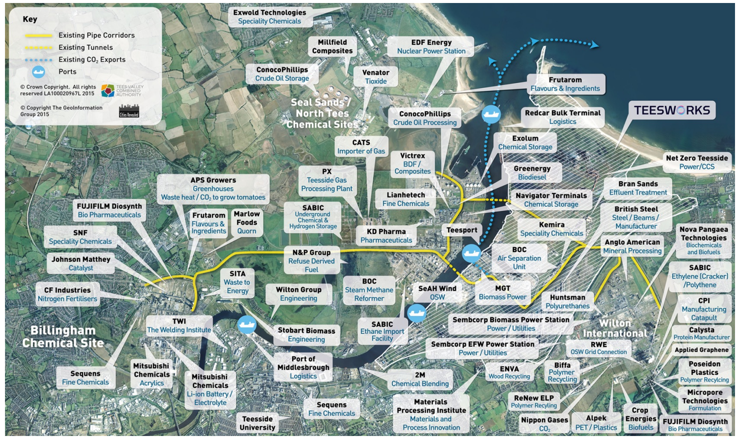


Figure A5: Various identified industrial users within the Teesside industrial cluster.
Source: Deep Decarbonisation Pathways for UK Industry [A13]

	Indirect Heating	Direct Heating
High Temperature	Steam Reformers Boilers (some)	Kilns and Furnaces Metal Rolling and Melting Blast Furnaces and Sinter Plants Dyers (some, e.g. rotary)
Low Temperature	Regasification Boilers (most) CHP	Ovens Dryers (most)

Table A2: Industrial heating technologies for direct/indirect and low/high temperature processes.
Source: Deep Decarbonisation Pathways for UK Industry. [A13]
[A2] Energy Research Partnership: Potential role of hydrogen in the UK Energy System, 2016
*2016 estimate does not account for changes since then such as closures CF Fertilisers Ammonia plant in Billingham in July 2023, this estimate will change each year as plants are opened and closed.

Industrial Hydrogen Demand: Annual Profile

Natural gas demand for the UK industry sector is observed to follow a recurring inter-seasonal trend within analysed quarterly data. Future hydrogen demand for the East Coast industry sector has been assumed to follow a similar trend when considered on a regional site-aggregated basis.

To estimate a representative hydrogen demand profile for the industry sector, the overall UK industry natural gas demand profile was analysed prior to localisation of data. Analysing industry data in isolation, a recurring seasonal trend in industrial natural gas demand is observed [A14].

Table A3: Quarterly percentage of annual UK industry natural gas demand.
Source: Analysis of 2023 UK Energy Trends data. [A3]

Year	2020 [98.4 TWh]	2021 [103.3 TWh]	2022 [98.4 TWh]	Average (2020-22)
Q1	31.5%	32.1%	31.4%	31.7%
Q2	18.2%	20.6%	22.7%	20.5%
Q3	18.9%	18.9%	19.1%	19.0%
Q4	31.5%	28.4%	26.8%	28.9%

The quarterly peak-to-trough variation in industrial natural gas demand is less pronounced than the interseasonal swings for the heating sector, where a ~50% drop is observed for industry compared to a ~6-fold decrease for heat. This is due to the seasonal variation in industrial space heating requirements, similar to that of space heating in the domestic heat sector. However with demand for feedstock and industrial heating processes assumed to remain relatively constant with the occasional drop off for planned or unplanned shutdowns, the profile is less extreme than for residential heating - at least on a regional site-aggregated basis.

In this assessment, the East Coast region industrial sector is assumed to follow a quarterly hydrogen demand profile, aligning with the 2020-22 average quarterly industrial natural gas demand proportions. The hydrogen demand proportions have been applied to total estimated East Coast industry sector hydrogen demand figures quoted in literature, as described later.

Given the approach to model hydrogen storage demands as a form of regional grid balancing, the quarterly demand profile assumption was deemed sufficient for the overall hydrogen storage demand modelling analysis. Analysing granular subtleties of potential hydrogen demand profiles of individual industrial sites (e.g. on an hourly or daily basis) wasn't undertaken in the modelling, however possible implications of fluctuating demand have been considered further along in the analysis.

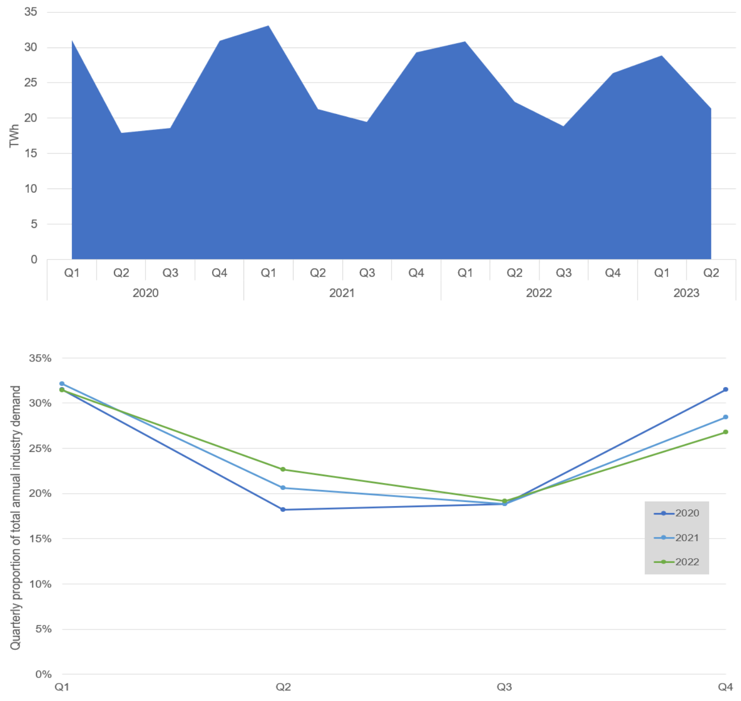


Figure A6: (a) UK industry quarterly demand profile for natural gas (Q1 2020 – Q2 2023) (b) UK industry quarterly proportions of total annual natural gas demand (2020 – 2022).
Source: Arup analysis of 2023 UK Energy Trends data. [Figure A6] [A14]

Industrial Hydrogen Demand: Understanding Individual Industrial Gas User Profiles

As the gas demand profiles of individual industrial sites are aggregated, the overall demand profile begins to 'flatten'. This effect increases with the number of sites considered and forms the basis of the storage modelling assumption of constant quarterly industry demand.

Gas demand profiles of industrial users can vary significantly due to specific process requirements, most notably when gas is used for variable input purposes and due to facility shutdowns. For additional context, National Transmission System (NTS) offtake data for four large industrial offtakers in the East Coast region (out of 22 sites reported across the UK [A1]) have been analysed, highlighting demand fluctuations and significant periods of downtime across a given year.

Downtime can often be attributed to periods of plant maintenance, where industrial facilities may have multiple process trains that can be taken offline individually to carry out necessary interventions. In Figure A7, when plants ramp down to 0% load this is assumed to be maintenance on the whole plant. When ramped down to c.50% this may be maintenance on a single train of a two-train plant. Within an industrial cluster, downtime periods are irregular and are unlikely to occur at the same time for all industrial users. Therefore, when aggregating demand profiles for hundreds of industrial users – where over 200 exist in the East Coast region [A2] – the total demand profile flattens.

In this study, only the inter-seasonal swing in industrial demand is modelled. It is assumed the resulting hydrogen storage capacity estimate will provide sufficient storage throughout the year for industrial plants to be taken offline for maintenance when required.

The following high-level case study example outlines potential hydrogen storage capacity considerations of a hydrogen producer supplying an offtaker. Producers supplying large demand and/or highly variable offtakers may opt for a direct connection to dedicated storage if security of supply requirements are critical to plant operations.

Case Study Example:
1 GW CCUS-enabled hydrogen production facility:

- Supply rate at full capacity = 30 te / hr.

- Offtaker requires average demand of 30 te / hr with slight, infrequent peaks in demand.

- Potential hydrogen storage considerations:

- Small-scale e.g. 15 te of working storage capacity, enabling 30 minutes of short-term response time during plant trips, allowing offtaker to fuel switch or ramp down.
- Medium-scale e.g. 30 – 90 te of working storage capacity, enabling 1 to 3 hours of storage to smooth peak demands, allowing relatively constant production facility rates.
- Large-scale e.g. 720 – 2,160 te of working storage capacity, enabling 1 to 3 days of storage in case of production facility plant trips (e.g. max case of 3 days can allow for 1 day each for shut-down, repair intervention and start-up).

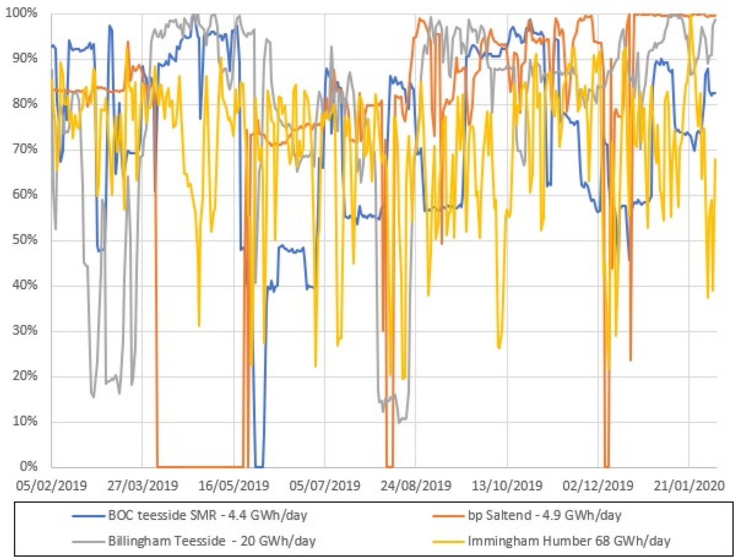


Figure A7: Daily load profiles of four major industrial users in the East Coast Region: BOC Teesside, Immingham, bp Saltend and Billingham. Profiles have been adjusted to highlight demand in terms of plant load factor. One year profile from February 2019 to February 2020.

Industrial Hydrogen Demand: Forecasts for the East Coast Industry Sector

Two key literature studies have been used to determine representative quarterly demand profiles for the East Coast industry sector up to 2050. Initial hydrogen uptake is expected to be led by Teesside with near-term hydrogen demands dominated by chemicals sites in the region.

Two key studies have been identified as providing hydrogen demand forecasts for the East Coast region industry sector.

- Deep Decarbonisation Pathways for UK Industry [A13]: prepared for the CCC to support the sixth carbon budget, the study assesses viable pathways for deep emissions reductions in UK industry through the developed Net Zero Industry Pathways (N-ZIP) model. Hydrogen demand forecasts are reported up to 2050 for key points across the UK, including Teesside and Humberside.
- East Coast Hydrogen Delivery Plan [A2]: based on input from 122 Consortium Members across the East Coast energy value chain, the study provides a strategic outline for delivery of the 15-year East Coast Hydrogen programme. Industrial and commercial (I&C) hydrogen demand forecasts are reported up to 2037 for the East Coast region, aligning with the 2040 industrial cluster net zero targets. Humber and Teesside account for 7.31 TWh (31.6%) and 5.32 TWh (23.0%) of the total 23.1 TWh forecasted East Coast demand in 2037, respectively.

For the purposes of hydrogen storage demand modelling, it is assumed that the 2037 I&C hydrogen demand forecast remains constant to 2050 (i.e. no additional hydrogen demand is developed as the industrial clusters are assumed to have achieved net zero), and an average of the reported figures is taken for the respective years. Low and high hydrogen demand scenarios were determined using the industry demand confidence intervals shown previously in Table A4.

	2030	2035	2037	2040	2050
Industry hydrogen demand (Teesside and Humberside) [A13]	9.3	13.5	-	21.1	22.6
I&C hydrogen demand (based on 270 sites across the ECR) [A2]	8.9	18.2	23.1	-	-

Table A4: (a) Reported hydrogen uptake forecasts (TWh) for the East Coast industry sector.
Sources: (a) Deep Decarbonisation Pathways for UK Industry, Element Energy (Nov 2020) [A13] (a-b) East Coast Hydrogen Delivery Plan, NGN; Cadent & National Gas (Dec 2023). [A2]

	Identified 2037 hydrogen demand [percentage of total]	
Chemicals	9.44	[40.8%]
Food and drink	3.28	[14.2%]
Steel	2.85	[12.3%]
Building materials	2.69	[11.6%]
Glass	1.52	[6.6%]
Manufacturing	1.24	[5.4%]
Automotive manufacturing	1.24	[5.4%]
Education & healthcare	0.68 & 0.2	[3.8%]

(b) Reported sector split of the 2037 hydrogen demand forecast (TWh) for the East Coast I&C sector.

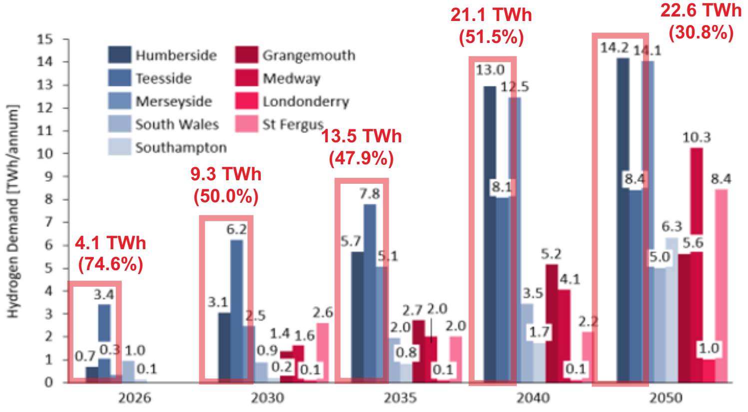


Figure A8: Hydrogen uptake forecasts in industry at nine key production points across the UK, with accumulated totals of Humberside and Teesside shown.
Source: Deep Decarbonisation Pathways for UK Industry, Element Energy (a report for the CCC) [A13]

Summary of Hydrogen Demand Modelling Assumptions

Total East Coast region industry sector demands:

2030 (+/-22.6%):	low: 7.0 TWh	high: 11.2 TWh
2035 (+/-37.5%):	low: 9.9 TWh	high: 21.8 TWh
2050 (+/-63.0%):	low: 9.9 TWh	high: 37.3 TWh

Constant quarterly demand proportions of annual demands:

Q1: 31.67% Q2: 20.49%

Q2: 20.49% Q4: 28.89%

Heating in Buildings Sector: Introduction

H_2 storage will be modelled for buildings with H_2 boilers and heat pumps.

In this study it is assumed commercial and residential heat (budlings) will be decarbonised by two technologies:

- Heat pumps*: Uses a refrigeration cycle, to transfer heat from surroundings to buildings, powered by electricity.
- Hydrogen boilers: Operate equivalently to incumbent natural gas boilers, but with modifications so boilers can combust H2 instead of natural gas.

**Many urban areas will operate with a district heat network, transferring heat with hot water. Here it is assumed that the water will be heated with a large-scale heat pump, and so buildings within district heat networks are treated as using heat pumps.*

Heating for buildings currently sees the greatest annual variation in energy consumption. This is driven by space heating only being required in winter during the cold months, and households switching their central heating off during the summer months.

Due to the regular seasonality of the UK weather, this demand profile has historically been consistent each year. Some smaller changes are expected moving forward, but the shape of the profile is expected to stay the same:

- Insulation of homes: Improvements in home efficiency through insulation will see winter demands drop.
- Warmer winters: The UK is predicted to see more mild winters, due to the impacts of global warming towards 2050, reducing winter heat consumptions.
- Air condition and home cooling: Summers are predicted to be warmer towards 2050, again from global warming, and so and so an increase in home cooling and air conditioning is expected, increasing UK buildings energy consumption in summer.

All these factors are predicted to reduce the inter-seasonal swing of energy consumption, and are discussed further on subsequent slides.

As heating is electrified, power demands will increase. Homes with heat pumps installed will have the same shaped annual profile to as gas-fuelled homes for their heating energy consumption, peaking in winter and reducing over summer (though the size of energy consumption will differ). In this instance it is assumed in summer extra hydrogen will be used to store energy that is then converted to power with a gas turbine, to supply homes heated with heat pumps in colder winter months. This use of hydrogen storage to balance inter-seasonal demands for home heating will be estimated in this study, and used as the basis for the hydrogen consumption in the power sector.

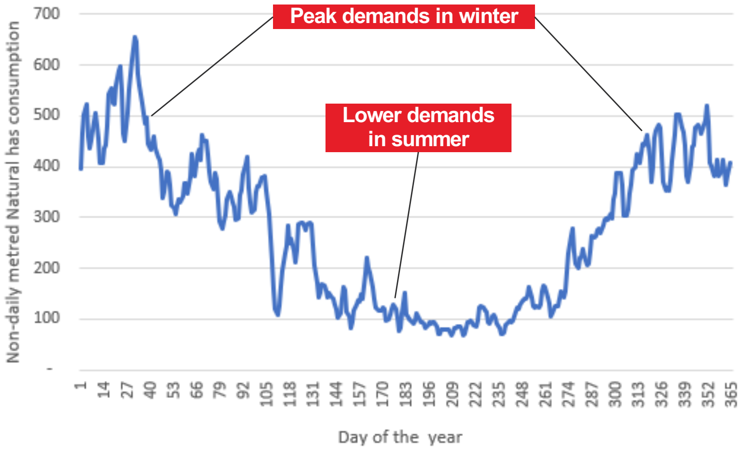


Figure A9: Annual Natural Gas consumption, Non-daily metred, (NDM) East Coast, 2019 Consumptions for LDZs EM, NE and NO – GWh/day, NDM covers domestic, commercial and medium industrial users.
Source: [A1] Data from national gas data portal, 2019 data sets for non-daily-metred (NDM) gas for East Midlands (EM), North East (NE), and North (NO)

Real-world demand data used for heating in buildings

Real-world data for the East-Coast is taken from National Gas website.

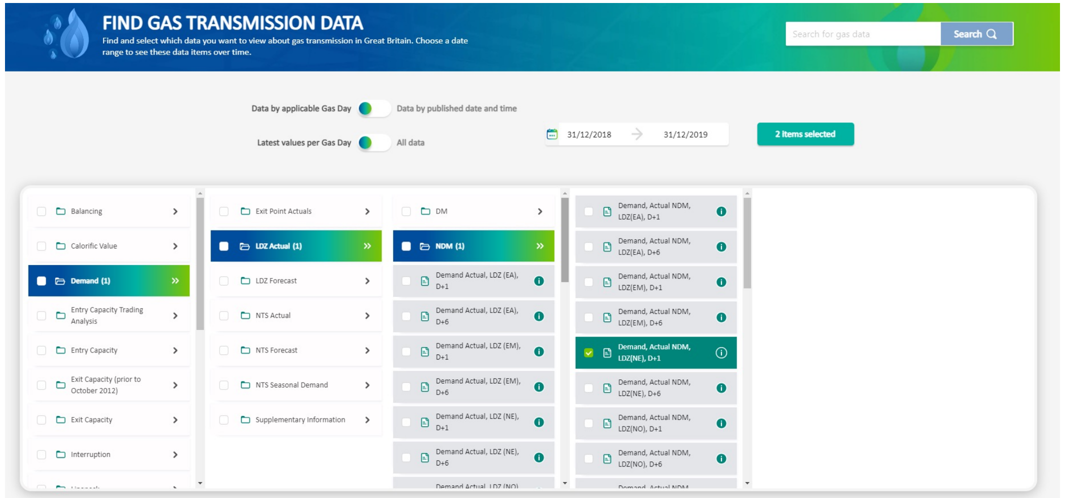
Gas is supplied to domestic users by Gas Network Operators (GNOs), which divide the UK into 13 Local distribution zones (LDZs). National Gas, who operate the National Transmission System (NTS) (connecting all 13 LDZs) publish daily metred exit data from the NTS to each LDZ online. This is used as an estimate for how much gas each LDZ consumes over the period of a year.

For this analysis, the LDZs, North (NO), North-East (NE) and East Midlands (EM) are assumed to make up the East Coast, highlighted in the map on the right [A1].

Daily metred and non-daily metered data is available from the National Gas data portal. Daily metred data is used for large industrial customers (demands over 73 MWh/year).

Non-daily metred data covers Residential properties, including blocks of flats, commercial buildings and medium industrial sized users. (Any metre point with a demand under 73 MWh per year) [A15].

Data from 2020 has been used, and assumed to be a typical year. This was the most recent complete year of data on National Gas's data portal, prior to the energy price spikes. Due to global warming, winters will become warmer overall, and peak gas demands are predicted to fall. The use of 2020 data may therefore be conservative, particularly for 2050 forecasts. This will be balanced by the importance of security of supply for customers, which may see extra hydrogen need to be stored, than to perfectly balance one year's demand.



LDZs defined by gas networks, scope of domestic demand highlighted.

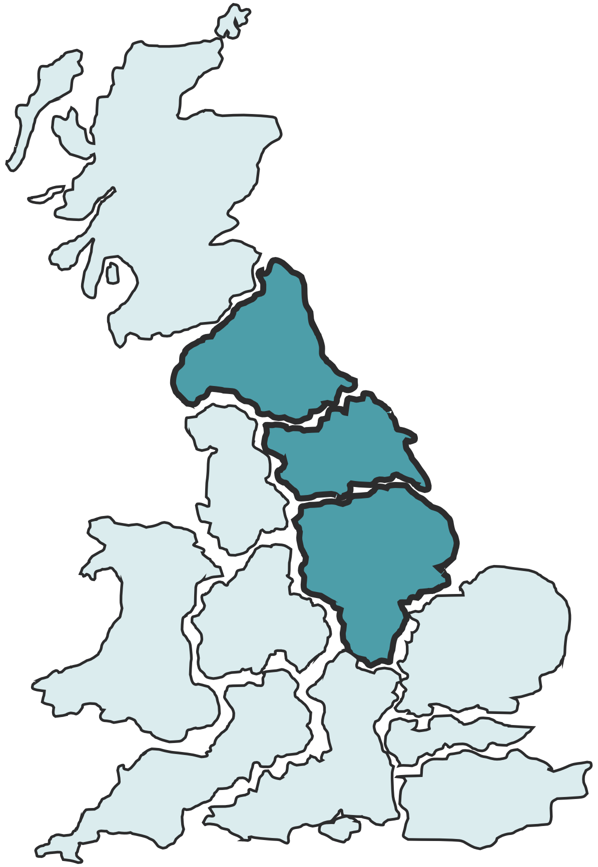


Figure A10: UK map divided by LDZs showing regions of usable salt and industrial clusters.

East Coast Gas demand data scaling

East Coast Gas Consumption data has been scaled to account for domestic heating for off-gas grid homes and future improvements of home insulation.

Off-gas grid homes

Not all residential properties are currently on the gas network. Some use oil, bottled gas, electric or other sources of heating. However, in this study it has been assumed all properties will either use a heat pump, or hydrogen boiler. (Other technologies such as heat networks are assumed to be powered by a large hydrogen heat boiler or heat pump and so encompassed in these demands).

As such 2021 Census data for the East Midlands, North-East and Yorkshire and Humber region, for different heating technologies has been used to scale the data from National Gas's data portal. See the table below for assumptions [A16].

Heating Technology	Proportion of properties in East Coast Region	Included in National Gas LDZ Domestic data (assumed)
Other	2.36%	✗
Electric only	6.09%	✗
Mains gas only	77.45%	✓
No central heating	1.21%	✗
Oil only	2.73%	✗
Tank or bottled gas only	0.85%	✗
Two or more types of central heating	9.31%	✓

Table A5: Breakdown of current heating technologies in homes in East Coast, UK Census 2021.

The above assumptions results in 87% of homes being included in National Gas LDZ non-daily metred data and so National Gas demand data is increased by a scale factor of 1.15, to account for other heating sources.

Insulation and home efficiency Improvements

In addition to transitioning to new heating technologies budling's heat demand will also be reduced through insulation. Insulation reduces the heat loss in buildings, causing a drop in heat demand, and cost-effective way of decarbonising.

Previous work for the Climate Change Committee on transitioning residential heat to net zero, estimated that insulation and home energy efficiency improvements will reduce heating demand by between 12% (balanced scenario) and 22% (widespread innovation)[2].

Heat demand reductions come from loft and fabric insulation. The CCC predict that a deep retrofit of a home could reduce its individual heat demand by 57%, but it is not anticipating all homes to receive a deep retrofit by 2050 [A17].

As such the following demand reduction assumptions are assume for modelling in this work.

Year	2030	2035	2050
High H_2 demand assumption	0%	3%	12%
Low H_2 demand assumption	0%	5.5%	22%

Table A6: Heat reduction through home energy efficiency improvement assumptions (adoption of insulation), A linear uptake between 2030 and 2050 is assumed to estimate 2035 reduction.

Government targets used as the basis for estimating the rate of uptake of low carbon heating appliances

Heat pump installation targets, coupled with historic UK heat pump installation data has been used to estimate the predicted growth rate of heat pumps in the UK. Building's heat demand form hydrogen has used recent government demand forecasts.

The UK government has set the following targets for heat pump installations [A18]:

- 2028: 600,000 heat pumps installed per year
- 2035: 1,900,000 heat pumps installed per year

There are currently 280,000 heat pumps installed in the UK, with 72,000 installed in 2022 [A19,A20]. To achieve government 2028 and 2035 targets an average growth rate of 40% to 2028 is assumed, 20% to 2035 assumed, to estimate the uptake rate for heat pumps in the UK. A more conservative scenario is also analysed where achieving government heat pump targets is delayed by 5 years (see graph below).

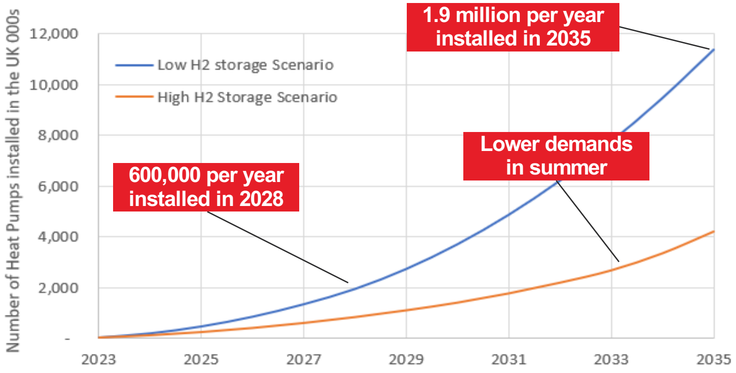


Figure A11: Assumed cumulative heat pump installations 2023 to 2035.
Blue – meeting gov. targets, Orange – 5 years behind gov. targets

Heat Pumps are assumed to be installed at the same rate for the whole of the UK, so the East Coast is assumed to follow the same uptake trend.

The role of hydrogen for heating is uncertain. It has not been ruled out and a formal decision is scheduled for 2026.

However recent government announcements have not looked to accelerate H_2 roll out for homes:

- Cancelling hydrogen village trial in Redcar [A21], and Whitby trial earlier in the year
- Future home standards consultation stating "fossil fuel boilers (including hydrogen ready boilers), will not meet proposed standards" [A22].

Given this the low H_2 demand scenario assumes no buildings use hydrogen boiler. The recent UK hydrogen roadmap (published December 2023), set upper and lower bounds (LB, UB) for hydrogen demand in the heating sector for 2030 and 2035. These have been compared to annual 2022 gas consumption for budlings of 330 TWh [A23], to estimate upper and proportion of domestic gas consumption converted to H_2.

Year	2030		2050	
	LB	UB	LB	UB
Demand (TWh)	0	3	0	60
% of domestic 2022 gas demand	0%	1%	22%	23%

Table A7: Lower and upper bounds for H2 in heating sector.
Source: DESNZ, Hydrogen Production Delivery Roadmap [A24].

This data has been combined and extrapolated to estimate uptake rates for heat pumps and H_2 boilers for a storage estimate with lower and upper bounds for the East Coast, given below:

Year		2030		2035		2050	
		H_2	HP	H_2	HP	H_2	HP
Proportion of appliances in East Coast	High H_2 demand	1%	8%	18%	19%	35%	65%
	Low H_2 demand	0%	13%	0%	38%	0%	100 %

Table A8: Hydrogen boiler and heat pump uptake assumptions for modelling

Power sector

Modelling approach for H_2 storage demand for power.

Power sector requirements for hydrogen storage are assumed to be from heating in buildings that has been electrified with heat pumps. In the UK this is currently very low, but its forecast to grow rapidly with ambitious government targets.

There is currently an inter-seasonal swing in domestic electricity demand, but it is assumed that once domestic heat has been electrified this will be the dominant swing in demand.

This would be delivered by excess hydrogen production in summer and stored in salt caverns. Then in winter to meet peak demands hydrogen would be withdrawn from salt cavern storage and converted back to electricity via gas turbines. (This could also be done with fuel cells, but gas turbines are assumed in this study). This process is illustrated on the right. (The diagram shows the case for electrolytic production for hydrogen, but excess CCUS-enabled H_2 could also be produced in summer and converted to electricity in winter).

The focus here is on inter-seasonal swings, and long duration energy storage. Other shorter term storage options such as line-pack in the gas network, are assumed not use hydrogen salt cavern storage. These would use other energy storage technologies, to respond to diurnal and inter-day peaks.

Assumptions for the efficiency of converting hydrogen to electricity/heat, and heat pump coefficients of performance are given in the table on the right.

As this study focuses on exploring salt cavern capacity constraints, infrastructure requirements to convert power to hydrogen, such as electrolysers have been excluded, or hydrogen to power, e.g. gas turbines. The model only examines how much hydrogen would be required to be in storage to meet peak power demands over for winter months.

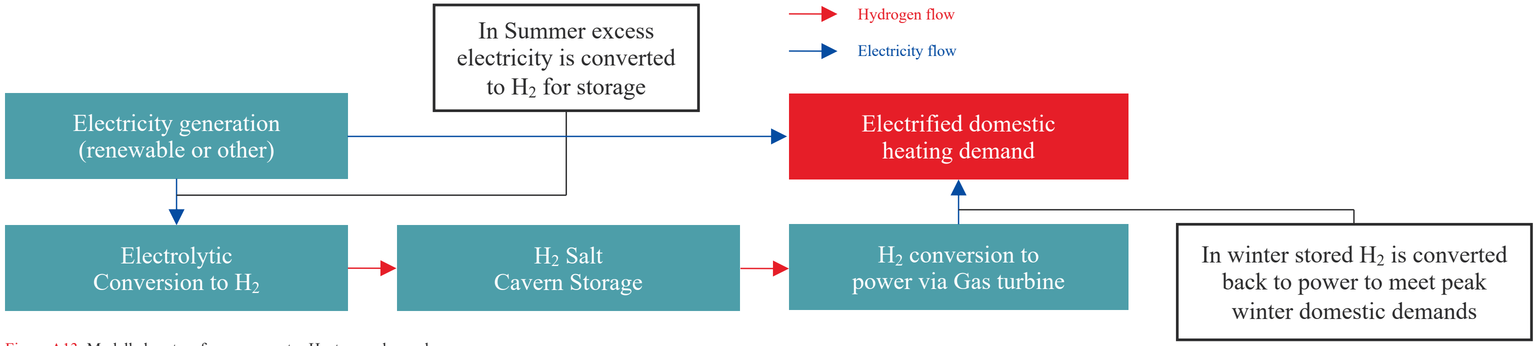


Figure A13: Modelled system for power sector H_2 storage demand.
H_2 used as a storage to balance inter-seasonal swings of electrified residential and commercial heating.

Assumption	Value	Source/rationale
H_2 boiler efficiency	90%	Assumed same as natural gas
Heat Pump Coefficient of Performance (CoP)	3 to 4*	Current UK performance and forecast improvement
Hydrogen Gas Turbine efficiency	50%	Assumed to be similar to natural gas

Table A9: Technical efficiency and coefficient of performance assumptions used for domestic sector storage demand modelling *Heat pumps installed in 2030 have COP, with steady improvement to COP 4 by 2040.

Residential and commercial heating & Power: Summary

Overall, the residential and commercial heat and power sectors use current National Gas data to model the profile of hydrogen demand over the year. Data is scaled for heat and power based on heat pump and hydrogen uptake scenarios, and home insulation and heating appliance assumptions.

Hydrogen demand scenarios for the residential and commercial heating sectors are summarised in the tables on the right*. In both instances heat and power demands are assumed to follow inter-seasonal profile currently exhibited for domestic heating, taken from National Gas data portal for the East Coast.

This data has been scaled to model improvements in home energy efficiency through insulation and account for homes not currently on the UK gas grid, with UK Census data.

In the assumptions there are a number of uncertainties that could be refined in a more detailed model. Most notably:

- Include current East Coast domestic power demands: in addition to forecasted demand form the electrification of domestic heat. There is a seasonal pattern to current UK domestic electricity demands, but the swing is currently lower than that for heating.
- Behaviour change in demand patterns: Domestic demand patterns may change, with more mild winters and harsh summer predicted to 2050. This is not currently considered.
- Consideration of other heating technologies: Heat pumps and H_2 boilers are the only technologies assumed, but other technologies biomass boilers may be used, and district heat networks may have other heat sources, e.g. energy from waste plants.

**Power sector hydrogen demand is higher in the low hydrogen demand scenario. This is because this scenario has a higher heat pump uptake and so higher power demands from the increased electrification of heat. This results in a greater inter-seasonal swing in domestic power consumption resulting in an increased hydrogen power demand for winter months. However, this is balanced with lower hydrogen for domestic heat in this scenario.*

Year	2030	2035	2050
% homes with H_2 boilers	1%	18%	35%
% homes with heat pump	8%	19%	65%
Annual domestic hydrogen heating demand (TWh/annum)	1.0	19.5	34.4
Annual hydrogen demand for domestic power consumption (TWh/annum)	1.3	2.7	7.0
Total domestic demand (TWh/annum)	2.3	22.2	41.4

Table A10: High H_2 demand scenario data summary.

Year	2030	2035	2050
% homes with H_2 boilers	0%	0%	0%
% homes with heat pump	13%	38%	100%
Annual domestic hydrogen heating demand (TWh/annum)	0	0	0
Annual hydrogen demand for domestic power consumption (TWh/annum)	2.0	5.2	9.6
Total domestic demand (TWh/annum)	2.0	5.2	9.6

Table A11: Low H_2 demand scenario data summary.

Hydrogen will be required for hard-to-abate transport sector, both in gaseous and derivative form

In this study the maritime and aviation sectors have been the focus for transport sector hydrogen storage requirements.

Hydrogen has been highlighted as a key decarbonisation technology for hard-to-abate transport sectors [A10].
In this analysis these are assumed to be:

- Aviation
- Maritime

These sectors account for most of the forecasted hydrogen demand in the transport sector (see graph on the right).

Storage for other transport modes have not been considered in this study. Hydrogen can be road used in road transport, with buses and cars already deployed in the UK. Additionally, the UK has allocated funding for two project to deploy heavy-duty hydrogen vehicles and associated infrastructure network in 2023 [A25]. However, with a range of battery-electric vehicles currently available from the market and comparatively few H_2, the use of hydrogen is uncertain for road transport.

Additionally, hydrogen refuelling stations have relatively small demands resulting in lower storage demands. The largest hydrogen refuelling station in the world has a demand of 4.8 tonnes per day [A26]. So even if there was requirement for several days of storage, this would only result in 10’s tonnes storage at each station. It is assumed this would not be of sufficient scale for salt caverns to be economically/technically feasible Therefore road transport has been excluded in assessment of hydrogen salt cavern storage demand assessment for salt caverns.

Both the aviation and shipping markets are nascent. First demonstration projects for hydrogen fuel cell and combustion applications are underway, but there are yet to be widespread commercial applications.

- Both sectors can use a range of applications to decarbonise:
- Battery electric
- Hydrogen fuel cell/combustion engines
- E-fuels and other hydrogen derivatives (ammonia, and e-methanol)
- Biofuels

The decision of which technology is optimal for each application is driven by the duty cycle. Batteries are often more economical for shorter range journey’s but not feasible at longer distances. (long haul flights, and international freight movement). E-fuels can be used as a dop-in for incumbent vessels and aircraft, but are expensive to synthesise.

The method for estimating both the uptake and storage requirement for hydrogen in aviation and shipping is outlined in the subsequent slides.


Zeroavia H_2 plane demonstration (left) – Image Link, and Nike H_2 barge demonstration (right) Image Link.

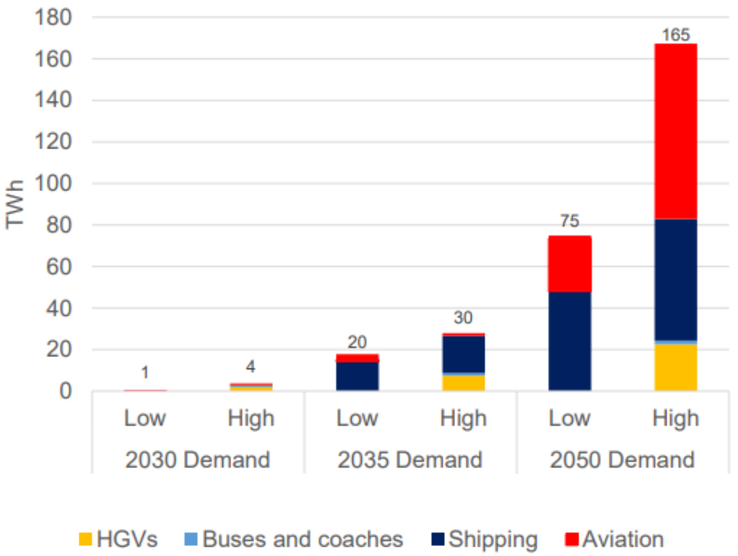


Figure A14: Forecast H_2 demand in the transport sector by transport mode (2030 to 2050).

H_2 fuel cell and combustion engines vessels are forecast to have a niche role in the maritime sector, with most duty cycles having more suitable alternatives

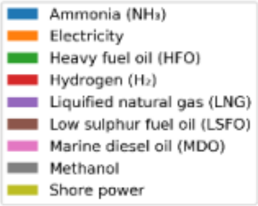
It has been assumed there will be a relatively low uptake of hydrogen/fuel cell vessels in the maritime sector, with the majority of hydrogen demand, coming from hydrogen derivatives such as ammonia and methanol.

In the maritime sector for lower-duty applications battery electric vessels are likely to be used. For the heaviest duty vessels hydrogen derivatives or biofuels are forecast to be used. “Mid-range” applications will be the most viable market for hydrogen fuel cell vessels.

This market size is likely to be relatively small and a low proportion of final demand [A27,A28] with other technologies still improving. Battery energy density performance is improving, and if solid-state batteries become commercially viable, they will significantly increase vessel range, and the proportion of maritime duty cycles batteries can cover.

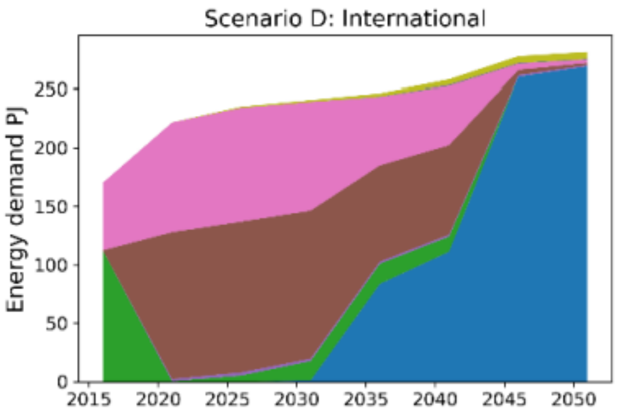
Additionally, the cost of hydrogen derivatives will decrease towards 2050, and improve the economic viability of shorter journeys. Therefore, a relatively low uptake of fuel cell and combustion engine vessel is expected, both for domestic and international shipping.

UK-wide hydrogen forecasts for the maritime sector have been taken as a basis for this assessment (see graph on the bottom right). These accounts for [A10]:



- Domestic and international shipping demands.
- Increase in total maritime fuel demand, driven by an assumption continued worldwide economic growth will continue to increase international shipping fuel demands in the UK.
- Use of hydrogen in derivative form, e.g. ammonia (which is predicted) to be the majority of shipping fuel consumption from other analyses2.

This data has then been localised to the East Coast region of the UK, by examining the proportion of current maritime demand in the UK.



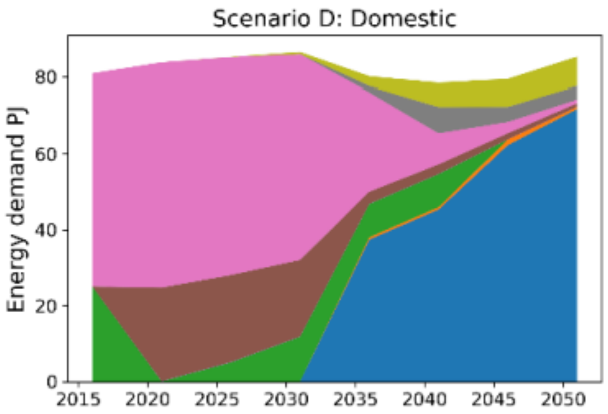


Figure A15: Projected future UK marine fuel demand for domestic and international shipping to meet net zero in 2050. H_2 (red) not visible on the graph Source: UMAS for department for transport.

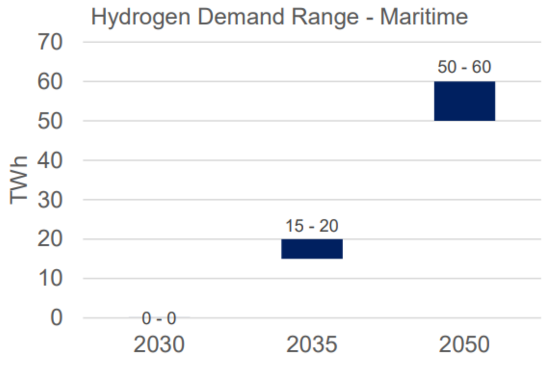


Figure A16: UK forecast H_2 demand for the maritime sector Both H_2 and H_2 derivatives Source: DESNZ

Estimating hydrogen storage requirement in the maritime sector is a complex multi-variable problem.

H_2 storage requirement for the maritime sector likely to be small as the majority of maritime H_2 consumption (H_2 derivatives) are not likely to be stored in salt caverns, and can vessels can be refuelled abroad where e-fuels are lower cost to produce.

Shipping has a relative continuous profile all year round, see Figure A17 which looks at freight movement over the yar for Northeast ports [A29]. This is different to other sectors in this study, (Industry, heat and power) which see a drop in demand over summer. Therefore, a temporal profile has not been analysed. Instead, a storage estimate required for bunkering has been estimated. This has been based on days of demand, that is typically seen at ports today, and considerations for the sector as it transitions to net zero.

In this study the requirement for bunkering hydrogen for use in hydrogen combustion engines and fuel cell vessels has not been considered in detail, as demand is assumed to be negligible.

However, hydrogen will still be required to synthesise derivatives such as ammonia and methanol for long-distance shipping.

Estimating this storage requirement becomes a complex multi-variable task, which is influenced by:

- International refuelling: As the maritime sector is a global market, ships that dock in the East Coast, do not have to refuel in the East Coast.
- Imported fuel on barges: Currently maritime fuel can be imported by barge to ports to refuel docked ships, where ships are exchanging cargo, and so does not need to be stored at the port. It is unclear if hydrogen derivatives would also be moved on barges in this manner.
- Competition from biofuels: Biofuels are also a cost-effective low carbon option for international shipping. However, they face scalability challenges, and so the split of biofuels vs hydrogen derivatives is uncertain.

Location of H_2 derivative plants: It is assumed where possible hydrogen would be stored in its more energy dense derivative form for maritime applications using derivatives. However, hydrogen storage may be required at the plants to synthesise derivatives, but locations of plants and size of storage requirements are uncertain.

International shipping is linked to economic growth, which creates uncertainty in the future total size of the end use market.

Choice of H2 storage technology: Depending on the size of storage requirement, salt caverns may not be the technology of choice. For smaller demands, some companies may use compressed gas cylinders, which become more cost effective at smaller scale.

In this assessment it is assumed there is a relatively continues demand for hydrogen derivatives throughout the year.

Therefore, in this work the following assumptions have been made:

- Low hydrogen uptake scenario: No hydrogen storage requirement for the maritime sector, which reflects a scenario where there is very limited hydrogen derivative production in the East Coast, and so any storage at East Coast ports will be in derivative form and not require salt caverns.
- High hydrogen uptake scenario: Two days storage of hydrogen of total hydrogen demand from the maritime sector (including derivatives), to reflect hydrogen bunkered for use in fuel cell/combustion engine vessels, and hydrogen required for the production of derivatives, which are located in the East Coast region.

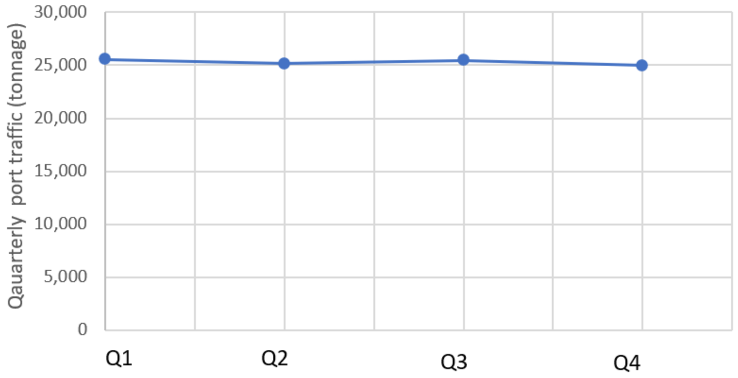


Figure A17: Quarterly port activity in Northeast* ports, by tonnage of freight movement, 2022.
Source: [A29] Department for Transport: Port and domestic waterborne freight statistics: data tables, Table 503
Northeast ports assumed to be: Grimsby & Immingham, Tees and Hartlepool, Hull, Tyne Goole, River Trent, Rivers Hull and Humber, Sunderland.

Scenario	Days of marmites H_2 demand
Low H_2 demand scenario	0 days
High H_2 demand scenario	2 days

Table A12: Maritime storage requirement assumptions *Includes both H_2 in fuel cell/internal combustion engine, and H_2 derivatives.

Similar to the maritime sector H_2 fuel cells and combustion engines are forecast to have a niche role in aviation

In the aviation sector, biofuels and e-kerosene are predicted to make up the majority of energy supply will smaller roles for hydrogen and battery electric vehicles.

The aviation will use a range of technologies to decarbonise including batteries for short-haul and biofuels an e-fuels for long haul flights. Hydrogen is assumed to be required for a more niche role within "mid-range" flights and be required to synthesise e-kerosene for e-fuels demand.

IEA data from the Net Zero Roadmap 2023 for aviation has been used to estimate the proportion of e-kerosene and H_2 uptake in aviation [A30]. In 2050 this is:

- E-kerosene: 37% of aviation fuel demand
- H_2: 7% of aviation fuel demand

It is noted as this is data representing the global transition so there will be uncertainty. East Coast airports, will have its own make up of short, medium and long-haul flights and require its own technology mix to decarbonise.

Future airport demand is uncertain in the UK. Due to the impacts of COVID-19 aviation energy consumption in 2022 is 20% lower than pre-COVID 2019 levels [A31]. It is not yet clear whether this drop due to COVID-induced behaviour change will be permanent or demand will recover. (Behaviour change assume to be a reduction in business travel, or recreational travel with fewer overseas holidays).

In the 2010s before COVID, UK aviation energy consumption was increasing steadily. Again, it is unclear, if this will be replicated in the 2020s and 2030s, or if demand will now be relatively constant at 2022 levels. Some key uncertainties here are:

- Global economic growth and if increased aviation activity in developing countries will lead to more demand in the UK.
- Government climate change policies to meet net zero targets, and if financial restrictions will be imposed on airport activity, causing a reduction in number of flights.
- Higher costs of low carbon fuels, compared to incumbent fossil fuels increasing cost of flying.

National hydrogen demand ranges published by DESNZ in December 2023, have been used to estimate the rate of uptake of hydrogen and hydrogen-based fuels for flying in this study. (See Figure A18 top right) [A10].

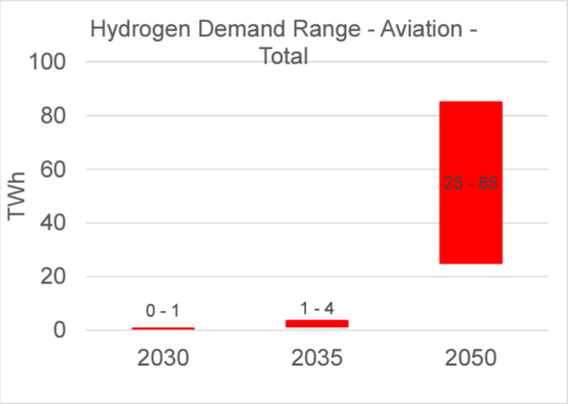


Figure A18: UK forecast H2 demand for the aviation sector. Both H2 and H2 derivatives Source: DESNZ.

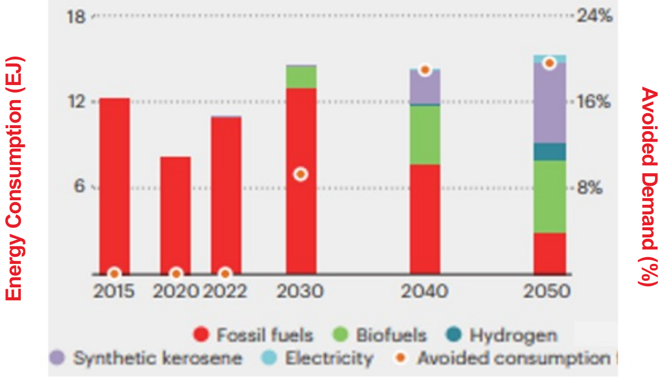


Figure A19: Global aviation fuel consumption transition Net zero in 2050. Source: IEA

Airports currently bunker relatively high quantities of Kerosene but there is uncertainty if this would be continued for H_2

Uncertainties in storage demand for H_2 in the aviation sector are similar to the maritime, and driven by choice of where to refuel (with options internationally), and requirements for H2 storage vs e-fuel storage.

As with the maritime sector, hydrogen demands are expected to come from predominantly low carbon hydrogen being required for e-fuel synthesis. In the case of aviation this is most likely to be e-kerosene. As the aviation sector is also an international market, this causes the hydrogen storage requirement to have uncertainties as with the maritime sector, such as:

- International choice of where to refuel
- Split of e-fuels and biofuels
- Choice of H_2 storage technology
- Location and operating pattern of e-fuel synthesis plants

Currently airports store around 3 to 4 days demand. Seasonality of demand varies between airport. In the UK some airports have relatively continuous traffic throughout the year, which conduct a number of commercial and business-related flights, are used for connecting flights, and have regular holidays traffic (e.g. London based airports). Other more local airports have a more seasonal demand, with higher numbers of flights occurring in the summer months as more people fly away on holiday. These are typically more local airports such as those located in the East Coast of the UK. As such airports with more regular traffic can have lower storage demands such as one day, and some airports that see more seasonal traffic can have higher demands, e.g. 5 days.

Annual aircraft movements on the East Coast are shown on the right for the year 2019. Data has been taken from the UK Civil Aviation Authority [A32]. 2019 has been used as the last year before air-travel became disrupted by COVID-19.

This data does show a seasonal trend, but as the swing is relatively small the profile has not been used as with other sectors.

Kerosene is relatively low cost to store compared to hydrogen, as it can be stored as a liquid under ambient conditions with a high volumetric energy density. Whereas H_2 requires significant compressions and even at elevated pressures does not achieve the same volumetric energy density. This will make it more economically challenging to store equivalent quantities of H_2.

The following assumptions have been made, shown in the table one the right. These are designed to represent the following for each scenario:

- High hydrogen storage demand: Airports require a large amount of hydrogen storage for hydrogen fuelled aircraft, and there is e-kerosene synthesis plants in the East Coast that require hydrogen storage to balance their operations.
- Low hydrogen storage demand: Airports have lower storage for their hydrogen-fuelled aircraft and e- kerosene synthesis plants are located outside of the East Coast, and so are not assumed to require any hydrogen storage.

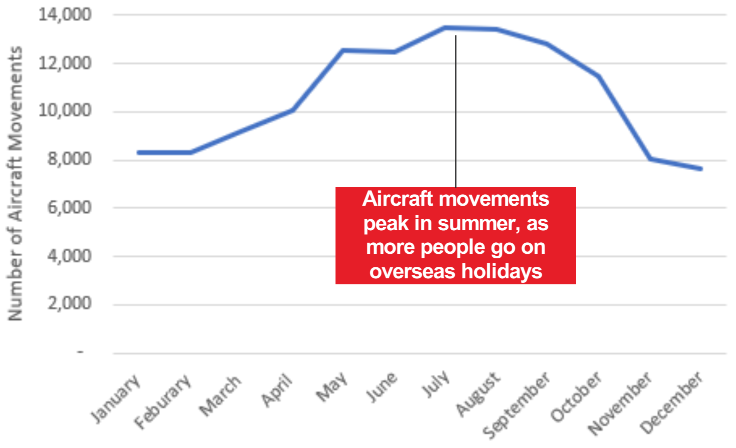


Figure A20: Monthly Aircraft movements in East Coast Airports 2019.
Humberside, Newcastle, Leeds Bradford and Doncaster Sheffield included in East Coast Airports,
Data Source: UK Civil Aviation Authority.

Sector	Low uptake storage assumption	High uptake storage assumption
H_2 - fuelled aircraft	2 days demand	4 days demand
E-kerosene fuelled aircraft	0 days demand	2 days demand

Table A13: Aviation storage requirement assumptions for the East Coast.

Aviation and Maritime forecasts have been localised to the East Coast examining total UK energy consumptions and passenger flow data

A significant proportion of UK maritime activity occurs along the East Coast, but only has a relatively small proportion of aviation activity.

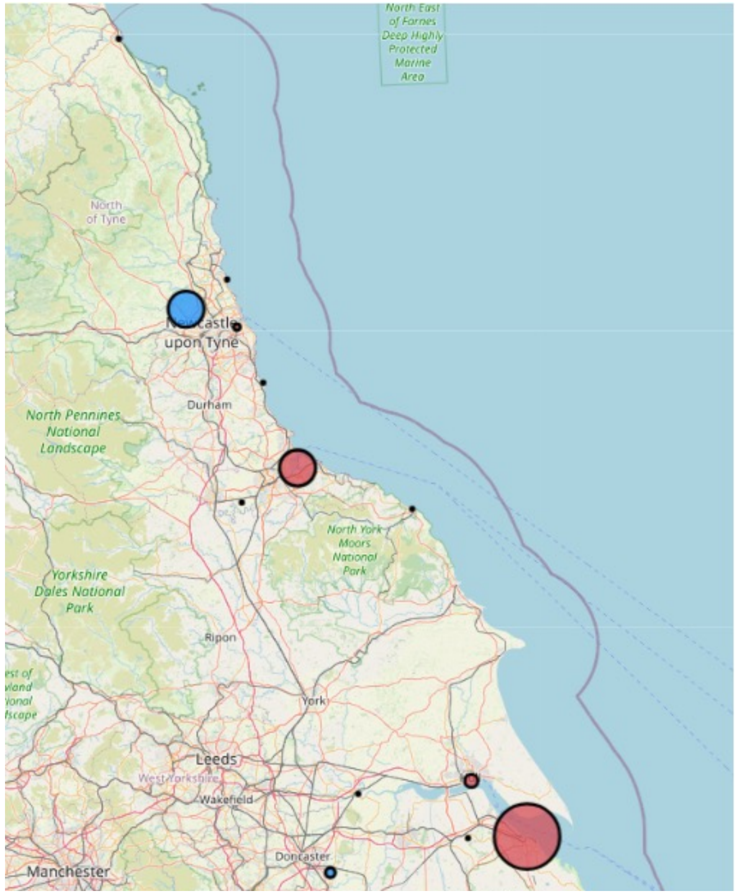


Figure A21: Airports and ports identified in the East Coast Region. Local East Coast aviation and maritime traffic used to scale national H_2 demands to East Coast Demands. Red blobs – ports, blue blobs – airports, size of blob indicates their relative size based on current freight activity or aircraft movements.

To assess demands specific to the East Coast, the following data has been used:

- UK total energy consumption data by sector [A31].
- Aircraft movement data at different airports [A32].
- Maritime freight movement at ports data [A29].

In each case the proportion of activity occurring at each port or airport in the East Coast, is the assumed proportion of hydrogen demand for the East Coast. However for a more granular assessment there are some important considerations and nuances:

- Airports: Traffic at local airports (airports outside of London), has a higher proportion of shorter and medium haul flights. This means a higher proportion of its activity may be suited to H_2-powered flight technology instead of e-kerosene and biofuels. If this was the case this could increase the need for H_2 storage at the airport.
- Ports: There is significant maritime activity in at East Coast ports, that does not involve the transport of cargo or freight. This is from the numerous offshore windfarms and oil and gas assets in the North Sea. Vessels are required to service the, and transport personnel to and from. Vessels used for these purposes will not show up in the freight moved statistics, therefore leading to and underestimated in the hydrogen demand for the maritime sector in the East Coast.

Additionally, where it is assumed that hydrogen storage will be used to facilitate the synthesis of e-fuels (e-ammonia, e-methanol and e-kerosene), only e-fuels demand for the East Coast region are considered. However, if the UK were to produce its own e-fuels then it is likely that much of this production would occur in the East Coast due to the established industrial and chemicals activity already occurring in the Humber and Teesside clusters. This would increase the demand for hydrogen storage in these sectors. (However it should be noted that there is uncertainty that the UK would synthesis all its e-fuels with the possibilities for international refuelling, discussed in more detail earlier in this section).

The proportions of UK activity occurring in the East Coast are:

- Maritime: 22.5%
- Aviation: 4.3%

Ports Identified
Grimsby & Immingham Tees and Hartlepool Hull Tyne

Airports Identified
Newcastle Leeds Bradford Doncaster Sheffield

Table A14: List of Airports and Ports Identified in the East Coast.

Transport storage forecasts have been calculated as fixed values not dependent on a profile as with other sectors

Transport sector storage demands in the East Coast are relatively small.

These have then been applied to the uptake forecast for hydrogen in the UK maritime and aviation sectors.

Low and high storage demands have then been calculated with the upper and lower assumptions for these sectors.

For the transport sector these values, are the final estimates for the storage demand. This is different to calculations for other sectors where an annual demand profile, has been modelled against an assumed hydrogen production profile to estimate storage requirements.

This assumption has been made as maritime and aviation demands are more continuous throughout the year, than other sectors like residential and commercial heating and industry. If the same approach was undertaken for the transport sector there is a risk this could underestimate their storage needs.

Storage can be required for:

- Managing annual production and demand swings, and seasonality.
- Ensuring functionality of operations for different sectors.

As an example within the transport sector, airports currently have up to 5 days of kerosene bunkered on site to ensure functionality, e.g. if there are disruptions in fuel supply.

It is assumed this storage to ensure functionality will be greater than management of annual production and demand swings, given the relatively low swings compared to other sectors.

This has therefore been used as the assumption for storage in the transport sector.

The storage requirements calculated in the East Coast for this methodology, are small compared to other sectors (See results section for comparison to other sectors).

Sector	% of current UK fuel demand in East Coast	Low uptake demand scenario – East Coast (TWh /annum)			High uptake demand scenario – East Coast (TWh /annum)		
		2030	2035	2050	2030	2035	2050
Aviation e-kerosene fuelled	4.3%	0	0.04	0.9	0.04	0.15	3.1
Aviation – H_2 fuelled	4.3%	0	0.01	0.16	0.01	0.03	0.6
Maritime	22.5%	0	3.4	11.3	0	4.5	13.5

Table A15: East Coast H2 demand scenarios for aviation and maritime sectors.

Sector	Low uptake storage assumption	High uptake storage assumption	Low Storage demand (GWh)*			High Storage demand (GWh)*		
			2030	2035	2050	2030	2035	2050
Aviation – H_2 fuelled	0 days demand	4 days demand	0	0	0	0.01	0.03	0.6
Aviation e-kerosene fuelled	0 days demand	2 days demand	0	0	0	0.2	0.8	17
Maritime	0 days demand	2 days demand	0	0	0	0	25	74
Total			0	0	0	0.21	26	102

Table A16: East Coast H_2 storage forecasts, for East Coast demand in aviation and maritime sectors.
*Storage demand from hydrogen salt caverns, storage of e-fuels not assessed, but likely required.

Context: Hydrogen Production in the UK East Coast Region

The announced hydrogen production projects in the East Coast region will see up to 11.6 GW of low-carbon hydrogen production capacity by 2037, with 10.8 GW by 2030. This places the East Coast well to make up a significant proportion of the UK's 2030 10 GW hydrogen production target.

The East Coast region is set to become a key producer of low-carbon hydrogen with up to 11.6 GW of planned capacity to be operational by 2037, representing around 58% of the UK's total announced capacity of over 20 GW [A2]. Teesside and Humber are set to account for 33.1% and 60.2% of this total regional capacity, respectively, highlighting the significance of the East Coast Cluster in developing the UK hydrogen industry.

	Total announced production by 2037 (GW)
East Coast Region	11.6
CCUS-Enabled	6.3 [54.5% of ECR total]
Electrolytic	5.2 [45.1% of ECR total]
Teesside	3.8
CCUS-Enabled	2.0 [52.4% of Teesside total; 2 sites]
Electrolytic	1.8 [47.6% of Teesside total; 5 sites]
Humber	7.0
CCUS-Enabled	4.3 [61.7% of Humber total; 4 sites]
Electrolytic	2.7 [38.3% of Humber total; 7 sites]

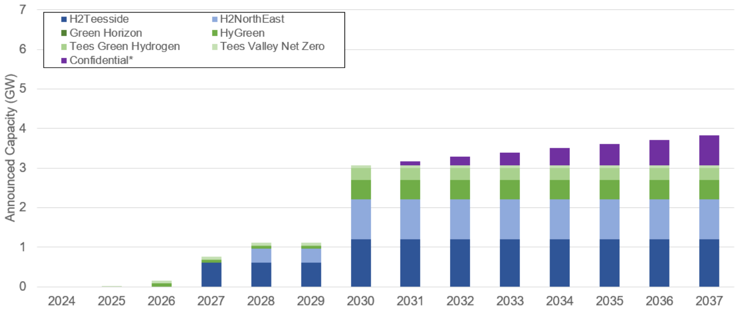
Table A17: Total announced low-carbon hydrogen production capacity in the East Coast region by 2037.

The growth of hydrogen production capacity is expected to accelerate in the mid-2020s, with large gigawatt-scale CCUS-enabled hydrogen projects leading the way and electrolytic capacity mostly contributing from 2030. However, the majority of the of the announced 11.6 GW of production is pre final investment decision and at the pre-planning or pre-FEED (front-end-engineering-design) stage. It is likely that only a fraction of this will convert into commissioned projects by 2030 [A2]. Especially given early hydrogen production projects require public support to enable a viable business model and UK national targets are set a 10 GW of hydrogen production nationally by 2030. (Only a fraction of the 10 GW will be in the East Coast)

During the early stages of adoption, production sites will be matched to specific customers with individual supply between CCUS-enabled or electrolytic hydrogen plants, that align with their schedules. Later on, if hydrogen infrastructure is rolled out at scale it will be possible for production points feed hydrogen into the grid with no specific customer, as is done with natural gas, on the National gas grid today.

The impact of a greater influence of wind variability on the increased electrolytic hydrogen production capacity from 2030 is assessed in the seasonality of hydrogen production sensitivity analysis.

(a) Teesside



(b) Humber

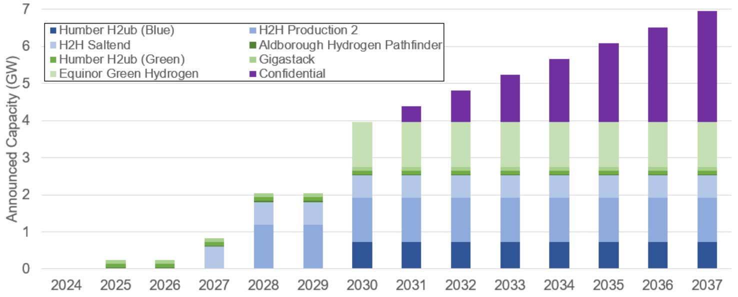


Figure A22: Total capacity profile of announced hydrogen production projects in (a) Teesside and (b) Humber. Sum of CCUS-enabled capacity and electrolytic capacity not aligned to 10.8 GW from East Coast Hydrogen plan, as only specific projects are plotted, with publicly announced capacities – *other confidential projects included as one in purple, and show an indicative linear growth from 2030 to 2037 to illustrate the full scale of ambitions for the East Coast.

Methodology: Summary of Sectoral Hydrogen Demand Analysis

Several data sources and assumptions have been applied throughout the study to develop a unique assessment of hydrogen demand across the East Coast region, in alignment with local developments and UK Government targets.

Sector

Industry | Heat | Power Generation | Transport

Data

Industry

- Representative quarterly hydrogen demand profile assumed, aligning with average 2020-22 quarterly UK industrial natural gas demand proportions.
- Total annual regional hydrogen demand forecasts averaged using East Coast Hydrogen Delivery Plan and CCC modelling data.

Heat and Power Generation

- Heat and power, use the same data sources.
- 2019 data from the National Gas portal, the East Coast, assumed to be NE (Northeast), NO (North) and EM (East Midlands) LDZ (Local demand zones) – used for the profile.
- UK government heat pump installations targets and forecasted H_2 demands, use to estimate uptake of domestic heat pumps and H_2 boilers between 2030 and 2050.

Transport

- National UK hydrogen forecasts for maritime and aviation sector
- Airport specific-aircraft movement data.
- Port-specific freight movement data.

Key Assumptions

Industry

- Low and high hydrogen demand scenarios between 2030 and 2050 determined using UK Government confidence interval ranges.
- Localisation of data to East Coast region by applying representative quarterly demand profile to hydrogen demand forecasts.

Heat

- Home energy efficiency (insulation) provide a domestic heat demand reduction between 2030 and 2050.
- All homes will use either a heat pump or a hydrogen boiler. District heat networks, will be powered by large – scale heat pumps.
- Off-gas grid homes not included in National-Gas demand data.

Power Generation

- Long duration energy storage for the power sector will require hydrogen.
- Domestic power consumptions will have the same shaped profile as domestic heat consumptions once heat is electrified.

Transport

- Each airport and port will require hydrogen storage equivalent to a number of days demand to support its operations.
- Hydrogen demands are scaled geographically proportionally with aircraft movements and freight movements.

Methodology: Hydrogen Storage Demand Model Construction

The model is designed to balance demand profiles from all sectors with hydrogen production to output the required storage capacity. Initially a constant hydrogen production rate is assumed throughout the year. This is explored as a sensitivity.

The model calculates the requirements to balance hydrogen production with demand profile across all sectors in the East Coast. Initially a constant production profile has been used. This assumes there is no variation in annual hydrogen production. Hydrogen production has therefore been sized to the annual hydrogen demand, so there is no accumulation of hydrogen in storage across multiple years. Under this assumption, storage will be the only mechanism of balancing hydrogen production and demands but in reality this may not be the case:

- Production could be oversized, with increased capacity to produce more in peak winter periods, rather than solely relying on storage. This means production would be ramped down during summer. In theory if production was sized to the maximum daily demand, then there would be no requirement for storage for balancing inter-seasonal swings. However, this would not be cost-effective as there would a very low utilisation of production plants and large capital investment. Equally, system costs can be saved by a smaller oversizing of production reducing storage requirements. Thus, the optimal point from a cost perspective will be between the two extremes of production sized to average demand and production sized to maximum demand. As system costs and estimating hydrogen production capacities are out of scope of this study this has not been considered in detail. An indicative oversizing is considered as a sensitivity to illustrate the relative impacts on storage.
- The East Coast is assumed to be a closed boundary. However, the East Coast may be a net importer or exporter of hydrogen with the rest of the UK, meaning production and demand do not necessarily have to match.
- Renewable generation sees a seasonal variation, which will be explored as a sensitivity.

East Coast storage forecasting model diagram

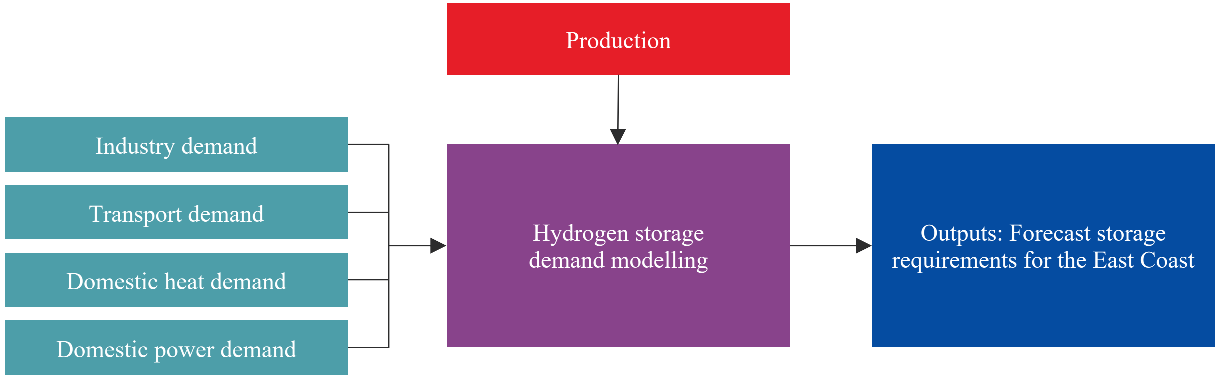


Figure A23: Block diagram, of hydrogen storage demand model.

Summary of Modelled Sectoral Hydrogen Demands

Industry is forecasted to have the greatest uptake in hydrogen demand across all sectors. This aligns with the plans of industrial sites, largely split between the Teesside and Humber industrial clusters, to decarbonise their operations by fuel-switching to low-carbon hydrogen.

The 'low' and 'high' sectoral hydrogen demand scenario-based analysis was undertaken to model the uncertainty of future hydrogen uptake. Based on the study assumptions, the industry, heat and power generation sectors were modelled using daily hydrogen demand profiles.

The industry sector follows a constant daily profile over each quarter, assuming average quarterly industrial natural gas demand proportions (due to data availability). This quarterly profile has been applied to reported total industrial hydrogen demand forecasts for the East Coast region, which account for the proportion of industrial customers switching to hydrogen based on direct stakeholder engagement with a variety of customers.

The heat and power generation sectors follow a variable daily profile with an inter-seasonal trend, assuming forecasted uptake rates of hydrogen boilers and heat pumps aligned to UK government targets. These have then been applied to natural gas LDZ data for the East Coast region. Power sector demands were estimated by assuming hydrogen-to-power generation required to accommodate increased future power demands due to the uptake of heat pumps.

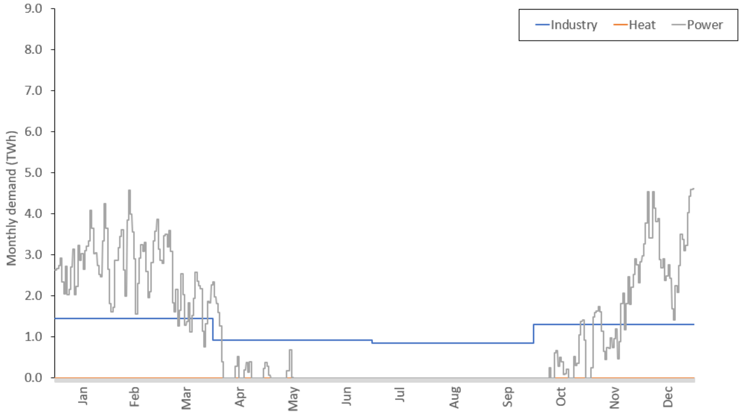
The total annual hydrogen demand for industry is estimated to significantly outweigh other sectors in the near-term (2030 and 2035), with the exception of the high hydrogen demand scenario in 2035 where the heating sector is estimated to have a similar annual demand. This is due to industry being an early adopter of hydrogen, with many of the largescale projects in the East Coast being developed within industrial clusters, which have early demand needs driven by 2040 decarbonisation targets [14,15].

In 2050, hydrogen demand for the power sector is estimated to represent a greater proportion in the low hydrogen demand scenario, due to the forecasted widespread residential heat decarbonisation with the uptake of heat pumps. Total hydrogen demands for the low and high hydrogen demand scenarios for the three sectors across the East Coast region in 2050 were estimated to be 19.5 TWh and 78.7 TWh, respectively.

Table A18: Forecasted annual low and high sectoral hydrogen demands (TWh) for the East Coast region.

Forecast Year	Industry	Heat	Power Generation	Total*
Low hydrogen demand scenario				
2030	7.1	0.0	2.0	9.1
2035	9.9	0.0	5.2	15.1
2050	9.9	0.0	9.6	19.5
High hydrogen demand scenario				
2030	11.6	1.0	1.3	13.4
2035	11.6	19.5	2.7	44.0
2050	11.6	34.4	7.0	78.7

**An annual demand profile was not determined for the transport sector due to the assumed requirement for hydrogen storage to provide a minimum capacity for the aviation and maritime sub-sectors (i.e. based on 0-4 days of supply, depending on scenario) rather than for demand matching purposes, see subsection later.*



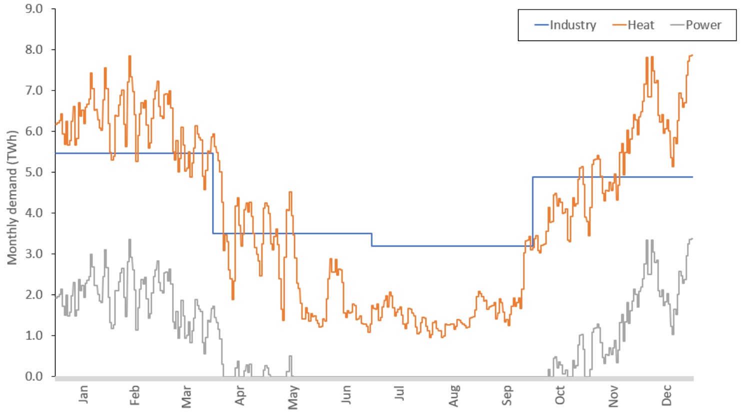


Figure A24: Assumed 2050 daily sector hydrogen demand profiles used for hydrogen storage demand modelling in the East Coast region (a) low hydrogen scenario above (b) high hydrogen scenario below, Transport not included as a temporal profile was not used.

IDRIC | BGS British Geological Survey | THE UNIVERSITY of EDINBURGH | ARUP

Key Findings: Annual Hydrogen Storage Demand Forecasts

Despite industry having the greatest hydrogen demand, the use of hydrogen in the heat and power sectors are the greatest drivers of hydrogen storage capacity. This highlights the importance of hydrogen storage to balance the misalignment between production and highly variable, inter-seasonal demand for power and heating sectors.

The following total hydrogen storage demand forecasts for the East Coast region were estimated by assuming simultaneous occurrences of all ‘low’ hydrogen demand scenarios across all sectors and, separately, all ‘high’ hydrogen demand scenarios across all sectors, to give the full range of possibilities. All values represent minimum working gas capacity requirements.

- 2030: 1.7 – 2.0 TWh.
- 2035: 3.8 – 8.2 TWh.
- 2050: 6.2 – 15.5 TWh.

Across all scenarios, transport sector demand is forecasted to have a minimal impact on the overall hydrogen storage demand due to the static 0-4 days security of supply storage assumption.

For the low hydrogen storage demand forecasts, the power sector is observed to require the greatest capacity of hydrogen storage across all sectors. This is due to the highly variable and inter-seasonal nature of the forecasted power sector demand, with large peak demands in the winter requiring additional storage to meet these peaks. In contrast, despite industry having greater annual hydrogen demands, the reduced variability and seasonality of the industry demand profile means production will be more closely matched to demand. This highlights an important feature of storage demand forecasting; storage demand is driven by both scale of demand and variability with respect to production.

For the high hydrogen storage demand forecasts, hydrogen storage demand is even more driven by the industry, heat and power sectors, with industry requiring the greatest storage capacity in 2030 and the heat sector representing the majority in 2035 and 2050. This highlights the greater need for hydrogen storage to support the industry sector in 2030 due to an earlier expected transition to hydrogen. In the later years, the heating sector has a greater influence on the hydrogen storage demand, from the scale up to the assumed 35% of homes using hydrogen boilers in the region in 2050. This consequently reduces power sector demand with fewer heat pumps installed in this scenario. This storage is within the large range of other UK-scale assessments, but there is a great range in other studies forecasting to net zero in 2050:

- National grid FES 2050: 19 to 55 TWh [16]
- AFRY Long duration Energy storage for BEIS,: 11.2 to 17.4 TWh [17]
- Royal Society, Large Scale Electricity storage: 60 to 100 TWh [18]

Forecasted hydrogen storage demands for 2050 are explored further in the following slides to highlight the key characteristics and test assumptions in the developed model estimations. Similar conclusions can be made when analyzing the 2030/2035 time periods for the low and high hydrogen scenarios.

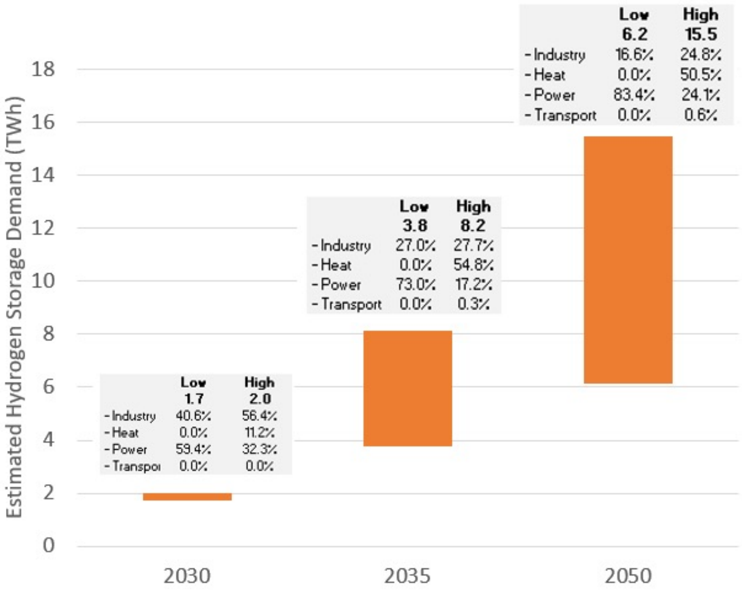


Figure A25: Forecasted hydrogen storage requirements for the East Coast region with data tables highlighting the illustrative hydrogen storage demand proportions for each individual sector.

**Note: While hydrogen storage demands for each sector have been reported individually for illustrative purposes, this does not suggest that hydrogen storage will be developed for the individual sectors in isolation. Data has been represented in this way to highlight the key drivers for the hydrogen storage demand estimates. The heat and power sector demands can also be considered in combination to represent an ‘overall heating sector demand’, representing hydrogen’s potential use for gas (hydrogen boilers) and electrified heating (heat pumps), respectively.*

Key Findings: Forecasted 2050 Daily Temporal Demand and Supply Balancing

The aggregated sectoral demand profile highlights the daily variability and inter-seasonal nature of hydrogen demand. The net balance between the constant production profile and the variable demand highlights the need for hydrogen storage to provide additional capacity in winter months.

Figure 11 shows the hydrogen injection and withdrawal pattern that modelling has forecasted. Hydrogen is injected during the summer months between April and October and withdrawn in winter months between November and March.

For both low and high hydrogen demand scenarios, an aggregated demand profile with daily variability and an inter-seasonal trend is observed. The daily variation is largely driven by the forecasted heat and power sector demands, with all three sectors contributing to the inter-seasonal trend, albeit to different degrees. By plotting daily annual demand with respect to average production, the area between the two profiles (i.e. the accumulated net difference between production and demand at daily intervals) provides an indication of the scale and duration of injection and withdrawal periods.

Maximum and minimum daily aggregated demands of the low and high hydrogen demand scenarios provides an indication of the minimum daily injection and withdrawal capacities required to prevent any unmet loads occurring throughout the year. The net difference of values greater than average daily production represent a daily minimum storage withdrawal capacity, whereas the net difference of values below the average daily production represent a daily minimum storage injection capacity.

This study only considers total capacity requirements (TWh) for hydrogen. However there will be significant infrastructure required to enable hydrogen to be injected into and withdrawn from storage at the required rate. The maximum withdrawal capacity varies from 33 to 116 GWh per day. Components such as compressors and dehydration plants will be needed. This type of infrastructure requirement has not been considered in detail in this study but should be considered when planning for hydrogen storage and the role it will play in the energy system.

Parameter	Low Hydrogen Demand Scenario	High Hydrogen Demand Scenario
Minimum daily aggregated demand	48 GWh/day	296 GWh/day
Maximum daily aggregated demand	172 GWh/day	596 GWh/day
Daily average production	81 GWh/day	412 GWh/day
Minimum daily storage withdrawal capacity	91 GWh/day	184 GWh/day
Minimum daily storage injection capacity	33 GWh/day	116 GWh/day

Table A19: Forecasted hydrogen storage demand modelling parameters for the 2050 low and high hydrogen demand scenarios.

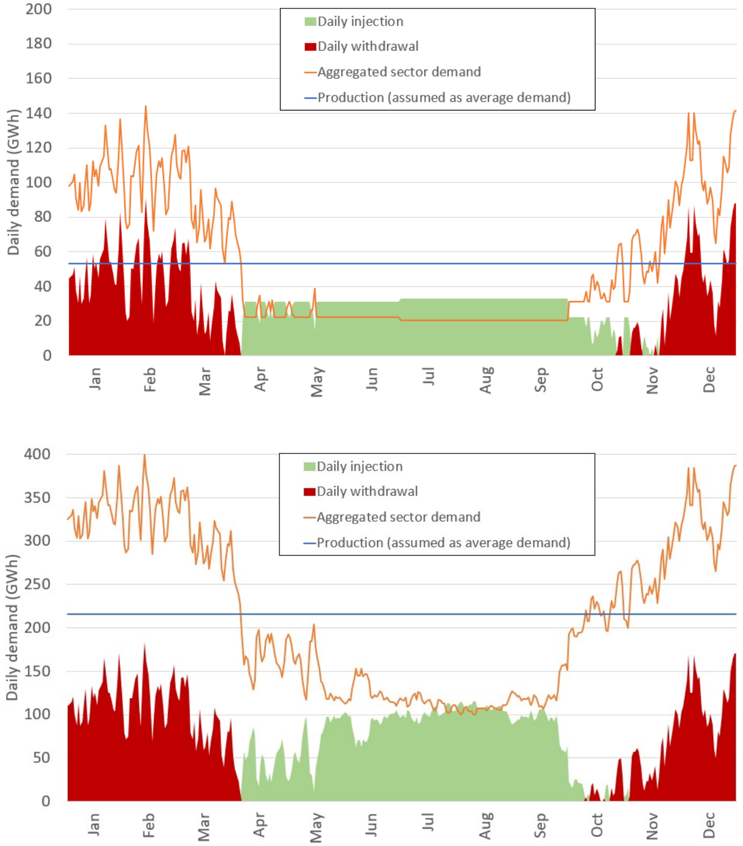


Figure A26: Aggregated 2050 daily demand profiles of the industry, heat and power sectors against production at average demand, with highlighted periods of injection and withdrawal (a) low hydrogen demand scenario above (b) high hydrogen demand scenario below – Graphs have different y-axes.

Key Findings: Forecasted 2050 Hydrogen Storage Demand for Seasonal Balancing

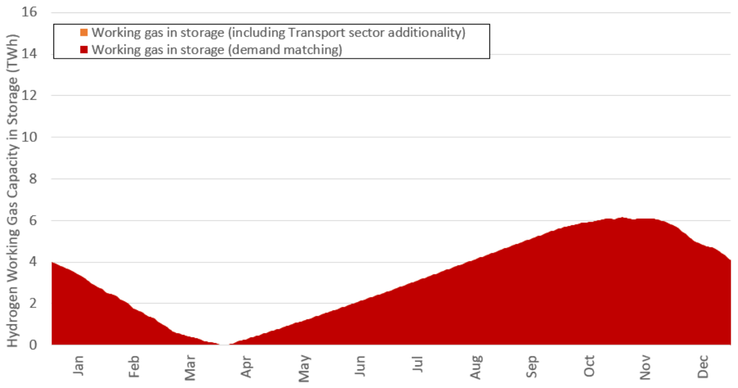
The developed profile of minimum daily hydrogen working gas capacity highlights the inter-seasonal balancing benefit of hydrogen storage. In 2050, a minimum hydrogen storage working capacity demand of 6.2 – 15.5 TWh was forecasted.

A profile of minimum daily hydrogen working gas capacity in storage was developed by accumulating the net difference between production and demand across the full year and assuming an initial working gas inventory such that the minimum value of the analysis returns a zero value for working gas. For each scenario this ensures the most significant withdrawal period doesn't fully deplete the entire working gas capacity available, thus providing an estimation of the minimum working gas capacity requirement for seasonal balancing as indicated by the maximum value of the profile.

- For the low hydrogen demand scenario, a minimum working gas capacity requirement of 6.2 TWh was determined. This scenario assumes there is zero additional storage demand from the Transport sector due to the 0-day storage assumption for the hydrogen- and e-kerosene-fuelled aviation and maritime sub-sectors.
- For the high hydrogen demand scenario, a minimum working gas capacity requirement of 15.5 TWh was determined. This estimate accounts for a small minimum storage additionality of 0.1 TWh from the transport sector, based on the 4-day storage assumption for hydrogen-fuelled aviation and the 2-day storage assumption for e-kerosene-fuelled aviation and the maritime sub-sectors.

The profile highlights the inter-seasonal energy system balancing opportunity of large-scale hydrogen storage at the regional level – hydrogen is withdrawn from storage during the winter months and is then injected into storage over summer. A smooth curve is observed from daily demand modelling, however in reality, increased intraday variability between injection and withdrawal is likely to occur creating more frequent demand fluctuations. Additionally, non-constant production will also increase variability of injection and withdrawal patterns. More frequent demand fluctuations will not strongly influence the total capacity required to balance inter-seasonal demands. Given the focus of this study on total capacity constraints, these higher frequency fluctuations have not been explored further (There are also additional complexities of whether hydrogen salt cavern should be the technology of choice for providing storage to balance higher frequency fluctuations).

It is important to reiterate that the hydrogen storage demand forecasts represent a working gas capacity. When designing storage systems and/or determining available hydrogen storage capacities to accommodate the hydrogen storage demand, cushion gas requirements and specific geometries of individual caverns will need to be considered. This is explored further in WP2 when assessing the surface and subsurface constraints to hydrogen storage development.



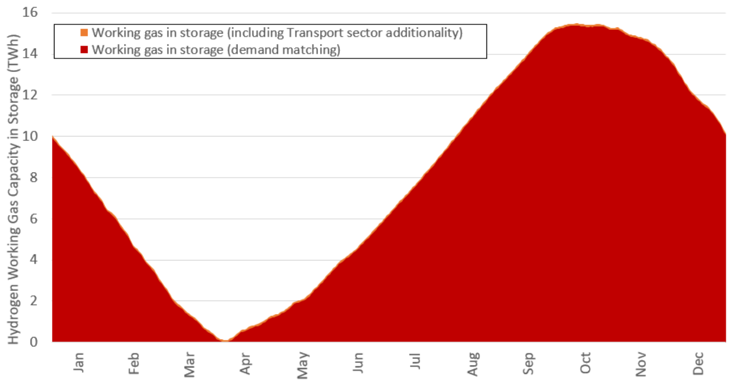


Figure A27: Minimum daily hydrogen working gas capacity requirement in storage (a) low hydrogen demand scenario above (b) high hydrogen demand scenario below – Additional demand for transport in orange is very small and so challenging to see when plotted to scale.

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Sensitivity Analysis & further considerations: Summary of Sensitives Explored

To estimate the storage requirement of the East Coast a number of assumptions have been made which carry uncertainty. These have been tested through selected sensitives to improve the robustness of the analysis.

In conducting the hydrogen storage demand forecasting there are a number of assumptions made to derive the forecasts, which carry uncertainty.

Key assumptions have been selected to be tested with sensitivity analysis. This is to improve the robustness of results and, resulting conclusions.

The sensitivities selected in this study are:

- Assumption of East Coast salt field, only supporting East Coast storage demands: As salt is limited to a few geographies in the UK, the East Coast salt field may have to support hydrogen storage demands from outside the East Coast region. This will increase storage requirements.
- Seasonality of hydrogen production: In the base case assessment hydrogen production was assumed to be continuous throughout the year. However, electricity sources such as offshore wind power do show a regular seasonality. If production and demand profiles align this can reduce storage requirements.
- Oversizing production: In the base case it was assumed hydrogen production would be sized to meet annual hydrogen demand, resulting in production requiring to operate continuously, and operating an energy system that would derive it's entire flexibility through storage. In reality this is unlikely to be most cost-effective, particularly where power is converted to hydrogen, before being converted back to power due to a low round trip efficiency. In reality it is likely production will be oversized, so system flexibility can be provided from both production capacity ramp up and down and storage.
- Strategic reserves: The UK currently has strategic reserves of oil, for emergencies, if there are severe supply chain disruptions. The impact and requirement of converting this storage to hydrogen is considered, and the likelihood of requiring them in the future.

Sensitivity Analysis & further considerations

Hydrogen Storage Demand Model Outputs

Hydrogen storage to support the Southeast of England

Base case: Power and heat sector demands determined using NTS LDZ data for NO, NE and EM regions.

Sensitivity: LDZ data for EA, NT and ST regions included as an additionality to base case.

Hydrogen storage to support the Southeast of England

Base case: Constant hydrogen production capacity assumed, equal to average total hydrogen demand.

Sensitivity:

Seasonality of hydrogen production

Base case: Only seasonality of demand assessed, reflected using LDZ data for the heat and power sectors, with constant production.

Sensitivity: Seasonality of electrolytic hydrogen production assessed using representative offshore wind profile data.

Strategic reserves

No formal numerical modelling has been conducted here. Current legislation and obligations have been outlined, and additional context around how the needs for strategic reserves will change as the UK transition to energy independence and net zero in 2050.

Sensitivity Analysis 1: Supporting Demand Outside the East Coast

Currently the UK only has salt caverns deployed in the North-west and North-east of England, other regions have salt deposits but some regions, particularly the Southeast and Scotland do not have available salt in their geology.

Currently UK salt caverns only operate in the Northeast and Northwest of England. Other salt fields exist in the South-west of England, but salt suitability is yet to be proven with operational salt caverns. Regions such as the Southeast of England and Scotland do not have any available salt and therefore do not have access to hydrogen salt cavern storage in their own geography.

It is therefore likely that the East Coast salt filed will be required to provide storage to balance demand-swings for the energy system in regions outside the East Coast.

To explore this, demands from East Anglia, London and the South-East of England have been added. Data from the National Gas data portal has been used to estimate heat and power demand form hydrogen with the same methodology described earlier the Heat modelling assumptions Section. Daily data was used to determine a demand profile to estimate storage requirements. With significantly lower industrial activity in these regions, it is assumed domestic demand will make up the majority of storage requirements for these regions and is the only additional sector assessed.

With up to additional 36% of the UK population, there will be a significant demand swing.

	Base Case	Sensitivity
2019 NDM LDZ natural gas demand	96.7 TWh per year	224.6TWh per year
% Demand Increase	n/a	+ 132%

Table A20: Inclusion of London, South East and East Anglia demand assumptions summary, NDM – Non daily metred.

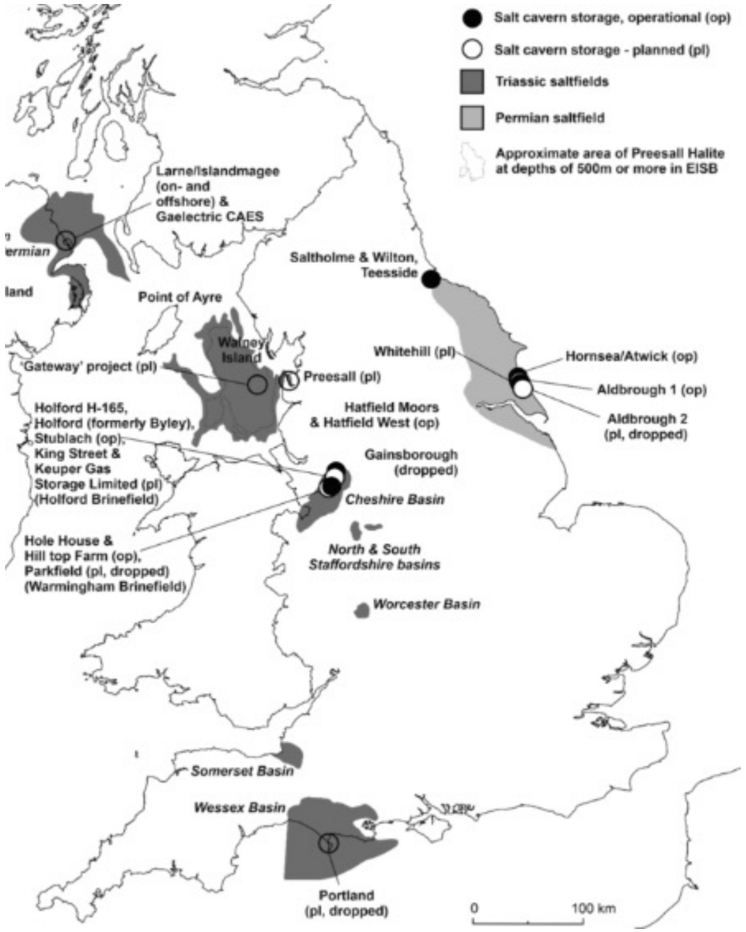


Figure A28: UK salt field, with operational and planned salt cavern facilities, 2021.
Source: [A33] Journal of Applied Sciences.

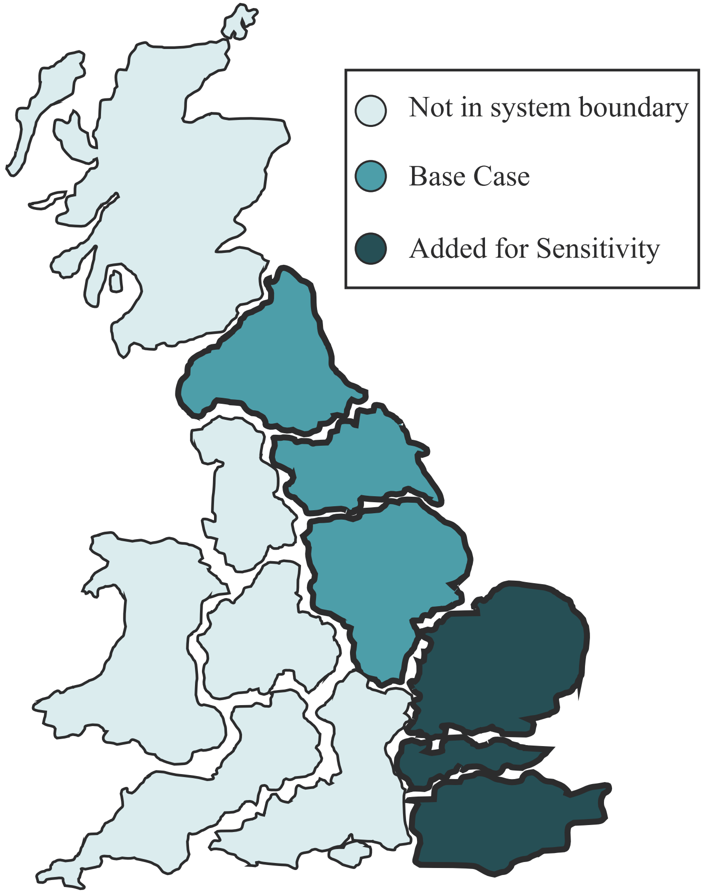


Figure A29: UK map divided by LDZs showing regions of usable salt and industrial clusters. LDZs defined by gas networks, scope of domestic demand highlighted (inc. Sensitivity) [A1]

Sensitivity Analysis 1: Supporting Demand Outside the East Coast

If the East Coast salt basin was required to support storage demand form the South East, then demand for storge approximately doubles.

If the East Coast salt basins are required to provide storage support for the Southeast of the UK, then this increases the storage requirement significantly. Approximately two times more storage will be required.

This is because the Southeast is a population dense are of the UK, and has a greater proportion of domestic demands in its total energy demand, with lower industrial activity.

Residential and commercial energy consumptions were shown in the base case results to have the highest storage requirement due to their large demand swings, on a seasonal basis.

Due to the seasonality of demand swings it will be challenging, to offer this storage of the required duration (> 3 months), entirely with other storage technologies, and without the use of hydrogen (which is currently lowest cost to store in salt caverns).

Other salt fields in the UK exist. Natural gas caverns currently operate in Cheshire, and salt has been identified in Wessex (although there are currently no operating caverns).

Previous work has identified the East Coast region as the highest capacity salt field. (Before surface constraints and others are considered, which WP2 of this study is examining) [A34].

The East Coast delivers a much greater capacity than Cheshire from:

- Greater depth of salt
- Greater area of salt

While the total capacities are far greater than demands forecast in WP1, they do not take into account surface constraints and some sub-surface constraints which will heavily restrict their capacity, which are being explored for the East Coast in WP2.

If there was a similar proportion of reductions to the theoretical capacity of Cheshire basin as for the East Coast once surface constraints were applied (of up around 95%, see WP2 analysis), this would significantly restrict Cheshire's storage capacity. Additionally, there are further UK geographies with restricted access to salt which the Cheshire and/or East Coast basin may need to provide storage for, such as Scotland.

With the Wessex Basin, unproven this would render the East Coast salt basin as the highest capacity, 'low-risk' basin. This means it is likely that the East Coast region will need to provide storage to other regions such as the Southeast.

There would be other factors to consider such as the increased transport capacity needed to connect the Southeast to the East Coast salt basin (not considered in this study).

Salt field	Theoretical capacity	Proportion
Cheshire	129 TWh	6%
East Coast	1,465 TWh	68%
Wessex	557 TWh	26%

Table A21: Theoretical Capacity of different salt field in the UK comparison.

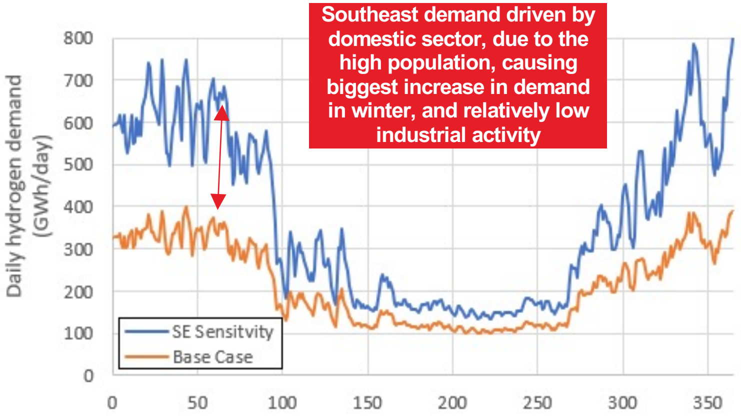


Figure A30: Annual H_2 demand profile, high demand scenario 2050. Southeast Sensitivity compared to base case.

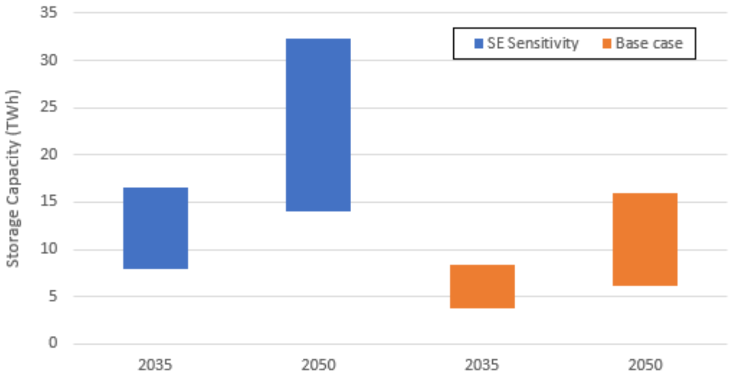


Figure A31: Southeast storage needs vs Base Case. Southeast Sensitivity (left, blue) and base case (orange, right). Source: [A1] Williams et al, "Does the United Kingdom have sufficient geological storage capacity to support a hydrogen economy? Estimating the salt cavern storage potential of bedded halite formations", Journal of Energy Storage, June 2022.

Sensitivity Analysis: Increasing Hydrogen Production Capacity and Reducing Load Factor Assumptions

In the base case assessment, production was sized to the average hydrogen demand, meaning all energy system flexibility would be delivered by storage. This has been challenged in sensitivity analysis which explores oversizing production as an alternative mechanism to deliver energy system flexibility.

In the Base Case hydrogen production capacity was assumed to be constant throughout the year, and capacity equal to the average demand. As a result, hydrogen production assets would have to operate continuously at maximum load for the whole year with no capacity to flex.

This means all energy system flexibility would be delivered by storage. This will maximise the storage requirement.

However, in reality it is likely that production capacity will be sized to over the average demand, and hydrogen production assets will have capacity to ramp up and down to deliver energy system flexibility in addition to storage.

When determining the split of production capacity vs storage, there will be boundary conditions to be met, most importantly ensuring sufficient security of supply for customers. Then once these conditions are met, the choice of how much to increase production capacity or increase storage will be a cost trade-off:

- As production capacity is increased, the average load factor will be lower, as demand is unchanged, and so production costs will increase. (The same quantity of hydrogen will be produced at a higher CAPEX for a larger plant operating with a lower load factor).
- If storage is increased, the total CAPEX of storage will increase, and increase the cost of the total energy system.

This trade-off is complex and dependent on a number of factors, and so is out of scope for this study.

However, to explore this phenomenon an indicative increase in production capacity of 10% is assumed. This would result in hydrogen production assets operating at a reduced load factor, with a theoretical average drop of 17% compared to the base case. This is assumed to be the same for both electrolytic and CCUS-enabled production in this sensitivity.

Additionally, there are no demand sector specific assumptions. In the modelling demand form each sector has been summed, and the model sizes storage, with boundary condition of production capacity being able to flex to 10% above average demand.

In reality some sectors as power will favour oversizing production more, due to the low round trip efficiency of converting renewables electricity, to electrolytic hydrogen and then converting hydrogen back to electricity. Whereas other sectors that consume hydrogen without converting git back to electricity do not have as low a round-trip efficiency.

In this sensitivity the East Coast is still considered a "closed system". This means all hydrogen produced in the East Coast is consumed I the East Coast, and all East Coast demand is met by East Coast production, i.e. not net import or export of hydrogen. Overall in the future the East Coast could become a net importer or exporter of hydrogen depending on industry and policy direction.

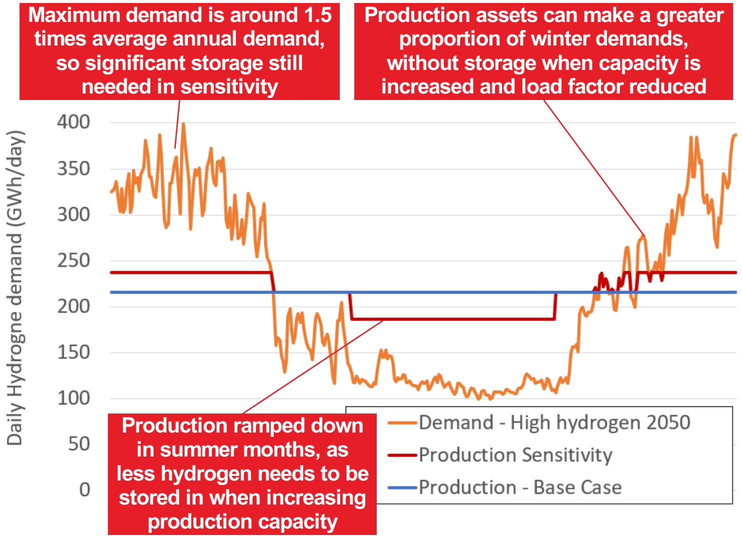


Figure A32: Demand and production profiles for increased H2 production capacity sensitivity – High hydrogen 2050 scenario. Northeast demand, base case shown for reference, 10% increase in production capacity in sensitivity, and 17% load factor reduction.

Sensitivity Analysis: Increasing Hydrogen Production Capacity and Reducing Load Factor Results

In a system with production can be operated flexibly to deliver system resilience, storage requirements reduce.
The future energy system will require a combination of storage and flexible production to deliver system resilience.

Increasing the capacity of hydrogen production to deliver energy system flexibility reduces the reliance on storage and consequently the storage capacity required.

An increasing of production capacity by 10% was explored, and this reduced the storage requirement by approximately 20 to 30%, depending on demand scenario. Higher hydrogen demand scenarios see a greater % reduction. This is because they have a higher proportion of more variable sector demands, such as power and hydrogen that are able to utilise more of the flexible production capacity to reduce storage demand

This reduces the load factor of production by approximately 17%. Early hydrogen production projects plan to operate as close to maximum load as possible. This is primarily to make a viable business case. However, as hydrogen production projects scale up and costs reduce, through experience and innovation, operating hydrogen production projects at lower average loads will become more economically viable.

Industry makes up a significant proportion of hydrogen demand and is less variable than other sectors such as heating and power. This enables a 10% increase in total production capacity to have a significant reduction in storage requirement.

The future energy system will use a combination of hydrogen storage and flexible hydrogen production to manage hydrogen demand profiles. The system must meet security of supply obligations to customers.

It is currently assumed for all sectors that this

Flexibility will be delivered by increasing the size of the production. However, for sectors such as power, other sources such of dispatchable power can be used to deliver the same impact. These could include:

- Hydropower
- Power-CCS. (A natural gas fired gas turbine with carbon capture storage technologies).
- Interconnectors with other countries.

This has not been explored in this study. However, they would have the same impact as increasing hydrogen production, as dispatchable assets can be turned up during winter, to help meet peak winter demands and reduce the reliance on storage.

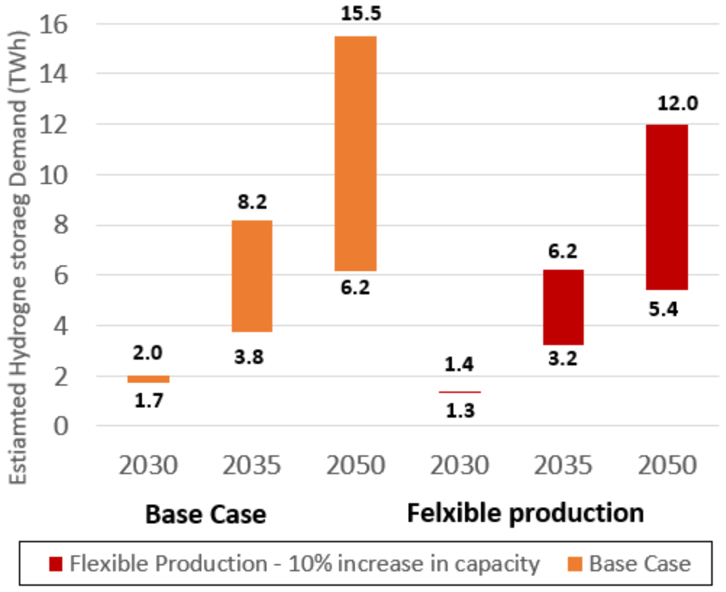


Figure A33: East Coast storage demand when considering flexible production compared to the base case Northeast demand, base case shown for reference, 10% increase in production capacity in sensitivity, and average load factor reduction of 17%.

Sensitivity Analysis: Seasonality of Hydrogen Production in the East Coast

A constant hydrogen production profile was assumed over the year in the UK in the base case scenario. However, this is challenged in the sensitivity analysis, with impacts of seasonality of offshore wind and thus electrolytic hydrogen production explored.

For the base case, only seasonality of hydrogen demand was assessed, whereas hydrogen production was assumed to follow a continuous annual profile. However, in reality, seasonal trends are expected due to the variable renewable input for electrolytic hydrogen production, which is a result of weather patterns:

- Offshore wind: Offshore wind generation are typically greater in winter and lower in summer. (See profile from Crown Estate for offshore wind generation below, in Figure A34) [A35].
- Solar: Solar production is greater in summer and lower in winter.

This sensitivity explores an electrolytic hydrogen production profile aligning with an offshore East Coast wind profile. Offshore wind is assumed to account for most renewable generation in the region, and so solar profiles have not been modelled. The hydrogen production profiles for each method were modelled as follows with the technology split between CCUS-enabled and electrolytic production proportional to announced project capacities today.

- CCUS-enabled hydrogen: no seasonal trend assumed as production utilises natural gas input. (Same as base case).
- Electrolytic hydrogen: assumed to follow offshore East Coast wind production as electrolysers. Due to the highly stochastic nature of wind speeds, a wind proxy analysis based on hourly wind profile data was undertaken to determine a representative hourly electrolytic hydrogen production profile*. A load factor of 45% was determined. This aligns with the monthly profile published by the crown estate for offshore wind generation on the East Coast.

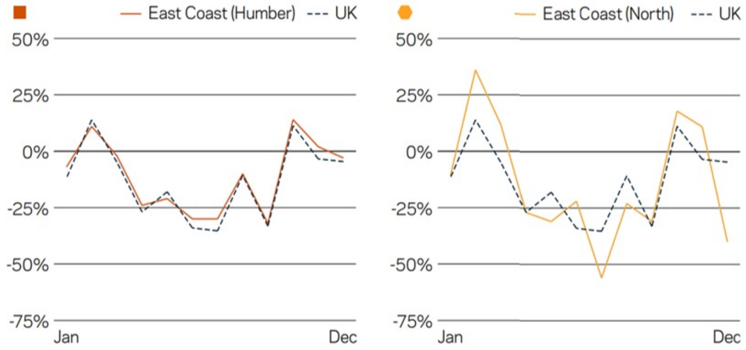
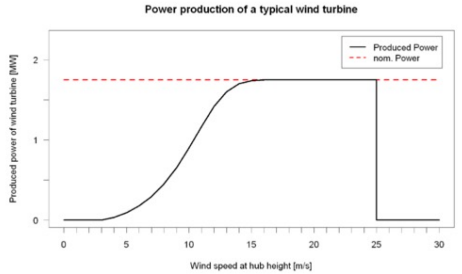


Figure A34: Offshore Wind generation monthly profile in the East Coast region, Crown Estate.
Source: Crown Estate, Offshore Wind Report 2022.

**Due to data availability, a representative hourly wind profile for the offshore East Coast region was determined by applying a scalar to onshore UK East Coast wind speed data obtained from Climate Consultant 6.0 [A36]. The applied scalar enabled the adjustment of data to align with the mean wind speed (at 100 m hub height) across the offshore Dogger Bank area of around 10 m/s [A37].*

	CCUS-Enabled	Electrolytic
Proportion of generation	55%	45%
Assumed seasonality	No seasonality	Daily tracking of offshore wind profile
Assumed load factor	95%	45%

Table A22: Summary of hydrogen production seasonality assumptions.



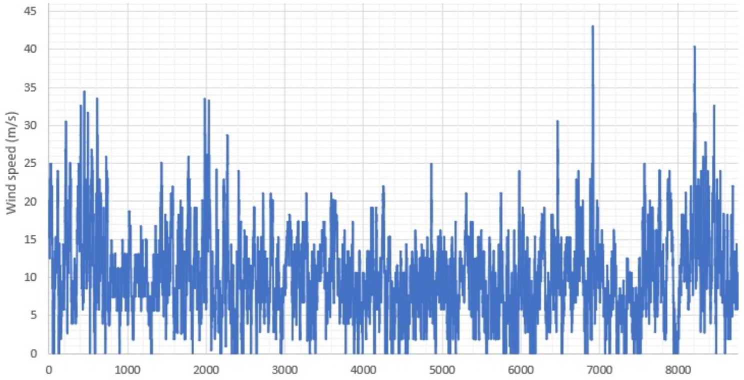


Figure A35: Representative typical offshore wind profile for the offshore East Coast region used in the electrolytic production wind proxy analysis. For wind turbines, wind speeds above 25 m/s typically result in curtailment thus the slight deviation between maximum values and those reported in literature do not impact the analysis.

Sensitivity Analysis: Seasonality of Hydrogen Production in the East Coast

When considering seasonal electrolytic hydrogen production, hydrogen storage demand in 2050 is forecasted to be 5.6 – 13.4 TWh. This represents a reduction from 6.2 – 16.0 TWh in the base case, highlighting the benefit of large-scale hydrogen storage in energy systems with high renewable penetration.

Within this sensitivity analysis, total annual supply was also assumed equal to average demand as actual hydrogen production capacity in future years remains uncertain. However, considering electrolytic hydrogen production as a function of load factor (as influenced by the wind proxy analysis), fluctuations in daily hydrogen production were balanced with the fluctuating aggregated sectoral hydrogen demand profile, resulting in intraday fluctuations between injection and withdrawal.

Similar to the base case, the profile also highlights an interseasonal trend – hydrogen is withdrawn from storage during the winter months and is injected into storage over summer. However, in comparison to the base case where demand in winter months was sustained above the constant production profile at average demand, high wind generation in the winter results in production exceeding demand over a greater period across the year. This highlights the additional potential for hydrogen storage to provide intraday grid balancing for energy systems with high renewable penetration, assuming feasible operational requirements can be met, e.g. if fast-cyclic salt caverns can be proven at full commercial deployment (or TRL 9).

With high wind generation in the winter considered, the following hydrogen storage demand forecasts - reduced from the base case - were determined.

- 2030: 1.5 – 1.6 TWh.
- 2035: 3.4 – 7.0 TWh.
- 2050: 5.6 – 13.4 TWh.

It is important to note that while electrolysers can more easily ramp up and down compared to CCUS-enabled hydrogen facilities, a highly variable production profile can reduce electrolyser stack life. This further builds the case for hydrogen storage to complement renewables and electrolytic hydrogen systems as the stores can act as a long-term energy buffer and enable electrolysers to operate at less variable loads. Optimisation of electrolyser-wind systems to make use of wind curtailment is also preferable to allow otherwise wasted wind energy to be transformed into hydrogen, allowing for an additional pathway between supply and demand, whether the hydrogen is transported, stored, used in its primary form and/or reconverted back into electricity.

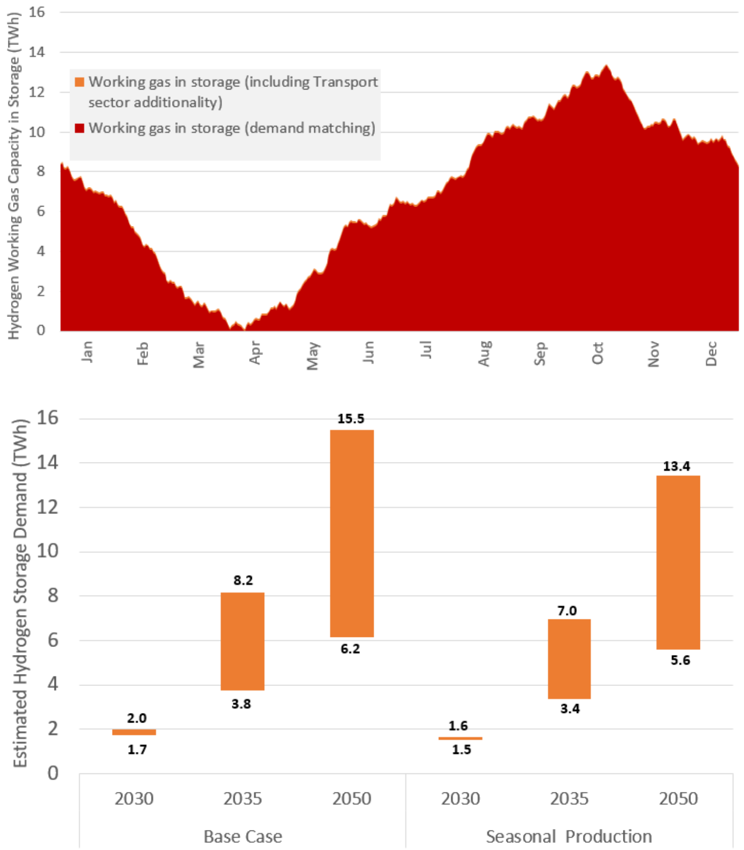


Figure A36: For hydrogen production at 55% CCUS-enabled and 45% electrolytic: (a) Minimum daily hydrogen storage requirement for 2050 high hydrogen demand scenario (b) Comparison of forecasted hydrogen storage requirements for the East Coast region.

Considerations: Strategic storage

As the UK shifts to energy independence the need for strategic storage will shift from global energy crises, to multi-year weather patterns. Strategic storage has not been considered in detail in this study, but must be considered when making energy storage plan for net zero.

The UK currently holds strategic energy reserves, which it is obliged to do under IEA compulsory stock obligations. It was previously also governed by the EU oil stocking directive, but is no longer required to post-Brexit [A38] Regulations are based on oil stock These regulations state [A39,A40]:

- IEA Compulsory stock obligations: UK must hold 90 days of imports of the previous year.
- EU Oil Stocking Directive (2009/119/EC): the UK to maintain a minimum volume of emergency oil stocks corresponding to 90 days of average daily net imports or 67.5 days (61 days + 10%) of average daily inland consumption, whichever of the two quantities is greater. A minimum of 22 days' bust be held as finished products.

The UK currently exceeds all these reserves targets. In September 2023 it held both oil and gas as reserves [A41]:

- Oil: The UK held the equivalent of 130 days net imports of oil stock. In March and April 2022 the UK released 2.2 and 4.4 million barrels of oil respectively as part of a co-ordinated response led by the IEA t release oil stocks up on Russia's illegal invasion of Ukraine. (It began replenishing these stocks in June 2023)
- Gas: The UK currently holds 3.1 billion cubic metres of gas, across eight facilities. Equivalent to approximately 34 TWh. 50% of this is stored in the offshore storage facility rough, which has a limited response time, and can only be emptied and filled on a seasonal basis. The other seven can respond to daily or weekly demands.

These compulsory oil stock obligations are driven at providing reserves for countries in time of global crises, often driven by conflicts. As oil supply is integral to modern society functioning, but trade is international across all continents, the IEA and EU deemed it necessary to set compulsory stock targets to mitigate the impacts of disruption from global conflicts.

Compulsory stock targets are currently focused on oil and not gas. The EU has recently passed legislation on natural gas reserves and usage , again in response to Russia's illegal invasion of Ukraine. However, legislation has not yet set a quantitative compulsory tock obligation, as with oil.

The UK does not yet have equivalent legislation around natural gas.

The UK is targeting energy impendence and reducing its energy imports. The need for compulsory stocks form concerns in global supply chains will therefore reduce.

However, the UK seeks to gain much of its energy from renewables, and specifically offshore and onshore wind. As explored earlier these energy sources have seasonal variations on an annual basis. They also have variation across multi-year periods up to a length of multiple decades. Analysis in this study has been based on a single year and so has not account for this.

Previous work from the Royal Society has estimated accounting for this could see the UK need 100 TWh of storage. This is a two to four times increase on may other studies looking at UK energy storage requirements.

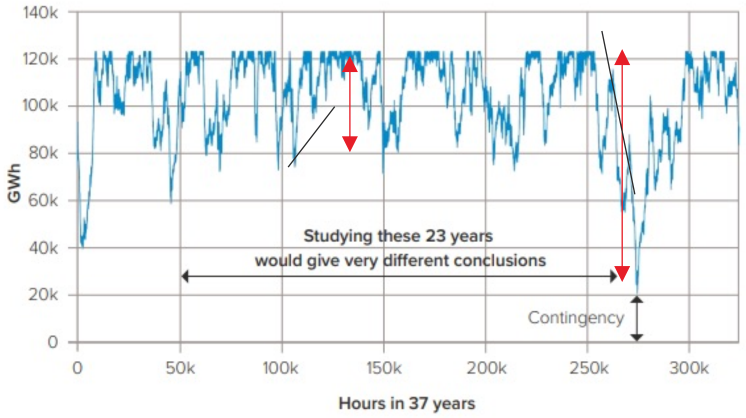


Figure A38: UK energy storage profile over 37 years. Profile estimated from historic weather data.
Source: [A7] The Royal Society.

This analysis showed that over periods of time of under 1 years, it was unlikely that studies would capture the need for storage to manage low-wind generation periods which show intermittency on a frequency of many decades. The study modelled weather data over 37 years for the period 1980 to 2016 to capture this.

It shows that studies analysis based on data up to as long as 23 years may significantly underestimate the storage. Any future demand modelling use to impact decision on energy storage therefore incorporate this need for strategic storage.

The form of this energy storage is not yet clear. It could be in hydrogen salt caverns, depleted oil and gas fields, large interconnectors with other countries, oil reserves (with Direct air capture offsets), or a combination of options. Further work will be required to determine the best approach of managing this inter-decade renewable variation.

Conclusions: Hydrogen Storage Demand Modelling for the East Coast Cluster

The 6.2 – 16.0 TWh hydrogen storage requirement in 2050 highlights the significant opportunity for storage site developers and investors to focus efforts within the East Coast region. Storage projects can support up to 10.8 GW of announced low-carbon hydrogen production capacity by 2030.

The hydrogen storage demands estimated in this work package highlight the critical need for localised strategic planning and policy-led interventions to drive hydrogen storage infrastructure investment. Low-carbon hydrogen will play a crucial role in the UK. However, uncertainty remains around the scale and speed of uptake of demand across the industry, heat, power generation and transport sectors. This uncertainty creates high risk for first-mover hydrogen storage projects, making it difficult for storage site developers and investors to focus efforts. The study was localised to the East Coast, a region of key hydrogen activity and with an abundance of suitable salt basins for salt cavern development. This makes the East Coast a relatively low-risk region for initial hydrogen storage investment, with constraints facing the development of salt cavern capacity explored in WP2. In combination with WP2 outcomes, the following insights underpin the WP3 strategic case for hydrogen storage investment which aims to remove market barriers and improve investor confidence.

- High forecasted hydrogen demands highlight the need for hydrogen storage to improve energy system resilience.

The base case estimates that 6.2 – 15.5 TWh of WGC hydrogen storage demand is required to support the total aggregated sectoral hydrogen demand of 19.5 – 78.7 TWh for the East Coast alone in 2050. The UK has relatively low quantities of natural gas storage (approximately 16 TWh in salt caverns [19]*) so it will be challenging to convert natural gas caverns to hydrogen in the near term, given the importance of security of energy supply. Hydrogen salt cavern storage is proven in the UK at Teesside, but capacities are mall, approximately 25 GWh. Given newly developed salt cavern sites can have development lead times of up to 15 years, accelerated development is critical and there is a need to act now.

- The use of hydrogen in the heat and power sectors are the greatest drivers of hydrogen storage demand.

Despite industry forecasted to have the greatest hydrogen demand across all sectors, the heat and power sectors are observed to have a greater influence on hydrogen storage capacity requirements due to their highly variable and inter-seasonal demand profiles. In the low hydrogen demand scenario, the power sector is forecasted to account for around 83.4% of the 6.2 TWh hydrogen storage demand in 2050 despite having a similar hydrogen demand to the industry sector. In
the high hydrogen demand scenario, the heat sector is forecasted to require around 52.1% of the 16.0 TWh hydrogen storage demand in 2050, aligning with a government decision in favour of hydrogen for heating in 2026.

- Medium-term government targets are driving a large hydrogen storage demand in 2035.

The analysis localises UK-wide government targets to the East Coast, such as decarbonising the heat sector by assuming the same uptake of hydrogen boilers and heat pumps in the heat and power sector analyses in the East Coast as UK wide. Hydrogen storage demands become significant in 2035 as the variable demand of these sectors begins to ramp up significantly. This is driven by modelling assuming key UK government targets are met in 2035; a decarbonised electricity grid, and 1.9 million heat pump installations per year [20]. This will see significant portions of the inter-seasonal swing in residential heating shifted from the gas network to the electricity network, consequently increasing requirements for storage to balance a future power sector, than is unable to rely on unabated CCGT generation for flexibility.

Forecast Year	Industry	Heat	Power Generation	Transport	Total
Low hydrogen demand scenario – Demand, TWh [proportion of demand (%)]					
2030	7.1 [40.5%]	0.0 [0.0%]	2.1 [59.6%]	0.0 [0.0%]	9.2
2035	9.9 [26.8%]	0.0 [0.0%]	5.5 [73.2%]	0.0 [0.0%]	15.4
2050	9.9 [16.6%]	0.0 [0.0%]	10.2 [83.4%]	0.0 [0.0%]	20.1
High hydrogen demand scenario					
2030	11.2 [55.8%]	1.1 [11.9%]	1.3 [32.2%]	0.0 [0.01%]	13.5
2035	21.8 [26.6%]	20.4 [56.4%]	2.8 [16.7%]	0.03 [0.3%]	45.0
2050	37.3 [23.9%]	35.8 [52.1%]	7.5 [23.4%]	0.1 [0.6%]	80.7

Table 5: Summary of forecasted sectoral hydrogen demands (TWh) for the East Coast region [with illustrative hydrogen storage demand proportions highlighted].

Forecast Scenario	2030	2035	2050
Base case	1.8 – 2.0	3.8 – 8.4	6.2 – 16.0
Hydrogen storage to support the Southeast of England	n/a	7.0 – 16.6	14 – 32.3
Oversizing production	1.3 – 1.4	3.2 – 6.2	5.4 – 12.0
Seasonality of hydrogen production	1.5 – 1.6	3.4 – 7.0	5.6 – 13.4

Table 6: Summary of forecasted hydrogen storage demands (TWh) for the East Coast region, including base case and sensitivity analysis scenarios. *When converting natural gas salt caverns to hydrogen, hydrogen will only have 25 to 30% the storage capacity, depending on storage pressure, due to a lower volumetric energy density.

Appendix B:

Geological Hydrogen Storage Capacity Modelling for the East Coast Cluster

Executive Summary

A spatial analysis has been undertaken to determine a revised hydrogen storage potential of salt caverns in the East Coast region. It combines geographical occurrence of halite-bearing strata with land-based constraints to development. The methodology can be easily replicated to better understand the hydrogen storage potential in salt caverns across other key regions.

This work package provides a storage capacity assessment of salt caverns in the onshore East Coast Region by developing:

- A comprehensive theoretical storage volume, referred to as "resource potential" (Figure B1), accounting for geological and some social and environmental limitations.
- A dynamic multi-criteria assessment of viable host geology and above-ground constraints provided as an interactive tool to support decision making by developers, end-users and offtakers.

The purpose of this study is to the appraise and integrate existing public datasets to develop an estimate of the resource potential. The aim is to better inform decision makers on the ability of the East Coast region to meet future storage demand and challenge current assumptions on the timescales to deploy salt cavern storage.

Below-ground and above-ground constraints are integrated through spatial mapping techniques to derive revised storage estimates. Boulby Halite Formation and Fordon Evaporite Formation provide the host geology for salt cavern development in the East Coast region. The extent, purity, thickness and depth of these halite formations govern the size and scale of energy storage.

Above-ground constraints which limit surface development include existing and planned civil, social and industrial land use and environmentally sensitive sites.

A dynamic, spatially-driven model enables the user to visualise and analyse this data, allowing a weighted multi-criteria assessment of feasible host geology and above-ground constraints.

It is found that current assumptions on resource capacity of salt caverns for hydrogen storage are many levels removed from the feasible workable storage volume i.e., realisable potential. Existing published work [B1][B2] has appraised only the reserve potential of salt cavern storage in the East Coast region. This study has rationalised previous work to a resource potential by refining development requirements and development constraints.

In doing, this study has reduced the previous best estimates of storage capacity by c.95%. Storage capacity in the East Coast region is still significant, at least 22 TWh, however, significant barriers exist which limit the ability to deploy salt cavern storage to realise storage potential by 2050. These barriers include timescales for developing and commissioning new salt cavern storage assets at the scale which is required; approximately 1000 caverns are required to achieve 22 TWh of storage.

The analysis can be easily replicated for other UK saltfields to understand potential storage capacity and development considerations.

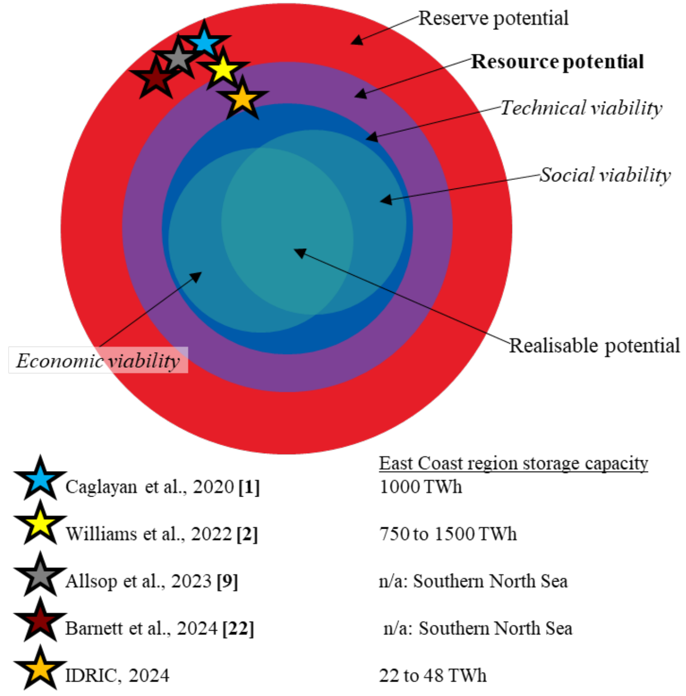


Figure B1. Concept of "potential", adapted from [B1][B3]. Where "realisable potential" is the refinement of "resource potential" based on technical, social and economic viability. Annotated are published studies of East Coast region storage capacity [B1][B2].

Literature Review: Existing storage narrative and research gap

It is commonly assumed that there is readily available storage capacity in UK onshore salt caverns without appreciation of the development constraints and development timescales.

Salt caverns for hydrogen storage represent a mature technology readiness level (TRL Stage 9 [B3] Figure B2), and have operated successfully in Teesside since the 1970's.

The extent of the halite-bearing geological formations is regionally well mapped and characterised. It indeed represents a vast reserve which, from the East Coast, stretches beneath industrial centres in Teesside and Humberside and into the southern North Sea. The target strata in the East Coast region are Boulby Halite Formation and Fordon Evaporite Formation, which are typically referenced as 30 m to 40 m and 150 m to 300 m thick respectively. It should be noted that local variability of the halite formations is not believed to be well understood.

A common oversight in existing published literature is the effect of above-ground planning restrictions and existing infrastructure on the opportunity to develop subsurface caverns. It is considered in this study that, as with any exploitable reserve, the extent which is readily available for cavern development (i.e., the "resource") could be severely impacted if available land does not match well with localities of viable halite.

National and regional strategy documents for underground hydrogen storage consistently provide a narrative of energy storage in salt which is often lacking depth, comprehension and awareness of the halite "resource", the challenges around delivering the infrastructure and social and environmental obstacles.

For example (Figure B3):

The Royal Society, 2023 [B4]

"A Great Britain electricity system largely powered by wind and solar energy will need 10's TWh large-scale energy storage…best provided by storing hydrogen in salt caverns."

East Coast Delivery Plan 2023 [B5]

"The East Coast region has a large… potential for salt cavern development for hydrogen storage, with the largest Permian saltfield in the UK".

The narrative provides an impression of a large, readily-available energy storage resource in salt caverns, with no comment on delivery timescales.

DNV Energy Storage Strategy 2023 [B6]

The report references storage capacity in the Netherlands as an analogy to what can be achieved in the UK however fails to point out critical differentiators.

E.g., Each cavern at the Zuidwending site is up to 400 m tall and can store up to 200 GWh of energy. The UK saltfields are typically much thinner which constrains the size and energy storage potential of caverns to around 20 GWh for existing caverns in the East Coast region, hence requires many more caverns to achieve a similar storage capacity.

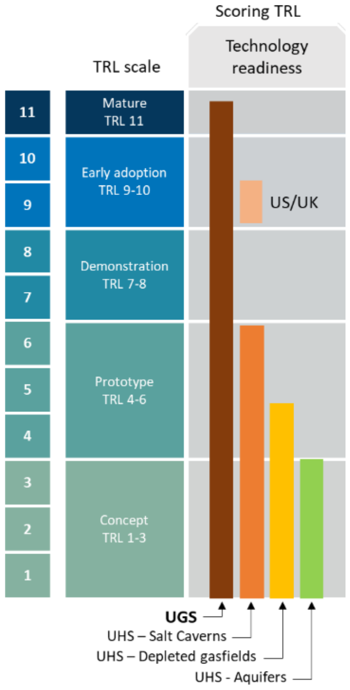


Figure B2. TRL for Underground Hydrogen Storage (UHS) technologies. Note TRL Stage 9 for UHS in salt caverns in the UK [B3].

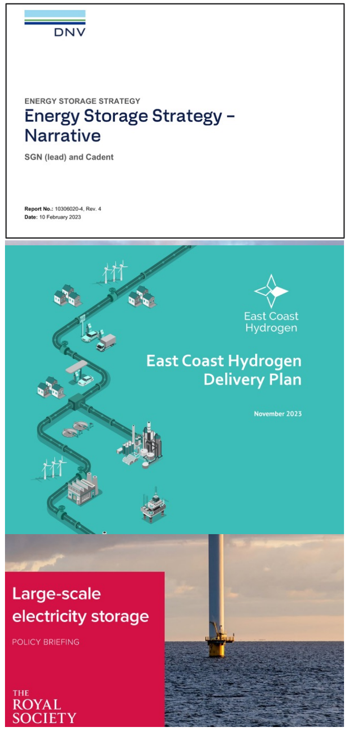


Figure B3. Referenced reports on hydrogen storage in salt caverns [B6][B5][B4].

Literature Review: UK East Coast region saltfield storage capacity

A number of studies have been published which have estimated the salt cavern storage potential of the UK and East Coast region.

Host geology

Storage in the East Coast region is focussed on two halite-bearing formations, Boulby Halite (BHF) and Fordon Evaporite Formation (FEH) and are both currently utilised for small scale natural gas and hydrogen storage. Evans and Holloway (2009) [B7] and ETI & Foster-Wheeler (2013) [B8] indicate that both salt formations have potential for storage cavern development for hydrogen.
The BHF has been mined at Teesside where it is typically between 350 m and 650 m deep and between 30 m to 50 m thick. The FEH occurs below the BHF, separated by 10’s m of non-halite beds, and is typically between 1200 m and 1900 m depth and between 150 m to 200 m thick.

Cavern depth

There is a recognised sweet spot between 600 m and 1700 m depth for locating gas storage caverns (Figure 14; [24]). Storing gas at depth benefits from high lithostatic pressures, however caverns which are too deep may suffer from costly development, operation and maintenance costs, including balancing the pressure differential between surface infrastructure (pipeline) and storage caverns, and may suffer from salt creep (volume loss).

Existing capacity assessments

Storage capacities have previously been assessed for onshore UK: Caglayan et al. [B1] suggests total capacity is around 1000 TWh, and most recently, Williams et al. [B2] indicates a “potential capacity” of up to c. 2100 TWh. The latter goes on to conclude that the East Coast region provides the majority of the UK’s capacity, accounting for c. 1500 TWh (Table B1).

Figure B5 presents a map which indicates variability in storage capacity across the region.

The most recent assessment [B2] accounts for storage in the Fordon Evaporite Formation only, and where viable thickness of it occurs, cavern locations have been screened out based on proximity to the following:

- Surface infrastructure, including roads, railways and urban settings
- Environmentally sensitive areas
- Geographic features including waterways and coastlines
- Wet rockhead (where halite is present at rockhead)
- Geological faults

Cavern pillar widths were assumed to be no less than 3x maximum cavern radius and a spatial buffer of 150 m was applied to all spatial features.

The study undertaken in this work package presents a continuation of the research from Williams et al. [B2], by challenging the assumptions and further refinement of development sites, geological and surface constraints.

In addition to providing a refined energy capacity assessment across the East Coast region, this study evaluates the relative “attractiveness” of a development site based on the perceived criticality of multiple criteria. It is the ambition of this study that both aspects can be iterated over to establish realistic salt cavern development opportunities.

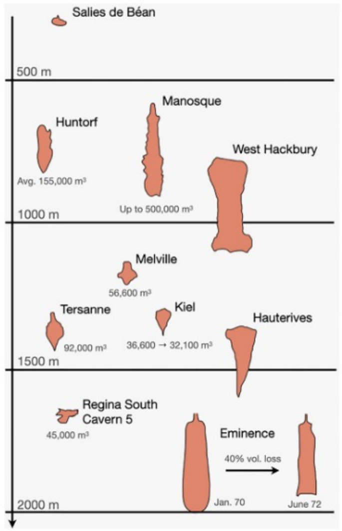


Figure B4: Distribution of salt caverns used for gas storage around the world. [B9]

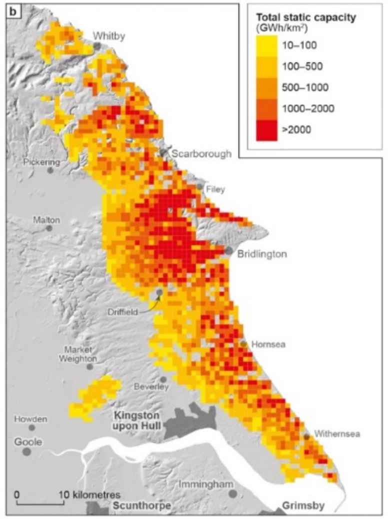


Figure B5: Total static capacity of hydrogen in salt caverns in East Yorkshire. [B2]

Theoretical H_2 storage potential in new dedicated caverns (TWh)			
Cheshire	East Yorkshire	Wessex	UK Capacity
128.8	1464.9	556.6	2150

Table B1: Theoretical salt cavern storage capacity. [B2]

Methodology: Overarching Approach

A comprehensive site selection methodology has been established to derive storage “resource potential”.
It is based on previous publications and accounts for subsurface and surface constraints for cavern development.
Spatial analysis underpins the identification and evaluation of suitable development sites.

A summary of the methodology and approach is provided below:

Model pre-requisites and development

Geological model development ●

- Identification and characterisation of salt formations.
- Geo-referencing of ground data.
- Digitalisation and rasterisation of ground model (extent, thickness and depth).
- Scoring of rasters based on sub-surface constraints.

Surface criteria assessment ●

- Identification of datasets relevant to constrain surface development.
- Establishment of exclusion and evaluation criteria.
- Rasterisation of datasets and scoring of rasters based on proximity to surface constraints.
- Mapping of rasters to hexagonal grid.

Geometrical assessment ●

- Geometrical configuration of cavern by deriving viable height and diameter of cavern. Consideration of geometrical differences for wet and dry operated caverns.
- Cavern placement based on assumptions of cavern spacing.

Site selection

Multi-criteria assessment ●

- Exclude hexagons from hexagonal grid based on surface constraints and geological model (i.e., geological viability of cavern development).
- (Optional: Evaluate the score of selected hexagons against the evaluation criteria and determine most attractive sites to develop.)

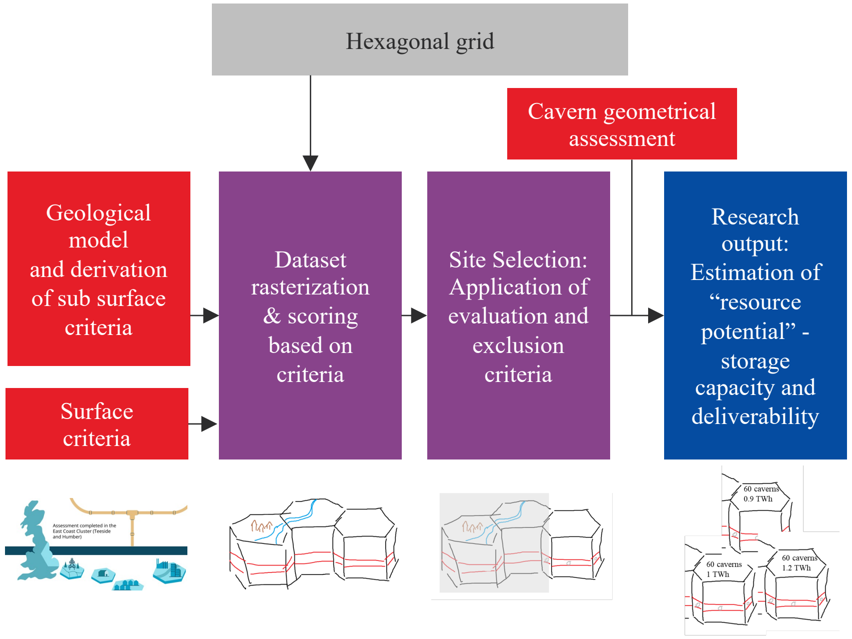
Research output ●

Storage cavern capacity, deliverability and estimated development programme

- Calculate the resultant energy capacity and flow rate for the selected development sites.
- Approximate the development programme to commission caverns to achieve the desired energy capacity.

Assumptions adopted throughout the study and limitations and opportunities for the future stages of analysis are provided in subsequent sections.

East Coast storage capacity development
(click each box to navigate to relevant section)



Geological Model Development: Boulby Halite Formation & Fordon Evaporite Formation

Salt cavern development in the East Coast region is focussed on halite-bearing units within the Boulby Halite Formation & Fordon Evaporite Formation.

The Southern Permian Basin (SPB) is a major sedimentary basin which extends for over 1000 km from eastern England and across Northern Europe to the eastern border of Poland. During the Late Permian, a thick cyclic carbonate-evaporite sequence was deposited, ascribed to the Zechstein Group, which includes the Boulby Evaporite Formation and Fordon Evaporite Formation.

The formations are present along a large part of the east coast of England and extends beneath the southern part of the North Sea.

The Z3 Boulby Halite Formation (Figure B6) is typically around 30 m to 50 m thick. It has been developed for gas storage (including hydrogen) in Teesside where it is found between 350 m to 650 m depth. Due to the geological constraints, these caverns are operated at constant pressure as brine-compensated (wet) storage caverns.

The Z2 Fordon Evaporite Formation (Figure B6) has already been developed for natural gas storage and comprises the most extensive gas storage target in Eastern England. The formation hosts several large gas storage caverns at Hornsea and Aldbrough [B34] where it is found at >1600 m depth and is almost 300 m thick, it is typically around 100 m below the base of the Boulby Halite Formation. Elsewhere, the formation is generally buried at depths exceeding 500 m and deepens towards the coast. Its thickness exceeds 300 m in some places.

The current gas storage projects do not exploit the full thickness of available salt. Caverns are up to c.100 m high and typically operated at depths between 1700 and 1800 m.

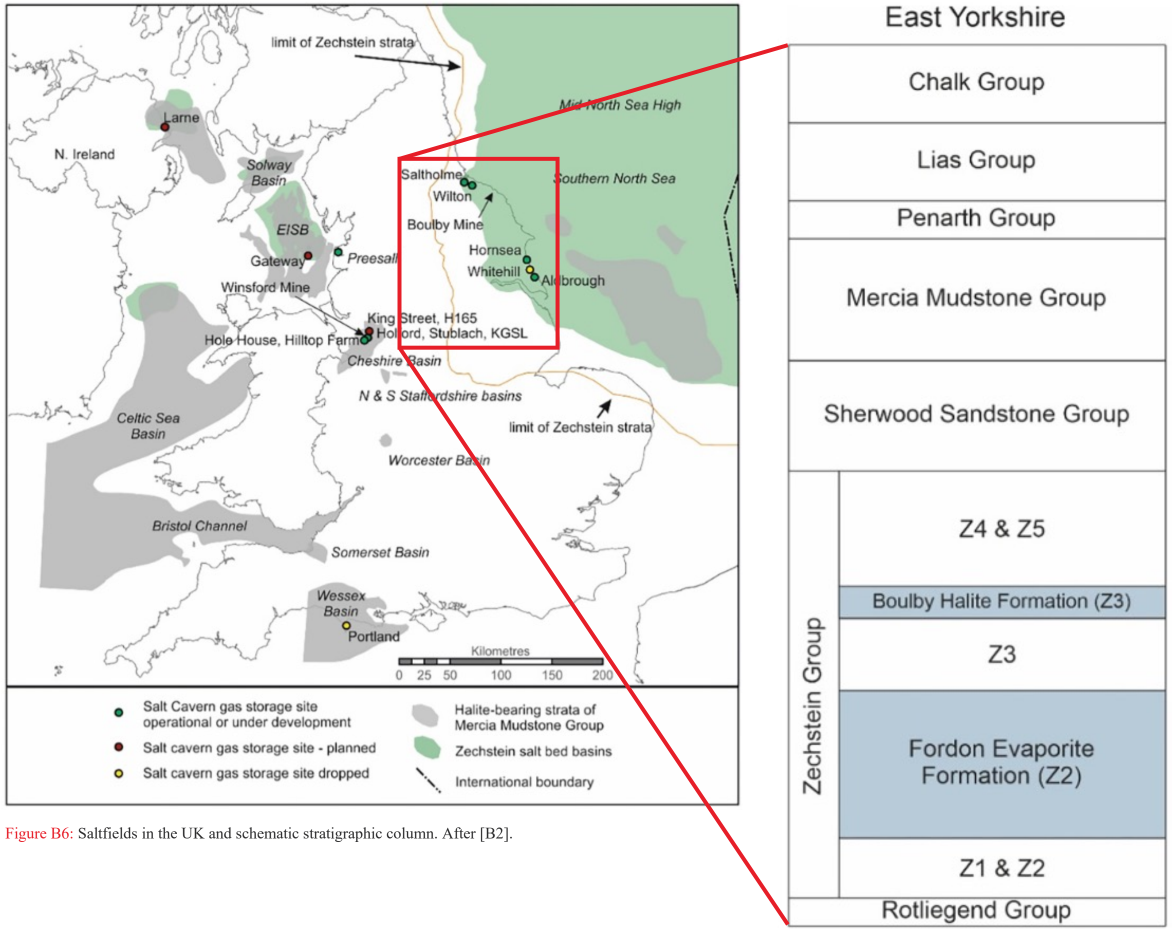


Figure B6: Saltfields in the UK and schematic stratigraphic column. After [B2].

Geological Model Development : Boulby Halite Formation

The Boulby Halite Formation is typically thin and overlain by very weak geology, which limits the storage capacity and operational flexibility of any caverns.

The Boulby Halite is typically between 30 m and 50 m thick (Figure B7).

Historically caverns have been developed with a broad roof, typically with a cavern diameter larger than the cavern height. The caverns are operated at constant pressure, through brine-compensation, to maintain geomechanical stability.

To develop variable pressure caverns in the Boulby Halite, the geometry and volume would be severely restricted, hence it is not widely regarded as a readily available resource for long-term energy storage [B2].

The output from WP2 only reports capacity from the Fordon Evaporite Formation, however the tool allows the user to appreciate additional capacity from the Boulby Halite as either constant pressure (wet) storage cavern or variable pressure (dry) storage cavern.

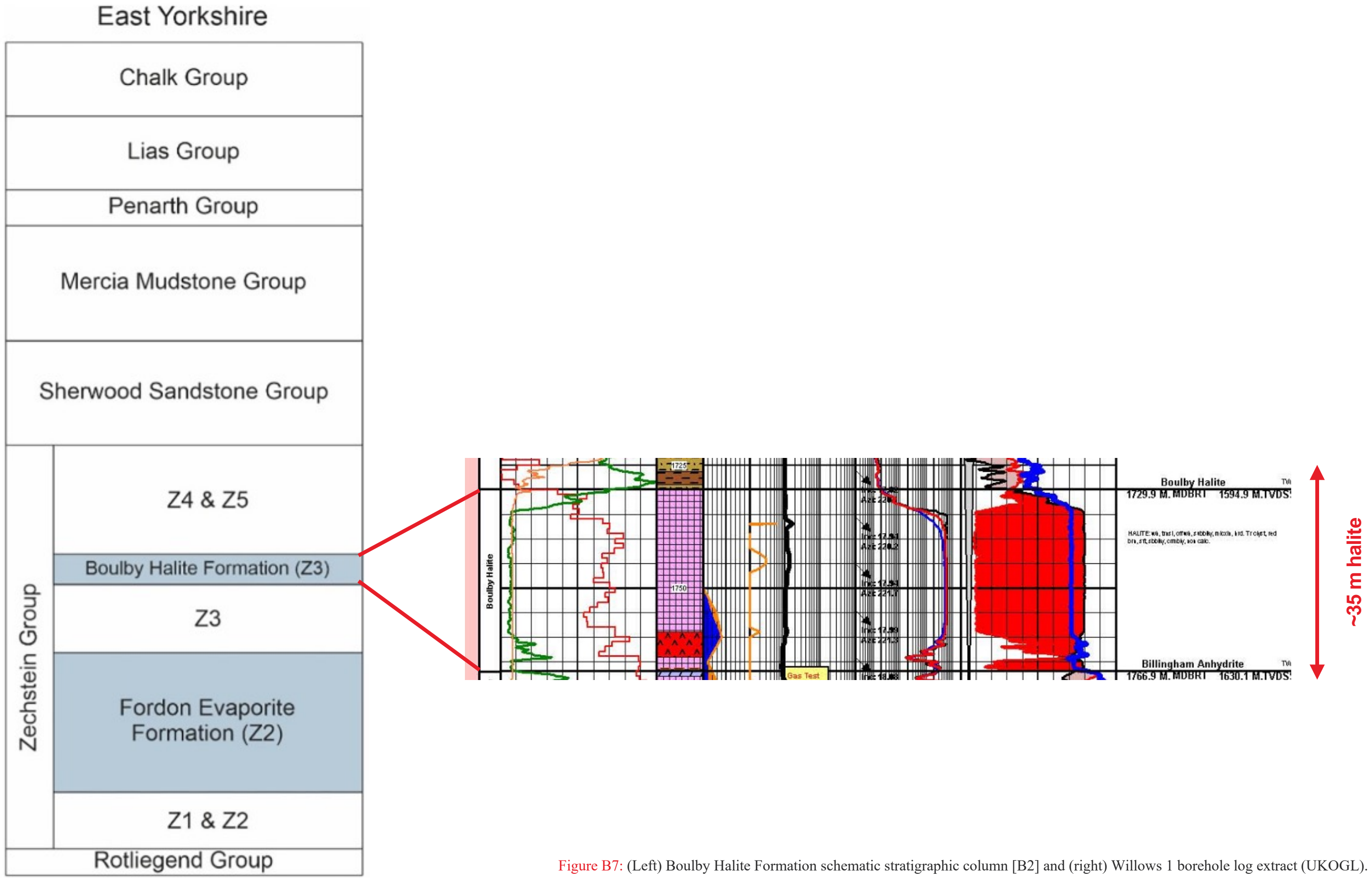


Figure B7: (Left) Boulby Halite Formation schematic stratigraphic column [B2] and (right) Willows 1 borehole log extract (UKOGL).

Geological Model Development: Fordon Evaporite Formation

The viable thickness of the Fordon Evaporite Formation for cavern development is rationalised based on the thickness of the halite member.

The halite member of the Fordon Evaporite Formation is typically up to 150 m (Figure B8), up to 50% of the complete Fordon Evaporite Formation thickness.

It is noted that previous studies [B2] have accounted for the complete thickness of the Fordon Evaporite Formation, therefore accounting for anhydrite, polyhalite and other non-halite lithologies.

For the purposes of this report, storage capacity from the halite-bearing strata in the Fordon Evaporite Formation is considered only.

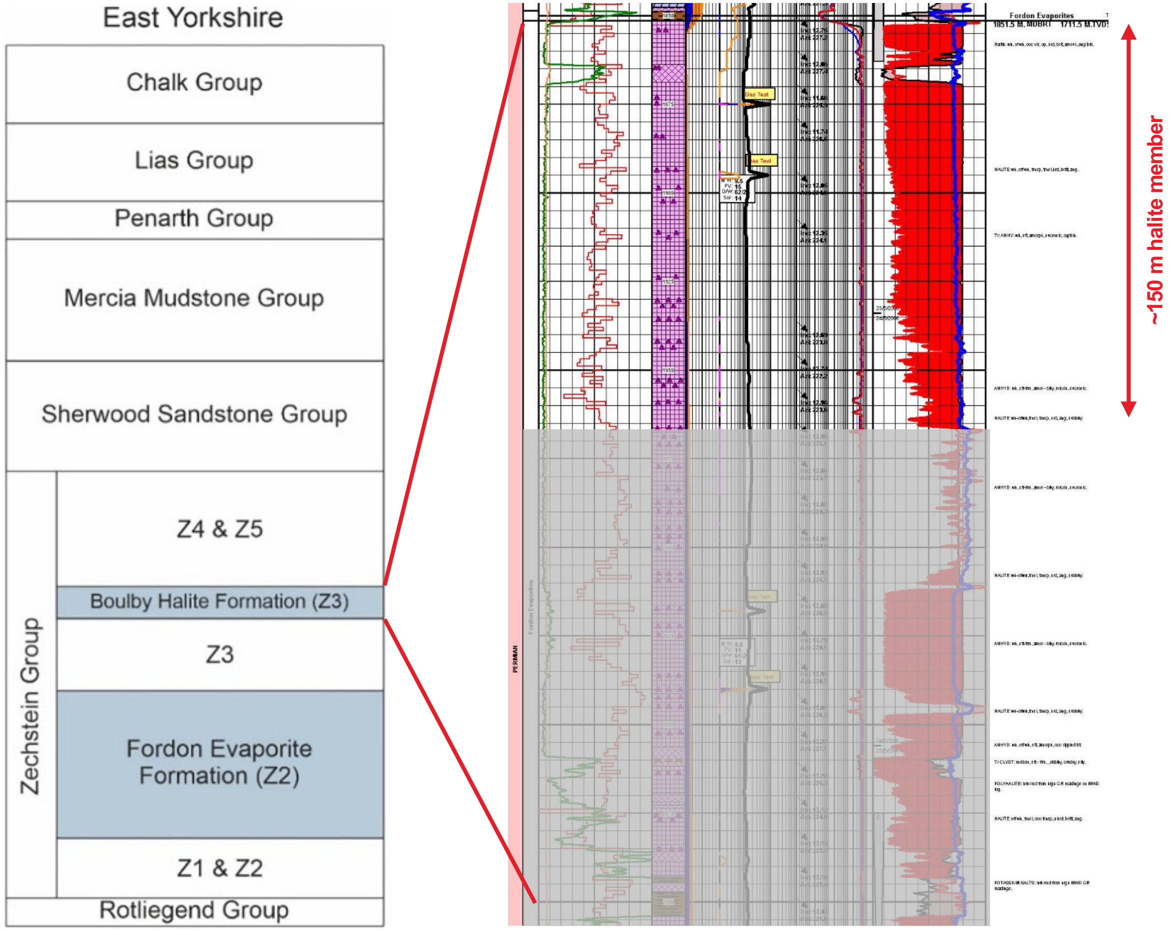


Figure B8: (Left) Fordon Evaporite Formation schematic stratigraphic column [B2] and (right) Willows 1 borehole log extract (UKOGL).

Geometrical Assessment: Cavern Geometry

An idealised cavern geometry is defined for both dry and wet operated caverns. Prescient for bedded halite formations, cavern development must account for roof and floor thickness of halite to minimise geomechanical instability.

Cavern Geometry

Cavern geometry is influence by the thickness of the host halite layer (Figure B9), which in turn can dictate the operating modes. Figure B10 and Figure B11 provide schematic illustrations of the section geometry for dry and wet operated caverns used in this study:

Dry caverns | Geometry is approximated to a cylinder with a height to diameter ratio of 2. A minimum diameter of 10 m is set which in turn limits the cavern height to 20 m (in line with literature [B2])

- Wet caverns | Geometry is approximated to a cone or "spinning top" as per Teesside wet storage caverns, with a diameter to height ratio of 2 [B16].

Cavern Geometry

To minimise cavern geomechanical instability, the siting of each cavern must account for a thickness of salt between the cavern boundary and non-halite geology above and below the cavern. This is termed as roof thickness and floor thickness respectively (see Figure B9). For this study, the following has been assumed for both dry and wet caverns:

- Roof thickness | 0.75 x cavern diameter [B1][B10]
- Floor thickness | 0.2 x cavern diameter [B1][B10]

Design assumptions are provided in more detail further in the report.

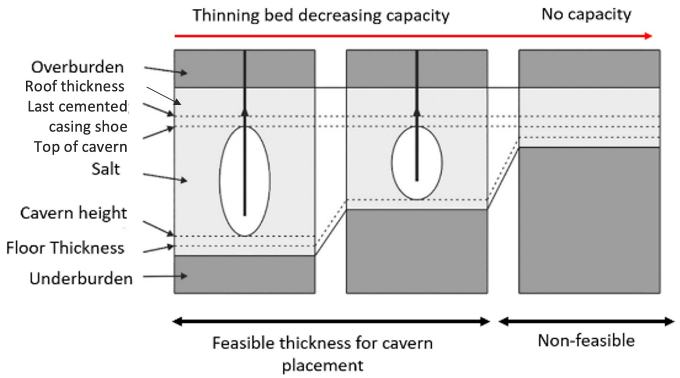


Figure B9: Schematic diagram highlighting the influence of floor and roof allowance on salt cavern height and capacity.

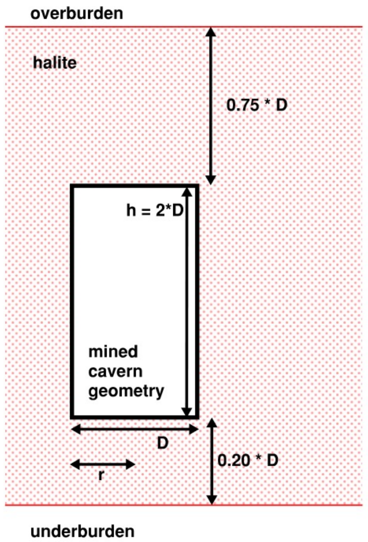


Figure B10: Schematic diagram of dry cavern geometry and necessary allowances. Abbreviations: h = height, D = diameter, r = radius.

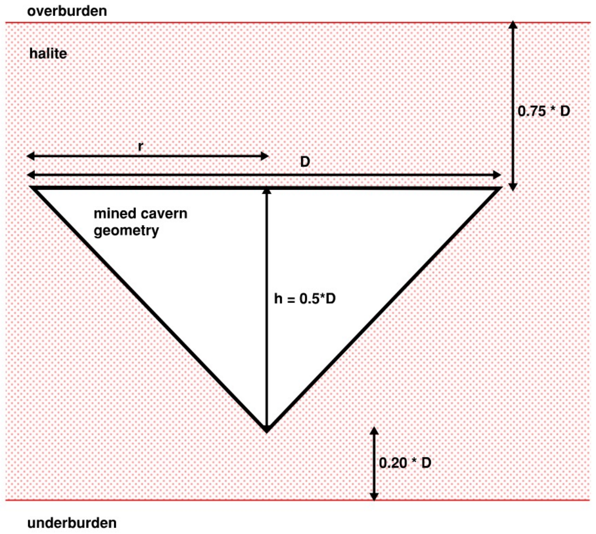


Figure B11: Schematic diagram of wet cavern geometry and necessary allowances. Abbreviations: h = height, D = diameter, r = radius.

IDRIC British Geological Survey THE UNIVERSITY of EDINBURGH ARUP

Geometrical Assessment: Cavern Fitting

Caverns are mapped spatially based on a cavern separation rule, pillar width is typically between 3 x cavern radius and 5 x cavern radius. An algorithm has been developed which optimises the fit of many caverns of different sizes within a hexagonal column. This approach aims to replicate the development of "cavern clusters" and ignores isolated or stranded cavern assets.

Where caverns can be feasibly located within a thickness of salt, the plan layout is driven by the cavern separation distance. Cavern separation i.e., the width of halite between adjacent cavern walls, is defined as a multiple of the cavern radius. Assumptions are provided in subsequent sections.

A fitting algorithm has been developed to optimise the plan layout of caverns inside hexagonal grids (Figure B12). A similar approach was undertaken by Williams et al (2022) [B2]. The fitting algorithm used in this study allows for a cavern layout to be optimised given variable cavern radii e.g., a radius which ranges between 10 m and 30 m, and in turn optimises the storage volume per hexagonal column.

For the purpose of this report, the research output assumes a uniform cavern size of radius 20 m, governed by the thickness of the halite-bearing strata in the Fordon Evaporite Formation. This compares to a uniform cavern radius of 50 m used by Williams et al [B2].

Modification of Williams et al.'s [B2] approach for this work package includes considering storage caverns as part of a cavern development site; previous assessments site individual caverns first [B1][B2]. This leads to stranded or isolated caverns in small sites which are unlikely to be attractive to develop (Figure B13). WP2 sites caverns within hexagons. Hexagons are treated as "storage development sites" or cavern facilities. The effect of this is to eliminate development sites less than c.2.5 km2 (areal extent of each hexagon).

A schematic representation of the hexagonal development site is presented in Figure B14.

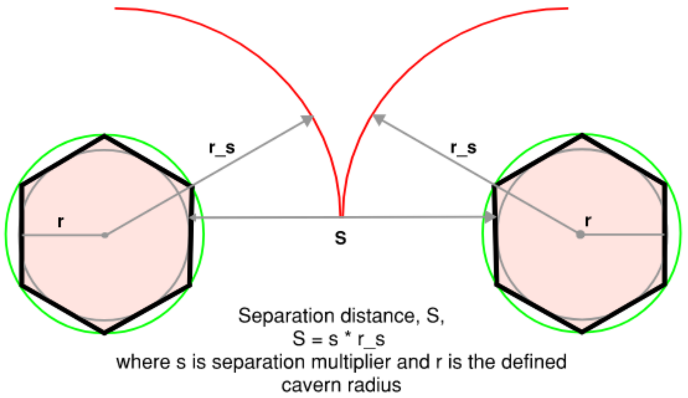


Figure B12. Schematic figure of the calculation of cavern separation.

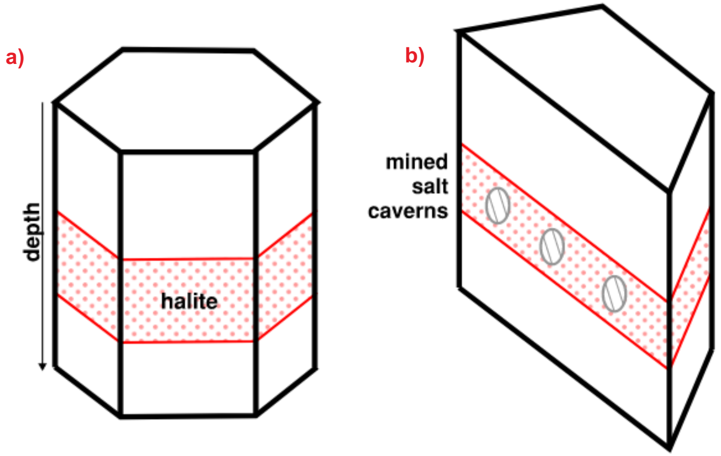


Figure B14. Schematic 3D representation of caverns located within each hexagonal geological column: a) hexagonal column, b) section through column showing caverns (grey) located in the halite geology.

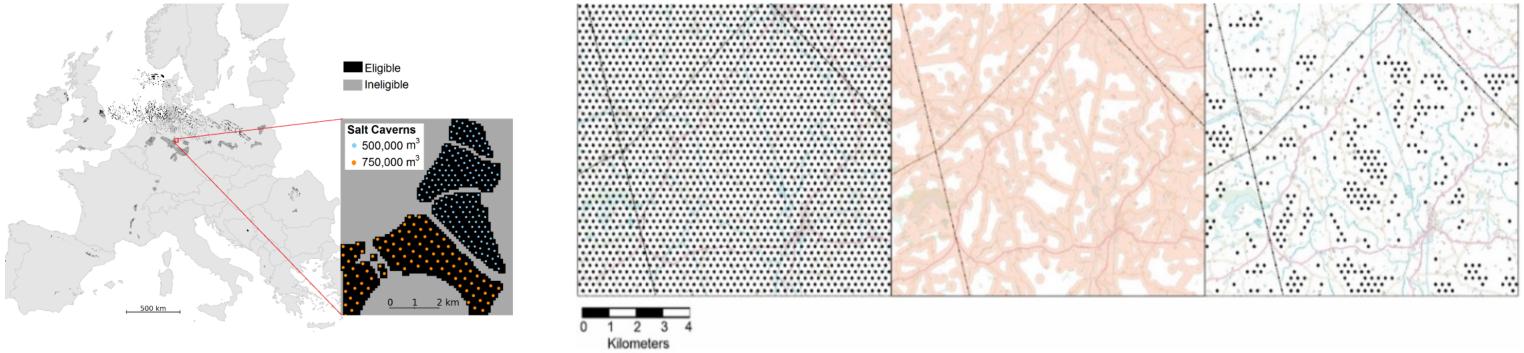


Figure B13. Cavern placement methodology from a) Caglayan et al. (2020) [B1], and b) Williams et al. (2022) [B2].

Sub-surface and Surface Constraints: Defining Exclusion and Evaluation Criteria

Development potential of sites across the East Coast region is evaluated based on a suite of defined criteria.

19 spatial datasets are considered in determining the storage capacity in the East Coast region (Table B2). The datasets comprise 6 sub-surface constraints and 13 surface constraints.

Sub-surface constraints are:

- Depth and thickness of BHF and FEH
- Geothermal gradient and temperature at depth
- Major faults

Surface constraints are:

- Proximity to restricted development area (SSSI, SAC, RAMSAR, watercourses, National Parks)
- Proximity to built-up areas
- Proximity to reservoirs
- Proximity to railways and major roads
- Proximity to major pipeline networks/ corridors including Project Union pipeline.
- Proximity to COMAH sites
- Proximity to current and potential offtakers

Each constraint is appraised on its impact on the development potential of a site. Sites are typically excluded where they do not meet the criteria e.g., directly intersect the constraint or lie outside of the allowable range. Sites which have not been excluded are evaluated on the criteria of a sub-surface or surface constraint such as, the further from a built-up area the better, and they are ranked accordingly, so the further a site is from a built-up area, the higher the rank.

Relevance	Constraint	Allowable range/ criteria	Reference	Comment	Data sources
Sub-surface	Subsurface temperature	Below 80 degC. Excludes temperature above 80degC. Based on geothermal gradient of 30degC/ km	[B11]	Exclusion criteria only	n/a
Sub-surface	Depth to top of salt	Above 300 m. Closer to Goldilocks zone (600 m – 1200 m) the better.	B12][B13][B14][B15]	Exclusion & evaluation criteria	[B43]
Sub-surface	Salt thickness	Above 30 m	Previous work considers a site if salt thickness is greater than 50 m (cavern height of 20m + roof and floor thickness of 30m) [B2]	Exclusion & evaluation criteria	[B43][B7]
Sub-surface	Proximity to major fault	Above 200 m or 3 x cavern radius (whichever is greater). No grading.	[B10][B16]	Exclusion & evaluation criteria	[B44][B45]
Surface	Proximity to restricted development area (SSSI, SAC, RAMSAR, watercourses, National Parks)	Above 0 m from boundary. Further the better	Assumption based on [B1]	Exclusion & evaluation criteria. Does not account for minor watercourses.	[B46][B48][B49][B50][B51]
Surface	Proximity to built-up areas	Above 2500 m or 3 x cavern radius (whichever is greater). Further the better.	Assumption based on [B1]	Exclusion & evaluation criteria	[B58]
Surface	Proximity to reservoirs	Above 200 m or 3 x cavern radius (whichever is greater). Closer the better.	Assumption based on [B13]	Exclusion & evaluation criteria	[B52]
Surface	Proximity to railways and major roads	Above 200 m or 3 x cavern radius (whichever is greater). Closer the better.	Assumption based on [B1][B13]	Exclusion & evaluation criteria	[B53][B54]
Surface	Proximity to major pipeline networks/ corridors including Project Union pipeline	Above 200 m or 3 x cavern radius (whichever is greater). Closer the better.	Assumption based on [B1][B13]	Exclusion & evaluation criteria	[B47][B55]
Surface	Proximity to COMAH sites	Above 1000 m or 3 x cavern radius (whichever is greater). Further the better.	Assumption	Exclusion & evaluation criteria. Does not represent site-specific COMAH requirements.	[B57]
Surface	Proximity to planned hydrogen projects (i.e., offtakers)	Closer the better	Assumption	Evaluation criteria only	[B59]

Table B2. Sub-surface and surface evaluation and exclusion criteria.

Literature Review: UK East Coast region saltfield storage capacity

A number of studies have been published which have estimated the salt cavern storage potential of the UK and East Coast region.

Rasterisation and ranking of datasets

Each dataset is integrated with a base grid of hexagons and the proximity of each hexagon to the dataset is calculated (Figure B15 and Figure B16). Each hexagon is ranked based on the ability to meet the criteria of each constraint (Table B2).

A weighting is applied to each constraint based on the perceived impact that constraint has on development. The rank x weighting determines a score for each hexagon.

When many constraints are considered, an overall score is derived based on the "Weighted Sum Method" (see below). The overall score indicates the relative ease of cavern development for each site (Figure B17).

A generalised equation for the Weighted Sum Method is provided below:

$$\begin{aligned} Weighted\ Rank \\ &= \sum\left[\left(normalised_{rank_{criteria_1}} \times weighting_{criteria_1}\right) \right. \\ &\left. + \left(normalised_{rank_{criteria_2}} \times weighting_{criteria_2}\right) + \cdots\right] \end{aligned}$$

Site selection through application of exclusion and evaluation criteria

1. Hexagons are treated as "storage development sites" or cavern facilities of c.2.5 km2 (areal extent of each hexagon). This is similar to other cavern facility footprints such as Stublach and Keuper Gas Storage facilities in Cheshire.
2. For this study, the weighting for each constraint is set at the maximum value as all are considered to be challenging for development (Table B2). If a hexagon intersects a constraint or does not satisfy the criteria, it is eliminated from the storage capacity assessment (Figure B17).
3. For a given set of data, each hexagon is normalised and then ranked by the total number of non-excluded hexagons. As more hexagons are excluded, this method has an incidental effect of making each increment in rank more significant.

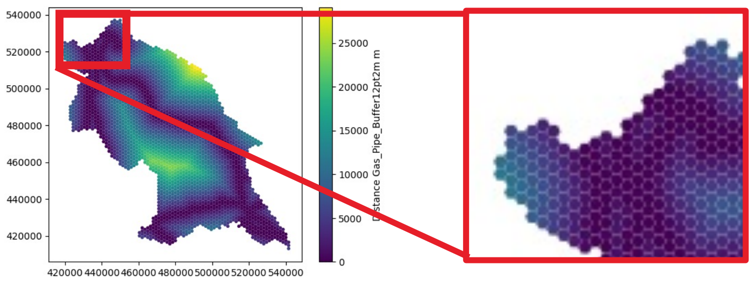


Figure B15. Integration of spatial datasets with a hexagonal grid. Hexagons of 1 km side length. Darker colours indicate where the dataset exists, in this example gas pipelines.

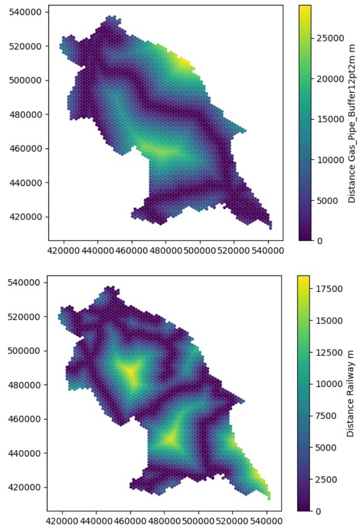


Figure B16. Rasterisation of datasets and calculation of proximity to constraints. Examples above present hexagons shaded according to the proximity to a) gas pipelines, and b) railways. Brighter colours indicate site which are further away.

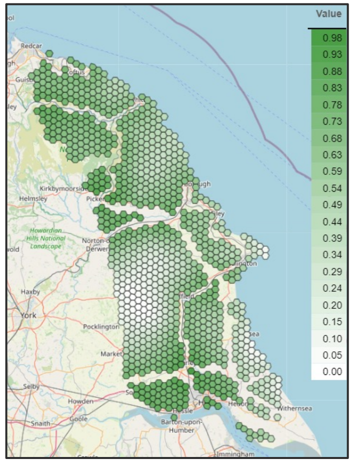


Figure B17. Implementation of evaluation and exclusion criteria for spatial constraints. Example above considers only gas pipelines and railways. Note higher scoring hexagons (i.e., development sites) closer to the gas and railway infrastructure; perceived as beneficial to site development.

Storage Capacity and Deliverability Calculations

Working energy capacity and deliverability of stored energy is embedded into the salt cavern storage appraisal.

Following selection of feasible development sites, storage capacity calculations are undertaken following previous published approaches, using the Real Gas Law [B1][B2][B9] (Figure B18).

Mined cavern volume (Vbulk) is corrected to account for reduction in usable cavern volume (Vcorr) due to deviation from the idealised cavern geometry (Shape Correction Factor, SCF), presence of insoluble materials within the salt which remain in the cavern following solution mining (Insoluble Fraction, IF), and bulking factor (BF) to account for the uneven stacking of insoluble material retained in the sump.

Mass capacity is calculated by assuming the temperature at the midpoint of the cavern (Tmidpoint), and maximum and minimum operating pressures (Pmax_operating and Pmin_operating) relative to the lithostatic pressure at the casing shoe (Pcasing). Hydrogen density at the operating pressure limits is multiplied by the usable cavern volume to determine the working mass (mworking), which is converted to energy using the Lower Heating Value (LHV).

It is widely regarded for fast-cycling storage caverns to be limited to a withdrawal capacity equivalent to 10 barg to 20 barg per day ([B16][B24][B25][B26]). Note that wet storage caverns are not a prefered option for deliverabily as they require additional infrastructure such as surface brine ponds, dehydration equipment and flow is restricted by the brine-compensation system.

For this study, a typical dry cavern of 40 m diameter at 1000 m depth can deliver the following:

- Working energy capacity: 16 GWh
- Deliverability: 1.3 GWh/ day at 10 barg per day.
- A typical wet cavern (exclusive to Boulby Halite) of same dimensions can deliver the following:
- Working energy capacity: 10 GWh
- Deliverability: 4.0 GWh/ day (withdrawal limited to 4.5 m/s brine flow velocity (industry rule of thumb)

$$V_{corr} = SCF \times ((1 - IF) \times BF)) \times V_{bulk} \quad [1]$$

Where V_{corr} is the available cavern volume.

$$T_{midpoint} = T_0 + \Delta T \times (Z_{casing} + 0.5 \times H_{cavern}) \quad [2]$$

Where, T is temperature, T_0 is ambient surface temperature, ΔT is geothermal gradient, Z_{casing} is depth to casing shoe, H_{cavern} is height of cavern

$$P_{casing} = (\rho_{overburden} \times t_{overburden}) \times g \quad [3]$$

Where, P is pressure, ρ is density, t is thickness, g is gravitational acceleration.

$$P_{max\_operating} = 0.8 \times P_{casing} \quad [4]$$

$$P_{min\_operating} = 0.24 \times P_{casing} \quad [5]$$

$$m_{max\_operating} = \rho_{H2max} \times V_{corr} \quad [6]$$

$$m_{min\_operating} = \rho_{H2min} \times V_{corr} \quad [7]$$

Where, m is mass, ρ is density.

$$m_{working} = m_{max\_operating} - m_{min\_operating} \quad [8]$$

$$E = m_{working} \times LHV \quad [9]$$

Where, E is energy (kWh), LHV is Lower Heating Value of 33.33 kWh H2/kg

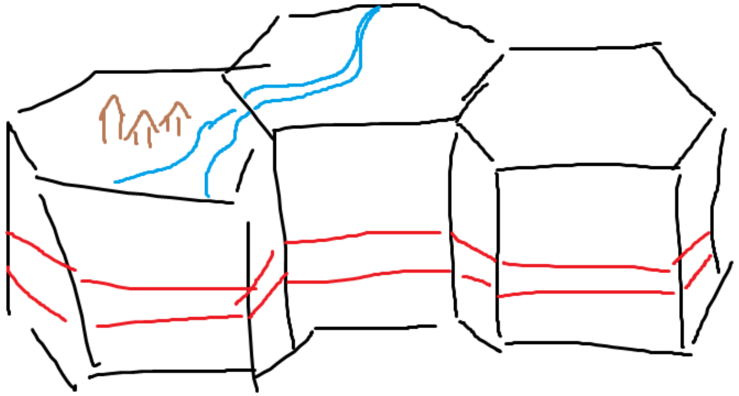
Figure B18: Calculation steps for determining cavern working capacity. After [B1][B2][B9].

Result Output: Hexagonal Grid & Cavern Development Sites

Development sites are represented as hexagonal geological columns of 2.5 km2 footprint. This approach is informed from existing cavern clusters in the UK and ensures that isolated caverns are not considered as viable storage locations.

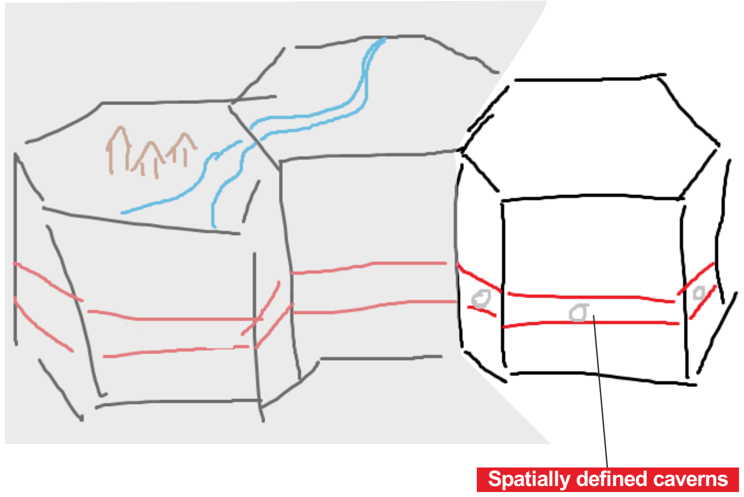
Mapping of sub-surface and surface constraints and integration with hexagonal base grid.

1



Elimination of development sites which do not meet the defined criteria. Caverns are modelled in viable halite.

2

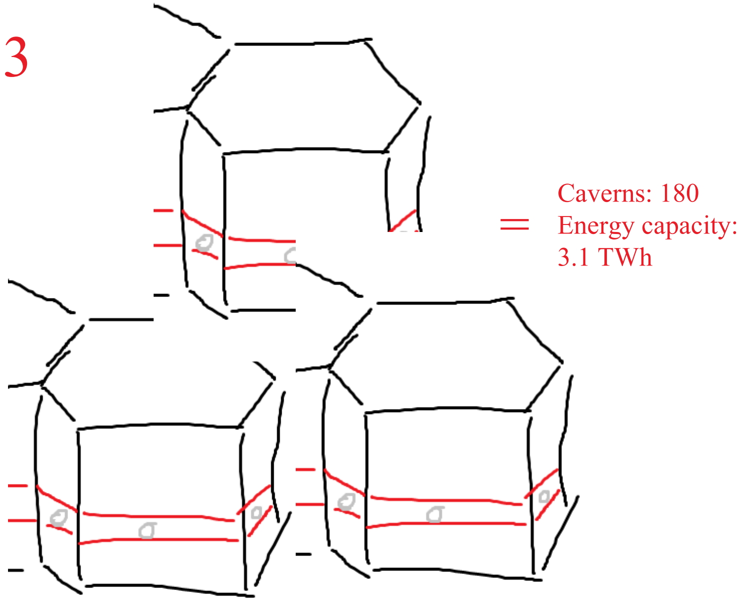


Hexagons which do not meet the defined criteria (e.g., occur close to sensitive environments or close to built-up areas) are eliminated from the analysis. Remaining hexagons are evaluated on how well they meet the criteria.

Storage caverns are geometrically modelled within viable halite thicknesses within the remaining hexagons.

Determination of storage capacity, deliverability and development timescale.

3



Storage capacity and deliverability is calculated for each available hexagon to derive a gross total. The storage capacity is governed primarily by the salt depth and thickness, which controls the volumetric capacity of the cavern.

Design Assumptions: Dry and Wet Caverns

Key design assumptions in cavern design to minimise geomechanical instability of the salt cavern and adequately evaluate net cavern volume potential.

Relevance	Parameter	Assumption	Reference
Sub-surface	Cavern floor thickness	Floor allowance = 0.2 x cavern diameter	[B1][B10]
Sub-surface	Cavern roof thickness	Roof allowance = 0.75 x cavern diameter	[B1][B10]
Sub-surface	Cavern shape factor	Apply volume reduction of 0.7 based on irregular shape formation from leaching and allowance for creep closure over time, reducing the intended usable volume.	[B1][B2][B9][B17]
Sub-surface	Non-salt content	"Industry standard" of 25%	[B2][B17]
Sub-surface	Insoluble bulking factor	Factor of 1.46 to on the percentage of insolubles to account for bulking in the sump.	[B2]
Sub-surface	Sump volume factor	Leached volume reduction factor from non-halite content and bulking: V_net = %impurities * V_leached * shape factor * bulking factor	Assumption based on [B2]
Sub-surface	Temperature/ Geothermal gradient	30degC/ km depth.	[B18][B9]
Sub-surface	Temperature at surface	10degC assumed mean surface temperature	Assumption
Sub-surface	Cavern separation (pillar width)	Pillar width: 3*cavern radius (5x cavern radius centre to centre)	[B17]
General	Lower Heating Value	Use Lower Heating Value (net calorific value) to convert between tonnage and power.	[B9][B19]
Sub-surface	Lithostatic pressure calculation	Internal lithostatic pressure of the cavern is computed from vertical stress only. No consideration of horizontal stresses.	Assumption
Sub-surface	Overburden density	Overburden assumed to be 0.0225 MN/m3, in line project experience in the UK salt fields (aligns to the overburden density used in Cheshire salt fields).	[B9][B20]

Table B3. Design assumption relevant for storage capacity calculations in dry and wet caverns in East Coast region.

Design Assumptions: Dry Cavern Specific

Key design assumptions in cavern design of dry operated caverns to minimize geomechanical instability of the salt cavern.

Relevance	Parameter	Assumption	Reference
Sub-surface	Cavern height	Cavern is modelled as a flat-topped cylinder. Max cavern height is calculated by salt thickness - roof thickness - floor thickness. Max ratio with diameter = 2D:H	[B17]
Sub-surface	Cavern operation	Capacity calculations will allow for dry caverns to be modelling in the Boulby Halite Formation and Fordon Evaporite Formation. This study only models capacity in the Fordon Evaporite Formation from dry caverns.	n/a
Sub-surface	Cavern radius	Cavern is modelled as a flat topped cylinder. Max cavern height is calculated by salt thickness - roof thickness - floor thickness. Max ratio height with diameter = 2D:H Minimum radius set at 5 m. Therefore minimum salt thickness required for caverns to be constructed: (cavern height = 20 m + roof thickness + floor thickness = 10 m) = 30 m.	[B1][B10][B17][B21]
Sub-surface	Operating pressure limits	Pmin set at 24% lithostatic. Pmax set at 80% lithostatic.	[B1] (Note that [B22] assumes Pmin = 0.2 x lithostatic)

Table B4. Design assumption specific to dry cavern storage, relevant for storage capacity calculations.

Design Assumptions: Wet Cavern Specific

Key design assumptions in cavern design of wet operated (brine-compensated) caverns to minimise geomechanical instability of the salt cavern.

Relevance	Parameter	Assumption	Reference
Sub-surface	Cavern height	Cavern is modelled as a spinning top. Max cavern height is calculated by salt thickness - roof thickness - floor thickness. Max ratio with diameter = H:0.5D	[B23]
Sub-surface	Cavern operation	Wet operated caverns will only be applied to Boulby Halite Formation (BHF). The site selection tool allows the user to choose to model caverns in Boulby (BHF) as either wet or dry operated caverns.	[B23]
Sub-surface	Cavern radius	Cavern is modelled as a spinning top. Max cavern height = salt thickness - roof thickness - floor thickness. Diameter at widest point is approximately twice the length of cavern height (2D:H) [23]. This is to maximise storage volume given the thin halite bed. Minimum cavern radius is set at 10 m, therefore caverns can only be sited in salt equal to or greater than 30 m thick (cavern height = 10 m; roof allowance = 15 m; floor allowance = 5 m).	[B23]
Sub-surface	Operating pressure limits	Constant internal pressure at halmostatic pressure (full-head of brine). Brine assumed to have unit weight of 0.0118 MN/m3.	[B23]

Table B5. Design assumption specific to wet cavern storage, relevant for storage capacity calculations.

Limitations & Opportunities

To enable further development of the research presented in this work package, key limitations are presented. Additionally, there exists many opportunities to further refine the theoretical storage capacity in salt caverns towards a "realisable potential".

Limitations

- Development sites are predefined on a 2.5 km2 hexagonal footprint. The area is considered to be appropriate and similar to other development sites in the UK, such as Keuper Gas Storage Project. If a hexagon intersects with any surface constraint, the entire hexagon will be removed from the analysis. A smaller hexagonal grid size could be considered to better optimise the available land for development.
- The geological model has been informed from publicly available dataset from UK Onshore Geophysical Library (UKOGL) and onshore mapping published by British Geological Survey (BGS). Additional datasets such as seismic sections and intrusive data should be considered at any future stage.
- For the scope of this study, a region-wide appraisal, the granularity of the ground data used to develop the geological model is considered to be appropriate. It is worth noting that as the input data is generally at a much lower resolution than the size of a hexagon, significant geological uncertainty exists for each hexagon.
- Site-specific geological models should be developed to assist more rigorous development opportunities on a local basis.
- Ultimately, this is a regional study and all assumptions should be tested and refined on a site-specific basis with site-specific data.

Opportunities

- Refine geological model. Incorporate additional ground data such as BGS GeoIndex boreholes and geophysics sections to better constrain the extent, depth and thickness of salt horizons.
- Refine workable volume insoluble content. A uniform value of 25% of non-halite geology is considered for the workable volume of Boulby Halite Formation and Fordon Evaporite Formation. This should be refined to capture lithological and mineralogical heterogeneity.
- Communicate uncertainty in the geological model. This could be through statistical analysis of ground data and/ or incorporation of an uncertainty factor.
- Refine topography model to reflect true land elevations. Currently the regional topography is defined as constant 0 mOD. This can result in over-conservative estimates of capacity where there is significant positive elevation.
- Refine potential capacity model. Incorporate extents of existing subsurface developments e.g., historical mining (e.g., coal), mine extraction limits (underground storage sites, Boulby Mine and Woodsmith Mine extraction limits), and underground infrastructure (Boulby Mine shafts and associated developments and Woodsmith Mineral Transport System and other associated developments)
- Industry engagement. Refine and develop the tool based on industry requirements. This will set the scene for subsequent revisions.
- An adequate estimation of realisable potential will require additional consideration of technical, social and economic viability, and is beyond the scope of this study and should be considered at the next stage.
- Understand the geomechanical viability of hydrogen storage. This will include geological modelling for cavern responsiveness to hydrogen cycling.
- Extend methodology to refine offshore storage estimates in the Fordon Evaporite Formation and Boulby Halite Formation.
- Economic analysis of CAPEX required to meet UK's hydrogen storage demand.

Key Findings: Capacity

A "resource potential" for hydrogen storage in salt caverns has been determined for the East Coast region. The storage potential ranges from 22 TWh to 48 TWh, up to 95% lower than previous estimates.

WP2 estimates the theoretical resource potential for storage to be at least 22 TWh, equivalent to c.1000 caverns of 20 m radius (Table B6).

Table B7 compares key parameters from the peer-reviewed publication by Williams et al (2022) [B2] to this study and the results are compared in Table B8.

A key differentiator between the studies include:

- The evaluation of the Fordon Evaporite Formation for salt cavern development. In this study only the halite member has been identified as suitable for salt caverns, typically up to 100 m thick, in contrast to the assumption from Williams et al., that most of the (up to) 300 m thickness of Fordon Evaporites could be exploited.
- This study assumes a uniform cavern radius of 20 m, in comparison to Williams et al. [B2], which assumes a cavern radius of 50 m.
- The assessment of storage capacity is undertaken on a grid basis, where each grid is approximately 2.5 km2. This removes the possibility of having isolated single caverns prone to becoming "stranded assets".
- Note that as highlighted in the methodology, both studies have employed similar logic to assessing the impact of surface constraints and excludes any development site which intersects the exclusion zone of a mapped constraint.

Storage capacity findings from this study are an order of magnitude lower than previously determined; 750 TWh compared to a revised estimate of 22 TWh. From an assessment of the viable regions in the UK for salt cavern storage of hydrogen, Williams et al. [B2], estimates that the UK East Coast region represents approximately 70% of the UK's storage capacity. The findings of this study can be extrapolated to derive an approximation of the UK's total revised resource potential for salt cavern storage of approximately 35 TWh, which is provided in Table B8.

Mean deliverability of hydrogen per cavern has also been calculated as part of this study. A mean withdrawal rate of 1.2 GWh/ day per cavern is provided in Table B6 and represents the rate as limited by a 10 bar/ day pressure drop inside the storage cavern [B24][B26][B31][B37]. Note that the delivery rate is unlikely to scale linearly for many caverns; for a cavern cluster (10 – 20 caverns) the rate will largely be limited by topside infrastructure such as decompressors and dehydrators.

This study has co-developed an interactive site selection tool for the development of a salt cavern facility (a cluster of salt caverns).

A sensitivity analysis on the overall capacity of a selected site can be undertaken by altering:

- Cavern radius
- Cavern pillar width
- Withdrawal rate

	Resource potential of salt cavern storage	Caverns required to be developed	Mean deliverability rate per cavern
3 x cavern radius	48 TWh	2200	1.2 GWh/ day
5 x cavern radius	22 TWh	1000	

Table B6: IDRIC estimate for salt cavern storage capacity and deliverability.

	Williams et al., 2022	IDRIC Study, 2024
Cavern casing shoe depth [m]	747 – 1800	650 – 1800
Cavern height [m]	20 – 300	Up to 88
Cavern operating pressure [MPa]	14 – 34	12 - 32
Working hydrogen mass range [te]	486 – 13239	700 - 1500
Equivalent energy storage range [GWh]	16 - 441	23 – 49

Table B7: Key parameters for modelled caverns. Williams et al., [22] uses R=50m; IDRIC Study uses R=20m.

	Williams et al., 2022		IDRIC Study, 2024	
	East Coast Region	UK Capacity	East Coast Region	UK Capacity
3 x cavern radius	1500 TWh	2150 TWh	48 TWh	68 TWh
5 x cavern radius	750 TWh	1100 TWh	22 TWh	35 TWh

Table B8: IDRIC estimate of salt cavern storage in comparison to Williams et al. [22]

Key Findings: Programme

Development timescales for caverns are long and will require a robust supply chain and concurrent development of cavern clusters to realise the storage capacity potential by 2050.

A literature review supports the general understanding that it can take around 15 years to develop one cavern facility (nominally up to 20 caverns) (Figure B19), assuming there is an accepting local population, a robust, mature and available supply chain and a mature and efficient pathway through regulations and permitting.

This study has found that a lower-end resource potential of 22 TWh of storage capacity could be achieved in the East Coast region. The figure assumes a uniform cavern radius of 20 m and cavern to cavern pillar width of 5x cavern radius.

Due largely to geological constraints, notably the form of the bedded halite, approximately 1000 caverns are required to achieve 22 TWh and 2200 caverns for 48 TWh of storage capacity.

This is in agreement with literature estimates from Williams et al., [B2] and The Royal Society [B4], which estimate that 3000 caverns are required to achieve up to 100 TWh.

The findings therefore indicate that to achieve an additional 22 TWh of storage capacity in salt caverns by 2050 (in 25 years), 50 cavern clusters of 20 caverns each will need to be constructed. Many cavern clusters will also need to be developed concurrently to achieve the storage capacity by 2050. The challenge becomes greater for any larger storage capacity requirement.

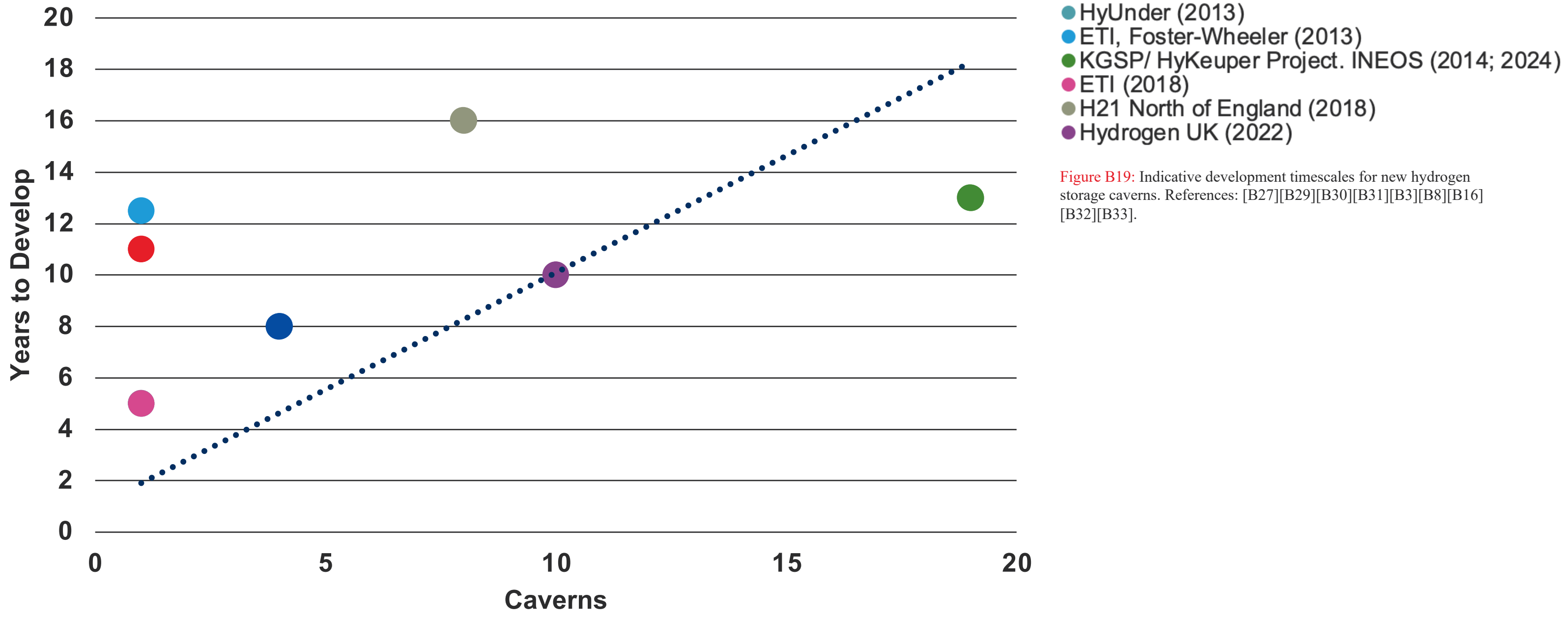


Figure B19: Indicative development timescales for new hydrogen storage caverns. References: [B27][B29][B30][B31][B3][B8][B16][B32][B33].

Key development activities and approximate duration for the development of a single cavern are provided below:

1. Site selection & consultations | 1.5 – 2 years
2. Planning & permitting | 1.5 – 2 years
3. Detailed design & procurement | 2 to 2.5 years
4. Construction & commissioning | 2 to 3.5 years

Note that for the development of a cavern cluster the programme will largely benefit from optimised phasing of "Detailed design & procurement" and "Construction & commissioning" activities for multiple caverns e.g., phased development of 3 to 5 caverns at a time, which benefits from already mobilised resources such as solution mining equipment.

Key Findings: Programme (additional information)

Development timescales for caverns are long and will require a robust supply chain and concurrent development of cavern clusters to realise the storage capacity potential by 2050.

A literature review supports the general understanding that it can take around 15 years to develop one cavern facility (nominally up to 20 caverns) (Table B9), assuming there is an accepting local population, a robust, mature and available supply chain and a mature and efficient pathway through regulations and permitting.

This study has found that a lower-end resource potential of 22 TWh of storage capacity could be achieved in the East Coast region. The figure assumes a uniform cavern radius of 20 m and cavern to cavern pillar width of 5x cavern radius.

Due largely to geological constraints, notably the form of the bedded halite, approximately 1000 caverns are required to achieve 22 TWh and 2200 caverns for 48 TWh of storage capacity.

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The findings therefore indicate that to achieve an additional 22 TWh of storage capacity in salt caverns by 2050 (in 25 years), 50 cavern clusters of 20 caverns each will need to be constructed. Many cavern clusters will also need to be developed concurrently to achieve the storage capacity by 2050.
The challenge becomes greater for any larger storage capacity requirement.

Key development activities and approximate duration for the development of a single cavern are provided below:

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4. Construction & commissioning | 2 to 3.5 years

Note that for the development of a cavern cluster, the programme will largely benefit from optimised phasing of "Detailed design & procurement" and "Construction & commissioning" activities for multiple caverns e.g., phased development of 3 to 5 caverns at a time, which benefits from already mobilised resources such as solution mining equipment.

Study	Time for cavern development
HyUnder (2013) [B27]	5 years for cavern construction only. This does accounts only for activities between well drilling and commissioning,
ETI, Foster-Wheeler (2013) [B8]	12.5 years from planning through to commissioning and start-up. Assumed this is for a single cavern. Exploration and planning: 3-4yrs. FEED: 1.5yrs. EPC Tender: 1yr. EPC execution and commissioning: 6yrs.
KGSP/ HyKeuper Project. INEOS (2014 [B28]; 2024 [B29][B30])	13 years for the development of a cavern facility of 19 new caverns. Comprising: • 3 years for pre-planning and application and acceptance of DCO. • 10 years for phased and concurrent development of 19 new caverns. Consultations started in 2014. DCO application accepted in 2017. Commissioning of storage due in 2028.
ETI (2018a) [B16]	4 to 5 years for cavern leaching and commissioning only. This does not account for other related development activities.
H21 North of England (2018) [B31]	First cavern storage unit operational within 10 years. All 8 facilities online in 16 years.
Hydrogen UK (2022) [B32]	7 to 10 years for "cavern facility". "Cavern facility" believed to represent a cluster of up to 19 (as per Holford Gas Field development, Cheshire) [B35]
IEA TCP Task 42 (2023) - HyStock Project [B3]	4 caverns are due to be operational by 2030, since demonstration successfully concluded in 2022. Extrapolated to 8 years for 4 caverns, which could be perceived as a "cavern facility".
H_2eart for Europe (2024) [B33]	11 years for single cavern. Also provides indicative programme of 8 years for repurposing existing caverns.

Table B9: Indicative development timescales for new hydrogen storage caverns.

Conclusion: Current assumptions around capacity of caverns are overstated and the ability to deploy within the required timeframe is challenging

Current assumptions on resource capacity of salt caverns for hydrogen storage are many levels removed from the feasible workable storage volume; this study has rationalised the workable volume towards a "realisable potential" and in doing so has reduced the previous best estimates of storage capacity by c.95%. Storage capacity is still large, at least 22 TWh, however, significant barriers exist which limit the ability to deploy salt cavern storage to realise storage potential by 2050.

Salt caverns for hydrogen storage is a mature technology (TRL Stage 9) having existed in the UK for over 50 years, albeit at relatively small scale compared to future requirements by 2035 and 2050.

Current rhetoric from national policy documents and published literature assumes that large-scale hydrogen storage in salt caverns is readily available within the timescales for the Net Zero pathway.

The purpose of this study is to challenge the current assumptions and begin to rationalise the theoretical onshore storage capacity in the East Coast region towards a realisable potential.

This study finds that a resource potential (Figure B1) estimate of storage capacity is between 22 TWh and 48 TWh, based on the following assumptions on constraints:

- Development is specific to the Fordon Evaporite Formation only.
- A uniform cavern radius of 20 m.
- Development cannot occur within any defined surface constraint boundary.

An adequate estimation of realisable potential will require additional consideration of technical, social and economic viability, and is beyond the scope of this study but is recommended for future research.

Development of salt cavern storage is found to be strongly limited by:

- Geographical and geological limitations of the halite-bearing strata, and surface and subsurface constraints.
- The time required to develop at scale, including inefficiencies of a nascent supply chain.
- The location of suitable salt deposits in relation to the producers and end-users.

Three principal conclusions have been drawn from this work package:

1. Not all salt can host large caverns

The UK is host to bedded halite, typically limited to formations of interbedded halite and non-halite up to 300 m thick. Note that once allowances are made for suitable thicknesses of halite above and below the cavern, and presence of impurities/ non-halite geology within the formation, the thickness of workable halite is a fraction of the overall formation thickness.

For example, in the Netherlands, salt caverns are located in a salt diapir up to 1500 m thick. Owing to the geological nature there is a higher halite purity, and owing to its thickness caverns have been constructed to larger sizes and volumes than in the UK.

Therefore, many more caverns are required to be constructed in bedded halite to achieve the same storage capacity and deliverability rate. To achieve up to 22 TWh of hydrogen storage, c.1000 caverns are required to be constructed.

2. Operational capacity of the salt cavern is often overlooked and not considered

Volume capacity and rate of withdrawal of hydrogen from the storage vessel, is critical for end-users and offtakers.

Rate of withdrawal is constrained by stability requirements in the salt cavern, this differs depending on the operation mode (wet vs dry) of the salt cavern.

This study has incorporated an approximation of total deliverability, which can be used to support the developer's analysis on how storage and supply requirements can be met.

3. Salt cavern development timeline is long and challenging

For example, to achieve the lower-end storage potential identified in this study of 22 TWh, c.1000 new caverns are required. Based on a comprehensive literature review and stakeholder engagement, it is estimated that the delivery programme to deliver cavern clusters of 10-20 caverns is approximately 15 years.

To achieve this storage capability in the East Coast region before 2050, multiple concurrent developments (up to 50) are required. This assumes the supply chain is mature and has sufficient capacity.

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Conclusion: Current assumptions around capacity of caverns are overstated and the ability to deploy within the required timeframe is challenging

Current assumptions on resource capacity of salt caverns for hydrogen storage are many levels removed from the feasible workable storage volume; this study has rationalised the workable volume towards a “realisable potential” and in doing so has reduced the previous best estimates of storage capacity by c.95%. Storage capacity is still large, at least 22 TWh, however, significant barriers exist which limit the ability to deploy salt cavern storage to realise storage potential by 2050.

Case Example: HyKeuper, Cheshire

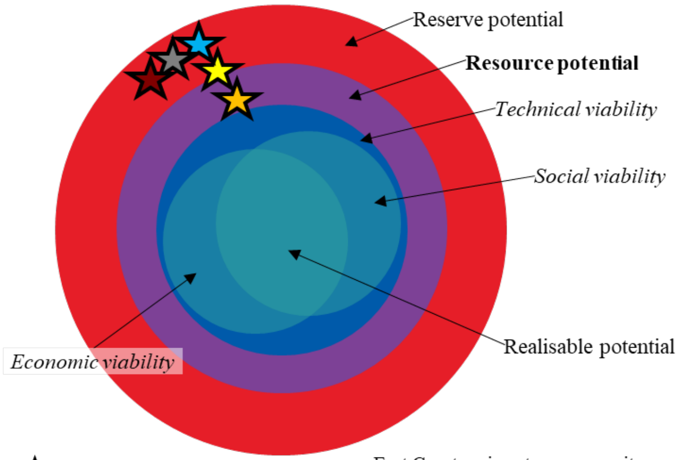
Development of 19 new hydrogen storage caverns, providing 1.3 TWh energy storage and up to 6 GW power deliverability.

The project is adjacent to current gas storage sites, hence represents an optimist case example given public acceptance and well understood ground conditions and mature FEED plans.

Nevertheless, pre-construction lead in-time, accounting for activities for planning application submission (DCO) was 3 years. Construction to commissioning of all 19 caverns is forecast to run over 10 years, hence 13 years from inception to delivery.

Key limitations to the scale of development (i.e., 19 caverns) include water availability for solution mining, brine discharge limits and dispersal rates, material and skill availability for topside development and well construction.

For a new cavern cluster in a greenfield site, the development timeline is anticipated to be much longer, largely due to protracted pre-planning and construction activities. If many cavern clusters are concurrently developed in the UK, there is likely to be a significant constraint on material and skill availability which is controlled by national and international market conditions.



	East Coast region storage capacity
Caglayan et al., 2020 [1]	1000 TWh
Williams et al., 2022 [2]	750 to 1500 TWh
Allsop et al., 2023 [9]	n/a: Southern North Sea
Barnett et al., 2024 [22]	n/a: Southern North Sea
IDRIC, 2024	22 to 48 TWh

Figure B1. Concept of “potential”, adapted from [21][23]. Where “realisable potential” is the refinement of “resource potential” based on technical, social and economic viability.

Given the challenges facing the development and commissioning of adequate salt cavern storage for the UK’s Net Zero ambitions, it is clear that there is a need for a diverse portfolio of energy storage options. Included in this will be salt caverns, alongside lined rock caverns, depleted oil and gas fields and saline aquifers.

Conclusion: Salt Cavern Capacity & Development Appraisal Tool

A new tool allows the user to estimate salt cavern storage potential and development programme for selected sites in the East Coast region.

Purpose

This study has co-developed an interactive site selection tool for the development of a salt cavern facility (a cluster of salt caverns).

The tool allows the user to identify suitable sites for development (hexagonal grids) based on a suite of constraining criteria. Storage capacity and deliverability is calculated for the sites and an indicative development programme can be reviewed.

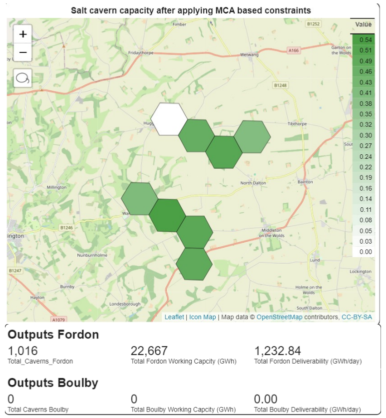
User control

- The user can influence the relative rank of each site for development by reviewing a comprehensive set of constraining criteria. It includes spatial occurrence of halite-bearing geology (in plan extent and depth), and land-based features which may hinder surface and subsurface development. The lower the rank, the poorer the hexagon scores and the least attractive it is as a site for salt cavern development e.g., this may be due to close proximity to existing infrastructure or sensitive natural environments.
- The user also has control on which halite-bearing geology to develop e.g., Boubly Halite and/ or Fordon Evaporite Formation, the radius and spacing of the caverns.
- An indicative programme is provided which the user can adopt based on the perceived timescale for each activity from pre-planning to commissioning.

The 'Hydrogen Storage Salt Cavern Development & Capacity Tool – East Coast Region' online platform and user manual are provided at the links below:

- Online Platform / User Manual

a) Selected development sites



b) Total development time required (years)

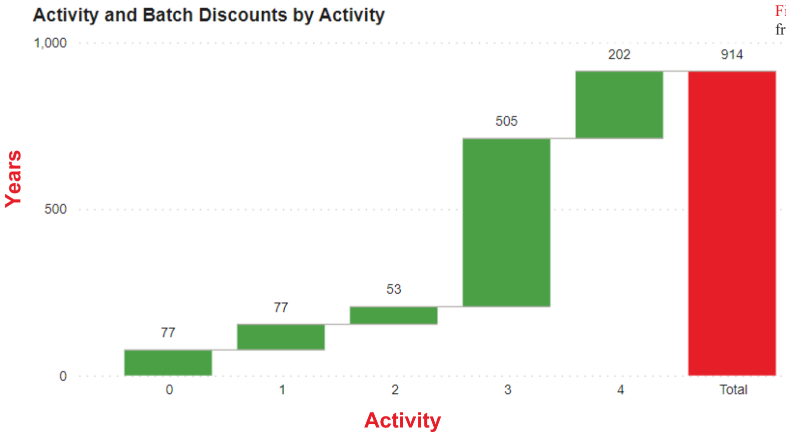
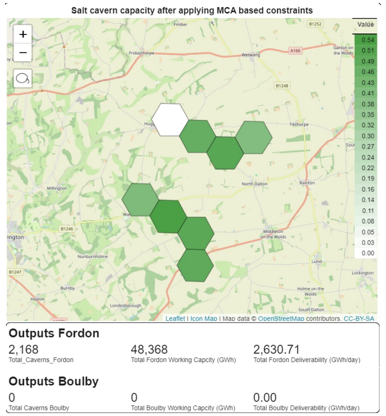


Figure B21. Lower end capacity estimate – extract from Salt Cavern Capacity & Development tool.

a) Selected development sites



b) Total development time required (years)

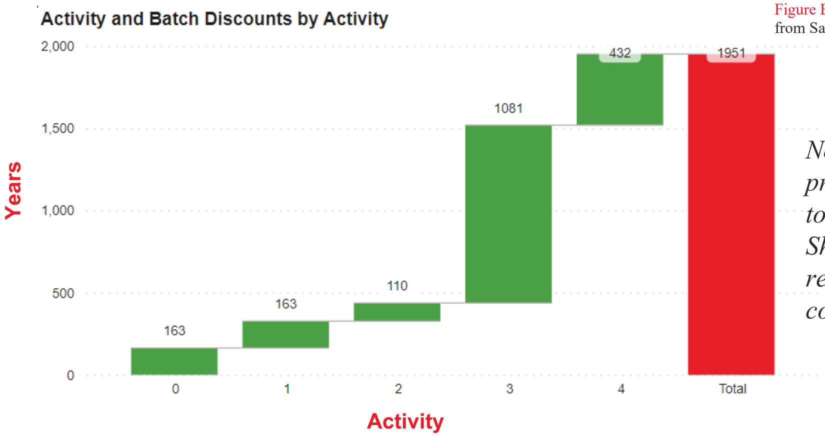


Figure B22. Upper end capacity estimate – extract from Salt Cavern Capacity & Development tool.

Note, the tool is in the process of being migrated to a publicly accessible Sharepoint site; links in report to be updated once complete.

Appendix C:

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