Bacton Energy Hub

Stage 1 report launch

20 May 2021

Supporting the Hydrogen Economy across the East of England

Hydrogen East

Bacton Energy Hub

Stage 1 report launch

20 May 2021
Introduction and report context

Energy infrastructure and hydrogen

XODUS CCUS assessment

Hydrogen demand assessment

Illustrative development pathways

Conclusions and next steps

Q&A
Bacton in context
Rapidly developing landscape

- June: UK Hydrogen Strategy
- Dec: Low Carbon Hydrogen Production Fund
- Sep: Low Carbon Hydrogen Supply Competition
- March: Industrial Fuel Switching Competition
- Green Distilleries Competition

Policy, Networks, Industry
Why Bacton?

- Entry point for up to 20% (equivalent to 30% of UK end-user gas demand) into the NTS
- Proximity to SNS and gas fields/offshore wind
- Import and export links to Europe
- Bacton has the potential to become a major UK hydrogen reception and processing terminal
- National Grid Gas has flagged Bacton as one of three key sites requiring asset investment work to "retain safe operation [ ] and in consideration of Net Zero"
- Potential to support heat, transport and energy infrastructure locally, regionally and nationally
## Norfolk and Suffolk SWOT

### Strengths
- Large and growing fleet of offshore wind
  - 537MW of solar capacity (81MW in planning)
- Two gas interconnectors providing access to future European hydrogen markets
- Bacton meets 30% of present end-user gas demand

### Weaknesses
- No industrial load compared to prospective ‘Hydrogen Clusters’
  - Access to gas is mixed, especially in rural areas
- Constrained electricity network requiring Active Network Management
  - No current large-scale hydrogen production or infrastructure

### Opportunities
- Six large ports could stimulate significant demand from ships, portside ops and surface freight traffic
  - Strong build out plans for new renewables
- Engaged Local Authorities looking at how hydrogen can form part of Climate Action Plans
  - Heat from Sizewell nuclear facility could support highly efficient electrolysis

### Threats
- Lack of regulatory and policy certainty, including roadmap for updating licences and codes
  - Ensuring demand and supply emerge in parallel
- A lack of coordinated planning and joined-up thinking
Bacton Energy Hub: Stage 1

- Project formally launched on 22 February 2021
- Main objectives
  - To scope potential building up of hydrogen supply as part of an integrated energy hub
  - To carry out a regional hydrogen demand assessment
  - To identify re-purposing and re-use of existing assets, including for CCUS and integration with offshore wind
  - To identify barriers and solutions
  - To assess benefits case
  - To build a collaborative, whole-system approach and bring together relevant players and interested parties
Project scoping and development

October 2020

Deep regional spatial mapping

November – December 2020

Granular regional demand modelling

January – February 2021

CCUS, supply and re-use/re-purposing assessment

March 2021

Report writing

March – May 2021

Report dissemination

May 2021

Bacton Energy Hub – Stage Two

June 2021 – onwards

Project process

Official project commencement
Energy infrastructure
Bacton Terminal and gas infrastructure

- Bacton site will remain a strategic piece of UK infrastructure
- Bacton presently flows up to 20% (equivalent to 30% of UK end-user gas demand) into the NTS
- Excellent gas connection to SNS, GB and Europe
- Dedicated pipeline running to Great Yarmouth CCGT
Onshore gas distribution

- Consensus that hydrogen offers a **feasible opportunity to repurpose the gas grid**
- **Cities and towns** to benefit the most from hydrogen in NTS
  - Norwich and Ipswich
- 11 existing distributed injection points
Gas infrastructure implications

- **Excellent connections to onshore network** and rest of GB
  - Subject to appropriate integration work and regulatory approvals
- Onshore sections can be converted to be **hydrogen-ready by 2030** with **connection to industrial clusters by 2035**
- **Connection of Bacton into European Hydrogen Backbone**
  - Hydrogen-ready by late 2030s
- **Options for offshore infrastructure re-use** as part of a CCUS system
  - this could be anchored by a **blue hydrogen terminal at Bacton producing up to 55.9Twh/year**

**Ongoing work by networks and GGG programme will be essential for furthering development**
Offshore electricity

- **3GW+ of offshore wind** connecting into New Anglia (2021)
- **Major growth expected** as part of 40GW 2030 target
- **Increase in periods of surplus electricity production**

Offshore Transmission Network Review will have implications for future hydrogen production.
Onshore electricity

- New Anglia region is **significantly constrained**
  - 2020 saw increasingly frequent periods of curtailment
- Opportunity for deployment of **behind-the-meter electrolysis**
  - Plans for 2MW electrolyser in Sizewell region

Constraints of New Anglia region creates value for electrolyser development
Electricity implications

- Size is constrained by electricity connection and water resources so very locational.
- Early green hydrogen developments will be small onshore pockets each <5MW in size.
- Largest examples in the market are ~20MW, but indications globally show interest in GW-scale clusters so possible that we could see a 0.5-1GW coastal cluster in 2040s.
XODUS - CCUS in the SNS
Bacton CCS Scope – Hydrogen East

Bacton Energy Hub Report
Introduction
What is Blue Hydrogen and why CCS?

> Blue Hydrogen is $\text{H}_2$ that has been made using methane and steam, whilst capturing and storing the $\text{CO}_2$ that is also produced.

$$\text{CH}_4 + 2 \text{H}_2\text{O} \rightarrow \text{CO}_2 + 4 \text{H}_2$$

> CCS enables large stationary $\text{CO}_2$ emitters to decarbonise their industry using offshore underground storage.

> Clusters of $\text{CO}_2$ emitters surrounded by established gas infrastructure can take advantage of combined $\text{CO}_2$ generation to reduce shared costs of injection and storage.
Why Bacton?

Introduction

- Offshore Wind – 20GW+ operational and planned
- Proximity and connection to UK demand (London)
- 2 gas connection to Europe (Belgium and Netherlands)
- Vast CO₂ storage capacity in depleted reservoirs and aquifers (15 Gt in SNS)
- Extensive offshore infrastructure – pipelines, facilities, etc.
Flow Diagram

Introduction

Bacton Terminal
Blue H₂ production

Other CO₂ sources

Natural Gas
From CNS / SNS assets

H₂ to demand
Local Hub
London

CO₂ Storage
Injected into depleted reservoir

Europe

Natural Gas

Hydrogen
Reuse of existing pipelines can lead to a significant reduction in up-front CAPEX.

In the SNS, the Hewett field has been identified as potential candidate for CO₂ storage.

The Hewett field currently has 2 pipelines that connect it to the Bacton terminal, both with a transport capacity of 15 MMT/yr of CO₂.

Other depleted gas fields and saline aquifers have also been identified.

Previous Xodus report highlighted that these pipelines are potentially suitable candidates for CO₂ transport.

However, these pipes would have to undergo inspection and assessment before they are deemed suitable for CO₂ transport.
At pressures above the critical pressure (~72 barg), CO₂ has a high density and low viscosity. This means it can be transported efficiently in pipelines. These ‘dense phase’ conditions are generally preferred.

Depleted gas fields that are suitable for CO₂ storage, such as Hewett, are at a low pressure.

When CO₂ is injected into a low pressure reservoir from a dense phase pipeline, there is a large pressure drop. This pressure drop leads to cooling of the CO₂ to temperature below 0°C. These temperatures cause ice and/or hydrate(*) formation, and can damage parts of the well or the rock formation the CO₂ is being injected into. Additional costs of remediation as well as interruption to operation.

Therefore measures must be taken to prevent these low temperatures:

- **Keep CO₂ pressure lower**
  - Eliminates very low temperatures.
  - CO₂ density is lower.
  - Lower transport capacity for given pipeline size.
  - Higher £/te transport costs.

- **Heat CO₂ offshore before injecting**
  - Provides large margin for temperature loss.
  - Higher pressures used for dense phase CO₂.
  - Higher offshore CAPEX costs.

- **Conserve heat of CO₂**
  - CO₂ heats up post-compression
  - Insulated or heated pipeline to can keep the CO₂ warm.

* Hydrates are ice-like structures which can be formed by water and hydrocarbons.
## Case Matrix

**Definition of chosen cases**

<table>
<thead>
<tr>
<th>Case</th>
<th>Description</th>
<th>Pipeline</th>
<th>Structure</th>
<th>Heating</th>
<th>CO₂ Injection Rate MMT/yr</th>
<th>H₂ Production Rate TWh/yr (GW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Base Case</td>
<td>30 km 30”</td>
<td>Platform</td>
<td>None</td>
<td>4</td>
<td>22.4 (2.6)</td>
</tr>
<tr>
<td>2</td>
<td>Subsea</td>
<td>30 km 30”</td>
<td>Subsea Tie-in</td>
<td>None</td>
<td>4</td>
<td>22.4 (2.6)</td>
</tr>
<tr>
<td>3</td>
<td>Platform Heating</td>
<td>30 km 30”</td>
<td>Platform</td>
<td>DEH Offshore</td>
<td>10</td>
<td>55.9 (6.4)</td>
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<tr>
<td>4</td>
<td>Reduced Flow</td>
<td>30 km 16”</td>
<td>Platform</td>
<td>DEH Offshore</td>
<td>4</td>
<td>22.4 (2.6)</td>
</tr>
<tr>
<td>5</td>
<td>Pipe-in-Pipe</td>
<td>30 km 16” in 22”</td>
<td>Platform</td>
<td>None</td>
<td>3.6</td>
<td>20.1 (2.3)</td>
</tr>
<tr>
<td>6</td>
<td>Existing Pipeline – No Heating</td>
<td>Existing</td>
<td>Platform</td>
<td>None</td>
<td>4</td>
<td>22.4 (2.6)</td>
</tr>
<tr>
<td>7</td>
<td>Existing Pipeline – Heating</td>
<td>Existing</td>
<td>Platform</td>
<td>DEH Offshore</td>
<td>10</td>
<td>55.9 (6.4)</td>
</tr>
</tbody>
</table>

> Case 5 – No heating, however, assuming the CO₂ is not cooled after compression.  
> Pipe-in-Pipe solutions retain heat very well.
Costing Results
Bacton competitive with leading projects

> Reuse of existing pipelines is an obvious way to reduce the cost per tonne of storage.

> Heating offshore adds significant cost despite increase injection rate – overall higher £/t of CO₂
Costing Results
Bacton competitive with leading projects

> Storage capacity and injection rate is key – economy of scale, lower OPEX;

> Pipe-in-Pipe option good for short distances, however, they are limited to 16” flowline which reduces transport potential compared to larger diameter pipes of 30”.

> Other Hewett project had 250 km pipe (from Kingsnorth), leading to higher CAPEX and OPEX costs. Also had an injection rate of 2.5 Mt/yr and used 12 wells (vs. 4 Mt/yr and 5 wells).

**Benchmarking Source:**
“A Summary of the Results from the Strategic UK CO₂ Storage Appraisal Project” – April 2016
(data converted to Real Terms 2021 to enable comparison)
Previous Xodus work has assessed North Sea assets for remaining life and power requirements.

Results of the work suggest that SNS is a lower priority region for electrification. The SNS is a mature basin in decline with low remaining field life in comparison to the CNS and West of Shetland basins.
Bacton benefits from its proximity to a large number of depleted gas reservoirs, namely the Hewett field, and represents a prime candidate for Blue Hydrogen production. Further storage is available in saline aquifers within the SNS.

Direct heating offshore is technically challenging for the injection rates considered. At 4 MMt per annum and 10 MMt per annum, the amount of heat required to enable dense phase injection is 30 MW and 70 MW respectively.

While re-use of infrastructure could result in lower capital cost, there is uncertainty and risk associated with this. Given the relatively short distance (30 km), the cost saving of re-using pipelines is relatively small. When risk and speed of development are considered, it is expected that a new pipeline would be the preferred solution.

A passively insulated Pipe-in-Pipe system is very simple and therefore low risk to operate. It will also have a low operating cost. In areas where the carbon capture site is farther from the storage site, Pipe-in-Pipe in less likely to be cost competitive. This is a differentiator for the Bacton area, in that it can offer a lower risk / lower operating cost CO2 transport and storage solution than other areas. Both of these may be attractive to potential investors.
Regional hydrogen demand
In order to establish a thriving hydrogen economy in Norfolk and Suffolk, we need to evaluate the opportunities to adopt and use locally produced hydrogen.

We have established three demand scenarios:

- **Low**: Hydrogen demand is limited to certain subsectors and emerges later.
- **Central**: Hydrogen demand grows strongly in certain sectors, with assumptions built on current industry consensus.
- **High**: Local hydrogen demand opportunities are grasped early and across the majority of subsectors.

We have provided assessments for road transport, selected passenger rail lines, domestic and non-domestic heat and electricity generation.

The assessment is intentionally cautious and covers just a core set of applications. There are a number of areas where we could extend the breadth and depth of our analysis in future phases of the work programme.
Demand from transport

<table>
<thead>
<tr>
<th></th>
<th>2030</th>
<th>2040</th>
<th>2050</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low</td>
<td>0.02TWh</td>
<td>0.20TWh</td>
<td>0.74TWh</td>
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<tr>
<td>Central</td>
<td>0.05TWh</td>
<td>0.60TWh</td>
<td>1.94TWh</td>
</tr>
<tr>
<td>High</td>
<td>0.06TWh</td>
<td>0.75TWh</td>
<td>2.30TWh</td>
</tr>
</tbody>
</table>

Significant additional demand will also come from:
- Rail freight
- Transiting road freight
- Domestic and international shipping
- Non-road mobile machinery: ports, agriculture, construction

**Selected passenger rail**

- Hydrogen-flagged lines
- Felixstowe Branch Line
- Railway stations

**Road transport (resident)**

**Road market share**

- Hydrogen market share (%)
  - Cars
  - Vans
  - HGVs
  - Buses
  - Other

Graphs showing trends from 2030 to 2050.
Demand from heat

- Volumes demanded for heat are intrinsically tied to the level of hydrogen blending permitted in the gas network.
- The increase in demand between 20% and 100% hydrogen blends is non-linear.
- Determined by the interplay between the timing of 100% hydrogen availability, adoption rate of electric heating, and changes to annual consumption.

### Hydrogen for heat (by sector)

<table>
<thead>
<tr>
<th></th>
<th>2030</th>
<th>2040</th>
<th>2050</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low</td>
<td>0.48TWh</td>
<td>0.14TWh</td>
<td>0.07TWh</td>
</tr>
<tr>
<td>Central</td>
<td>0.55TWh</td>
<td>0.41TWh</td>
<td>4.58TWh</td>
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<tr>
<td>High</td>
<td>0.78TWh</td>
<td>9.71TWh</td>
<td>8.49TWh</td>
</tr>
</tbody>
</table>

### Domestic and small non-domestic properties with hydrogen for heating

- Number of properties
- 2030, 2040, 2050

- Breckland
- Great Yarmouth
- King’s Lynn
- North Norfolk
- Norwich
- South Norfolk
- Babergh
- West Suffolk
- Ipswich
- Mid Suffolk
- East Suffolk
Demand from electricity generation

- Assets across Norfolk and Suffolk that currently burn natural gas to generate electricity (and heat) could adopt a blended hydrogen fuel
  - Including large CCGTs at **Great Yarmouth** (398MW) and **King's Lynn** (382MW), as well as a range of smaller assets at the distribution level
- The central and high scenarios assume that deblending technology is adopted to ensure a consistent 50% blend of hydrogen for combustion

<table>
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<tbody>
<tr>
<td>Low</td>
<td>0.48TWh</td>
<td>0.48TWh</td>
<td>0.48TWh</td>
</tr>
<tr>
<td>Central</td>
<td><strong>1.47TWh</strong></td>
<td><strong>1.47TWh</strong></td>
<td><strong>3.82TWh</strong></td>
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<tr>
<td>High</td>
<td>1.88TWh</td>
<td>8.11TWh</td>
<td>8.11TWh</td>
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</table>

<table>
<thead>
<tr>
<th>Potential hydrogen demand (TWh/year)</th>
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</thead>
<tbody>
<tr>
<td>2030</td>
</tr>
<tr>
<td>0.0</td>
</tr>
<tr>
<td>0.5</td>
</tr>
<tr>
<td>1.0</td>
</tr>
<tr>
<td>1.5</td>
</tr>
<tr>
<td>2.0</td>
</tr>
<tr>
<td>2.5</td>
</tr>
<tr>
<td>3.0</td>
</tr>
<tr>
<td>3.5</td>
</tr>
<tr>
<td>4.0</td>
</tr>
</tbody>
</table>

- In future stages of research we would like to investigate in detail the potential for hydrogen-powered assets (supply side) and electrolysers (demand side) to provide balancing and flexibility services to the local and national network

**Hydrogen demand by asset type**

- King's Lynn A CCGT
- Distributed CCGTs
- Large CHP
- Great Yarmouth CCGT
- Distributed OGTCs
Conclusions

Our selective assessment reveals that hydrogen demand in Norfolk and Suffolk could exceed 10TWh/year by 2050.

In a high scenario where hydrogen sees strong adoption across heat and power generation, demand approaches 20TWh/year.

This would increase significantly once we add in estimates for shipping, cross-country road freight, and explore hydrogen’s potential in system balancing.

- Our assessment mirrors trends seen in national hydrogen demand estimates.
- FES and CCC provide a range of scenarios that reflect the uncertainty around future hydrogen uptake.
- Heavy duty road transport is a priority area but stark ranges for hydrogen for domestic heating.
- Both FES and CCC see a role for dispatchable hydrogen generation.

<table>
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<td>Low</td>
<td>0.98TWh</td>
<td>0.82TWh</td>
<td>1.29TWh</td>
</tr>
<tr>
<td>Central</td>
<td>2.07TWh</td>
<td>2.48TWh</td>
<td>10.34TWh</td>
</tr>
<tr>
<td>High</td>
<td>2.72TWh</td>
<td>18.57TWh</td>
<td>18.90TWh</td>
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</table>

<table>
<thead>
<tr>
<th>NG FES 2020 (ST)</th>
<th>CCC 6th CB (HW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2030</td>
</tr>
<tr>
<td>Road transport</td>
<td>1.1TWh</td>
</tr>
<tr>
<td>Domestic heat</td>
<td>1.4TWh</td>
</tr>
<tr>
<td>Generation</td>
<td>0.3GW</td>
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Pathways for Bacton
Bacton Energy Hub

• The physical infrastructure, regional demand potential and emerging national policy priorities mean that Bacton is a strategically important site that should have an important role in supporting both regional and national Net Zero ambitions.

• We believe that the creation of an 'energy hub' which combines multiple technologies and processes at scale is the most efficient means to do so.

• There are many different combinations and permutations that could be considered, but the core components of a Bacton Energy Hub should include:
  • Re-use of O&G assets for carbon storage
  • Blue and green hydrogen production
  • Strong collaboration with offshore wind
Piecemeal adoption

- Relatively small-scale blue hydrogen production facility is established alongside CCUS in the SNS
- Some dispersed green hydrogen production also emerges regionally. There is no proactive strategy to scale offshore wind and to integrate it into the energy hub and the regional energy market
- The development provides sufficient hydrogen to serve local demand but its national impact is hampered by lack of co-ordination and limited security of demand, as well as limitations on volumes that can be injected into the NTS, national policy bottlenecks and continuing regulatory barriers
- Pockets of local supply would emerge around solar installations and be used predominantly for heavier vehicles for transport. Depending on the size of the hydrogen production facility at Bacton, domestic markets and European markets would compete for surpluses
• More co-ordinated action and greater policy certainty is used to establish an energy hub at and around the Bacton terminal

• It sees a blue hydrogen production facility established at Bacton, alongside CCUS in the SNS, and green hydrogen production clustered along the coast, as well as early-stage dispersed sites

• DNO flexibility tenders extend to resolution of local bottlenecks, and investment in hydrogen electrolysers is seen as an integral part of the distribution system operator (DSO)’s toolkit

• The development provides sufficient hydrogen to serve local demand. Over time, it also makes a rising contribution to meeting hydrogen demand outside the region, utilising the NTS to access customers in London and in the South East
Facilitated model

- **An actively planned, whole system pathway:** This describes an optimised energy hub that integrates all relevant sectors active in Norfolk and Suffolk across heat and transport as well as electricity.

- **There are material contributions from blue hydrogen from SNS and green hydrogen from offshore wind but also including nuclear power and heat, and local solar at scale.**

- **Demand would be across economic subsectors** with active strategies adopted to decarbonise these. The region would be the focal point of a clean transport hub with a core infrastructure of hydrogen refuelling stations. Hydrogen use extends extensively across heavier transport, including shipping and aviation.

- **Bacton would be connected into the European Hydrogen Backbone** at the earliest opportunity.
Conclusions and next steps
Next steps for Bacton

- Project definition
- Evidence gathering
- Spatial mapping
- Frameworks
  - supply
  - demand
  - transport infrastructure
- Initial benefits assessment
- Stage 2 scope

- Priority frameworks
  - Bacton Energy Hub
  - Electrolyser demonstrators
  - Fuller demand assessment
  - Project 2050 capabilities
- Governance framework
- Funding arrangements
- Full benefits assessment
- Stage 3 scope

- Project specification
  - supply
  - demand
  - transport infrastructure
- FEED
- Full timetable
- Project inception documentation
- Governance documentation
Bacton Energy Hub
Stage 2 workstreams

- Bacton Energy Hub Consortium
  - Hydrogen Production Facility
  - New Anglia Electrolyser Plan
  - Full Demand Assessment

Production

- Supply Chain Assessment
- Project Design & Timetable
- Issues and Risks

Capabilties

Hydrogen East
Hydrogen priorities

New Anglia opportunities:
- Heavy-duty road transport (freight and passenger)
- Selected passenger rail lines
- Local Authority fleets, including refuse collection
- Agricultural applications
- Port-side operations
- Marine applications
- Flexible generation and system balancing functions
- Blending into the grid
- Export potential
The Power Park is at Ness Point, Britain’s most easterly point:

- **Existing onshore wind turbine** (itself a demonstration offshore wind turbine) coming to the end of its economic life – **repurpose or repower?**
- Consented flexgen site with **co-located batteries**
- OrbisEnergy centre next door has a biomass-based heating system which could offer a **demonstration opportunity for hydrogen for heating**
- Direct **local gas grid injection point** (Cadent network) on Gas Works Road, directly adjacent to Gulliver
- Close proximity to a **range of potential users** including; PowerPark tenants, ABP Lowestoft, port users (vessels), Birdseye, and First Bus
- **Nearby domestic properties**, including low EPC and social housing

**Option 1: Onshore**
- Gulliver Turbine
- OrbsEnergy
- PowerPark
- Gas Injection Point
- Lowestoft Port
- First Bus
- Birdseye

**Option 2: Inshore**
- Potential zone for development
Contact details

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- Email: mail@hydrogeneast.uk
- Twitter: @HydrogenEast

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Co-founder

Johnathan Reynolds  
Co-founder

Michael Brown  
Analyst

Charlotte Farmer  
Analyst