Bacton Energy Hub
Hydrogen Demand – SIG report

Lead Author - Progressive Energy

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Report for the North Sea Transition Authority

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This document includes estimates, forecasts and assessment of a number of phenomena which are unquantifiable. As such, the judgements drawn in the report are offered as informed opinion. Accordingly the authors give no undertaking or warranty with respect to any losses or liabilities incurred by the use of information contained therein.

Version Control Table

Version	Date	Author	Description
V0.1	27/10/21	John Aldersey-Williams	Working draft (internal)
V1.0	21/9/22	John Aldersey-Williams	Near-final version (circulated to BEH SIG leads)
V2.0	26/9/22	John Aldersey-Williams	Final version following BEH SIG leads' review

Executive Summary

The North Sea Transition Authority ("NSTA"), (formerly the Oil & Gas Authority ("OGA")), has procured the formation of a number of Special Interest Groups ("SIGs") to explore opportunities for the Bacton Catchment Area ("BCA") in the context of Net Zero.

This document is the report from the Hydrogen Demand SIG. Its key task was to determine an aggregated forecast for hydrogen demand in the BCA.

Its key findings are:

- Potential for hydrogen demand to be served by hydrogen produced in Bacton is dominated by domestic demand from London and the South East
- The realisation of this potential demand will be critically determined by the ability of the NTS and local gas transmission and distribution systems to accommodate a blend of hydrogen in natural gas, and later to convert to 100% hydrogen
- By 2030, sufficient hydrogen demand (for blending into domestic supply, and with limited contributions from power generation and industry) is recognised to consume supplies from the "core" 350 MW project
- In the longer term, hydrogen demand continues to be dominated by domestic supply, but significant demand may also arise from power and industrial sectors
- This report has presented a range of estimates of hydrogen demand from transport sectors. We recognise that, subject to technological development and implementation, both marine and aviation sectors could evolve into significant demand sectors for hydrogen, but have not included these in the core demand estimates.
- We also note that the Interconnectors to Belgium and the Netherlands which land at Bacton may offer scope for import of feedstock gas for blue hydrogen production, import of European CO_2 for permanent geological storage in the UK sector or export of hydrogen and integration with a European Hydrogen Backbone.

Definitions

A number of terms with specific meanings are used through this report. They have been defined here.

- **"Blue" hydrogen** – hydrogen produced by the chemical reforming of natural gas, with the resulting CO_2 captured and permanently stored.
- **"Calorific value"** – this report uses HHV for both methane and hydrogen
- **"Capacity factor"** – the average output achieved by a (typically renewable) generating plant as a percentage of its maximum output.
- **"Dispatchable"** – the output of electricity generated by thermal or nuclear generation is, in principle, adjustable by the generator operating that plant (although in practice, nuclear plants aim to operate at a high load factor).
- **"Green"** hydrogen – hydrogen produced by the electrolysis of water, powered by renewable energy.
- **"Load factor"** – the average output achieved by a (typically dispatchable) generating plant as a percentage of its maximum output.
- **"T&S"** – the arrangements for transport and permanent subsurface storage of captured CO_2 from power stations, industrial sites and other locations at which CO_2 may be captured.

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Glossary of Terms

ASHP	Air Source Heat Pump
BCA	The Bacton Catchment Area – the study area in this report as defined in Section 1.2.1
Bcf	Billion standard cubic feet
Bcm	Billion cubic metres
boe	Barrel of oil equivalent
BECCS	Bioenergy with Carbon Capture and Storage
BEIS	Department for Business, Energy and Industrial Strategy
BEV	Battery Electric Vehicles
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CfD	Contract for Difference
cuft	cubic feet
DAC	Direct Air Capture (capture of CO_2 directly from the atmosphere)
ETS	Emissions Trading Scheme
EV	Electric Vehicle
FES	Future Energy Scenarios
GDN	Gas Distribution Network

LCOE	Levelised Cost of Electricity
LCOG	Levelised Cost of Gas
LCOH	Levelised Cost of Hydrogen
LDZ	Local Distribution Zone (for gas)
MER	Maximising Economic Recovery
Mcf	Thousand cubic feet
MMcf	Million cubic feet
MMcm	Million cubic metres
NGET	National Grid Electricity Transmission
NGGT	National Grid Gas Transmission
NIA	Network Innovation Allowance
NTP	Normal Temperature and Pressure (298 K, 1 atm)
NSTA	North Sea Transition Authority
NTS	National Transmission System (for gas)
NUI	Normally Unattended Installation
OCGT	Open Cycle Gas Turbine
OFGEM	Office for Gas & Electricity Markets
OGA	Oil & Gas Authority
RO	Renewables Obligation
SNS	Southern North Sea
Tcf	Trillion cubic feet (=1,000 Bcf)
UK	United Kingdom
UKCS	United Kingdom Continental Shelf
VAT	Value Added Tax

Note on units

Hydrogen
1 tonne of hydrogen = 39.4 MWh[1] = 11,200 Nm^3 = 395,000 cuft (at NTP)

1 TWh of hydrogen = 10 billion cuft (at NTP) = 285 MMcm (at NTP)

Oil equivalent
6 Mcf = 1 boe[2]

CO_2 from natural gas
Combustion of 364 kg of methane (the principal component of natural gas produces 1 tonne of CO_2[3].

The energy content of this quantity of methane, which has an energy content of 55.5 MJ/kg, is 20.2 GJ = 5.6 MWh[1].

Load factor and capacity factor
Wind farm output is generally described in terms of capacity factor, which is the average annual output divided by the nominal capacity and is determined by the wind turbine type, hub height, wind conditions and operational availability.

Power station output is generally described in terms of load factor, which is the average annual output divided by the nominal capacity. It is determined by the demand for power from that power station (driven in terms by overall grid demand and supply and that station's position in the merit order), as well as operational availability. The merit order defines the priority in which power stations on the grid are called on to generate to satisfy demand.

[1] Source:
https://www.engineeringtoolbox.com/fuels-higher-calorific-values-d_169.html

[2] Industry standard
[3] Derived from stoichiometry and molecular weights of 16g/mol CH_4, 44 g/mol CO_2

1.0 INTRODUCTION

In late 2020, the North Sea Transition Authority (at that time, the Oil & Gas Authority) commissioned Progressive Energy to consider the potential for the Bacton area to be developed as an Energy Hub and the potential role of hydrogen in the area, in the contexts of Maximising Economic Recovery and Net Zero.

1.1 Maximising Economic Recovery (MER) and Net Zero

The North Sea Transition Authority states that "it works with industry and government to maximise the economic recovery of UK oil and gas and support the UK government in its drive to reach net zero greenhouse gas emissions by 2050"[i].

1.2 The role of hydrogen

The transition to Net Zero will involve the replacement of fossil fuels with zero carbon alternatives. The main options for this are electricity generated from renewable sources (mainly offshore wind), and the replacement of natural gas with hydrogen. Across the energy sector, there is a lively debate as to the potential roles of these alternatives. This SIG takes the view that hydrogen should be positively advocated as a key part of the energy mix in Net Zero.

Firstly, it is clear that zero carbon thermal power generation technologies will be required to fill the generation gap when wind output is low: hydrogen can be used for this (and many CCGT plants may already be able to use a blend of hydrogen in natural gas). Additionally, hydrogen can make use of existing gas distribution infrastructure, and be adopted by boilers at all scales from domestic to industrial at relatively limited cost, thereby avoiding the costs of upgrades to the electricity grid.

The BEH Hydrogen Demand SIG participants strongly endorse the development of hydrogen as a replacement for natural gas, and as a strong participant in the Net Zero transition.

1.3 Special Interest Groups

The Hydrogen Demand SIG is one of five SIGs which are developing the ideas in the original report for OGA into what is intended to be a solid foundation for a hydrogen project at Bacton.

1.3.1 Hydrogen demand

This SIG, the Hydrogen Demand SIG, is led by Progressive Energy, and has set out the following vision:

- **Quantify** potential hydrogen demand by sector in the Bacton Catchment Area.
- **Understand** seasonal and diurnal variability in demand across sectors.

- **Understand** key sensitivities, drivers and blockers to demand cases.
- **Assess** hydrogen storage requirements and identify storage scenarios.
- **Inform** the work of all other SIGs.

1.3.2 Hydrogen supply

The Hydrogen Supply SIG, led by Summit E&P, has set out the following vision:

- **Outline** a technically feasible and sustainable pathway for low carbon energy production.
- **Identify** constraints and blockers to using indigenous gas production for blue hydrogen production.
- **Understand** and **overcome** current technological constraints to achieve 90 TWh or more of low carbon hydrogen production.
- **Identify**, **investigate** and **progress** CCS opportunities in the SNS for the project.
- **Determine** development, operating and abandonment costs to make a project viable and investable.

1.3.3 Infrastructure

The Infrastructure SIG, led by Xodus, has set out the following vision:

- **Enable** Hydrogen supply and demand.
- **Identify** risk, uncertainty and possible mitigation to deliver a timely project.
- **Establish** a technically feasible and investable concept.
- **Integrate** oil and gas and renewable infrastructure to deliver hydrogen solutions.
- **Engage** industry and local stakeholders to support the project or mitigate blockers.

1.3.4 Supply Chain and Technology

The Supply Chain and Technology SIG, led by Petrofac, has set out the following vision:

- **Map** the existing local, regional, national and international capability across the hydrogen value chain.
- **Assess** key supply chain and technology gaps and **identify** opportunities to **grow** technology and the supply chain.
- **Assimilate** best practice and learnings from other clusters to deliver the project at pace.
- **Establish** local, regional and national hydrogen capability to support delivery of an executable project.
- **Explore** and **describe** a delivery and contracting model for the project.

1.3.5 Regulatory

- **Engage** industry and local stakeholders and **collate** relevant lessons learned from historical and ongoing projects.
- **Identify** barriers and enablers for the Hub.

- **Investigate** any precedents which will be set by other hydrogen projects.
- **Understand** the existing and future regulatory landscape.
- **Outline** potential Government funding opportunities to support development of the Hub.

1.4 Scope of this report

The objectives of the Hydrogen Demand SIG will be to:

- Further define the demand potential through detail analysis incorporating available technical data
- Generate a robust and fit for purpose assumption set to be taken forward to the concept select and later detail design phases of the project
- Generate a detailed demand model to reflect the full BCA demand potential
- Share the most likely demand scenarios with the hydrogen supply SIG to inform the hydrogen supply modelling and scenario development
- Share any identified future demand opportunities for example export markets, private purchase power agreements with the Regulatory SIG to inform their workstreams

2.0 APPROACH AND METHODOLOGY

2.1 Approach

Following initial discussions on workscope, Progressive Energy agreed to take the lead role in developing demand forecasts, with other SIG members invited to input, review and comment as required.

It was agreed that Progressive would refresh its earlier work for OGA, and that Hydrogen East would consider transport demand from aviation and marine sectors.

We have developed estimates of hydrogen demand, without regard for supply and infrastructure constraints, at time stamps of 2030, 2040 and 2050. By disregarding these constraints, we provide a maximum theoretical demand profile, against which the Supply and Infrastructure SIGs can evaluate their own forecasts and an optimised, integrated timeline for hydrogen roll out can be identified across the SIGs.

It will then be for a later cluster consortium to specify a project in the context of the supply, demand and infrastructure SIGs (and other SIGs) findings.

2.2 Methodology

This report has gathered, interpreted, analysed and synthesised public domain information to deliver an estimate of future potential hydrogen demand, together with a number of sensitivities and uncertainties.

We have considered each of the demand sectors for hydrogen, based on publicly available data, which has been interpreted and analysed as specified sector by sector below.

The rationale for using public domain data is to accommodate the likelihood that the ultimate beneficiaries of the work of the SIGs may well include companies that are not currently part of the SIG process, and may therefore be outside the scope of any NDA which the SIGs might put in place.

2.2.1 Data sources

As discussed above, the data used to inform these forecasts has been limited to public domain sources. These sources have included actual gas supply and demand data from the National Grid Data Item Explorer website[ii], EU-ETS CO_2 emissions data[iii] and the National Grid Electrical System Operator's Future Energy Scenarios work[iv].

2.2.2 Timeline and workflow

The project aims to report by early 2022 and has adopted an approach comprising a number of “sprints”, with confirmatory checkins both within and across SIGs at the end of each sprint.

2.2.2.1 Sprint 1 – initial forecasting

Preparatory to Sprint 1, a detailed table of contents (ToC) was developed and circulated across the SIG core team. Following a limited response from the Core Group members, Progressive has undertaken to develop a first pass demand forecast, based on the methodology used in the original OGA report.

The checkin will involve socialising this initial demand forecast across the Core Group members and other SIG leaders, to gather comments.

Sprint 1 will be complete by the end of December 2021 and will comprise the initial demand forecast. This version of the report only includes results from Sprint 1.

2.2.2.2 Sprint 2 – revised forecast

Sprint 2 will involve socialisation and revision of the initial demand forecasts, and incorporation of comments from Demand SIG core group members and SIG leads.

Sprint 2 will be complete by the end of January 2022.

2.2.2.3 Sprint 3 – final socialisation

Sprint 3 will involve Core Group and support group members commenting on the revised draft, and Progressive refining this into a final version in the light of feedback from both within this SIG and from other related SIGs.

The checkin will be an intra-SIG review of these refined assessments, and a socialisation of the report with other SIGs. It will deliver a presentation pack summarising findings.

Sprint 3 will be complete by the end of March 2022.

2.1 Study area

The study area comprises the area to which Bacton might reasonably be expected to supply hydrogen in future, comprising National Grid NTS areas “East Anglia” and “North Thames” (which include the NTS offtakes described in Table 3-1 and are considered to serve the postcodes set out in Table 2-1.

Table 2-1: Post codes in study area

Postcode	Postal town	Population

AL	St Albans	250,427
CB	Cambridge	421,467
CM	Chelmsford	653,492
CO	Colchester	411,418
E	E London	990,035
EC	E Central London	33,205
EN	Enfield	344,434
HA	Harrow	480,953
HP	Hemel Hempstead	458,351
IG	Ilford	335,694
IP	Ipswich	595,934
LU	Luton	335,950
MK	Milton Keynes	507,978
N	N London	848,197
NR	Norwich	722,087
NW	NW London	551,407
PE	Peterborough	890,223
RM	Romford	516,824
SG	Stevenage	402,911
SL	Slough	373,607
SS	Southend	518,677
TW	Twickenham	490,472
UB	Southall	371,969
W	W London	533,706
WC	W Central London	35,995
WD	Watford	255,988
	TOTAL	12,331,401

3.0 HYDROGEN DEMAND ASSESSMENT

In the earlier report, Progressive Energy reviewed and analysed public domain data on gas demand in the Bacton Catchment Area (“BCA”) and used this as a basis for developing estimates of potential future hydrogen demand. This updated forecast adopts a similar approach.

3.1 The gas system in the study area

Movement of gas within the NTS is entirely dependent on within day gas system flows: depending on demand, gas landed at Bacton may meet demand across a large part of the southeast of Britain and the Midlands, while on another it may not reach London. In general, we have taken the NTS East Anglia and North Thames areas (see Figure 2-1 and Figure 2-2). We have chosen not to include South Thames region, as that is substantially supplied with natural gas from the south and from Isle of Grain LNG and we anticipate that emerging hydrogen demand in the South Thames region will be met similarly.

These areas contain the following NTS Entry Points (the points at which gas leaves the NTS and enters the Local Distribution Zones (LDZ). LDZs are operated by Gas Distribution Network Operators (GDN Operators); in the case of the BCA, the GDN Operator is Cadent.

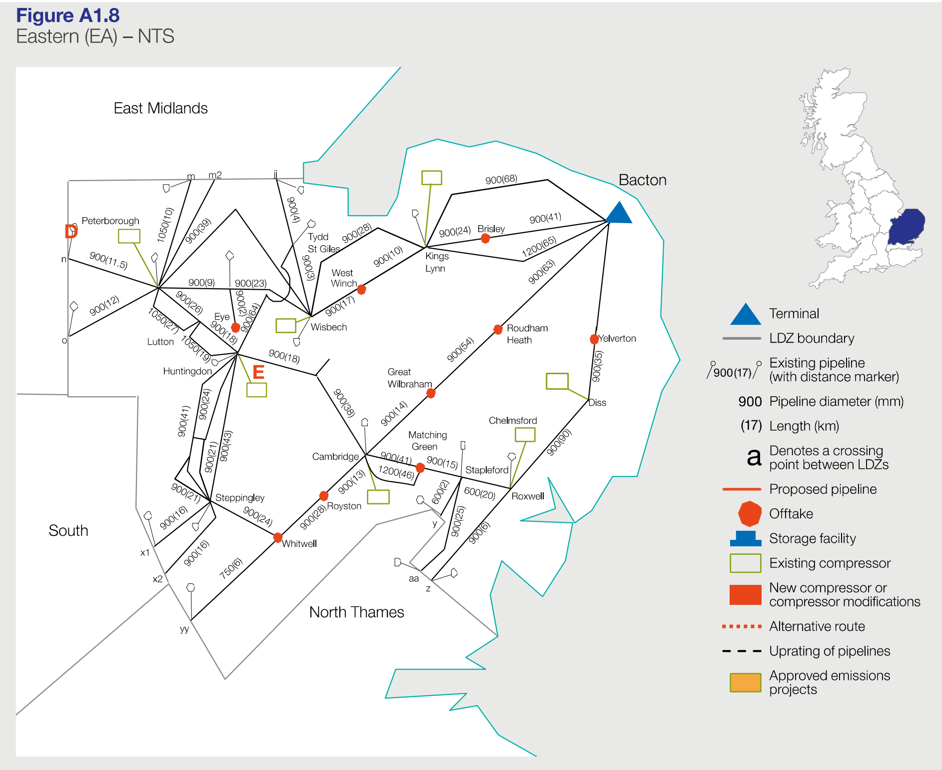

Figure 3-1: East Anglia NTS area (from National Grid Ten Year Statement, 2018)

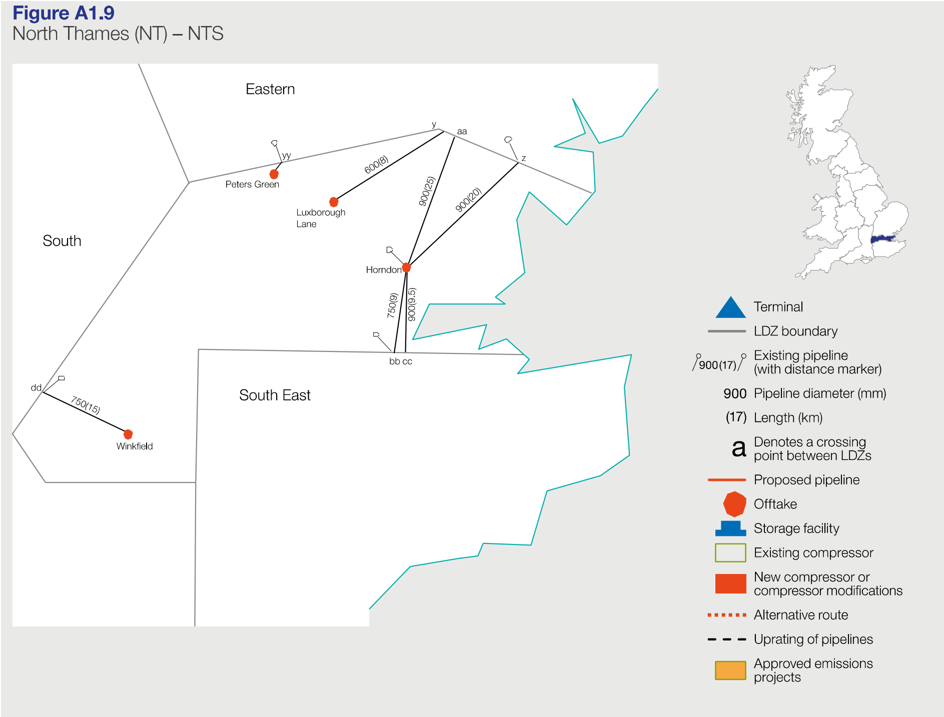

Figure 3-2: North Thames NTS area (from National Grid Ten Year Statement, 2018)

Table 3-1: LDZ Entry Points in study area (in approximate distance order from Bacton)

LDZ Entry	Location	NTS area
Bacton	Bacton	East Anglia
Brisley	Dereham	East Anglia
Roudham Heath	Thetford	East Anglia
Yelverton	5 miles SE Norwich	East Anglia
West Winch	S Kings Lynn	East Anglia
Gt Wilbraham	11 miles East Cambridge	East Anglia
Matching Green	SE Sawbridgeworth	East Anglia
Pbrgh Eye Green	Peterborough	East Anglia
Royston	Royston	East Anglia
Whitwell	S Hitchen	East Anglia
Peters Green SM	SE Luton	North Thames
Peters Green	SE Luton	North Thames
Luxborough Ln	Chigwell	North Thames
Horndon	Nr Basildon	North Thames

We have excluded the Winkfield LDZ Entry Point from this analysis as gas flows at that site are small – on the order of 20 GWh/yr.

We have not included any demand in South London, or considered potential blue hydrogen production in the Isle of Grain which may serve South London. We understand that there is limited communication between gas networks in North and South London, and this analysis is limited to North London demand only.

3.2 Methodology

Gas supply to users into the catchment area is routed, in most cases, through the Local Distribution Zones (LDZ) which are operated by Gas Distribution Network Operators (GDN Operators). The points at which gas leaves the NTS to enter the LDZ are known as NTS Entry Points or LDZ Entry Points (both terms are used).

Additionally, some very large users are supplied directly through the National Transmission System (operated by National Grid).

In general, we have extracted energy supply data (reported in MWh/yr) for each NTS Entry Point and for large users from National Grid published data for 2019 (the most recent available year)[v]. Noting that the major power stations in the study area are supplied directly from the NTS, and that LDZ data describes gas supply to industrial and domestic / commercial customers, which have quite different daily and seasonal demand profiles, we have estimated industrial demand from EU ETS data.

EU-ETS data reports record the CO_2 emissions by emitter. This data is used to back calculate the gas usage (on the basis that each molecule of CO_2 is produced by the combustion of 1 molecule of CH_4), and this allows us to calculate energy demand across these industrial sites. In some industrial sites, we believe that the carbon emissions arise from burning non-gas fuel (eg sewage gas in water treatment plants, heavy crudes in asphalt plants), process emissions (eg cement works) or both. In these cases, these sites have been identified and held separate from the bulk of the gas demand analysis, although the overall impact is small.

The total industrial gas demand is subtracted from the total volumes in the LDZ to leave the domestic/commercial annual total demand.

We note that the LDZ gas usage in the study area is dominated by domestic and commercial usage, so the effect of any simplifying assumptions regarding industrial usage will be small.

3.3 Notes on base case

We have assumed that population growth and energy efficiency improvements offset one another over the period 2030-2050.

In calculating load factors for thermal power, we have developed forecasts for the installed capacity of nuclear, solar, onshore and offshore wind across the UK by 2050, and combined these with current UK-wide demand data to assess the impact of these changes on the energy system.

Table 3-2: UK-wide capacity forecasts - nuclear and renewables

	Current	2030	2040	2050
Nuclear[vi]	9 GW	5 GW	8 GW	10 GW
Solar[vii]	13 GW	15 GW	20 GW	30 GW
Onshore wind[viii]	14 GW	15 GW	15 GW	15 GW
Offshore wind[ix]	10 GW	40 GW	50 GW	75 GW

These inputs define our UK system model, which combines these capacities with actual hourly wind data for three wind years (2012, an average output year, 2015, a high wind year and 2017, a low wind year). We have assumed a merit order in which nuclear is dispatched first, followed by solar and then wind, and then finally thermal generation is brought on to address any shortfall). This allows calculation of the likely load factor and load duration curves to be achieve by thermal generation under these assumptions.

3.4 Current gas demand by sector

The gas demand analysis has been based on National Grid data from 2019. We have taken this as a representative year, as we consider that 2020 was likely to have been distorted by COVID-19.

3.4.1 Power sector

The large power stations supplied directly from the NTS in the study area are set out in Table 2-2.

Table 3-3: NTS-supplied power stations (source NG data)

Name	Operator	Post Code	Capacity (MW)	Actual gas demand 2019 (TWh)	Load factor 2019 (%)
Coryton	InterGen	SS17 9GN	730	5.5	52%
Enfield	Uniper	EN3 7PL	410	3.6	69%
Great Yarmouth	RWE	NR30 3PY	420	5.3	86%
King's Lynn	Centrica	PE34 3RD	380	0.8	14%
Little Barford	RWE	PE19 6YT	730	3.3	31%

Peterborough	Centrica	PE1 5NT	360	0.1	2%
Rye House	Drax Power	EN11 0RF	715	0.7	7%
Spalding	InterGen	PE11 2BB	860	10.4	83%
Sutton Bridge	Calon Energy	PE12 9DF	850	4.4	35%
TOTAL / AVERAGE			**5,455**	**34.1**	**44%**

The National Grid data indicates total gas demand over the year of 34.1 TWh. EU-ETS data shows total emissions of 6.46 million tonnes CO_2 over the same period, which we calculate to be equivalent to some 35 TWh (see Table 2-2). We consider that these estimates of gas demand for power, derived by different means, are sufficiently close to be valid for these demand forecasting purposes.

Based on an expected thermal efficiency of 60% for modern CCGT generation[ix] (best of class achieves c. 64%), and their known gas usage and rated capacities, we estimate that these power stations were operating at an average load factor of 44% during 2019[4]. In our modelling, this equates to around the top 25% percentile of the thermal merit order.

3.4.2 LDZ Usage

National Grid data indicates total LDZ supply of 97.8 TWh, split across the LDZ Entry Points as set out in Table 2-3.

Table 3-4: LDZ gas demand 2019 (source National Grid data)

LDZ Entry	Location	NTS area	Gas supply GWh
Bacton	Bacton	East Anglia	362
Brisley	Dereham	East Anglia	363
Roudham Heath	Thetford	East Anglia	4,558
Yelverton	5 miles SE Norwich	East Anglia	5,280
West Winch	S Kings Lynn	East Anglia	1,660
Gt Wilbraham	11 miles East Cambridge	East Anglia	3,455
Matching Green	SE Sawbridgeworth	East Anglia	8,265
Pbrgh Eye Green	Peterborough	East Anglia	2,443
Royston	Royston	East Anglia	384

[4] We note that Statista reports that these power stations delivered a load factor of 43% in 2019

Whitwell	S Hitchen	East Anglia	17,830
Peters Green SM	SE Luton	North Thames	24,155
Peters Green	SE Luton	North Thames	16,944
Luxborough Ln	Chigwell	North Thames	8,065
Horndon	Nr Basildon	North Thames	4,072
TOTAL (TWh)			**97.8 TWh**

These totals can be disaggregated into industrial and domestic/commercial demand, according to the methodology set out in section 3.2.

We have applied a cutoff at 10,000 tonnes CO_2 in 2019 and set out the major emitters from EU-ETS data in Table 2-4. Each of these emitters is categorised as "NTS", "LDZ" of "Not gas". NTS emitters are supplied from the NTS, and do not contribute to total LDZ offtake. "Not gas" emitters produce their emissions from other processes, including chemical (the processing of calcium carbonate to calcium oxide in cement manufacture) or burning other fuels (eg the balance of emissions from cement manufacture, asphalt) and are excluded from the analysis.

For the LDZ-connected sites, gas demand is modelled based on CO_2 emissions, with adjustments made as required to reflect where part of the emissions arise from sources other than the burning of gas. We have also identified, as accurately as possible, the NTS offtake serving each of these emitters, to allow for calculation (by difference). This allows the larger industrial demand by NTS offtake to be assessed.

We then add a pro-rata share (by NTS offtake volume) of the smaller industrial demand, and took the balance as the domestic/commercial by NTS offtake.

Table 3-5: Large industry (green) and LDZ power (orange), CO2 emissions and gas demand

PROJECT NAME	LDZ entry	Post Code	Industry	2019 emissions (tCO2/yr)	Implied gas demand (TWh)
Wissington Sugar Factory	Roudham Heath	PE33 9QG	FOOD	332,391	1.82
Bury Sugar Factory	Roudham Heath	IP32 7BB	FOOD	280,174	1.53
Palm Paper	West Winch	PE34 3AL	PAPER AND PULP	138,605	0.76
Cantley Sugar Factory	Yelverton	NR13 3ST	FOOD	96,303	0.53
Tate & Lyle	Luxborough Ln	E16 2EW	FOOD	89,423	0.49

McCain Trading WHI	Pbrgh Eye Green	PE7 2PG	FOOD	33,438	0.18
O-I Harlow Trading	Matching Green	CM20 2UG	GLASS	33,040	0.18
Pauls Malt Limited	Roudham Heath	IP32 7AD	DRINK	31,879	0.17
Pura Foods Ltd	Pbrgh Eye Green	RM19 1SD	FOOD	29,936	0.16
Muntons Stowmarket	Yelverton	IP14 2AG	DRINK	23,246	0.13
Stevenage Site	Whitwell	SG1 2NY	PHARMA	22,508	0.12
Garden Isle	West Winch	PE13 2RN	FOOD	20,755	0.11
Ford Motor Company	Whitwell	LU2 0TY	AUTOMOTIVE	20,579	0.11
Haltermann Carless UK Ltd	Yelverton	CO12 4SS	OIL REFINERY	20,452	0.11
Olympics Stratford City	Peters Green (assumed)	E15 1DB	COMMERCIAL	20,450	0.11
Citigen CHP Plant	Peters Green (assumed)	EC1M 6PB	POWER-CHP	18,727	0.10
Slough Heat and Power	Likely Winkfield so not included in total	SL1 4TU	POWER-CHP	18,251	0.10
Johnson Matthey Plc Trading	Royston	SG8 5HE	CHEMICALS	17,350	0.10
Operator Account	Yelverton (assumed)	NR4 7TJ	COMMERCIAL	15,879	0.09
Princes Long Sutton	West Winch	PE12 9EQ	FOOD	14,984	0.08
Olympics Kings Yard	Peters Green (assumed)	E15 2ED	COMMERCIAL	14,372	0.08
Princes Wisbech	West Winch	PE13 3DG	FOOD	13,092	0.07
Ware Site	Whitwell	SG1 2NY	PHARMA	12,450	0.07
Briar Chemicals	Yelverton	NR6 5AP	CHEMICALS	11,836	0.06
Ford - Dunton Technical Centre	Horndon	SS15 6EE	AUTOMOTIVE	11,127	0.06
Ford Motor Company - Dagenham	Horndon	RM9 6SA	AUTOMOTIVE	10,988	0.06
The Francis Crick Institute Limited	London	NW1 1AT	UNIVERSITY	10,956	0.06
GSK Ware GMS 5140	Whitwell	SG12 0DJ	CHEMICALS	10,779	0.06
TOTAL – Large Industry					**7.6 TWh**

Table 3-6 summarises the total current (2019) gas demand by sector and the associated carbon emissions reductions which would be achieved by switching this gas demand to net zero sources. As the value of carbon emissions becomes more clearly expressed, these carbon emissions reductions will come to represent a potential value stream.

Table 3-6: Current gas demand (TWh, 2019)

Sector	Annual demand	Comment
Power	32.1 TWh	Average load factor of 44%
Industry	9.3 TWh	Excluding non-gas fuelled activities
Domestic/Commercial	88.3 TWh	Includes domestic and commercial
TOTAL	**129.7**	

3.5 Forecast hydrogen demand, medium and long term

In forecasting hydrogen demand, assumptions about the switching of demand from natural gas and other fuels to hydrogen are necessary. This section details the assumptions we have made, and then moves to set out hydrogen demand forecasts for 2030, 2040 and 2050.

3.5.1 Assumptions on fuel conversion - Power

The energy supply for the power sector will be driven by two factors: the load factor at which these plants will operate, and the degree to which hydrogen can be substituted for current fuels. Across the study area, we note that all of the large power generators are currently gas-fired CCGTs.

Load factors for dispatchable, thermal power generation are likely to fall very considerably from their current levels as the penetration of intermittent offshore wind and solar increases.

In this analysis, we have assumed that this effect is limited by 2030. Our modelling suggests that the top 25% percentile merit thermal tranche represented by the mix of power stations in the study area will have average load factors of around 30% based on our modelling of the interaction of wind and thermal generation (see Section 2.5.1). At the same time, we have assumed that a blend of hydrogen at 20 $\%_{vol}$ (c. $6.5\%_{energy}$) will be used in these power stations[5]. We note that there are reports that the gas grid will be able to accommodate 20%vol blend by 2023[x].

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[5] We note that current generations of gas turbines in CCGT applications may be able to operate at a range of blends of hydrogen in natural gas from zero to c. 40%, depending on the specific turbine characteristics. We take the view that this assumption represents a realistic middle case.

In 2040, we model that load factors have fallen further to 23%, but a 100% hydrogen gas feedstock is available for all NTS connected power stations. We note that some 100% hydrogen trials are due to be completed by 2025[xi], so the assumption of conversion to 100% hydrogen by 2040 may be cautious.

For 2050, we assume that the fuel mix remains 100% hydrogen, but our modelling (see Section 2.5.1) suggests that load factors may fall to 16% or even further.

In all of these cases, we would add that a high degree of electrification of heat will help to support load factors for the thermal tranche (as overall electricity demand would be higher), but the effect is relatively small. Accordingly, these estimates of future hydrogen demand are considered to be central cases. Sensitivity work, in which the effects on hydrogen demand of electrification of heat is required[6].

To achieve net zero, we assume that the non-gas industrial emitters (see Table 2-4) have also found a net zero solution to their energy needs.

3.5.2 Assumptions on fuel conversion - Industry

We have assumed that by 2030, industry will be able to accept a $20\%_{vol}$ ($6.5\%_{energy}$) blend of hydrogen into natural gas.

By 2040, we have assumed that 30% of the process heat has been electrified or engineered out of the process, with the balance is met by 100% hydrogen for plants served by the Feeders which run west and south from Bacton (Bacton, Brisley, West Winch and Eye NTS offtakes to the west and Yelverton and Horndon to the south), while those fed from the main London feeder (Roudham Heath, Great Wilbraham, Matching Green, Royston, Whitwell, Peters Green and Peters Green SM and Luxborough Lane), deliver a $20\%_{vol}$ blend to Norwich, Cambridge and the North Thames region.

By 2050, we have assumed that 30% of the process heat has been electrified or engineering out of the process, with the balance is met by 100% hydrogen across the whole study area.

3.5.3 Assumptions on fuel conversion - Domestic/commercial

We have assumed that by 2030, domestic and commercial demand will be able to accept a $20\%_{vol}$ ($6.5\%_{energy}$) blend of hydrogen into natural gas.

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[6] We note that increased demand of hydrogen for domestic heating and commercial adds to hydrogen demand for this purpose, but reduces the demand for power generation (some of which is sourced from hydrogen burning). Conversely, increased electrification of heating will increase the demand for electricity (and therefore increase load factors for thermal power), whilst reducing the demand for hydrogen demand for heating. The interaction between these demands requires further analysis in the sensitivity review.

By 2040, we have assumed that 30% of the heating demand has been met through electrification or energy efficiency measures. The remaining 70% is met by either 100% hydrogen if this is available at the relevant NTS Offtake (as specified in section 3.5.2) or 20%$_{vol}$ blend if 100% hydrogen is not available.

The 2050 forecast uses the same assumptions as 2040 but assumes that all of the gas demand is now met by 100% hydrogen.

We note that National Grid Future Energy Scenarios records gas demand for home heating in 2019 as 336 TWh, and electricity demand for home heating at 24.5 TWh. The same source notes 297 TWh of electrical supply across all sectors in 2020 (data for 2019 was not supplied). Even if heat pumps were able to achieve a weighted average Coefficient of Performance of 3, fully replacing gas demand for heat with electricity would add 112 TWh of electricity demand – the vast majority of it in winter – and would therefore likely require very significant (and costly) Grid upgrades.

3.5.4 Assumptions on fuel conversion - Transport

Hydrogen and battery electric vehicles are expected to play an increasing role, with trains and heavy goods vehicles, together with other "return-to-base" duty cycle vehicles (such as buses, refuse trucks and so on) expected to become dominated by hydrogen technologies, and private and light goods vehicles dominated by BEVs.

National Grid's 2020 Future Energy Scenarios anticipates nationwide annual hydrogen demand for transport between 0 TWh (Steady Progression scenario) and 50 TWh (System Transformation scenario. Scaling this latter scenario by population, this would add up to 10 TWh/yr (around 1 GW) of hydrogen demand for transport in the study area, which we have assumed grows linearly from zero in 2030 to 10 TWh/yr in 2050.

We have not considered the seasonal or diurnal variation in this demand, as we assume that hydrogen storage is available at the refueling stations used by these applications.

3.5.5 Hydrogen East transport demand forecasts

3.5.5.1 Road transport

Hydrogen East has background data on the number of vehicles registered in Norfolk and Suffolk and have modelled hydrogen demand assuming certain uptake rates by vehicle sub-sector.

The methodology has been refreshed to include a broader definition of East Anglia, as well as looking to include an assessment of the HGV demand from vehicles that are not registered in the area, but regularly travel across East Anglia to visit the ports/airports.

Hydrogen East has used data for vehicle numbers and typical annual mileages in the region and assumed that the percentage of useage shifting to hydrogen by year is as set out in Table 3-7.

Table 3-7: Hydrogen East assumptions on adoption of percentage of journeys using hydrogen for road transport

Year/type	2030	2040	2050
Cars	0.2	2.3	4.2
LGV	0.6	6.6	12.6
HGV	1.6	22.6	87.7
Bus	3.7	40.0	82.5
Other	1.1	15.8	61.5

Applying these assumptions to data on vehicle numbers, mileages and fuel use, generates the following estimates for hydrogen use for road transport over the three time stamps.

Table 3-8: Road demand for hydrogen

Vehicle type/demand	2030(GWh/yr)	2040(GWh/yr)	2050(GWh/yr)
Cars	35.4	407.6	744.4
LGV	22.8	251.3	479.8
HGV	65.5	925.0	3,589.4
Bus	11.5	124.0	255.7
Other road	3.4	49.0	190.6
TOTAL ROAD	**138.7**	**1,756.9**	**5,260.0**
Total off-road[7]	11.5	124.0	255.7
GRAND TOTAL	**150.1**	**1,880.9**	**5,515.7**

3.5.5.2 Rail transport

A similar approach to estimate hydrogen demand for rail was taken. This approach considered both passenger and freight traffic on the currently non-electrified lines, and assumed that electrified lines would continue to present no demand for hydrogen fuel,

[7] Hydrogen East had been unable to gather data on agricultural, construction and warehouse use before withdrawing from the proejcet, and proposed using the bus figures as an interim proxy

and that in 2030, 20% of journeys would use hydrogen fuel, rising to 40% in 2040 and 60% in 2050. This generated demand figures as in Table 3-9.

Table 3-9: Rail demand for hydrogen

Demand sector/year	2030 (GWh/yr)	2040 (GWh/yr)	2050 (GWh/yr)
Passenger rail	4.5	10.7	25.0
Rail freight	13.7	27.4	41.1
TOTAL RAIL	**18.2**	**38.1**	**66.1**

The large port of Felixstowe (including Harwich) is within the study area, and represents a large potential demand hub for hydrogen. Additionally, a number of smaller ports, including Great Yarmouth, Ipswich and others are within the study area, and were considered by Hydrogen East to have potential demand of 20% of the Felixstowe.

3.5.5.3 Marine transport

There are 6 significant ports in East Anglia (Kings' Lynn, Great Yarmouth, Lowestoft, Ipswich, Felixstowe, Harwich), as well as a number of smaller harbours. Felixstowe (including Harwich) massively dominate demand, and as a simplifying assumption, the other ports have simply been assumed to amount to 20% of Felixstowe/Harwich demand.

Marine demand for hydrogen was assessed by Hydrogen East reviewing the numbers of vessel movements, by type in 2019 (the last "normal" year for which data is available). Hydrogen East then applied assumptions on the degree to which hydrogen would be adopted for vessel movements, and the percentage of the vessel movements for which the vessel concerned would refuel in Felixstowe (see Table 3-10).

Table 3-10: Assumptions on hydrogen use in shipping

%age adoption of H_2

Vessel type	Number	2030	2040	2050
Large container vessels	1,100	10%	40%	80%
Ro-Ro	2,100	10%	40%	80%
Tankers	120	10%	40%	80%
Ferries	9	20%	40%	80%

%age refuelling in port

Vessel type	Number	2030	2040	2050
Large container vessels	1,100	15%	20%	25%
Ro-Ro	2,100	15%	20%	25%
Tankers	120	15%	20%	25%
Ferries	9	50%	50%	50%

Hydrogen East then assumed scalars for fuel use in different vessel types, against a norm of a small ferry (for which fuel use of 0.137 tonnes of hydrogen per day was considered to be normative). Table 3-11 sets out the resulting hydrogen demand estimates.

Table 3-11: Hydrogen demand from shipping (Felixstowe and Harwich)

Vessel type	Number	Per vessel (tonnes /yr)	TWh/yr 2030	TWh/yr 2040	TWh/yr 2050
Large container vessels	1100	3,750	2.4	13.0	32.5
Ro-Ro	2100	1,500	1.9	9.9	24.8
Tankers	120	1,000	0.1	0.4	0.9
Ferries	9	250	0.0	0.0	0.0
TOTAL FELIXSTOWE AND HARWICH			**4.4**	**23.3**	**58.3**
OTHER PORTS			0.9	4.7	11.7
GRAND TOTAL MARINE			**5.3**	**28.0**	**70.0**

3.5.5.4 Maritime – Jacobs Peer Review

Jacobs' peer review of this assessment of marine transport demand for hydrogen made several observations. First, the energy consumption figures for a small ferry were used which assumed scalar factors to adjust this consumption into other, larger vessel types.

To peer review this approach, Jacobs applied revised scalar factors, based on the deadweight tonnages of the different vessel types, and also reconsidered the assumptions on the percentage of this energy demand which was served by fuel delivered at the port.

Under Jacobs' analysis, which assumed lower fuel consumption per day per vessel (particularly for the most proportionately significant large container vessels) but a higher level of local refuelling, the total demand estimates were significantly lower than the original forecast figures.

Jacobs then applied an emissions-based model, which took regional data on maritime emissions from UK sources and used these as a basis for assessing the energy used and hence hydrogen. This produced very significantly lower demand estimates than the original assessment (see Table 3-12).

Table 3-12: Comparison of Hydrogen demand estimates for ferries using two different methodologies

Vessel type	2030 (TWh/yr)	2040 (TWh/yr)	2050 (TWh/yr)
GRAND TOTAL MARINE (Hydrogen East)	5.3	28.0	70.0
Jacobs estimate (Scalars method)	0.31	1.25	2.5
Jacobs estimate (emissions method)	0.09	1.04	2.04

We recognise that the original demand estimates appear to be very high for marine demand, and consider that the peer review estimates are likely to be more conservative. We also note that the conversion of marine traffic to hydrogen demand requires technology developments (eg hydrogen fuelling, ammonia engines, infrastructure redevelopment) which are not well advanced.

3.5.5.5 Marine opportunity

While there is considerable uncertainty in this analysis, we note that hydrogen demand potentially arising at Felixstowe for marine use could be very material under some assumptions. Further contact with Felixstowe port and its larger marine operators is warranted, to improve resolution on this opportunity area.

3.5.5.6 Aviation

Aviation in East Anglia is dominated by traffic through the hub airport at Stansted, with Norwich acting as a regional airport and Cambridge City having extremely limited traffic. There are also smaller private airfields, as well as RAF bases at Marham and Honington.

Hydrogen East took their estimate for daily demand at a hub airport as 2,000 tonnes (79 GWh) from McKinsey's CleanSky2 report[xii], with the regional airport at 120 tonnes (5 GWh), the local airport as essentially de minimis, and RAF activities at 200 tonnes (8 GWh). Hydrogen East assumed the conversion to hydrogen demand as set out in Table 3-13.

Table 3-13: Assumptions on hydrogen adoption - Aviation

Demand sector/year	2030 adoption of H_2	2040 adoption of H_2	2050 adoption of H_2
Hub airport (Stansted)	20%	40%	80%
Regional airport (Norwich)	20%	40%	80%
RAF activity	10%	40%	80%

This translates to total hydrogen demand from aviation, as shown in Table 3-14.

Table 3-14: Estimates of hydrogen demand - Aviation

Demand sector/year	2030 (GWh/yr)	2040 (GWh/yr)	2050 (GWh/yr)
Hub airport (Stansted)	4,867	9,733	19,467
Regional airport (Norwich)	292	584	1,168
RAF activity	24	97	195
TOTAL AVIATION	5,183	10,415	20,829

3.5.5.7 Aviation - Jacobs Peer Review

Jacobs reviewed the original analysis, and reassessed demand by scaling Stansted (which dominates demand) according to the number of aircraft movements relative to Heathrow to assess demand. This produced a reduction in demand estimate to around 40% of the original estimate.

Jacobs also applied a bottom-up model approach, combining numbers of aircraft movements, aircraft types and fuel consumptions, and typical flight distances to develop an assessment of energy requirements. This is shown in Table 3-15.

Table 3-15: Jacobs estimate (Stansted as hub airport)

Demand sector/year	2030 (GWh/yr)	2040 (GWh/yr)	2050 (GWh/yr)
Regional airport (Stansted)	626	1,375	3,022
Regional airport (Norwich)	11	24	52
RAF activity	6	14	30
TOTAL AVIATION	643	1,414	3,104

Again, we take the view that Jacobs estimate is the more conservative than the original, but again recognise that the quantum of demand will be driven by the speed of take-up of these alternative fuels for aviation.

3.5.5.8 Total transport demand

Total transport demand for hydrogen, as determined by Hydrogen East are set out in Table 3-16. It is immediately apparent that this demand is vastly dominated by marine (46% of the total in 2030, rising to 70% in 2050) and aviation (53% in 2030, falling to 25% in 2050), with road and rail contributing only very small amounts to the total.

Further assessment and refinement of the marine and aviation demand is clearly warranted, as these loci could become critical demand hubs for hydrogen production at Bacton.

Table 3-16: Grand total hydrogen transport demand

Demand sector/ year	2030 (GWh/yr)	2040 (GWh/yr)	2050 (GWh/yr)
Cars	35	408	744
LGV	23	251	480
HGV	66	925	3,589
Bus	12	124	256
Other road	3	49	191
Other off-road	12	124	256
Passenger rail	5	11	25
Rail freight	14	27	41
Maritime – Jacobs estimate (Scalar method)	313	1,252	2,504
Aviation – Jacobs estimate	644	1,414	3,104
GRAND TOTAL (GWh/yr)	**1,127**	**4,585**	**11,190**

3.5.6 Demand forecasts

The demand forecasts by sector for 2030, 2040 and 2050 are set out below.

Table 3-17: Power demand forecasts (2030, 2040, 2050)

Year	Hydrogen demand	Comments
2030	1.6 TWh	Based on 30% load factor, 20%$_{vol}$ blend
2040	20.0 TWh	Based on 23% load factor, 100%$_{vol}$ hydrogen
2050	12.0 TWh	Based on 16%$_{vol}$ load factor, 100%$_{vol}$ hydrogen

Table 3-18:Industry demand forecasts (2030, 2040, 2050)

Year	Hydrogen demand	Comments
2030	0.6 TWh	Based on 20%$_{vol}$ blend
2040	4.8 TWh	30% of process heat electrified or no longer needed, combination of 100% hydrogen or 20%vol blend dependent on NTS offtake
2050	6.5 TWh	30% of process heat electrified or no longer needed, 100% hydrogen in study area

Table 3-19: Domestic/commercial demand forecasts (2030, 2040, 2050)

Year	Hydrogen demand	Comments
2030	5.7 TWh	Based on 20%$_{vol}$ blend
2040	28.4 TWh	30% of heat demand met through electrification or energy efficiency, balance supplied by of 100% hydrogen or 20%vol blend dependent on NTS offtake
2050	61.8 TWh	30% of heat demand met through electrification or energy efficiency, balance supplied by 100% hydrogen across study area

Table 3-20: Non-marine, aviation transport demand forecasts (2030, 2040, 2050)

Year	Hydrogen demand
2030	0.2 TWh
2040	1.9 TWh
2050	5.6 TWh

Note: these demand forecasts exclude forecasts for marine and aviation-based demand. These have the potential to be large (see Sections 3.5.5.3 and 3.5.5.5) but are considered to require further analysis before they can be included. Use of hydrogen in marine and aviation requires a number of technical, economic and other challenges to be addressed. These include developing planes and marine engines capable of using hydrogen or ammonia, developing large scale hydrogen to ammonia conversion capacity (if ammonia is the preferred vector) and others.

Table 3-21: Total demand forecast by sector analysis (excluding marine, aviation)

Year	Hydrogen demand	Power (TWh, %)	Industry (TWh, %)	Domestic / commercial (TWh, %)	Transport (TWh, %)
2030	8.1 TWh	1.6 (20%)	0.6 (7%)	5.7 (70%)	0.2 (2%)
2040	55.1 TWh	20.0 (36%)	4.8 (9%)	28.4 (52%)	1.9 (3%)
2050	85.9 TWh	12.0 (14%)	6.5 (8%)	61.8 (72%)	5.6 (7%)

The total CO_2 abated through meeting this demand with hydrogen, rather than through continuing use of natural gas rises from 1.6 Mt/yr in 2030 to 11 Mt/yr in 2040 and 17 Mt/yr in 2050.

3.6 Geographical breakdown of demand

We have analysed demand for each NTS Offtake (or, for large power stations, each direct NTS connection) and present this analysis in Figure 3-3, Figure 3-4 and Figure 3-5 below. The bars on these figures are located at the site of the relevant NTS offtake or NTS-connected power station. Note that these offtakes are where gas enters the Local Distribution Zones from the NTS, and does not therefore correlate exactly with the actual location of sites of demand. Hence the apparent demand at Peters Green in Figure 3-5 in fact describes demand arising in North London.

This demand breakdown relies on the assumptions (detailed above) about the conversion of NTS feeders and GDNs to carrying a blend of hydrogen and natural gas, or (later) 100% hydrogen. Interaction with the infrastructure SIG will be required to test and validate these assumptions.

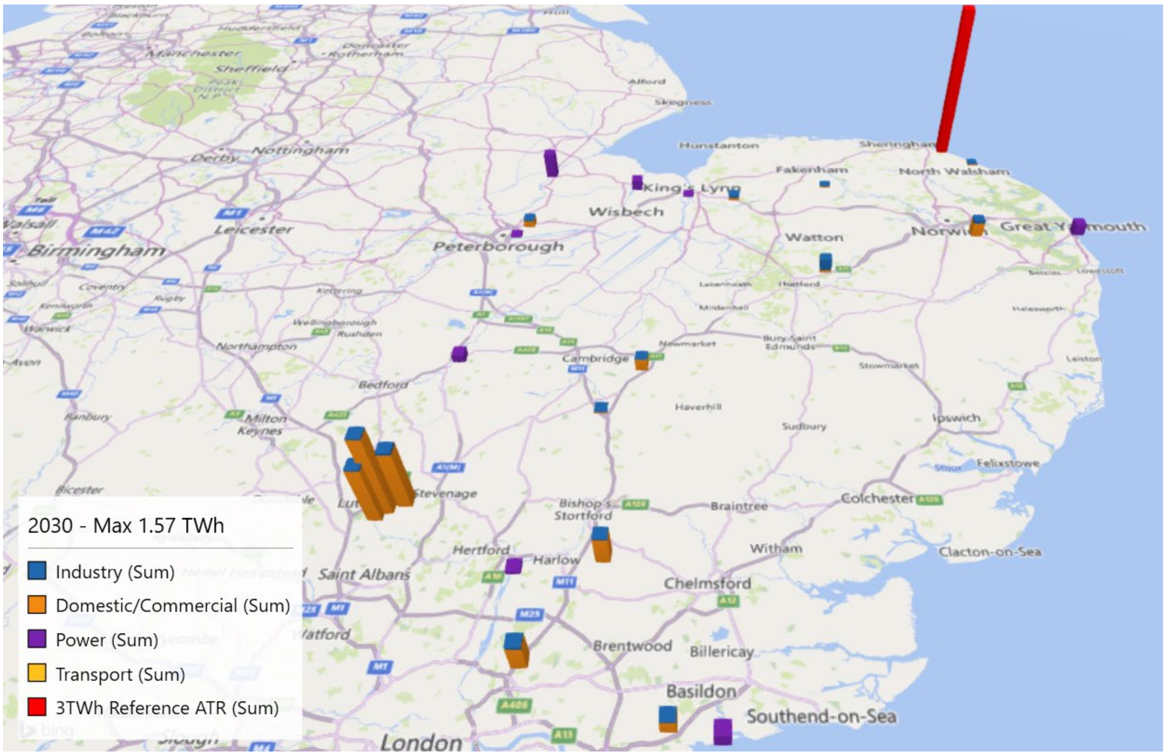

Figure 3-3: 2030 hydrogen demand forecast (max demand 1.57 TWh)

In 2030, it is clear that domestic demand in London and served by the NTS offtakes at Peters Green and Whitwell vastly dominates the near term demand picture. Power demand, particularly at Great Yarmouth and Spalding, contributes considerably to demand.

We note that the reference output of 3 TWh (typical for a single train ATR plant) is large in the context of local demand, but could be substantially absorbed by the demand arising from North London (serviced by the NTS offtakes at Peters Green, Whitwell and Luxborough Lane).

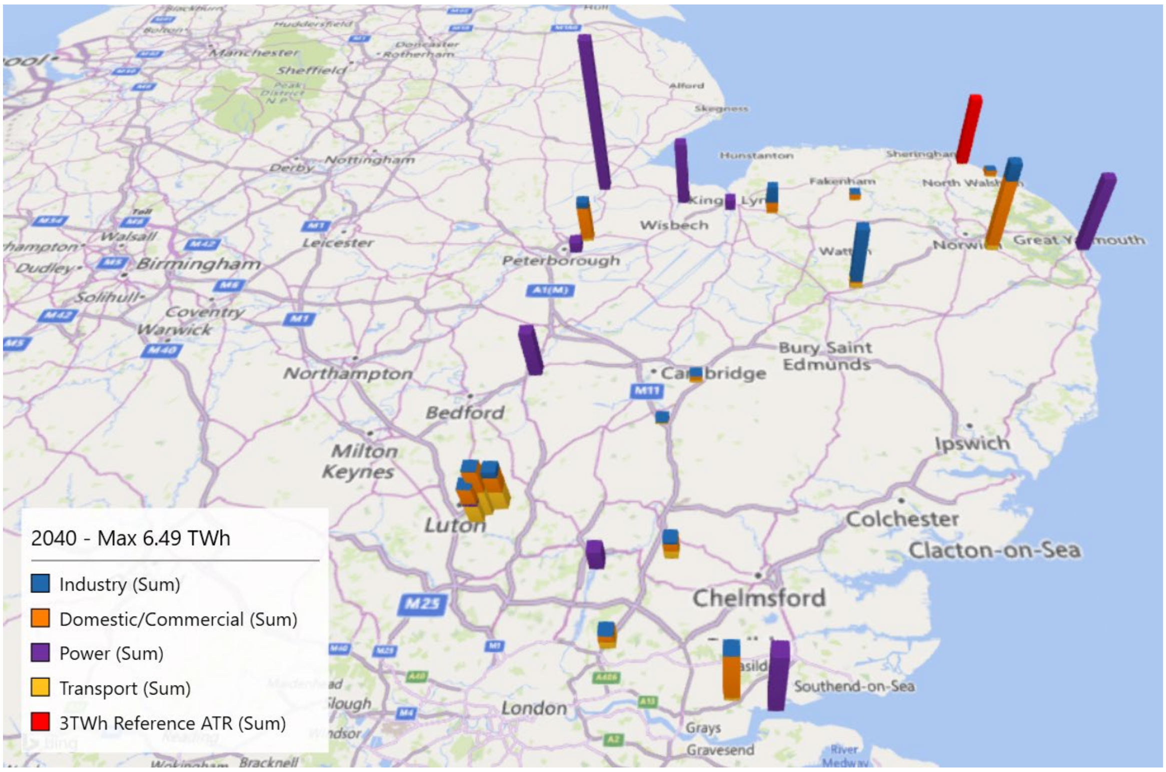

Figure 3-4: 2040 hydrogen demand forecast (max demand 13.4 TWh

In 2040, we have assumed that the feeders to the west and south of Bacton are carrying 100% hydrogen, while London (Peters Green) is still supplied with a blend.

In this case, the conversion of large power stations to 100% hydrogen offers a significant market for Bacton hydrogen. Great Yarmouth alone, even at the lower load factors expected by 2030, could absorb the production of the reference unit.

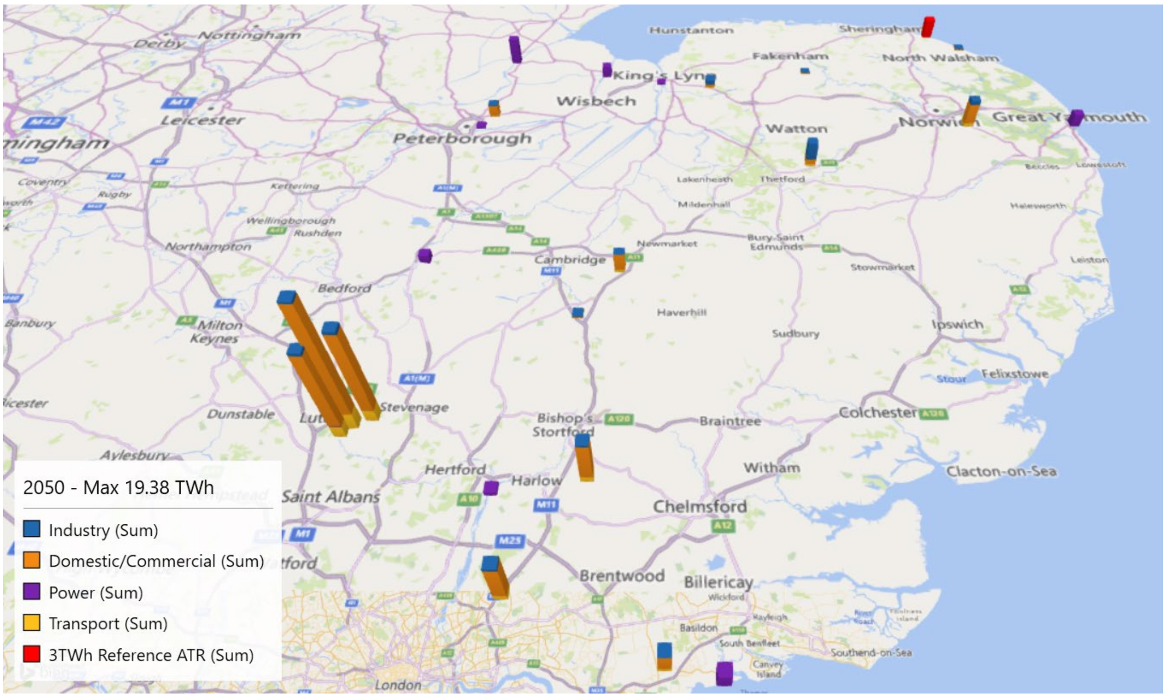

Figure 3-5: 2050 hydrogen demand forecast (max demand 19.4 TWh)

In 2050, domestic demand from London, served by Whitwell and the two Peters Green offtakes strongly dominates the scenario, and easily absorbs the output of the reference plant at Bacton.

4.0 SENSITIVITIES AND FORECAST

The foregoing section details the base or central case demand forecast. We have also developed sensitivities on the upside and downside, as detailed here.

4.1 Key sensitivities

Key sensitivities on hydrogen demand are:

- The rate at which domestic/commercial demand shifts to a blend and then to 100% hydrogen
- The degree to which domestic/commercial heating demand is decarbonised through electrification rather than fuel switching to hydrogen
- The degree to which transport demand is met by hydrogen, rather than battery electric vehicles

4.1.1 Shift to blend and 100% hydrogen

A blend of 20% vol hydrogen in natural gas only contains 86.5% of the energy of the same volume of natural gas. Accordingly, volumes through the network would have to increase by around 15% to maintain energy delivery volumes. We have assumed that such an increase could readily be accommodated by the existing gas networks in the study area. We note that additional compression may be required to increase pipeline pressures to deliver the necessary flow rate of hydrogen, and that this may also necessitate network enhancements, if these higher flow rates start to reach erosional pipeline velocity limits. Clearly, much detailed work will be required to consider the necessary network upgrades.

However, a switch to 100% hydrogen would require a tripling of volumes in both the NTS and LDZs. At this stage, we have assumed that the networks would be capable of carrying these volumes, but recognise that a sensitivity should investigate whether they are, or whether network upgrades might be required.

4.1.2 Decarbonisation approaches to domestic heat

The decarbonisation of domestic/commercial heat is likely to involve both fuel switching of natural gas to hydrogen and the electrification (generally expected to be dominated by the installation of heat pumps).

The baseline demand analysis has assumed that 70% of current domestic gas demand is met with hydrogen (by 2040), while 30% is either electrified or is no longer required due to improvements in energy efficiency. In relation to current electricity demand for heat, we have implicitly assumed that all homes and businesses which currently use electricity for heating continue to do so and that there is no switching from electricity to gas (or hydrogen).

A number of reports have been published addressing the potential for electrification (by heat pump) of the existing housing stock in the UK. The Energy & Utilities Alliance's report[xiii] "Decarbonising heat in buildings" suggests that retrofit of heat pumps may not be a reasonable practicable approach to decarbonising domestic heat in 40-55% of typical housing stock. In contrast, a recent study by the Energy Systems Catapult[xiv] states that "there is no property type or architectural era that is unsuitable for a heat pump", although it does recognise "a greater challenge in successfully designing heat pump systems for older homes…[but] that such challenges are manageable".

There is clearly a range of possible outcomes which should be tested in sensitivity work. In our baseline assumption, it might be argued that we have taken a "pro-gas" stance. We justify this by noting that homes currently heated by gas are already connected to a network which is ideally configured to deliver molecules to homes, and that much of this network is thought to be possibly capable of 100% hydrogen operation.

We note that significant upgrading of either or both of the gas and electrical networks might be required to accommodate either greater gas volumes (from the shift to hydrogen from natural gas) or electricity (from the increased demand).

We also note that electrification of heating creates additional demand for hydrogen, as when the renewables on the system are unable to meet demand, thermal dispatchable power (likely in the form of hydrogen-fired plant) will be required.

4.1.3 Transport

We have used National Grid's Future Energy Scenario assumptions on the growth in hydrogen demand for transport services. These assume that heavy transport (HGVs, trains, buses) shift to hydrogen, while cars, light vans and motorcycles shift to battery electric vehicles. This scenario requires testing.

Additionally, we have identified that a demand for marine fuels (principally at Felixstowe, but also at Great Yarmouth and Ipswich) may emerge as and when marine traffic moves to a hydrogen (or hydrogen-based) fuel model. This too requires testing.

4.1.4 Other markets

We note that other markets for hydrogen may emerge, including the potential for hydrogen export to the Continent through one or both Interconnectors, export potential to other regions of the UK, and use of hydrogen as a feedstock for other products (most obviously ammonia as a transport fuel and chemical feedstock).

In this review, we have not attempted to estimate the possible scale of these other markets.

4.2 High hydrogen sensitivity

In the high hydrogen use case sensitivity, we assume that the transition to 100% hydrogen in the system is complete by 2040

4.2.1 Power

The high hydrogen case assumes that thermal load factors are slightly higher than in the central case, as the roll out of nuclear is assumed to be delayed relative to the core assumptions. This case assumes 3 GW of installed nuclear is available in 2040 and 5 GW is available in 2050.

As a result, 2040 thermal load factors are increased from 23% to 30%, and 2050 load factors from 16% to 21%.

4.2.2 Industry

The high hydrogen use case for industry assumes full availability of 100% hydrogen from 2040, and that demand reduction from electrification or energy efficiency only reduces demand by 10%.

4.2.3 Commercial/Domestic

The high hydrogen use case for commercial/domestic also assumes that only 10% of demand falls away through efficiency and electrification, rather than the 30% reduction in the central case.

4.3 Low hydrogen sensitivity

The low hydrogen use sensitivities are based on the assumption that all pipeline networks are currently operating at full capacity and are subject to maximum flow rate constraints. The maximum supply of hydrogen under the same velocity constraints would be around one third of current supply due to energy density differences.

This implicitly assumes that all of difference is taken on by electrification (and that costs of upgrading electricity network) are cheaper than upgrades to gas network.

4.3.1 Power

In the low hydrogen case, the effect of greater electrification of heat adds to load factors for power stations and hence hydrogen demand in this sector. This demand is more than offset by reductions in hydrogen demand for heating by commercial/domestic customers.

We have modelled this, and find that 2040 thermal load factors are increased from 25% to 30% (assuming 30% of heat demand is electrified), and 2050 load factors from 16% to 23% (assuming that 50% of heat demand is electrified).

We have also assumed that gas supply in 2040 is a mix of 20%$_{vol}$ blend of hydrogen in natural gas in the NTS feeders which run southwest from Bacton towards London, and 100% hydrogen in the NTS feeders running south and west from Bacton to more industrial demand site. 2050 we have assumed that the system has switched to 100% hydrogen across the whole study area.

4.3.2 Industry

For industry, we have adopted the same assumption as for power: that gas supply in 2040 is a 20%$_{vol}$ blend of hydrogen in natural gas across the study area, whilst in 2050 it has switched to 100% hydrogen.

In the low hydrogen use case, we further assume for 2040 that a 50% reduction in demand has been achieved through electrification.

In 2050, we assume that a 70% reduction in demand has been achieved through electrification, with the remaining 30% approaching operational (flow rate) limits in the gas system.

4.3.3 Commercial/Domestic

In the case of commercial/domestic demand, we have assumed the same gas supply mix as above, with a 20%$_{vol}$ blend available in 2040 and 100% hydrogen in 2050.

We have assumed that in 2040, 50% of demand has been electrified (or removed through energy efficiency), and in 2050, 70% of demand has been electrified, allowing the existing gas system to operate within existing flow rate constraints.

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[xii] "Hydrogen-powered aviation – A fact-based study of hydrogen technology, economics and climate impact by 2050", May 2020, McKinsey for CleanSky2. Available at https://www.fch.europa.eu/sites/default/files/FCH%20Docs/20200507_Hydrogen%20Powered%20Aviation%20report_FINAL%20web%20%28ID%208706035%29.pdf

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[xiv] See https://es.catapult.org.uk/news/electrification-of-heat-trial-finds-heat-pumps-suitable-for-all-housing-types/