1.1 Xodus Group Limited

Bacton Energy Hub Project

Infrastructure SIG Final Report

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This report draws upon the knowledge, assistance and expertise of the companies comprising the members of the Bacton Energy Hub Infrastructure Group whose efforts are gratefully appreciated. Although Xodus is the author of this report, the Infrastructure Core Group played a key role in contributing to this report and dedicated material time and effort over the past 12 months during monthly meetings and supporting the delivery of each of the work packages. Xodus would like to thank and acknowledge the people and companies.

EXECUTIVE SUMMARY

The Infrastructure SIG considered both offshore and onshore infrastructure including the terminals required to produce and distribute both CCS-enabled 'blue' and electrolytic 'green' hydrogen.

The focus of the assessment was to identify key infrastructure required for:

- The production of hydrogen i.e. feedstock, power supply, transportation and distribution
- The storage of resultant CO2 from production of hydrogen.

The objectives of the Infrastructure SIG were to:

- Evaluate the Cessation of Production (CoP) of key infrastructure and the required CoP to support the establishment of a hydrogen hub at Bacton to inform the hydrogen supply SIG workstreams and decisions
- Clear line of sight of infrastructure owners plans to inform the hydrogen supply SIG workstreams
- Identification of opportunities and synergies within operators plans and the Bacton Energy Hub
- Identify key infrastructure that may be repurposed / re-used offshore and onshore
- Identify available footprint / real estate for hydrogen production to inform the hydrogen demand and supply SIGs
- Identify technical and legislative limits on hydrogen blending into existing infrastructure to inform the hydrogen demand and supply SIG workstreams. Identify credible injection points for hydrogen produced at Bacton
- Identify the most credible tie-in to renewable power for electrolytic hydrogen generation and indicative timelines to inform the Bacton Energy Hub development timelines and key decision points.
- Generate CAPEX and OPEX inputs for the Bacton Energy Hub economics.

Based on the Infrastructure SIG workscope and objectives, the Infrastructure SIG established a number of work packages, and has reported on the following areas:

- Repurposing of offshore infrastructure for CO2 or H2 transport and storage
- Repurposing of Bacton Terminals for H2 production
- Greenfield offshore infrastructure
- Offshore wind integration

Repurposing of Offshore Infrastructure for CO2 or H2 Transport and Storage

- There is no expectation that existing wells can be repurposed for CO2 injection.
- There is some potential for repurposing existing wells for hydrogen injection, but this would require significant evaluation effort and solid information on well integrity, including cement quality
- There is potential for reuse of jackets and topsides structures, including accommodation, lifesaving equipment etc, but this must be assessed on an individual asset by asset basis. There is no potential for reuse of topsides production facilities. This applies equally for CO2 and H2.
- It is considered unlikely infield gas gathering and utility pipelines can usefully be repurposed for CO2 or H2 transport.

- There is a strong possibility of repurposing major trunklines that land at Bacton, where the design pressure and pipeline condition is suitable, and where the pipeline is close to a favoured CO2 or H2 storage site. This depends on the gas pipeline being no longer required to transport natural gas.
- To determine trunkline condition suitability for hydrogen EMAT (Electro Magnetic Acoustic Transducer) phased array or Ultrasonic inspections are required to determine accurately the location and feature of any crack or potential crack.
- Trunklines landing at Bacton have been screened for suitability for CO2 repurposing.
    - There is no one candidate that is ideally suited for repurposing for CO2 transport
    - The majority of pipelines could transport CO2 in gaseous phase, however if dense phase transportation is preferred from Day 1, or is transitioned to later in operational life, this would reduce the number of potential pipeline candidates that could be suitable for repurposing
    - Sean is expected to reach CoP in the mid-2020s and therefore the pipeline represents a potential good candidate for re-use.
    - The Perenco and Shell operated pipelines to Leman could be potential candidates, but there is uncertainty in CoP timing for the fields.

Repurposing of Bacton Terminals for Hydrogen Production

- The Core Project (a 1 x 355 MW_{HHV} CCS-Enabled Hydrogen Plant) could be sited within the existing ENI terminal footprint, acknowledging that this would require brownfield remedial works to assess and remove existing services and foundations, and to assess any revisions to operational power / instrumentation and underground pipeline & drainage facilities.
- Based on the requirement to provide natural gas feedstock to the CCS-enabled plant, and from Operator feedback, it is expected that the Shell and Perenco terminals will be operational during the Build-out phase; accordingly, the Build-out scenarios could require additional footprint external to the existing Bacton Energy Hub complex.
- In the event that brownfield solutions are mandated, from initial assessment of footprint, the BEH hub could be utilised to install electrolytic hydrogen production facilities following CoP of the existing terminals.

Greenfield Offshore Infrastructure

- From preliminary assessment, for a generic 30km pipeline length, a 16" CO2 pipeline could accommodate 5Mtpa CO2 transport in dense phase, or up to 1Mtpa CO2 in gaseous phase. The Core Project requires just capacity for 1Mtpa. Therefore a 16" pipeline could accommodate an initial gaseous phase transport phase, with transition to dense phase in in the future.
- For greenfield offshore CO2 transport and injection facilities injection wells with dry trees located at a normally unmanned wellhead platform would be preferred over a fully subsea solution due to expected lower lifecycle cost. A wellhead injection platform would also enable an ability to workover the wells, which would be simpler than if subsea.

Offshore Wind Integration

- By 2030 the East of England will have ca. 15 GW of offshore wind capacity, delivering a third of the UK's target of 50 GW of offshore wind capacity by 2030.
- Future offshore wind farm lease rounds in the East of England are uncertain and would require engagement with the Crown Estate to establish whether further wind farms can be consented in the region.
- National Grid ESO's recommended design does not include any new connections from offshore wind farms into East Anglia beyond those currently planned.

- It is therefore unlikely that any grid upgrades onshore or new connections from offshore will connect to the vicinity of the Bacton Energy Hub in the short to medium term. This may be revised in the future, but there are currently no plans by National Grid ESO to upgrade the grid as part of the 2030 HND.
- National Grid ESO indicated that upgrades to the grid of <100 MW could be discussed, which could support a blue hydrogen plant's electricity requirements. However, grid upgrades to support a connection of > 1GW are unlikely in the near to medium future, given the focus is around connecting Scotwind offshore wind farm developments.
- Any connection would require modifications to the existing offshore substation and would need to ensure that there was no impact on the delivery of electricity to the market. This will require a commercial agreement and may be an opportunity once initial CfD contracts roll off after the initial 15 year period.

Recommendations

- Clarity is required on the intended CO2 phase for transportation and injection.
- Fullest possible understanding of historical pipeline integrity, operation, topography/seabed changes (wall thickness, corrosion, cyclic fatigue) is needed to support any pipeline repurposing analysis
- Engineering assessments for weight change between natural gas/condensate and dense phase CO2, particularly in areas of free-spans are needed to support pipeline repurposing analysis.
- Future works are anticipated for the development of the Basis of Design and requirements for the Core Project in order to support project planning and execution; including:
    - Establish tie-in details for primary interfaces: natural gas supply (both NTS grid supply and terminal inlet 'richer' sources), hydrogen product, carbon dioxide export, raw water (inlet/outfall) assessment and associated line routing
    - Develop the scope for underground / brownfield deconstruct activities within the existing ENI plot
    - Establish the local grid network upgrade plans, and identify an easement for grid power / utility pipelines
    - Evaluate the interface with existing interconnectors
    - Determine the project execution strategy (stick/modular, laydown, site labour, temporary facilities, construction sequencing, staging)
- Further discussion with the Crown Estate to establish whether alternative routes to market for the electricity, through hydrogen production would represent a change in perception, and could be supportive in meeting the hydrogen targets set by the UK Government.
- For any future electrolytic hydrogen plant at Bacton, consideration of connection to an existing offshore wind farm via an existing offshore substation should be considered, or potentially a private wire connection to a new offshore wind farm.

2 INFRASTRUCTURE OVERVIEW

2.1 Objectives

The Infrastructure SIG considered both offshore and onshore infrastructure including the terminals required to produce and distribute both CCS-enabled 'blue' and electrolytic 'green' hydrogen.

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- Generate CAPEX and OPEX inputs for the Bacton Energy Hub economics.

2.2 Workscope

The Infrastructure SIG workscope, as defined in the Infrastructure SIG ToR is outlined below:

- Identify key stakeholders and undertake engagements to gather the relevant and required data to inform the infrastructure analysis
- Review operator and owners forward plans and aspirations for key infrastructure and forecast economic and technical COP
- Review of the Bacton terminals to understand capacities and turndown
- Review the technical limits of existing infrastructure for the use of hydrogen transportation and generate credible blend scenarios
- Considering the end users identified by the hydrogen demand SIG review opportunities within existing infrastructure that may enable re-use for example parallel systems, modification of existing pressure and operating regimes. Incorporating any learning from hydrogen schemes and trials nationally and worldwide.
- Review infrastructure required to develop and transport hydrocarbons to provide the feedstock for blue hydrogen.
- Develop an infrastructure CoP map to identify key interdependencies and risks.

- Review technology opportunities to enable re-use for example pipeline liners or pipework coatings
- Review all credible tie ins into wind power by reviewing timelines and critical decision points to identify key opportunities and risks.
- End to end review of CCS infrastructure to identify screening level requirements to inform development concepts and CAPEX and OPEX estimates.

2.3 SIG Scope Boundaries

The Infrastructure SIG scope boundaries have been defined in the ToR:

Key boundaries of the Infrastructure SIG scope are:

- Hydrocarbon Gas:
    - Pipelines from hydrocarbon gas production facilities to Bacton (production facilities excluded, assessment of gas profiles excluded – both in Supply SIG scope).
- Onshore Terminals:
    - Assessment of space & utilities availability is in Infrastructure scope.
    - Supply SIG will identify the CCS-enabled blue hydrogen production technology (inc. carbon capture), utility requirements, CO2 capture rates and overall efficiency (kg H2 / kg hydrocarbon gas) and the footprint of these facilities.
    - Supply SIG will identify the electrolytic hydrogen production technology, utility requirements, and overall efficiency (kg H2 per MWh electricity)
    - Infrastructure will assess feasibility of locating within the existing terminal(s) boundary and will assess overall CAPEX and OPEX.
- CO2:
    - Infrastructure SIG will assess the transport of CO2 from the blue hydrogen plant to offshore storage site(s). Identification of suitable storage sites is Supply SIG scope.
- Hydrogen transport / storage:
    - Infrastructure SIG will assess the transport of hydrogen from the Bacton plant to users. Users will be identified by the Demand SIG.
    - Infrastructure SIG will identify suitable points of entry to the gas transmission network.

2.4 Identified Work Packages

Based on the Infrastructure SIG workscope and objectives, the Infrastructure SIG established a number of work packages to execute the study.

To deliver each of the identified work packages, a lead was assigned to provide overall responsibility.

#	Work package	lead
1	Establish Infrastructure Availability / CoP – Upstream	Neptune
2	Establish Infrastructure Availability – Downstream	Cadent
3	Establish Terminal Infrastructure Availability / Options	IOG
4	Establish Technical limits for reuse H2	Paradigm
5	Establish Technical limits for reuse CO2	Perenco

6	Onshore Greenfield definition	McDermott
7	Offshore greenfield definition	Xodus
8	Establish timeline for offshore wind integration to Bacton	Xodus
9	Define best fit solution for each scenario	All
10	Develop screening level CAPEX/OPEX/ABEX	All

2.5 Glossary of Terms

Term	Definition
BBL	Balgzand to Bacton Line
BEH	Bacton Energy Hub
BoP	Balance of Plant
CAPEX	Capital Expenditure
CCS	Carbon Capture and Storage
CfD	Contracts for Difference
CIPP	Cured in Place Pipe
CNS	Central North Sea
CO2	Carbon Dioxide
CoP	Cessation of Production
EMAT	Electro Magnetic Acoustic Transducer
ESDV	Emergency Shutdown Valve
ETS	Esmond Transmission System
H2	Hydrogen
HHV	Higher Heating Value
HIC	Hydrogen Induced Cracking
HND	Holistic Network D
LAPS	Lancelot Area Pipeline System
LTS	Local Transmission System
MAOP	Maximum Allowable Operating Pressure
MEG	Monoethylene Glycol
MFL	Magnetic Flux Leakage
MTPA	Million Tons per Annum
NSTA	North Sea Transition Authority
NTS	National Transmission System
NUI	Normally Unmanned Installation
OPEX	Operating Expenditure
SEAL	Shearwater Elgin Area Line (SEAL)
SIG	Special Interest Group

SIMOPS	Simultaneous Operations
SNS	Southern North Sea
UT	Ultrasonic Testing

3 EXISTING FACILITIES

3.1 Upstream Infrastructure

The natural gas infrastructure upstream of the Bacton terminals is extensive with installation dates ranging from the late 1960s right through to current day.

There are key gas trunklines from five main producing areas feeding natural gas into the Perenco operated terminal – Leman East, ETS, Hewett Area, Saturn Banks and the Lancelot Area – and trunklines from four main producing areas feeding gas into the Shell operated terminal – Leman West, Sean, Sole Pit and SEAL.

Source: Perenco

3.1.1 ETS (Esmond Transmission System)

The 24" ETS pipeline originally exported gas 204km from Esmond to Bacton but now only 165km is utilised. The pipeline is used to export gas from the Trent and Tors (Kilmar and Garrow) installations in addition to gas from the Cygnus hub, connected to the ETS by a new 24", 51km pipeline in 2016. The pipeline is anticipated to remain in use for hydrocarbon gas production beyond 2030.

3.1.2 Hewett System

Two 30" pipelines run from the Hewett Area to Bacton, which are 31-33km in length and around 50 years old. Production from the Hewett Area (which included Hewett, North Hewett, Little/Big Dotty, Deborah, Dawn, Della and Delilah) ceased in late 2020 therefore these pipelines are no longer in use and decommissioning activities have commenced.

3.1.3 Lancelot Area Pipeline System (LAPS)

The 20”, 61.7km LAPS pipeline to Bacton remains in operation, serving Lancelot, Guinevere, Excalibur, Galahad, Malory and Waveney offshore infrastructure.

3.1.4 Leman East

The offshore infrastructure around the linked Leman East and Indefatigable Areas is extensive with numerous interfield lines connecting fields including Camelot Area, Inde West, Davy, Tristan, Bessemer, Bell and Wenlock. Two 30”, 62-65km pipelines connect Leman East to Perenco Bacton, with production remaining online.

3.1.5 Saturn Banks Pipeline

Gas production from the Saturn Banks development, online from 2022, utilises around 60km of the 20” Thames pipeline to Bacton. Production currently flows from Blythe and Elgood fields with Phase 2 planned in the near future. The pipeline is anticipated to remain in use for hydrocarbon gas production beyond 2030.

3.1.6 Leman West

A 30”, 55.7km pipeline from Leman West to the Shell operated Bacton terminal remains in use while another 30” line from Leman BT installation to Bacton has been mothballed and is no longer in use. Additional fields served by the pipeline are Corvette, Brigantine, Caravel and Shamrock.

Source: Shell

3.1.7 Shearwater Elgin Area Line (SEAL)

The SEAL pipeline takes gas from the Central North Sea into Shell Bacton. Gas continues to flow from the Elgin Franklin Area hub while gas from the Shearwater installation was rerouted to St Fergus in 2020. The SEAL pipeline is 34" in diameter and around 462km in length. The pipeline is anticipated to remain in use for hydrocarbon gas production beyond 2030.

3.1.8 Sean

The 30", 106km long Sean pipeline to Shell Bacton remains in use for gas export from the Sean area.

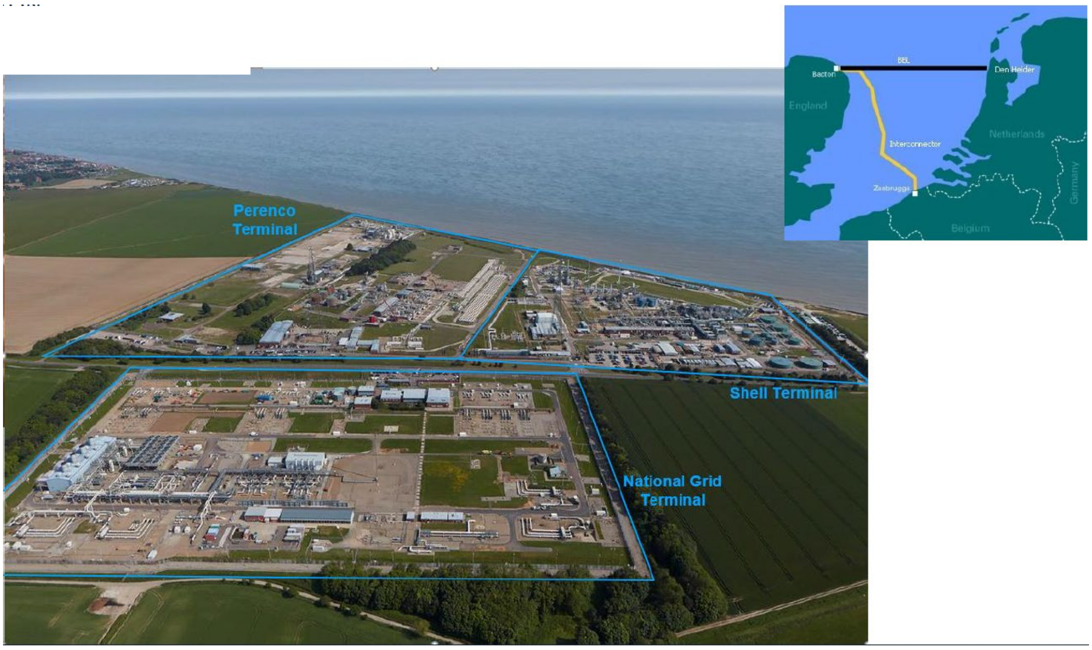
3.1.9 Sole Pit System

The Sole Pit System includes Clipper, Barque, Galleon, Skiff, Carrack and Cutter and remains in production. The main trunkline runs the 73km from the Clipper installation to Shell Bacton and 24" in diameter. The pipeline is anticipated to remain in use for hydrocarbon gas production beyond 2030.

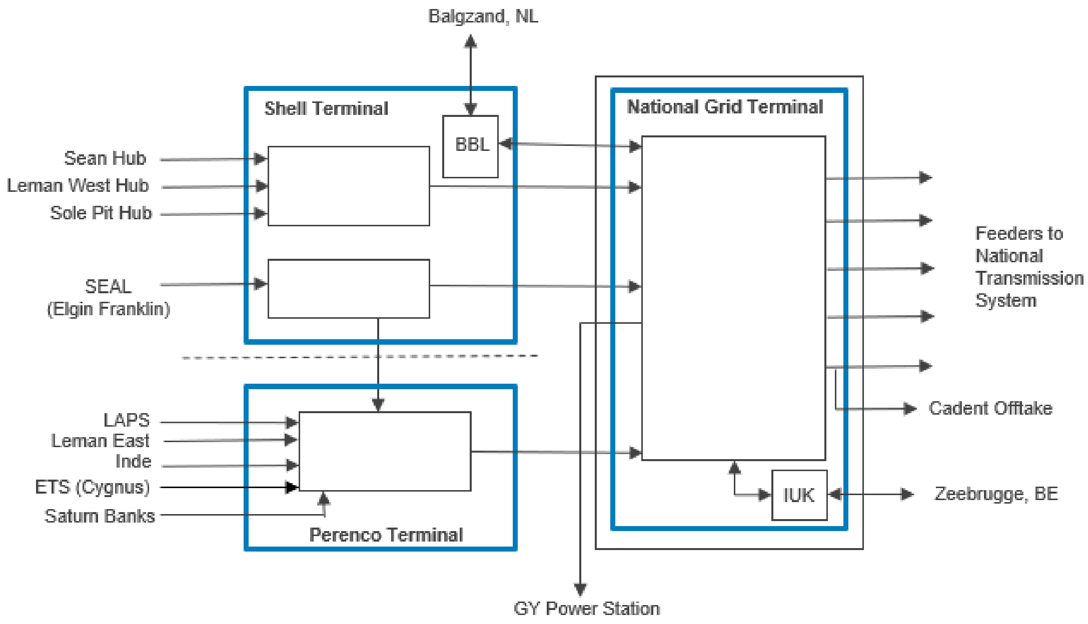
3.2 Bacton Overview

Bacton receives natural gas from the Southern North Sea (SNS), Central North Sea (CNS) and interconnectors from the Netherlands and Belgium. The Bacton site comprises of three gas processing plants, owned and operated by Shell, Perenco and National Grid. The existing Eni terminal has been decommissioned and gas routed through the Perenco terminal.

The total gas processing capacity at the Bacton terminals is 1650mmscfd.



An overview of the connections and pipelines entering Bacton are shown below.



3.2.1 Bacton Terminal Shell

The Shell Bacton gas processing terminal receives and conditions natural gas imports from the Southern and Central North Sea fields and provides a direct route for natural gas to the UK National Transmission System, operated by National Grid.

The Shell terminal accepts gas through four pipelines from various Southern and Central North Sea fields. These include:

- Leman pipeline – accepting production from Leman, Shamrock, Caravel, Corvette and Brigantine

- Clipper pipeline – accepting production from Galleon, Skiff, Carrack Main and East, Cutter, Barque, Clipper and Clipper South
- Sean pipeline – accepting production from Sean
- SEAL pipeline – accepting production from the Shearwater Elgin Area (Central North Sea)

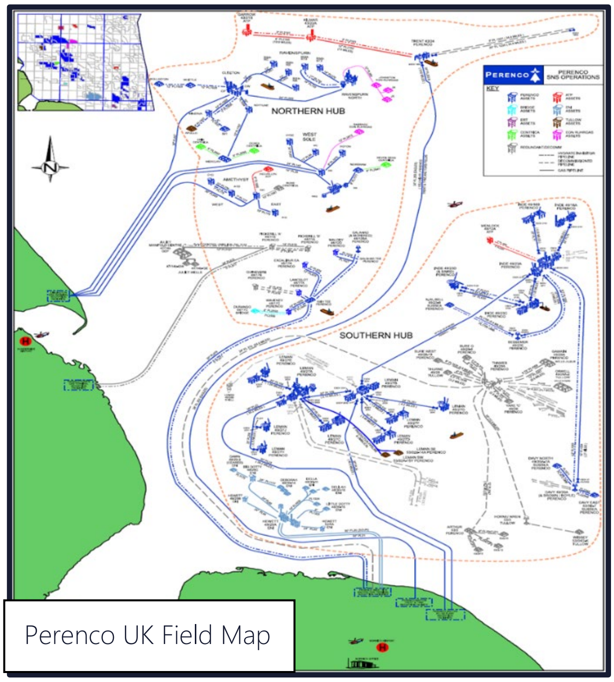
The terminal also receives gas from the BBL Interconnector, which is located at the terminal. The BBL interconnector allows to flow gas between the Netherlands and the UK (Forward flow) and the UK and the Netherlands (Reverse Flow).

The Shell terminal has a gas treatment capacity of 900mmscfd and liquids processing capacity of 5,000bbls/day. Prior to entry into the UK NTS, the gas is conditioned to remove liquid hydrocarbons and water through a propane refrigeration plant. A glycol regeneration and desalination plant is also located at the terminal to regenerate Monoethylene Glycol (MEG) which is used for hydrate inhibition in the pipelines to shore.

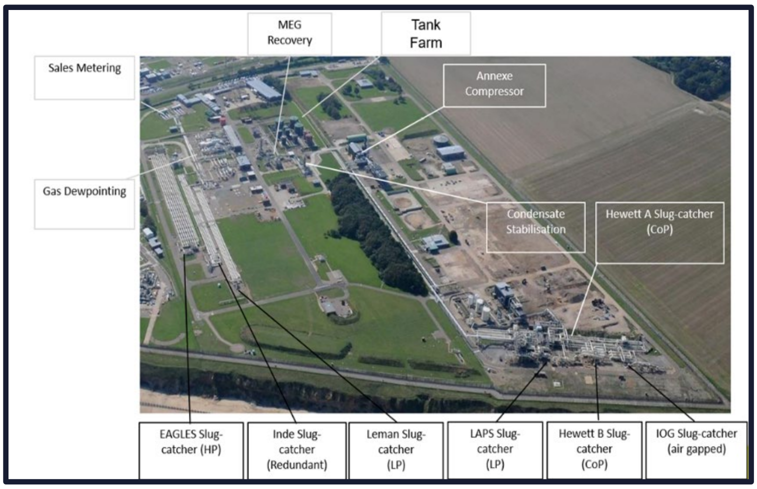
The terminal has no onshore gas compression and gas is balanced on the pressure of the UK NTS.

3.2.2 Bacton Terminal Perenco

The Perenco UK Bacton terminal is a key strategic inlet for natural gas from various fields within the UK Southern. North Sea. The Terminal, owned and operated by Perenco UK, is a key piece of infrastructure, able to facilitate both the development of CCUS and hydrogen industries.



Perenco UK Field Map



The Terminal sits on the east coast of Norfolk, as part of a larger terminal complex, including the Shell Bacton gas terminal, the Interconnector and National Grid, receiving gas from the following principal fields-

- Leman
- Indefatigable
- LAPS
- Cygnus
- other smaller fields tied into the larger network

The terminal is supported by a single gas compressor and supports a maximum gas dewpoint(processing) capability of 750MMmmscf/d. Dewpointing is achieved through a large propane refrigeration plant, prior to onward transportation to National Grid facilities, at an adjacent location. The site also supports condensate stabilisation and export facilities and MEG distribution and regeneration facilities.

Current terminal facilities are distributed over a large footprint with space for further development and CCUS integration.

3.2.3 Bacton Terminal National Grid

The National Grid terminal takes gas from the Perenco and Shell terminals and from Europe via the BBL (within the Shell terminal boundary) and Interconnector UK (within the National Grid terminal boundary) interconnectors. It provides gas to the South East of the UK, a key demand area including London. It is the only terminal on the network that regularly switches from being net supply to net demand, due to reversal of interconnectors.

National Grid are currently going through an exercise to evaluate options for the Bacton National Grid terminal, in order to understand the best way to ensure the terminal continues to function as required in the future. This process is considering the potential for hydrogen production at Bacton in the future.

3.3 Bacton Grid Connection

Currently, electricity generation for the Bacton terminal is primarily sourced from on-site power generators using natural gas as fuel gas.

There is currently a local substation that feeds the Bacton gas plants, which is known as the Knapton Primary. The current winter rating is 28.7 MW and in the summer 22.1 MW.

3.4 Downstream Infrastructure

3.4.1 National Grid

National Grid Gas Transmission owns and operates the onshore National Transmission System (NTS) comprising 7660km of steel pipeline feeders operating at pressures up to 94 bar, 24 compressor stations, 504 Above Ground Installations and connections to 8 distribution networks. Natural gas and the infrastructure that supplies it is a fundamental component in the UK energy mix, accounting for ~50% of the UK's energy consumption and plays a critical role in meeting peak demand requirements.

The National Grid Bacton Terminal receives gas from the two offshore reception terminals for onward transmission through the NTS. The terminal also provides links with European gas networks through the two interconnectors, the IUK interconnector to Belgium and the Balgzand to Bacton Line (BBL) to the Netherlands. There is also a dedicated pipeline owned by RWE from the Bacton Terminal serving Great Yarmouth Power Station.

Five onshore transmission feeders have connections to the National Grid Bacton Terminal which link into the wider NTS creating an integrated network serving the UK. The network serves 23million gas customers across the UK, and in 2020 the total gas demand was 811TWh, serving power generation, domestic, industrial and commercial consumers.

The onshore UK transmission pipelines with connections at Bacton are listed below and also shown highlighted on the map shown in Figure 1.

Feeder 2 – A 439km long 36" diameter pipeline running West through the Midlands into South Wales.

Feeder 3 – 179km long 36" diameter pipeline that runs South-West from Bacton to Hertfordshire

Feeder 4 – 442km long 36" diameter pipeline running West from Bacton through the Midlands to the North West of England.

Feeder 5 – A 289km long 36" diameter pipeline running South-West from Bacton connecting North and South London, and the Isle of Grain LNG terminal.

Feeder 27 – A total length of 113km long 48" diameter pipeline split over two sections. One section 68km running West from Bacton to Kings Lynn with a separate 45km section between Cambridge Compressor and Matching Green offtake North of London.

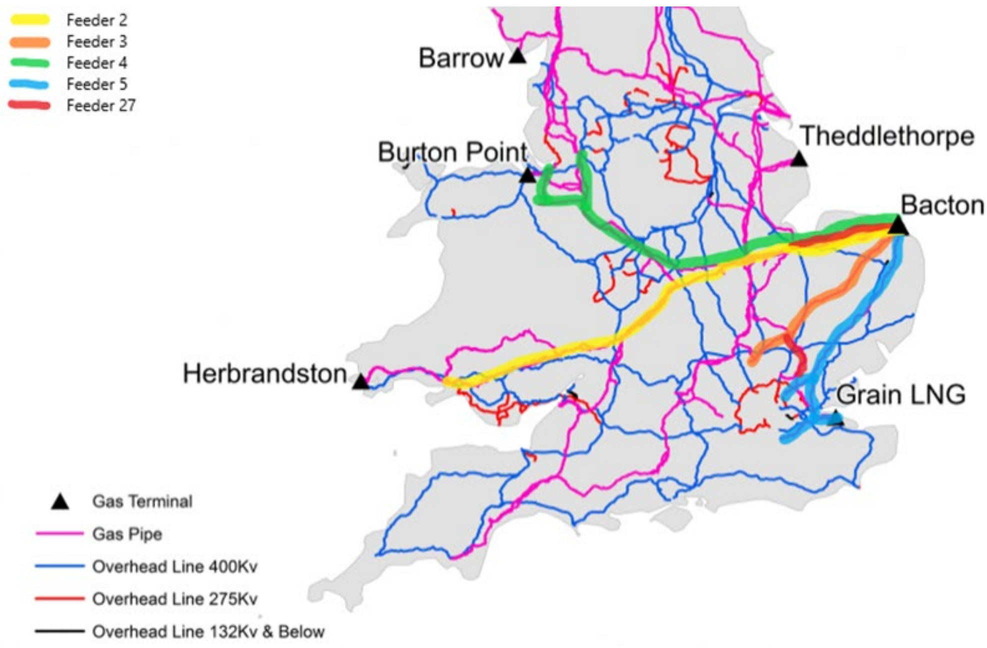


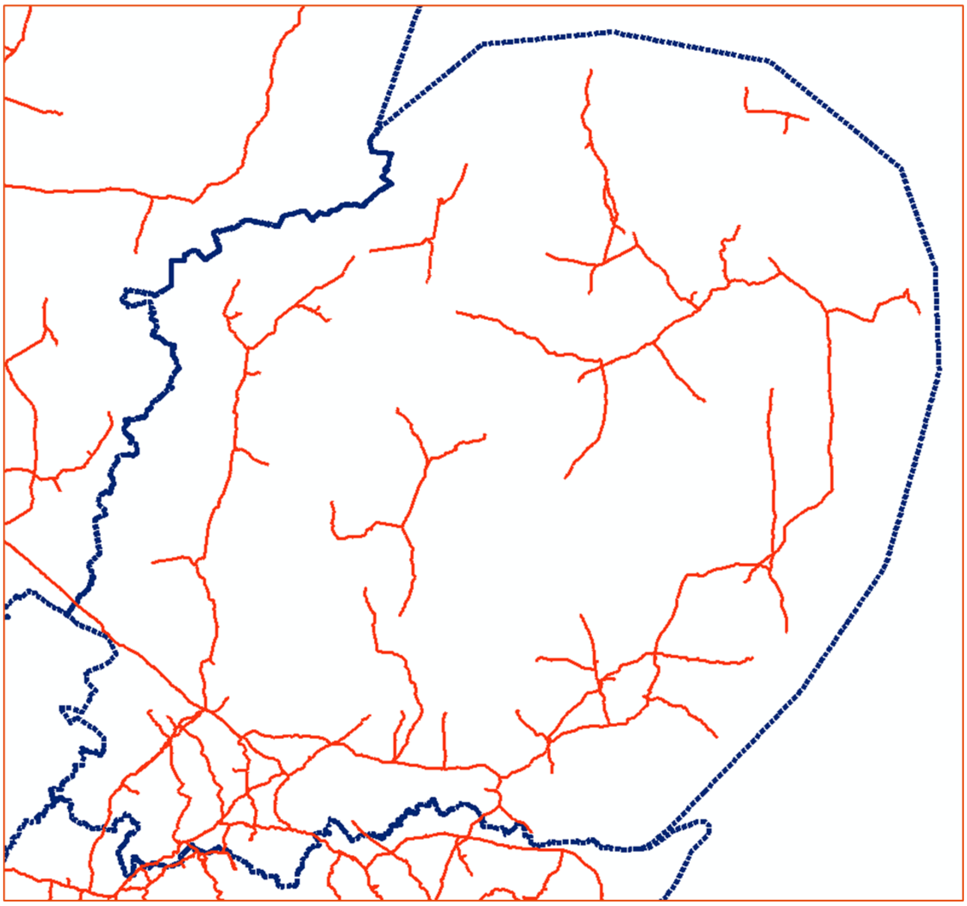
Figure 1 - NTS Feeders at Bacton

3.4.2 Cadent

Cadent operate and maintain the largest gas distribution network in the UK. The company brings natural gas to 11 million homes and businesses throughout the North West, West Midlands, East Midlands, South Yorkshire, East of England and North London. Cadent supplies natural gas to a very wide variety of business customers including some very large industrial gas users such as food, steel, chemicals and brick manufacturers.

Cadent's network receives gas from NTS feeders at offtakes that are distributed along their length. Cadent's pipelines fall into a range of different size and pressure categories from Local Transmission System pipes which are at the highest pressure, through intermediate and medium pressure pipelines and down to the low pressure pipelines that deliver natural gas into domestic properties.

The map below shows the highest pressure tier of pipelines in the wider Bacton Region, the Local Transmission system (LTS).



Cadent is at the forefront of distribution network activity to develop new and re-purposed hydrogen pipeline networks.

Cadent have a scheme to cover each one of their 5 regions. HyNet covers the North West and will eventually comprise hundreds of km of new hydrogen transmission pipelines serving heavy industry and power stations in the region. Dependent on the detail of the domestic and commercial heat policy decision taken by Government in 2026, a wider pipeline re-purposing programme would allow the use of hydrogen for heating of domestic and commercial buildings served by the gas distribution networks

A similar scheme, East Coast Hydrogen, is being developed for Cadent's East Midlands region as part of a wider collaboration between Cadent, National Grid Gas and Northern Gas Networks. Again, the initial phases will focus on new hydrogen pipeline to heavy emitters, but dependent heat policy decision, a wider re-purposing programme in the region would allow smaller domestic and commercial organisations to access hydrogen for heating.

Cadent has two regional schemes that consider hydrogen networks from Bacton: Capital Hydrogen and Hydrogen Valley.

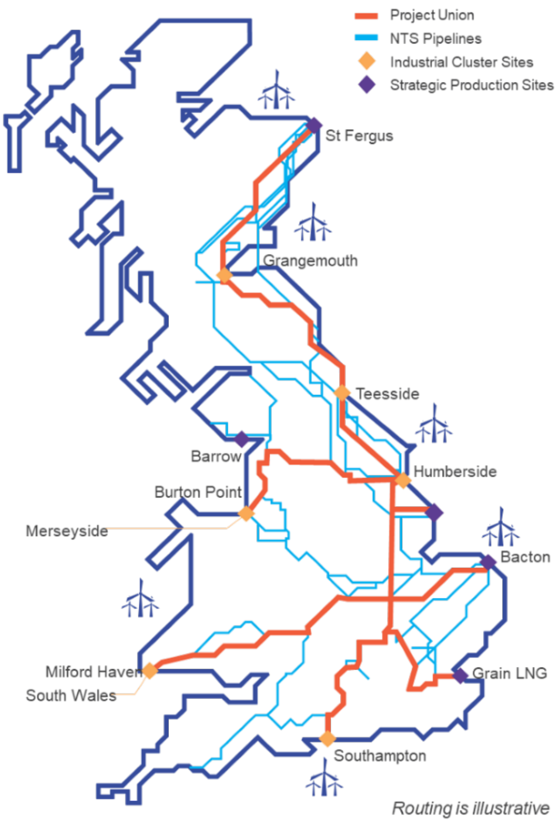
3.4.3 Transition to Hydrogen – Plans and Projects

Project Union

Project Union [1]is a project led by National Grid Gas Transmission that will deliver a "first of a kind" 100% hydrogen transmission backbone for the UK. Through the phased repurposing of existing assets alongside new ones, a hydrogen backbone of around 2,000km will be created, representing around 25% of the UK's current natural gas transmission pipelines.

The backbone will initially link strategic hydrogen production sites, including the industrial clusters, across the UK by the early 2030s and provide the option to expand beyond this initial hydrogen transmission network to connect additional consumers.

The project will explore how and when to convert existing pipeline infrastructure for a hydrogen backbone by connecting Teesside, Humberside and Grangemouth as well as linking up Southampton, the North West and South Wales. The backbone will also connect to strategic hydrogen production sites including St Fergus and Bacton. Below shows an illustrative view of a potential hydrogen backbone connecting clusters and strategic production sites, note that routing has not been confirmed and is for illustration only.



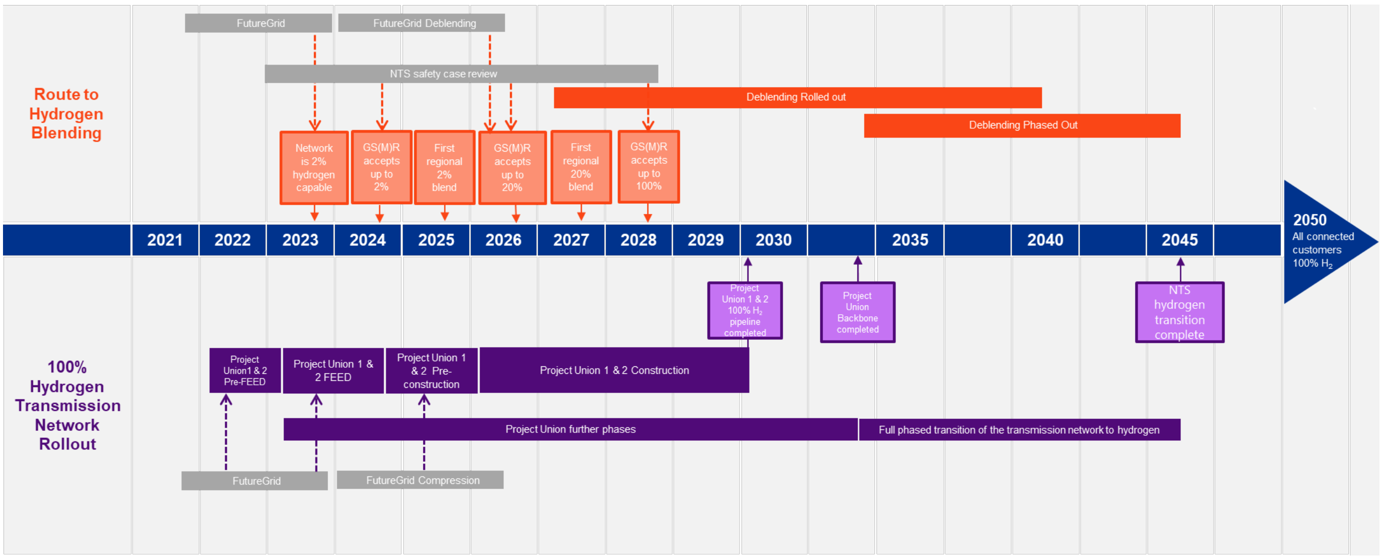
The project is currently in a feasibility phase for the initial sections to be converted which will deliver initial pre-FEED activities, assessments of Project Union's phasing strategy, as well as wider hydrogen market enabling activities.

[1] https://www.nationalgrid.com/gas-transmission/document/139641/download

Following this phase there will be a rolling programme of work covering all pipeline sections in line with the phasing strategy. Construction activities are expected to commence in 2026 for the initial sections of pipeline to be converted with a full backbone developed by the early 2030s.

National Transmission System Transition to Hydrogen

Delivering a blend of hydrogen across the NTS in parallel to the rollout of a 100% hydrogen transmission network, via Project Union's hydrogen backbone, will ensure an efficient and timely transition to hydrogen, whilst ensuring those connected to the remaining methane network are not left behind. Blending will enable hydrogen production to scale up in line with net zero policy targets whilst managing volume risk. The roadmap below in Figure 3 shows a possible working timeline for a pathway to a hydrogen NTS with both hydrogen blending and 100% hydrogen transmission pipelines. This timeline may be quicker or slower based on dependencies on outputs of regulation and policy decisions as well as outputs from the Gas Transmission FutureGrid[2] programme.



A critical step towards the transition to hydrogen and delivering the strategic rollout of a 100% hydrogen transmission network and hydrogen blends in the NTS will be to demonstrate the NTS and existing gas assets can operate safely with hydrogen. The FutureGrid test facility as well as a number of other ongoing innovative projects, studies and research, will demonstrate the NTS can transport hydrogen via an offline, purpose-built facility and develop the appropriate safety standards required to operate a future hydrogen transmission network. NTS assets will be tested with different blends of hydrogen and natural gas up to 100%, providing a representative view of potential future operations of the NTS.

Capital Hydrogen

Capital Hydrogen is a collaboration between Cadent, National Grid Gas and SGN. It is a programme that is seeking to orchestrate the transition of gas networks in the East of England, the South East and London away from natural gas to hydrogen. The feasibility stage is set to conclude in October 2022.

The feasibility stage is detailing how much hydrogen London may need over the next 30 years, where it may be produced and stored and how it will reach the capital, as well as the benefits of such a programme. It includes

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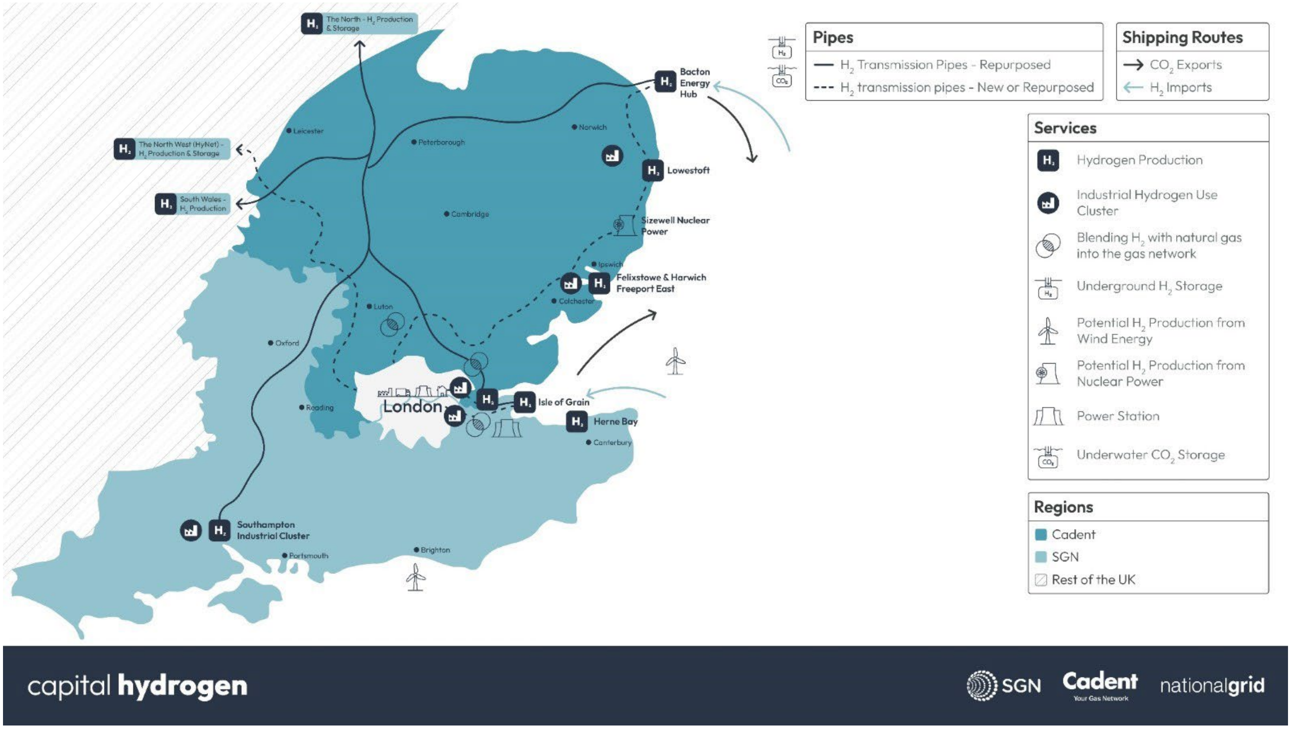
[2] https://www.nationalgrid.com/gas-transmission/insight-and-innovation/transmission-innovation/futuregrid

consideration of how best to re-purpose National Grid Gas Feeders to allow a hydrogen transmission route from Bacton to London.

There is close collaboration between the Bacton Energy Hub leads and the Capital Hydrogen and Hydrogen Valley project teams.

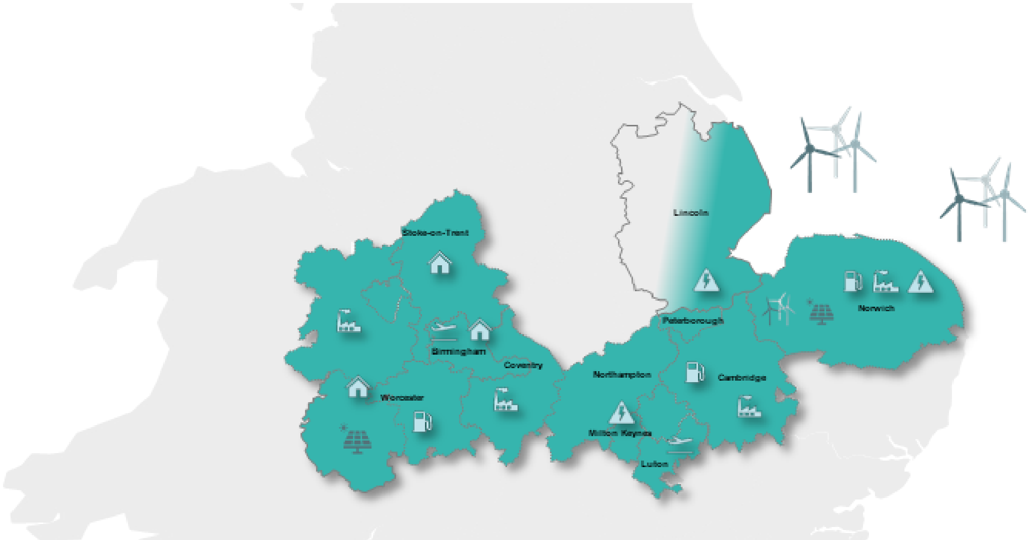


Hydrogen Valley

Hydrogen Valley is a collaborative programme between Cadent and National Grid Gas to develop a vision for Hydrogen in the West Midlands and East of England areas. The project is currently in a Feasibility Phase which commenced in July 2022 and is expected to complete in March 2023.

The project will develop a vision for hydrogen in the Hydrogen Valley region, creating a roadmap and feasibility study, including conceptional design for the conversion of existing networks to hydrogen. The project will establish supply and demand potentials in the region and investigate the roles of wider supply centres in delivering hydrogen into the region, including the Bacton Energy Hub supply potential.

The Hydrogen Valley footprint is as follows:



4 REPURPOSING ASSESSMENT

4.1 CO2 Assessment

4.1.1 Basis of work carried out

- Reviewed technical limits of existing infrastructure for the use of CO2 transportation.
- Reviewed technology opportunities to enable re-use - e.g. liners or coatings
- Incorporated any learning from CCS schemes and trials nationally & worldwide
- Literature reviewed to identify & document learnings from other CCS studies, schemes & trials.
- Identify / Define basis for transport – e.g. operating pressures, temperatures, velocities
- Offshore pipelines - establish screening criteria for likely re-use
- Offshore structures / wells - establish screening criteria for likely re-use
- Identify scenarios related to blue H2 production scenarios – e.g., how can CO2 transport be scaled up / gaseous phase vs. dense phase. Identify where re-use presents constraints (e.g. temperature management).
- Identify technologies that can support re-use - e.g. liners & coatings

4.1.2 CO2 Infrastructure Assessment

The current UK SNS offshore gas infrastructure can be segregated into the following categories:

Wells (including platform and subsea wells)

There is no expectation that existing well completions could be reused, unless they can be demonstrated to be compatible material (13Cr or similar) and with proven integrity for full life of project. Projects should consider new wells and completions.

Topsides Structure including accommodation, lifesaving, nav-aid, etc.)

Have the potential for reuse depending on condition, anticipated future lifetime required and proportionality to the application. A full assessment would be needed on each individual asset to determine condition, suitability and cost effectiveness.

Topsides Production Equipment (downstream of wellhead to ESDV valve + supporting utilities)

Highly unlikely to be any use for repurposing applications due to the nature of the application and the properties of CO_2 and associated process requirements

Jackets

May have the potential for reuse depending on the proximity to suitable reservoir, condition, anticipated future lifetime required. An individual assessment on each jacket would be required and a cost evaluation against alternatives carried out.

In-field Gas Gathering and Utility Pipelines

Less likely to be of use for any repurposing application for CO_2 injection.

Major Trunklines to Onshore.

Strong possibility of repurposing should the pipeline condition, operational parameters and proximity from a suitable reservoir be suitable.

4.1.3 Repurposing for CO2 Summary

A summary of the assessment is provided below:

The current UK SNS offshore gas infrastructure can be segregated into the following categories:

- Wells (including platform and subsea wells)
  No expectation that existing well completions could be reused, unless they could be proven to be compatible material(13Cr or similar) and with proven integrity for full life of project. Projects should consider new wells and completions.
- Topsides Structure including accommodation, life saving, nav-aid, etc.)
  Have the potential for reuse depending on condition, anticipated future lifetime required and proportionality to the application. A full assessment would be needed on each individual asset to determine condition, suitability and cost effectiveness.
- Topsides Production Equipment (downstream of wellhead to ESDV valve + supporting utilities)
  Highly unlikely to be any use for repurposing applications due to the nature of the application and the properties of CO_2 and associated process requirements
- Jackets
  May have the potential for reuse depending proximity to suitable reservoir, condition, anticipated future lifetime required. An individual assessment on each jacket would be required and a cost evaluation against alternatives carried out.
- In-field Gas Gathering and Utility Pipelines
  Less likely to be of use for any repurposing application for CO_2 injection.
- Major Trunklines to Onshore.
  Strong possibility of repurposing should the pipeline condition, operational parameters and proximity from a suitable reservoir be suitable.

4.1.4 Principle of Repurposing Gas Pipelines for CO_2

Can we repurpose natural gas trunklines for CO_2 service? Yes, but…

- Clarity required on CO_2 phase for transportation and injection. Assumption is that dense phase/ supercritical state will be preferred due to the improved delivery economics. However, gaseous transportation is also possible, but would result in lower transport capacity vs. dense phase operation where CO_2 has the density of a liquid, but a viscosity of a gas. Pipeline must be able to support supercritical/dense phase operation conditions >80 barg operating pressure
- Running ductile fracture management in dense phase. The pipeline arrest pressure must be higher than the saturation pressure of the CO_2 composition: Pa>Ps
- Very tight process control criteria required to maintain delivery in required state up to and including injection (water-free, pressures, temperatures, purity, PH levels, velocities).
- Fullest possible understanding of historical pipeline integrity, operation, topography/seabed changes (wall thickness, corrosion, cyclic fatigue

- Engineering assessments for weight change between natural gas/condensate and dense phase CO_2, particularly in areas of free-spans.

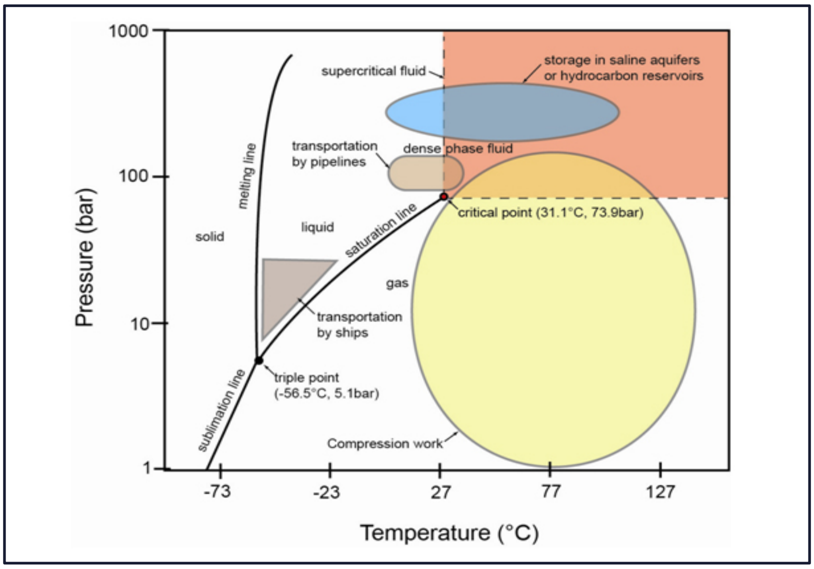


Figure 1 - CO2 Phase Temperature / Pressure Conditions

Main Issues Relating to CO2 usage/reusage

Component	Health and Safety	Pipeline Capacity	Water Solubility	Hydrate Formation	Materials	Fatigue	Fracture	Corrosion	Operations	Comment
CO_2	√	√	√	√	√	√	√	√	√	
H_2O				√	√	√	√	√	√	
N_2		√	√							
O_2			√					√		
H_2S	√	√			√	√	√	√		
H_2		√	√				√			
SO_2	√		√					√		
CO	√		√							
CH_4		√	√						√	
Amines	√									
Glycol	√									

Should be read in conjunction with DNV RP-F104 – Design and Operation of Carbon Dioxide Pipelines

Figure 2 - CO_2 Design and Operational Considerations

Candidate material types compatible with dense and vapour CO2

	No Free Water	No Free Water	Free Water	Free Water
	Pure CO_2	CO_2 and H_2S	Pure CO_2	CO_2 and H_2S
Carbon and Low Alloy Steel	√	√		
304SS	√	√	√	√
316SS	√	√	√	√
13Cr	√	√	√	√
22Cr (Duplex)	√	√	√	√
25Cr (Duplex)	√	√	√	√
Nickel Alloys	√	√	√	√

Should be read in conjunction with DNV RP-F104 – Design and Operation of Carbon Dioxide Pipelines

Figure 3 - CO2 Material Compatibility

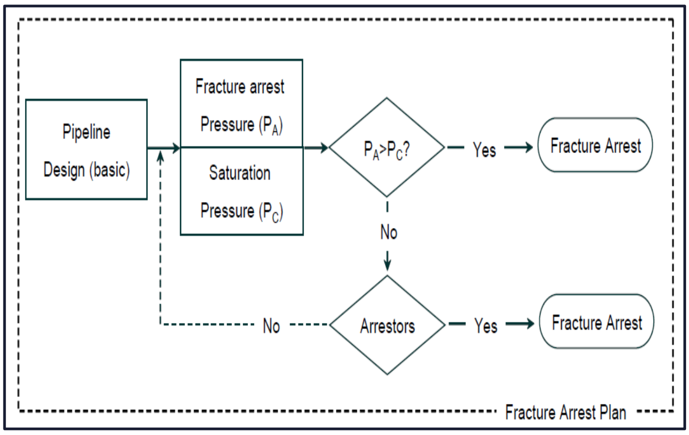


Figure 4 - Fracture Arrest Plan

Criteria	Comments
Running ductile fracture	*This criterion is only relevant for CO_2 transport in dense phase.* It is included to confirm if the pipeline design has sufficient resistance against running ductile fracture. For the criterion to be fulfilled, the arrest pressure of the pipeline should be higher than the saturation pressure of the CO_2 composition: Pa > Ps. The saturation pressure can be taken conservatively as the critical point pressure for pure CO_2 + some safety margin to compensate for the effects of impurities: For the screening, 80 bar saturation pressure has been used. A simplified Battelle formula[10] has been used to estimate the arrest pressure: $p_a = \frac{2 \cdot t \cdot \tilde{\sigma}}{3.33 \cdot c_f \cdot \pi R_o} \cos^{-1}\left[e^{\left(\frac{-\pi R_f E}{24\tilde{\sigma}^2 \sqrt{R_o \cdot t}}\right)} \right]$ The parameters and properties required for this analysis are the pipeline wall thickness t, the outer pipeline radius Ro, the "fracture toughness" per fracture area Rf, related to the Charpy V-notch energy (CVN), the yield strength σo, the "material flow stress" σ, the elasticity E, and a safety factor c_f (taken as 1.2). When a pipeline is made of several materials of construction the lowest steel grade was conservatively considered. Material properties vary between pipelines and all detailed data (CVN values) were not available for the screening. If the arrest pressure is below the saturation pressure, the pipeline should not be operated in dense phase. However, a score of 0 has not been applied to fully disqualify the pipeline as further actions can be considered: additional testing, reduce some conservatism in the formula, use of crack arrestor (etc...).
Transport in dense phase	*This criterion is only relevant for CO_2 transport in dense phase.* This is to check if the maximum operating pressure (MAOP) per current design of the pipeline is sufficient to enable transport of CO_2 in dense phase. A comparison of the MAOP to the critical pressure was carried out. If the MAOP is below the critical pressure, then transport of CO_2 is not possible in the dense phase. The critical pressure is impacted by the CO_2 feed composition and temperature conditions along the line. This cannot be accounted for in the screening but can be checked individually when doing a more detailed assessment of a specific pipeline. If the MAOP is above but too close to the critical pressure, it should however be noted that there will be limited benefit in terms of capacity for transporting the CO_2 in dense phase as compared to gas phase.
Internal pipeline condition	This criterion is based on internal pipeline inspection and is used to reflect the state of the pipeline with regards to internal corrosion. A penalty is applied in case of *non-negligible internal corrosion.*
Safety as compared to existing fluid	This criterion is used to reflect the fact that it may be easier to requalify the pipeline with regards to safety aspects if the new fluid is in the same fluid category as the existing one (gas vs. liquid pipelines). A penalty is applied if it is otherwise.
Safety w.r.t. location class	This criterion is used to reflect the safety risk with regards to location class along the pipeline route. As the details of the location class along the pipeline (based on population density) is not available for the screening, the only distinction made at this stage is between offshore and onshore pipelines.

Figure 5 - Typical Pipeline Assessment Criteria (Part a.)

Criteria	Comments
Operation	*This criterion is only relevant for dense phase CO_2.* This is to reflect the fact that there are less seasonal variations of ambient temperature for offshore pipelines, and that there might be less limitation in terms of operational envelope to maintain the CO_2 in dense phase. *The range of temperature considered for the transported CO_2 is around ambient temperature (< 30 °C). Equipment (cooler) may be needed upstream of the pipeline to maintain the fluid within acceptable temperature limits and avoid the two-phase region.*
Pipeline age	This criterion reflects the fact that it may be difficult to retrieve all necessary information for a full requalification if the pipeline is very old (for example, if there has been a change of ownership of the pipeline during its lifetime, or if some information is difficult to retrieve because they have not been digitized). In addition, the age is also an indicator for the stress cycles experienced in fatigue or external loading sensitive areas. The age of the pipeline is however not the only factor in the definition of the pipeline behavior in the future. Other parameters are also very relevant, for example the way a pipeline has been designed, built, tested and above all operated in the years because the frequency and the load ratio can be very different for different pipelines. These items could however not be accounted for in the screening. Penalties were applied for pipeline installed prior to 1990.
Transport capacity (1st check)	This criterion is further assessed at business case level. A first check is however performed here at screening level to confirm if any lines can be disregarded due to very limited transport capacity. ▪ For the CO_2 transport capacity in dense phase, the following assumptions are considered for the transport capacity estimates: * inlet pressure=pipeline current MAOP, * outlet pressure assumed to be 80bar (to still be in dense phase with some margin), * internal pipeline roughness=50microns, * considered limit on velocity for CO_2 dense phase: 5m/s ▪ For the CO_2 transport capacity in gas phase, the following assumptions are considered for the transport capacity estimates: * inlet pressure=40bar (sufficient margin from the dew point curve), * outlet pressure assumed to be minimum 20bar, * internal pipeline roughness=50microns, * considered limit on velocity for CO2 gas phase: 10m/s. Only pipelines being able to transport at least 0.01 $MtCO_2/y$ qualified at screening stage.

Figure 6 - Typical Pipeline Assessment Criteria (Part b.)

4.1.5 Key CO2 References:

CCUS Projects Network - Briefing on Carbon Dioxide Specifications for Transport (2019)

DNV-CO2 RISKMAN Guidance Level 1

DNV-CO2 RISKMAN Guidance Level 2

DNV-CO2 RISKMAN Guidance Level 3

DNV-CO2 RISKMAN Guidance Level 4

DNV-OS-F101 – Submarine Pipeline Systems

DNV-RP-F104 – Design and Operation of CO2 Pipeline

DNV-RP-J201 – Qualification procedures for CO2 Capture Technology

DNV-RP-J202 – Design and Operation of CO2 Pipeline Systems

DNV-RP-J203 – Geological Storage of Carbon Dioxide

Energy Institute - Good plant design and operation for onshore carbon capture installations and onshore pipelines

Energy Institute - Technical Guidance on Hazard Analysis for Onshore Carbon Capture Installations and Onshore Pipelines

Energy Institute - Hazard Analysis for Onshore Carbon Capture Installations and Offshore Pipelines

HSEx – CO2 PipeHaz Good Practice Guidelines for CO2 Pipeline Safety

HSEx – Guidance on conveying carbon dioxide in pipelines in connection with carbon capture and storage projects

IEAGHG – Corrosion and Materials Selection in CCS Systems

IPCC – Special report on CCS

Re-Stream Report 2021

SACS(BGS) Academic Paper – Best Practice for the Storage of CO2 in Saline Aquifers

TWI Technical paper – Material Selection for Supercritical CO2 Transport(2010)

4.2 Hydrogen

4.2.1 Basis of work carried out

- Reviewed technical limits of existing infrastructure for the use of hydrogen transportation & generate credible blend scenarios
- Reviewed technology opportunities to enable re-use

- Incorporated learning's from hydrogen schemes and trials nationally & worldwide
- Literature reviewed to identify & document learnings from other hydrogen studies, schemes & trials.
- Identified / Define basis for transport – e.g. operating pressures
- Offshore pipelines - establish screening criteria for likely re-use
- Onshore distribution network - engaged with Cadent / NG / SGN to understand blending story - how much / when
- Developed scenarios for technical / legislative driven blends
- Identified technologies that can support re-use - e.g. liners & coatings

4.2.2 Hydrogen Infrastructure Assessment

The current UK SNS offshore gas infrastructure can be segregated into the following categories:

Wells (including platform and subsea wells)

Have the potential for repurposing in certain applications but will require heavy evaluation and solid information on the well integrity including cement quality. Additionally, wells connected to a proposed reservoir that are plugged and abandoned will need assessing for their suitability to not be impacted by a change of product.

Topsides Structure including accommodation, lifesaving, nav-aid, etc.)

Have the potential for reuse depending on condition, anticipated future lifetime required and proportionality to the application. A full assessment would be needed on each individual asset to determine condition, suitability and cost effectiveness.

Topsides Production Equipment (downstream of wellhead to ESDV valve + supporting utilities)

Highly unlikely to be any use for repurposing applications due to the nature of the application and the properties of H_2 and CO_2.

Jackets

May have the potential for reuse depending on proximity to suitable reservoir, condition, anticipated future lifetime required. An individual assessment on each jacket would be required and a cost evaluation against alternatives carried out.

In-field Gas Gathering and Utility Pipelines

Less likely to be of use for any repurposing application for H_2.

Major Trunklines to Onshore.

Strong possibility of repurposing should the pipeline condition, operational parameters and proximity from a suitable reservoir be suitable.

4.2.3 Repurposing for Hydrogen Summary

A summary of the assessment is shown below

The current UK SNS offshore gas infrastructure can be segregated into the following categories:

Wells (including platform and subsea wells)
Have the potential for repurposing in certain applications but will require heavy evaluation and solid information on the well integrity including cement quality. Additionally, wells connected to a proposed reservoir that are plugged and abandoned will need assessing for their suitability to not be impacted by a change of product.

Topsides Structure including accommodation, life saving, nav-aid, etc.)
Have the potential for reuse depending on condition, anticipated future lifetime required and proportionality to the application. A full assessment would be needed on each individual asset to determine condition, suitability and cost effectiveness.

Topsides Production Equipment (downstream of wellhead to ESDV valve + supporting utilities)
Highly unlikely to be any use for repurposing applications due to the nature of the application and the properties of H_2 and CO_2.

Jackets
May have the potential for reuse depending proximity to suitable reservoir, condition, anticipated future lifetime required. An individual assessment on each jacket would be required and a cost evaluation against alternatives carried out.

In-field Gas Gathering and Utility Pipelines
Less likely to be of use for any repurposing application for H_2 and CO_2 .

Major Trunklines to Onshore.
Strong possibility of repurposing should the pipeline condition, operational parameters and proximity from a suitable reservoir be suitable.

4.2.4 Principle of Repurposing Gas Pipelines for Hydrogen

A strong probability exists that it would be feasible to repurpose existing main pipeline should the pipeline condition, operational parameters and proximity from a candidate reservoir be suitable. There could be environmental and financial advantages in doing so versus removing an existing pipeline and replacing it with a new pipeline. On review of the existing major pipelines into Bacton the following was established:

- Repurposing of natural gas pipelines for hydrogen service appears entirely feasible for a high percentage with the right controls in place.
- Materials up to X52 which represent most of the UKSNS major pipelines are more suited to hydrogen service (excludes risers). Other material grades need further performance-based testing as little experience has been gained in H2 transport. Various projects are ongoing in this space.
- The key elements of evaluating the suitability of the pipeline for hydrogen service are:

  a) Proximity of Offshore End to Suitable Storage Reservoir
  b) Pipeline Material Type
  c) Pipeline Capacity
  d) Pipeline Operational Limitations (MAOP, Pressure, Temperature, Internal Friction)
  e) Pipeline Integrity Status (Including the use of Internal Crack Detection Inspection Technology (EMAT / UT))
  f) Economics of Maintaining the Integrity over the projected life
  g) Other Critical Features (Tie-ins)
  h) Detailed pipeline integrity condition assessment (metal loss, deformation (dents / buckles) cracks and crack-like features, axial strain assessment). In addition, any data on stress/fatigue cycling and, historical completeness of information). Inspection campaigns will be cumbersome and include MFL, Crack detection technology (EMAT for gas or UT for example), Axial Strain. Note that EMAT pipeline data analysis is limited in wall thickness typically less than wall thickness of the pipelines.

A comprehensive risk-based inspection program will need to be worked out for periodic inspection to monitor pipeline integrity going forward including the frequency of inspections.

- A detailed engineering study for each pipeline suitability will be required to determine MAOP and derating factors considering ASME B31.12 and the evolution of regulatory requirements.
- Internal coating or lining technologies appear extremely limited at present but would be beneficial in reuse and further life extension.
- Seabed conditions for stress cycling may need monitoring. Technology to overcome this may be needed such Bragg Grating Strain Sensors (Fibre Optic). Free spans and other stresses could accelerate propagation of Hydrogen Induced Cracking (HIC).
- Pipelines would also act beneficially as additional hydrogen storage capacity potentially running into millions on M3.

Storage Potential

To illustrate the pipeline hydrogen storage opportunity, storage capacity has been assessed for the following pipelines (which have been screened as potentially suitable, see section 3.3). This storage assessment is based on the following simple assumptions.

- Pipeline nominal sizes and lengths have been taken from NSTA open data.
- Storage capacity has been assessed assuming the pipelines are operated between 30barg and 80barg. I.e. the storage capacity is equal to the difference in the pipeline contents at 80barg and 30barg.

It can be seen that storage potential of these lines is between 5 and 15 GWh, equivalent to 0.7 to 2 days production from the core project plant.

Pipeline	NB (inch)	Length (km)	Storage CAPACITY, Tonnes	Storage CAPACITY, GWh	Days production of Core project
Leman BT to Bacton A2	30	57.9	233	7.8	1.1
Leman 49/27 AP to Bacton A1	30	55.7	224	7.5	1
Lancelot to Bacton	20	61.6	248	8.3	1.2
Inde 49/23 AT to 49/27 BT	30	35.7	144	4.8	0.7
Clipper PT to Bacton	24	73.2	295	9.8	1.4
Leman AP to Bacton	30	61.9	249	8.3	1.2
Sean P to Bacton	30	106.3	428	14.3	2

4.2.5 Hydrogen Blending

Gas blending of Hydrogen is currently recommended not to exceed 20% concentration in domestic grade gas in pipelines (Note that as hydrogen is less dense than methane, that equates to approx. 7% in real energy terms). Note that some users may not be able to handle these concentrations depending on their application of the gas. Research will be required in this are to identify end user limitations. For example, Germany has a 10% limit on its network providing no sensitive customers are connected. Should for example a gas filling station be connected they limit the Hydrogen blending to 2%.

Injection points into the transportation system needs to be strategically distributed and controlled to prevent regional concentrations exceeding concentrations whilst others bring under specification.

Blending remains a suboptimal methodology compared to delivering 100% gaseous hydrogen to hydrogen users / applications from a cost and greenhouse gas perspective. Therefore, blending will be a temporary process. The NTS predict de-blending will commence as early as 2027 and be wound down completely nationally between 2034 and 2044 when the grid is predicted to be fully hydrogen.

4.2.6 Key Technologies:

EMAT (Electro Magnetic Acoustic Transducer Pipeline Inspection)

Suitable for crack detection and coating bonding inspection without the need for a liquid coupling which is ideal in determining UKSNS pipeline integrity. Also, another variant by NDT Global called ART (Acoustic Resonance Technology)

Key Providers:	Baker Hughes, Rosen, TD Williamson, NDT Global
Technology Readiness:	Fully commercial and available in the market, although with wall thickness limitations for heavy risers.

In-Situ Pipeline Coating Technology

This area provides a key technology opportunity for future development but today would not be at a level of reediness for the Bacton applications. It was explored in detail and no commercially ready products were identified suitable. This technology is only in the market with limitations on length and pressure capability. Prior to any coating application pipelines need cleaning and drying to a suitable level to avoid future issues. Access to pipelines for injecting a cleaning and spraying string is limited several kilometers from each end. Flexi-Coil Pipe Cleaning System is in the market and commercial for cleaning pipelines but has not been used for the application of a coating.

Current CIPP (Cured in Place Pipe) are typically used on shorter distance pipelines and only been used on water lines and shorter distances.

4.2.7 Key Take Aways:

The main-focus area will be the material steel grade and obtaining detailed pipeline inspection criteria.

Typically, in the UK SNS pipelines are inspected for wall thickness as part of the integrity status using Magnetic Flux Leakage (MFL) technology. Little data outside this methodology will be available on any pipeline in the UKSNS. This technology does not detect cracks suitably for crack growth assessments. Typically, EMAT (Electro Magnetic Acoustic Transducer) phased array or Ultrasonics are required to determine accurately the location and feature of a crack or potential crack to determine suitability for Hydrogen operation. Ultrasonics require a liquid coupling (water) to be effective which would only be viable if a hydrotest and subsequent dewatering operation was planned.

Various organisations are carrying out research on the material aspects of the pipeline which will reduce uncertainties and unlock further the potential for reuse. These studies will provide critical data points to be used as part of any assessment.

It should be noted that during a more detailed assessment, certain pipelines risk being disqualified due to detailed pipeline inspection which may highlight fatigue crack growth risks for H2 service. Additionally in the UK the regulatory aspects are still open and need to be formalised to provide more guidance on the tolerances allowed.

4.3 Screened Pipelines

4.3.1 Screening Criteria

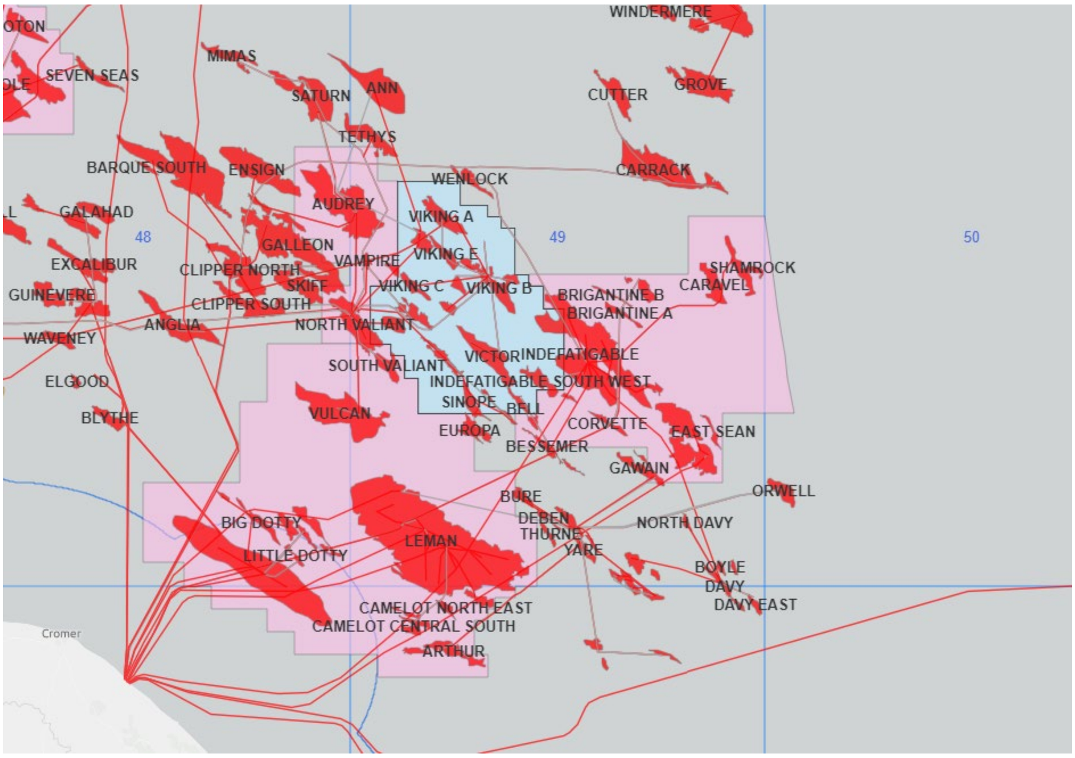
Each of the key pipelines that land at Bacton has been assessed for potential re-use for CO2 transportation to support a future blue hydrogen plant. A CO2 pipeline and storage site will be required to enable transport of captured CO2 from a future blue hydrogen plant and stored in a CO2 storage site offshore.

The following criteria were identified to carry out the preliminary assessment:

Criteria	Commentary
Likelihood of availability in 2030	Whether existing fields that currently produce through the pipeline will still be operational in 2030, therefore making the pipeline unavailable for CO2 transport in 2030
Connection identified potential store	Preference that existing pipeline is connected to an identified CO2 storage candidate that could be secured by 2030 for CO2 storage
Pipeline condition	Whether pipeline is currently operational or if it is currently in poor condition or not operating
Pipeline size	Ensure sufficient pipeline diameter to support CO2 transport at the required volumes
Pipeline age in 2030	To assess what the pipeline age would be in 2030 and likelihood of whether it could be operational over the life of the project
Maximum Allowable Operating Pressure (MAOP)	To assess whether the pipeline could be used for dense phase transportation, which would likely require a minimum operating pressure of at least 100 barg. It is noted that initial CO2 transport may be in the gaseous phase, which would require an operating pressure of c. 40 barg.

A number of the gas fields that currently transport hydrocarbons to Bacton have been considered as part of the NSTA's recent Carbon Capture and Storage licencing round, which closed on 13th September 2022. Licence awards are expected in early 2023. A summary of the CCS licence round, with respect to the existing SNS gas pipeline network, is shown below. This presents opportunities for repurpose of existing pipelines if CCS licences are awarded within the areas on offer.

The pink shade shows the areas considered as part of the CCS licence round and the light blue an awarded CCS licence block as part of Harbour Energy's V Net Zero CCS project.



A summary of the pipeline screening for CO2 transport is shown below.

Pipeline	Operator	Key fields	Likelihood of availability in 2030	Connection to Store	Pipeline Condition	Pipeline size (")	Pipeline Age in 2030	MAOP (barg)	Potential for re-use
Trent to Bacton	Perenco Oil and Gas	Cygnus	Unlikely CoP to mid 2030s	No		24	46	131	
Leman BT to Bacton A2	Perenco Oil and Gas	Leman	Currently producing	Maybe		30	60	99.3	
Leman 49/27 AP to Bacton A1	Perenco Oil and Gas	Leman	Currently producing	Maybe		30	62	93.1	
Lancelot to Bacton	Perenco Oil and Gas		Currently producing	Maybe		20	38	103.5	
Indefatigable 49/23 AT to 49/27 BT	Perenco Oil and Gas	Inde	Currently producing	Maybe		30	59	110	
THAMES to Bacton (Saturn Banks)	IOG PLC	Elgood	Unlikely CoP to mid 2030s	No		24	44	129	
HEWETT SOUTHERN EXPORT A-LINE TO BACTON	ENI UK LIMITED	Hewett	CoP now	Maybe	30" external (0.625" wall thi		62	ollowing pipeline failure*	
HEWETT NORTHERN EXPORT B-LINE TO BACTON	ENI UK LIMITED	Hewett	CoP now	Maybe	30" external (0.625" wall thi		57	26.89**	
Clipper PT to Bacton	Shell	Clipper South, Galleon	Currently producing	Maybe		24	40	112	
Bacton to Clipper PT	Shell	Clipper South, Galleon	Currently producing	Maybe		3	36	150	
Leman AP to Bacton	Shell	Leman	Currently producing	Maybe		30	63	99.3	
Bacton to Leman AP	Shell	Leman	Currently producing	Maybe		4	63	45	
LEMAN 49/26-BT TO BACTON	Shell	Leman	Currently producing	Maybe		30	57	Mothballed	
SHEARWATER TO BACTON (SEAL)	Shell	Elgin Franklin	Unlikely CoP to 2040s	No		34	31	153	
SEAN P TO BACTON TERMINAL TRUNKLINE	ONE-DYAS	Sean	CoP ~ 2025	Maybe		30	44	HOLD	

4.3.2 Conclusions

The following conclusions can be drawn:

- There is no one candidate that is ideally suited for repurposing for CO2 transport. The primary driver for selection is the uncertainty in field Cessation of Production (CoP) by 2030, given current market conditions and high gas prices. The majority of the pipelines will have exceeded their original design life, and in some cases by double, and any repurposing activity will require considerable assurance to ensure the integrity of the pipeline is suitable to transport CO2 over the life of the project. This would consider both the internal condition of the pipeline, as well as the external condition as scouring of the pipeline is a known issue in the SNS due to high levels of seabed movement.

- The following pipelines are highly likely to still have fields producing at 2030, making these pipelines unlikely candidates for CO2 transport in 2030:
    - ETS – Cygnus
    - Thames - IOG
    - SEAL – Elgin Franklin
    - BBL – Interconnector
- The Hewett field has reached CoP and does represent a potentially good candidate for CO2 transport. However, one of the pipelines currently has section removed due to a pipeline failure and the other pipeline has a reduced MAOP to 26 barg. Therefore, it is unlikely that the Hewett pipelines could be candidates for repurposing for CO2 transport, without material investment in replacing the sections of the pipeline that have been removed.
- Sean is expected to reach CoP in the mid 2020s and therefore the pipeline represents a potential good candidate for re-use. No details on MAOP could be acquired during the study.
- The Perenco and Shell operated pipelines to Leman could be potential candidates, but there is uncertainty in CoP timing for the fields.
- Two pipelines to Leman and Clipper were screened out as they are chemical inhibitor lines to the facilities and are small in diameter, 4" and 3" respectively.
- The majority of pipelines could transport CO2 in gaseous phase, however if dense phase transportation is preferred from Day 1, or is transitioned to later in operational life, this would reduce the number of potential pipeline candidates that could be suitable for repurposing.

5 ONSHORE PLANT

5.1 Core Project

5.1.1 Description

The Core Project considers the development of a 1 x 355 MW_{HHV} CCS-Enabled Hydrogen Plant with supporting Balance of Plant (BoP) and interface connections to the existing onshore terminal facilities. It is intended that the project development for the Core Project is undertaken within the boundary of the existing Bacton Energy Hub (BEH) complex utilising available plot space, with tie-ins to the source natural gas supply and provision for CO2 connection to the offshore pipelines. With these objectives in mind, the Infrastructure SIG assessed the unit operation footprint, design interfaces, operational facilities (control and power) and the associated design safety requirements for plant layout and proximity to boundary fence, in order to determine the layout feasibility. Input data for technology selection and footprint of additional facilities was sourced from the works by the Hydrogen Supply SIG.

The conclusion from the analysis was that the Core Project could be sited within the existing ENI terminal footprint, acknowledging that this would require brownfield remedial works to assess and remove existing services and foundations, and to assess any revisions to operational power / instrumentation and underground pipeline & drainage facilities.

5.1.2 Plant Location

The BEH terminal facilities comprise of two operating onshore terminals (Shell and Perenco) with reception and processing of natural gas meeting the NTS quality specification. The natural gas produced is routed to the NTS facility which is located to the south of the Perenco and Shell reception terminals. The ENI plot comprises a decommissioned brownfield footprint, with topside equipment removed but foundations and underground facilities remaining in situ; Figure 7 provides an overview of the existing BEH terminal infrastructure:

Figure 7 - Existing onshore Bacton terminal complex, with Core Project indicated and located within the ENI plot

5.1.3 Layout Screening

To determine the available footprint within the existing facilities supporting a brownfield execution, a desk top evaluation of the ENI, Perenco, Shell & NTS plots was carried out with discussions held with respective Operators. This activity was performed in consideration of the anticipated footprint for the Core Project.

Shell

Based on the retention of the existing facility, a review of the Shell Bacton Gas plant footprint determined that, despite there being pockets of space available, there is overall insufficient space to accommodate the Core Project.

Perenco

The screening of the Perenco Gas Terminal revealed that there is insufficient footprint to accommodate the Core Project. This is attributed to;

- Equipment and above ground piping are dispersed across the plot and thus limit the available footprint required to house the core project
- Safety distances associated with existing vent systems, and hydrocarbon sources
- Underground Pipeline corridor, mounds and separation between existing facility and core project further reduce the available footprint

ENI

Desk top screening indicate that the Core Project can fit within the envelope of the existing ENI plot.

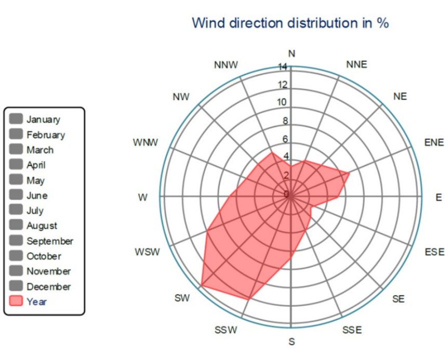
5.1.4 Basis of Design and Assumptions

The basis of design and assumptions used to develop the Core Project layout within the ENI site are summarised below:

Annual wind rose

The predominant wind direction is from the south west. The wind direction and wind speed are important factors in deciding the locations of fired equipment relative to potential hydrocarbon releases and occupied buildings.

		Wind Direction (deg)								
Lower	Upper	N	NE	E	SE	S	SW	W	NW	Sum
0	1	0.16%	0.15%	0.15%	0.17%	0.17%	0.16%	0.16%	0.15%	1.27%
1	2	0.47%	0.49%	0.49%	0.51%	0.52%	0.51%	0.51%	0.48%	3.98%
2	3	0.84%	0.86%	0.86%	0.94%	0.95%	1.04%	1%	0.84%	7.31%
3	4	1.17%	1.18%	1.1%	1.29%	1.52%	1.7%	1.54%	1.17%	10.67
4	5	1.33%	1.26%	1.26%	1.38%	1.87%	2.34%	2.01%	1.36%	12.81
5	6	1.43%	1.23%	1.21%	1.28%	1.92%	2.77%	2.32%	1.38%	13.54
6	7	1.3%	1.06%	1%	1.01%	1.81%	2.85%	2.21%	1.2%	12.43
7	8	1.05%	0.81%	0.75%	0.71%	1.51%	2.53%	1.97%	1.13%	10.46
8	9	0.74%	0.61%	0.5%	0.53%	1.21%	2.14%	1.55%	0.95%	8.23%
9	10	0.51%	0.43%	0.37%	0.34%	0.9%	1.75%	1.21%	0.7%	6.21%
10	11	0.37%	0.23%	0.31%	0.23%	0.64%	1.29%	0.94%	0.52%	4.52%
11	12	0.26%	0.17%	0.21%	0.13%	0.43%	0.97%	0.72%	0.37%	3.26%
12	13	0.17%	0.11%	0.14%	0.08%	0.32%	0.61%	0.5%	0.26%	2.2%
13	14	0.13%	0.06%	0.08%	0.05%	0.21%	0.38%	0.31%	0.19%	1.4%
14	15	0.07%	0.03%	0.04%	0.02%	0.13%	0.18%	0.19%	0.12%	0.79%
15	16	0.03%	0.02%	0.02%	0.01%	0.08%	0.09%	0.11%	0.09%	0.45%
16	17	0.02%	0.02%	0%	0.01%	0.04%	0.04%	0.06%	0.04%	0.23%
17	18	0.01%	0.01%	0%	0%	0.03%	0.03%	0.03%	0.02%	0.12%
18	19	0%	0%		0%	0.01%	0.01%	0.02%	0.01%	0.06%
19	20	0%	0%		0%	0.01%	0.01%	0.01%	0.01%	0.04%
20	21	0%				0%	0%	0.01%	0%	0.02%
21	22	0%				0%	0%	0%	0%	0.01%
22	23						0%	0%	0%	0%
23	24							0%		0%
24	25							0%		0%
25	26									0%
26	27									0%
27	28									0%
28	29									0%
29	30									0%
Sum		10.08	8.73%	8.48%	8.68%	14.27	21.4%	17.37	10.99	



Wind Rose (Shell Site Data)

Wind Rose (Perenco Site Data)

Figure 8 - Annual Wind rose; sourced from Shell and Perenco Operations respectively

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Battery Limits

The battery limits are outlined below:

Feed gas

Feed Gas to the Core Project CCS-enabled hydrogen plant is assumed to be taken from the NTS facility; consequently this will be a NTS quality, dew-pointed gas stream with a composition range within the NTS specification. It is downstream of the existing processing facilities and will be routed underground to the metering station located above ground to the south west of the Terminal.

Provision for a richer feed gas, containing higher chain hydrocarbons beyond the NTS gas quality specification, is not precluded, but would require further assessment of the existing processing facilities. The existing terminals provide offshore-onshore reception facilities, including slug catchers and process separation, which are specifically designed to satisfy the flow assurance and design requirements from the offshore reservoir sources. Accordingly, to extract individual process streams from the dedicated offshore sources would necessitate further engineering and design works in order to determine the process design schemes that would satisfy the design, control and high/low pressure interfaces that are presented.

The benefit of a richer feed gas is the potential to increase the hydrogen production from the CCS-enabled plant, albeit with additional inlet processing; however, for the Core Project the flowrate represents only a portion of the available capacity of Bacton complex, and hence simplifying the gas quality and tie-in connections for this initial investment supports project execution works, and minimise SIMOPS impact to the existing terminal facilities.

Cessation of Production (CoP)

The footprint / layout analysis undertaken has considered the facilities currently in operation to support the production of grid-quality natural gas and has not evaluated the dispersed potential plot space available from CoP decommissioning of existing plant. However, following inspection of the available plot space in the ENI (brownfield) plot, the simplification of not considering CoP is deemed to be valid.

Hydrogen product

The Core Project will produce hydrogen at conditions suitable for transfer into to the NTS grid via blending performed within the NTS facility. The onshore layout has considered a dedicated hydrogen export line that is routed from the Core Project to the NTS plot. Metering of the produced hydrogen is included within the Core Project facilities located on the ENI plot.

Raw Water

From review by the Hydrogen Supply SIG, it has been identified that there is no additional capacity available from the existing raw water supply by Anglian Water. All raw water required for hydrogen production at BEH will be produced as part of the Core Project development, with additional extraction and desalination facilities installed. The development may consider pre-investment, in particular for the intake and outfall, to satisfy later Build-Out requirements.

Electrical Power

For the purposes of the Core Project assessment, Electrical power is assumed to be available from the existing Electrical grid connections; no provision is made for onsite power generation and the requirements of grid upgrade external to the BEH terminal facilities has not been evaluated.

For the electrolytic hydrogen plant Build-Out scenario's, a dedicated offshore wind source electrical feed will be established with supporting onshore facilities.

Site Drainage

The BEH terminal has existing drainage systems and outfall. By achieving the development of the Core Project within the existing terminal boundary it is foreseen that the existing drainage system capacity and function can accommodate the requirements from the new facilities.

Road connection

For operational access to the Core Project facility, it is intended to utilise the existing connection to the B1159 road, with parking and site entry control undertaken into the ENI plot area. No additional road connection is envisaged for the permanent facilities.

Operational facilities

The Core Project will be a standalone plant, with dedicated facilities and buildings to support: administration, operation and maintenance, electrical substation(s), control and refuge. No consideration has been made of integrating the buildings within the currently operating terminal facilities.

Constructability

The BEH terminals have a history of construction activities relating to the staged development of the complex, and also for shutdown activities and workover. The primary access for equipment and construction services is the B1159 road, which runs adjacent to the south side of the reception terminals. The site logistics support road transfer of materials and equipment, with the potential for a staging area and associated site assembly and installation. A SIMOPS was undertaken on the Core Project as part of the BEH study works; this supported the principles of stick-built constriction with opportunistic modularisation.

Basis of design development

Future works are anticipated for the development of the Basis of Design and requirements for the Core Project in order to support project planning and execution; including:

- Establish tie-in details for primary interfaces: natural gas supply (both NTS grid supply and terminal inlet 'richer' sources), hydrogen product, carbon dioxide export, raw water (inlet/outfall) assessment and associated line routing
- Develop the scope for underground / brownfield deconstruct activities within the existing ENI plot
- Establish the local grid network upgrade plans, and identify an easement for grid power / utility pipelines
- Evaluate the interface with existing interconnectors
- Determine the project execution strategy (stick/modular, laydown, site labour, temporary facilities, construction sequencing, staging)

5.1.5 Plot Development

Layout description

The intent of a site layout is to provide a safe and functional configuration of permanent facilities. The overall site plan, Figure 4-1 was developed at conceptual level, arranging the unit operations to support safe operation and construction requirements. The dimensions for each unit operation is aligned with the Core Project capacity and design, and are based on data received from the Hydrogen Supply SIG which in turn are based on publicly available data for similar facilities and technology.

Feed gas from the NTS facility will be routed underground to the metering station located above ground to south east of the ENI terminal. From the metering station, the feed gas lines will be routed to the south of the process plant for conversion to H2. The H2 return line will be routed back to NTS for blending and /or transmission.

The Administration Building is located at the south west corner of the Terminal. The location is optimum relative to the proximity to the plant entrance, prevailing wind, overpressure and hydrocarbon releases. The Control Room building is located within the administration area thus providing an integrated project team i.e. operations, maintenance etc. in one location. The main plant access to the facility comes from B1159, through an access road and enters the plant towards the south west of the plot.

Utilities are located between the process plant and Administration / Control room thus providing a buffer between units containing hydrocarbon or hazardous inventories and buildings occupied by personnel.

A dedicated vent/flare is located in North of the ENI facility away from the public road.

Safety Consideration

Safety in Design is the over-arching consideration for the development of the plant layout and this was achieved by a combination of layout and separation to control escalation. The plot was laid out to reduce the risk to sufficient safety levels as set by the applicable standards, and for location of flammable sources in consideration of the prevailing wind. Unit separation to the plant boundary limit (fence line) and separation between units was achieved by performing consequence modelling of major failure and credible event, respectively. Credible event considered the separation distances between fire zones (unit blocks) to limit the potential escalation from one fire zone impacting the next. Major failure considered a significant failure of pipe or equipment that have a potential to generate consequence beyond the property boundary (fence line).

Figure 9 - Core Project Site Plan

5.1.6 Core Project Conclusion

The conclusion from the onshore facilities assessment is that there is adequate space within the existing Bacton Energy Hub complex to accommodate the Core Project within the ENI plot.

5.2 Build Out Scenario

Based on the requirement to provide natural gas feedstock to the CCS-enabled plant, and from Operator feedback, it is expected that the Shell and Perenco terminals will be operational during the Build-out phase; accordingly, the Build-out scenarios could require additional footprint external to the existing Bacton Energy Hub complex.

For the purposes of initial evaluation, processing facilities supporting the various Build-Out scenarios were assessed for footprint and conceptual layout. Anticipated build out scenarios are detailed below:

2030	1 x 700 MW_{HHV} CCS-enabled Plant assumed • Footprint identical to base case (355 MW_{HHV})
2040	2 x 1.8 GW $_{HHV}$ Upscaled CCS-enabled Plant • 1.8 GW_{HHV} assumed to comprise of 2x 900 MW_{HHV} plant • Buildings shared with 2030 build out 1 x 2.1 GW Electrolyser • Assumed stand alone to blue hydrogen • Space reserved for mobilization
2050	2 x 2.1 GW Electrolyser Note; Base case and 2030 build out retired

5.2.1 2030 Build Out

The 2030 build out scenario comprises of the addition of a 700 MW $_{HHV}$ CCS-enabled Plant. The build out would be a standalone plant with the exception of the vent/flare which is shared with the Core Project. The unit block layout is identical to the core project and such identical layout principles would be used to develop the plot.

5.2.2 2040 Build Out

The 2040 Build-out adds a further 2 x 1.8 GW_{HHV} CCS-Enabled blue hydrogen Plants and 1 x 2.1 GW electrolytic hydrogen plant.

- 2 x 1.8 GW_{HHV} Up scaled CCS-Enabled blue hydrogen plant

  For the purposes of layout analysis, 2 off 900 MW_{HHV} have been assumed; these addition plants are evaluated as standalone facilities with dedicated vent/flare. The unit block layouts are similar to the Core Project and therefore the same layout principles would be adopted to develop the plot.

- 1 x 2.1 GW electrolytic hydrogen plant

  The electrolytic hydrogen plant would utilise power from a future Offshore Wind Farm to convert an ultra-pure water feedstock into product hydrogen, and with oxygen and low-grade heat available as by-products. The plant is made up of two components; Offshore and Onshore.

  - Offshore

    The offshore portion comprises of a wind farm substation, mobilisation area and associated easements. Block footprints are in accordance with Hydrogen Supply SIG requirements. Cables from the offshore windfarm would be routed to the landfall and subsequently to the windfarm substation via an onshore underground cable route corridor. Electrical power from the windfarm would be fed to the grid and onshore electrolytic hydrogen plant.

- Onshore

  The electrolytic hydrogen plant constitutes the onshore portion. The technology selection and footprint have been applied in accordance with the H2 Supply SIG evaluation. The plant is stand alone with dedicated flare / vent, utilities, buildings etc. Product hydrogen would be routed to the NTS facility via pipeline for onward transmission / blending.

5.2.3 2050 Build Out

For the final stage of Build-out the onshore facilities extend further towards the production of electrolytic hydrogen with associated offshore wind power sources; the scenario considers a further 2 x 2.1 GW Electrolyser facilities added, with the Core Project and 2030 Build-out CCS-Enabled units retired.

The additional electrolytic hydrogen plants layout principles for the offshore and onshore portions are based on the 2040 electrolytic hydrogen build out plant.

5.2.4 Build Out Conclusion

Additional footprint (greenfield) would most likely be required to facilitate the build out phases, with opportunities arising for synergistic development between the CCS-enabled and Electrolytic plants. The Build-out stage would benefit from detailed analysis of plant sequencing with consideration of beneficial pre-investment opportunities, adoption of common utilities and interface routes, and also to perform further technology assessments at the time of enaction to take benefit of future capabilities which may offer reduced footprint and utility requirements.

In the event that brownfield solutions are mandated, from initial assessment of footprint, the BEH hub could be utilised to install electrolytic hydrogen production facilities following cessation of production of the existing terminals.

6 GREENFIELD OFFSHORE INFRASTRUCTURE

6.1 Basis

The following basis was used for the cost estimates:

- New 30 km pipeline
- Pipeline design pressure of 100barg, suitable for dense phase CO_2 transport.
- 3 wells required initially (no additional cost has been included for later tie-in of wells if needed for a build out scenario).
- 5 Million tonnes per annum (Mtpa) and 10 Mtpa capacities assessed.
    - The core project would require less than 1 Mtpa capacity.
    - The build-out project would require 10 Mtpa.
    - These assume dense phase pipeline operation. For a given pipeline diameter, the capacity would be lower if CO_2 was transported at a lower pressure in gaseous phase.
    - A pipeline with 5Mtpa capacity in dense phase operation would also have capacity for the core project rate of approximately 1 Mtpa when operating in gaseous phase.
- Subsea and offshore unmanned wellhead injection facilities assessed
- Optional power cable from shore for wellhead platform case.

6.2 Assumptions

The following assumptions were used for the cost estimate:

- Uninsulated carbon steel pipeline of 30 km
    - 5 Mtpa – 16" pipeline assumed, based on reasonable pressure drop (<10bar) over pipeline length.
    - 10 Mtpa – 20" pipeline assumed, based on reasonable pressure drop (<10bar) over pipeline length. This assumes dense phase operation – capacity would be lower if CO_2 transported at lower pressure in gaseous phase.
    - Allowance for three crossings
- Subsea option
    - 4 slot tie-in structure assumed, 3 well tie-ins costed
    - Umbilical providing controls, comms, chemicals and power from shore
- Normally Unmanned Installation (NUI) option
    - 4 slot wellhead platform
    - No umbilical – well control package, chemical storage and injection, and power generation located on the NUI

For well costs, a £30 million per well was assumed.

6.3 CAPEX Estimate

An in-house CO2 cost estimating tool was used to generate cost estimates for each of the cases identified. The cost estimating tool uses a bottom-up approach to estimate cost blocks for each of the elements of the transport value chain, including pipeline construction, installation, umbilicals and power cables, unmanned facilities.

The table below provides a summary of the costs for 5 / 10 Mtpa pipelines with either subsea or an unmanned facility.

Rate	5 MTPA - Subsea	10 MTPA - Subsea	5 MTPA - NUI	10 MTPA - NUI
Pipeline	16" uninsulated	20" uninsulated	16" uninsulated	20" uninsulated
Wells	3	3	3	3
Infield structure	4 slot TIS	4 slot TIS	NUI	NUI
Umbilical	control+chems	control+chems	no	no
	£M	**£M**	**£M**	**£M**
Pipeline	74.9	78.2	74.9	78.2
Umbilical	56.6	56.6	-	-
Infield	13.5	13.5	33.9	33.9
DSV Activities	16.1	16.1	10.2	10.2
Total - no power cable	**161.1**	**164.4**	**118.9**	**122.2**
Power Cable			28.4	28.4
Total - with power cable			**147.3**	**150.6**

- An unmanned installation case achieves a lower cost compared to a subsea case. This is primarily due to the requirement for an umbilical in the subsea case. Investigation of local power / control solutions should be investigated to determine whether a renewable local power solution could be achieved in the subsea case.
- The unmanned installation could be powered by solar panels, but would require some form of back-up generation, such as a diesel generator, which would have an impact on CO2 emissions over the project life.
- Given the water depth, a NUI would be the preferred solution and would enable an ability to workover the wells, which would be simpler than if subsea.
- Other CCS schemes in similar water depth have adopted a NUI approach for CO2 injection. This includes Hynet, Northern Endurance, Porthos and Aramis.

6.4 OPEX Estimate

The following OPEX items have been assumed:

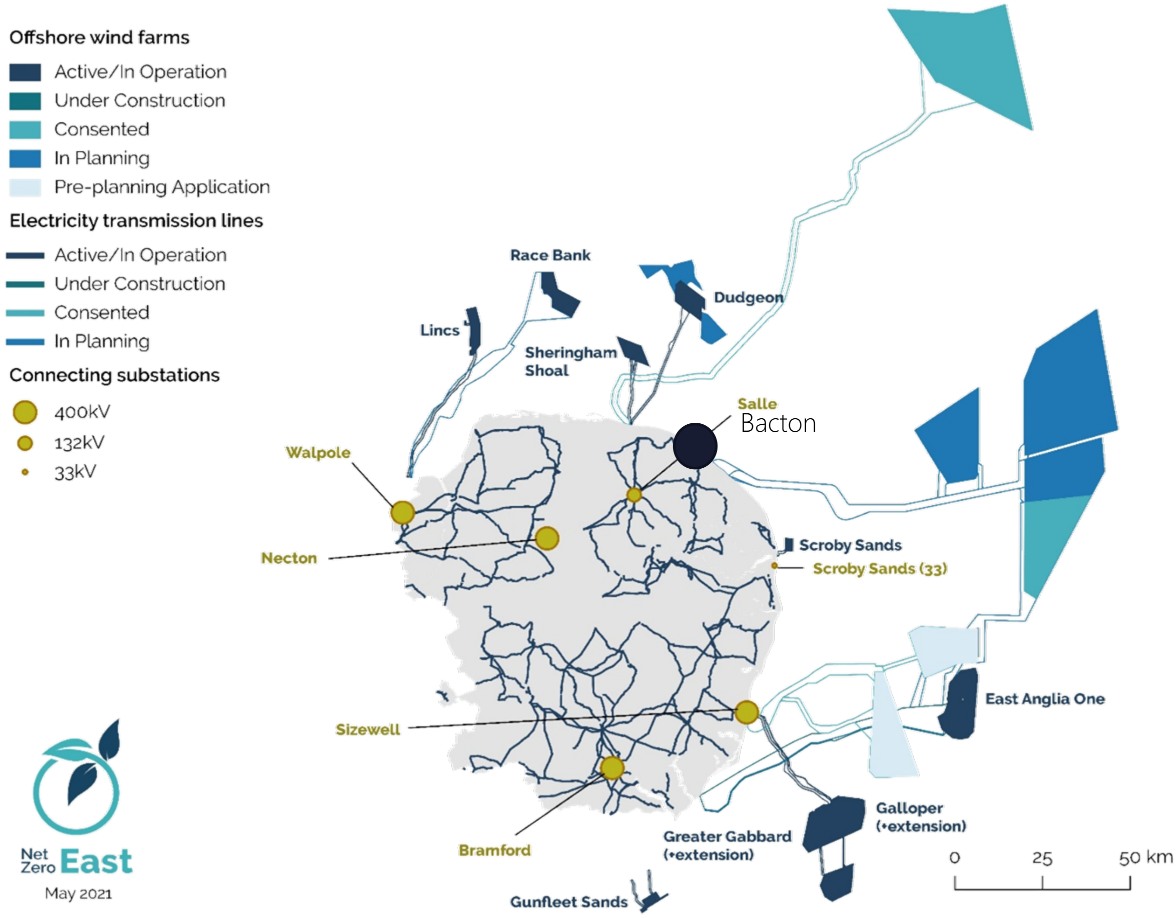
- Pipeline fixed OPEX of £1 million per annum

- NUI fixed OPEX of £5 million per annum
- Well maintenance of £1 million per well per annum, equivalent to £3 million per annum for three wells
- Offshore T&S G&A of £5 million per annum

7 OFFSHORE WIND INTEGRATION

7.1 Introduction

The East of England represents one of the major offshore wind regions in the UK with over 5 GW of current offshore wind capacity. The Infrastructure SIG engaged with East Wind, a regional working group to support on providing information relating to offshore wind in the region. The below information was shared by East Wind member, Opergy.



Source: EEEGR

7.2 Current Offshore Wind Capacity

The current installed offshore wind capacity in the SNS is approximately 5 GW. The size of each offshore wind farm has increased in capacity from c. 100 MW to East Anglia ONE delivering >700 MW.

Project	MW Capacity	Ownership	Status
Scroby Sands	60	RWE Renewables	Operational
Lynn & Inner Dowsing	194	Corio Generation; BlackRock	Operational
Gunfleet Sands	173	Orsted, DBJ Europe; JERA Co.	Operational
Greater Gabbard 1&2	504	RWE Renewables / SSE Renewables	Operational
Sheringham Shoal	317	Equinor; Equitix; Corio Generation; TRIG	Operational
Lincs	270	Corio Generation; Orsted	Operational
London Array	630	RWE Renewables; CDPQ; Orsted; Masdar	Operational
Gunfleet Sands (Demo)	12	Orsted	Operational
Dudgeon	402	Equinor ASA; Masdar; China Resources Power Holdings	Operational
Galloper	353	Corio Generation; RWE Renewables; Siemens; ESB; Sumitomo Corporation	Operational
Race Bank	573	Orsted; Macquarie Group; Sumitomo Corporation	Operational
Triton Knoll	857	RWE Renewables; J Power; Kansai Electric Power Co.	Operational
East Anglia ONE	714	Scottish Power Renewables; Corio Generation; The Renewables Infrastructure Group Ltd (TRIG)	Operational

Source: EEEGR

7.3 Planned Offshore Wind Capacity

A further 6.7 GW of offshore wind capacity has been consented in the SNS, with a further 3 GW in planning.

Of the 5 GW of consented projects, Norfolk Vanguard, Norfolk Boreas and East Anglia Three are due to start construction from 2024. Planning consent for East Anglia One North and East Anglia Two was given on 31 March 2022.

This would result in c. 15 GW of offshore wind capacity in the East of England by 2030.

Project	MW Capacity	Ownership	Status
East Anglia TWO	900	Scottish Power Renewables	Consented
East Anglia THREE	1400	Scottish Power Renewables	Consented
East Anglia ONE NORTH	800	Scottish Power Renewables	Consented
Norfolk Vanguard	1800	Vattenfall	Consented
Norfolk Boreas	1800	Vattenfall	Consented

Source: EEEGR

Project	MW Capacity	Ownership	Status
Dudgeon Extension	402	Equinor	In Planning
Sheringham Extension	317	Equinor	In Planning
Five Estuaries	353	RWE Renewables; Green Investment Group / Corio	In Planning
North Falls	504	RWE Renewables; SSE Renewables	In Planning
SNS Round 4 Bid	1500	Green Investment Group / Corio	In Planning

Source: EEEGR

7.4 Future Offshore Wind Plans

By 2030 the East of England will have ca. 15 GW of offshore wind capacity, delivering a third of the UK's target of 50 GW of offshore wind capacity by 2030.

Future offshore wind farm lease rounds in the East of England are uncertain and would require engagement with the Crown Estate to establish whether further wind farms can be consented in the region. Given the potential cumulative impact of the number of offshore wind farms in the region, we understand that the appetite from the Crown Estate for further offshore wind expansion is currently relatively limited. This has been demonstrated by a number of wind farm expansion projects, such as Race Bank, not achieving consent.

Further discussion with the Crown Estate to establish whether alternative routes to market for the electricity, through hydrogen production, would represent a change in perception and could be supportive in meeting the hydrogen targets set by the UK Government.

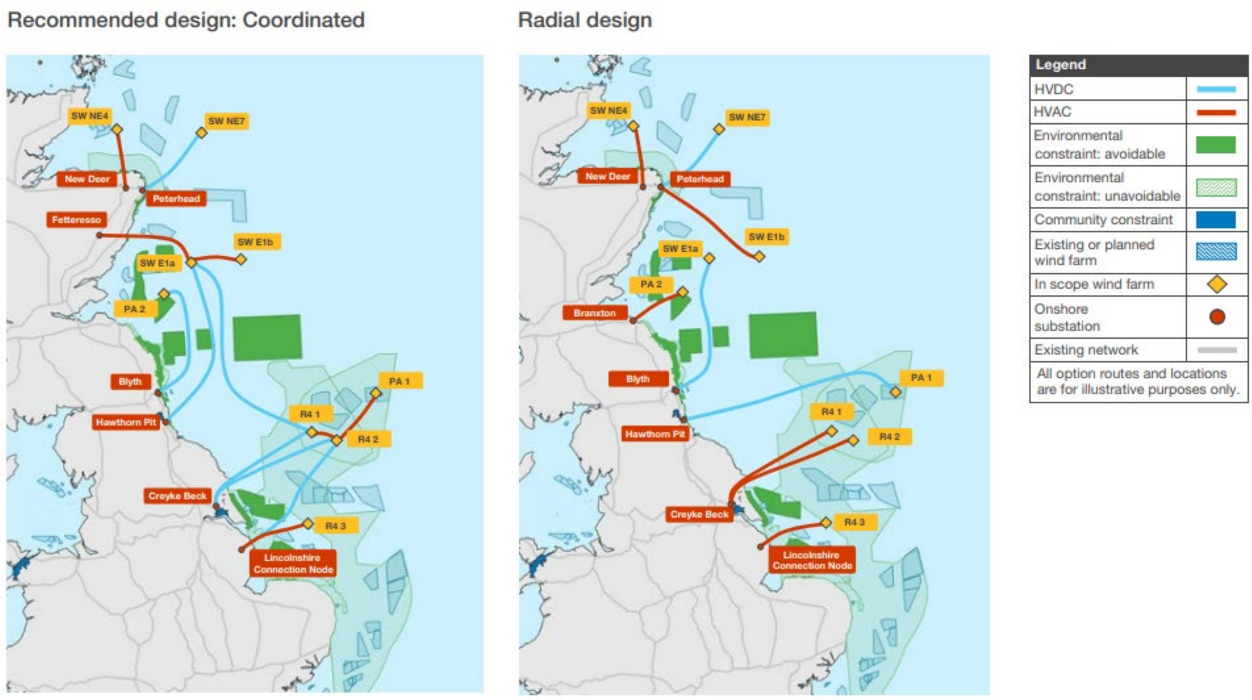
7.5 National Grid ESO Holistic Network Design

National Grid ESO recently announced their Holistic Network Design (HND) which provides the recommended offshore and onshore design for a 2030 electricity network, that facilitates the Government's ambition for 50 GW of offshore wind by 2030.

The HND enables investment and delivery of infrastructure, including locations in the North and South Wales, the Scottish Islands and West Coast, and the East Coast of Scotland and Aberdeenshire, Lancashire, North-East England and Yorkshire and Humber.

The HND was developed in consultation with the UK, Scottish and Welsh Governments, Ofgem, Transmission Owners, offshore wind developers and environmental stakeholders, the HND primarily includes offshore wind projects and secured seabed leases through the Crown Estate's Offshore Wind Leasing Round 4 and the Crown Estate Scotland's ScotWind Leasing Round.

For the East Coast Region, the following recommended design has been established.



Source: National Grid ESO

The primary focus on the East Coast Region is connecting Scotwind and Round 4 awards to the grid. National Grid ESO's recommended design does not include any new connections from offshore wind farms into East Anglia beyond those currently planned. National Grid ESO stated that although the location performed well from an economic point of view, environmental constraints mean that is unlikely to be feasible in the timescales the HND is considering to find a route that is acceptable from an environmental or technical perspective beyond those already in place and in development.

It is therefore unlikely that any grid upgrades onshore or new connections from offshore will connect to the vicinity of the Bacton Energy Hub in the short to medium term. This may be revised in the future, but there are currently no plans by National Grid ESO to upgrade the grid as part of the 2030 HND.

7.6 Integration Requirements

The Bacton terminal is currently located 20 km to the nearest onshore substations for existing wind farms. The electricity grid around Bacton would require material upgrades and reinforcement to support a +1 GW electrolytic hydrogen project. Based on initial discussions with National Grid ESO, there are currently no plans to upgrade the grid in the surrounding Bacton area. The primary focus for National Grid ESO, as part of the Holistic Network D (HND) is to upgrade the electricity network in Scotland as part of enabling a route to market for Scotwind to deliver electricity from Scotland to the rest of the UK.

National Grid ESO indicated that upgrades to the grid of <100 MW could be discussed, which could support the electricity requirements for a CCS-enabled blue hydrogen plant. However, grid upgrades to support a connection of > 1GW is unlikely in the near to medium future, given the focus is around connecting Scotwind offshore wind farm developments.

For any future electrolytic hydrogen plant at Bacton, consideration of connection to an existing offshore wind farm via an existing offshore substation should be considered, or potentially a private wire connection to a new offshore wind farm.

In either scenario, engagement with offshore wind developers is required to understand their appetite to route a portion of their electricity that is currently connected to the grid to the Bacton Energy Hub. Given a large proportion of the projects are either currently operational or have been consented, it is unlikely that consideration has been made for alternative routes to market, such as a connection to an electrolytic hydrogen plant.

Any connection would require modifications to the existing offshore substation and would need to ensure that there was no impact on the delivery of electricity to the market. This will require a commercial agreement and may be an opportunity once initial Contracts for Difference (CfD) contracts roll off after the initial 15 year period.

8 CONCLUSIONS

8.1 Repurposing of Offshore Infrastructure for CO2 or H2 Transport and Storage

- There is no expectation that existing wells can be repurposed for CO2 injection.
- There is some potential for repurposing existing wells for hydrogen injection, but this would require significant evaluation effort and solid information on well integrity, including cement quality. Any plugged and abandoned wells that are connected to a reservoir intended for H2 storage would need to be assessed for suitability for hydrogen.
- * There is potential for reuse of jackets and topsides structures, including accommodation, lifesaving equipment etc, but this must be assessed on an individual asset by asset basis. There is no potential for reuse of topsides production facilities. This applies equally for CO2 and H2.
- It is considered unlikely infield gas gathering and utility pipelines can usefully be repurposed for CO2 or H2 transport.
- There is a strong possibility of repurposing major trunklines that land at Bacton, where the design pressure and pipeline condition is suitable, and where the pipeline is close to a favoured CO2 or H2 storage site.
- To determine trunkline condition suitability for hydrogen EMAT (Electro Magnetic Acoustic Transducer) phased array or Ultrasonics are required to determine accurately the location and feature of any crack or potential crack. This information is unlikely to exist already as these techniques are generally not applied in the SNS. Ultrasonics require a liquid coupling (water) to be effective which would only be viable if a hydrotest and subsequent dewatering operation was planned. During a more detailed assessment, certain pipelines risk being disqualified due to detailed pipeline inspection which may highlight fatigue crack growth risks for H2 service.
- Trunklines landing at Bacton have been screened for suitability for CO2 repurposing.
    - There is no one candidate that is ideally suited for repurposing for CO2 transport. The primary driver for selection is the uncertainty in field CoP by 2030, given current market conditions and high gas prices. The majority of the pipelines will have exceeded their original design life, and in some cases by double, and any repurposing activity will require considerable assurance to ensure the integrity of the pipeline is suitable to transport CO2 over the life of the project. This would consider both the internal condition of the pipeline, as well as the external condition as scouring of the pipeline is a known issue in the SNS due to high levels of seabed movement.
    - The majority of pipelines could transport CO2 in gaseous phase, however if dense phase transportation is preferred from Day 1, or is transitioned to later in operational life, this would reduce the number of potential pipeline candidates that could be suitable for repurposing
    - Sean is expected to reach CoP in the mid-2020s and therefore the pipeline represents a potential good candidate for re-use. However, there is currently no CO2 store identified in the region.
    - The Perenco and Shell operated pipelines to Leman could be potential candidates, but there is uncertainty in CoP timing for the fields.

8.2 Repurposing of Bacton Terminals for Hydrogen Production

- The Core Project (a 1 x 355 MW_{HHV} CCS-Enabled Hydrogen Plant) could be sited within the existing ENI terminal footprint, acknowledging that this would require brownfield remedial works to assess and remove existing services and foundations, and to assess any revisions to operational power / instrumentation and underground pipeline & drainage facilities.

- Based on the requirement to provide natural gas feedstock to the CCS-enabled plant, and from Operator feedback, it is expected that the Shell and Perenco terminals will be operational during the Build-out phase; accordingly, the Build-out scenarios could require additional footprint external to the existing Bacton Energy Hub complex.
- In the event that brownfield solutions are mandated, from initial assessment of footprint, the BEH hub could be utilised to install electrolytic hydrogen production facilities following cessation of production of the existing terminals.

8.3 Greenfield Offshore Infrastructure

- From preliminary assessment, for a generic 30km pipeline length, a 16" CO2 pipeline could accommodated 5Mtpa CO2 transport in dense phase, or up to 1Mtpa CO2 in gaseous phase. The Core Project requires just capacity for 1Mtpa. Therefore a 16" pipeline could accommodate an initial gaseous phase transport phase, with transition to dense phase in in the future.
- For greenfield offshore CO2 transport and injection facilities injection wells with dry trees located at a normally unmanned wellhead platform would be preferred over a fully subsea solution due to expected lower lifecycle cost. A wellhead injection platform would also enable an ability to workover the wells, which would be simpler than if subsea.

8.4 Offshore Wind Integration

- By 2030 the East of England will have ca. 15 GW of offshore wind capacity, delivering almost a third of the UK's target of 50 GW of offshore wind capacity by 2030.
- Future offshore wind farm lease rounds in the East of England are uncertain and would require engagement with the Crown Estate to establish whether further wind farms can be consented in the region.
- National Grid ESO's recommended design does not include any new connections from offshore wind farms into East Anglia beyond those currently planned.
- It is therefore unlikely that any grid upgrades onshore or new connections from offshore will connect to the vicinity of the Bacton Energy Hub in the short to medium term. This may be revised in the future, but there are currently no plans by National Grid ESO to upgrade the grid as part of the 2030 HND.
- National Grid ESO indicated that upgrades to the grid of <100 MW could be discussed, which could support a blue hydrogen plant electricity requirements. However, grid upgrades to support a connection of > 1GW are unlikely in the near to medium future, given the focus is around connecting Scotwind offshore wind farm developments.
- Any connection would require modifications to the existing offshore substation and would need to ensure that there was no impact on the delivery of electricity to the market. This will require a commercial agreement and may be an opportunity once initial CfD contracts roll off after the initial 15 year period.

9 RECOMMENDATIONS

9.1 Repurposing of Trunklines for CO2 Transport

- Clarity is required on the intended CO2 phase for transportation and injection. Assumption is that dense phase/ supercritical state will be preferred due to the improved delivery economics. Pipeline must be able to support supercritical/dense phase operation conditions >80Barg operating pressure and > 31°C operating temperature.
- Running ductile fracture management in dense phase. The pipeline arrest pressure must be higher than the saturation pressure of the CO2 composition: Pa>Ps
- Very tight process control criteria required to maintain delivery in required state up to and including injection (water-free, pressures, temperatures, purity, PH levels, velocities).
- Fullest possible understanding of historical pipeline integrity, operation, topography/seabed changes (wall thickness, corrosion, cyclic fatigue)
- Engineering assessments for weight change between natural gas/condensate and dense phase CO2, particularly in areas of free-spans.

9.2 Onshore Terminals

Future works are anticipated for the development of the Basis of Design and requirements for the Core Project in order to support project planning and execution; including:

- Establish tie-in details for primary interfaces: natural gas supply (both NTS grid supply and terminal inlet 'richer' sources), hydrogen product, carbon dioxide export, raw water (inlet/outfall) assessment and associated line routing
- Develop the scope for underground / brownfield deconstruct activities within the existing ENI plot
- Establish the local grid network upgrade plans, and identify an easement for grid power / utility pipelines
- Evaluate the interface with existing interconnectors
- Determine the project execution strategy (stick/modular, laydown, site labour, temporary facilities, construction sequencing, staging)

9.3 Offshore Wind Integration

- Further discussion with the Crown Estate to establish whether alternative routes to market for the electricity, through hydrogen production would represent a change in perception, and could be supportive in meeting the hydrogen targets set by the UK Government.
- For any future electrolytic hydrogen plant at Bacton, consideration of connection to an existing offshore wind farm via an existing offshore substation should be considered, or potentially a private wire connection to a new offshore wind farm.