frontier economics

HYDROGEN OPTIONS FOR NORTHERN IRELAND

A report for NIE

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CONTENTS

1 INTRODUCTION

The ongoing transformation of the energy system is inducing large changes in the way electricity is generated, transported and used. With the Government's Net Zero greenhouse gas emissions by 2050 target now enshrined in law via the Climate Change Act, it is likely that the pace of change will accelerate further.

In Northern Ireland, the Department for the Economy (DfE) opened a consultation on the new Energy Strategy for Northern Ireland in March 2021[1]. The Energy Strategy will set Northern Ireland on a path to deliver on its commitments as part of the UK's Net Zero commitment, with a focus on:

- improved energy efficiency; and
- replacing fossil fuels with indigenous renewable energy sources.

There is significant debate over the mix of renewables that will be used to replace fossil fuels. In particular, while there is a clear role for electrification, it is unclear in the DfE's consultation the full extent of that role. There is also uncertainty as to the role of low carbon hydrogen, both in terms of sources of production, but also demand uptake across the various sectors.

To help address this uncertainty, this report provides an overview of the options for hydrogen in Northern Ireland. We consider two broad time frames: the near term (up to 2030), and the long term (up to 2050).

We set out our analysis in the following sections:

- Section 2 describes the opportunities for production and storage of low carbon hydrogen;
- Section 3 sets out the potential for low carbon hydrogen demand across key sectors; and
- Section 4 presents our conclusions.

Further details and background analysis are presented in an accompanying Annex.

[1] DFE (2021), *Energy Strategy for Northern Ireland*, https://consultations.nidirect.gov.uk/dfe/energy-strategy-for-northern-ireland-consultation-1/supporting_documents/energystrategyforNIconsultationonpolicyoptions.pdf

2 KEY FINDINGS: SUPPLY OF LOW CARBON HYDROGEN

The potential scale, location and reliability of the supply of low carbon hydrogen will help determine how it can be used in Northern Ireland. Therefore, before exploring how low carbon hydrogen can be used to abate carbon emissions on a path to Net Zero, we first describe potential options for production and storage.

2.1 Domestic production

The main domestic low-carbon hydrogen production options are:

- **Green hydrogen.** Green hydrogen is produced from electrolysis from renewable electricity. Dedicated renewable investment can be made for the purpose of producing low carbon hydrogen, or low carbon hydrogen can be produced via curtailed wind.
- **Blue hydrogen.** Blue hydrogen is produced by methane reformation with CCUS, either via steam methane reformation (SMR) or autothermal reformation (ATR). SMR is a more mature technology than ATR, but the capture rate of emissions is generally lower.
- **BECCS.** It is also possible to use biomass gasification with CCUS (BECCS) to produce hydrogen and negative emissions.

Of these, green hydrogen appears to be the most likely option for hydrogen production in Northern Ireland.

- Northern Ireland already has high levels of renewable electricity generation, and strong renewable investment is expected to continue, which makes it well suited to green hydrogen production.
- In the near term, blue hydrogen production with CCUS is unlikely to be feasible in Northern Ireland due to a lack of carbon storage options under development (Box 1). In the longer term, once the relevant receiving infrastructure is in place, shipping carbon to nearby offshore storage sites in Great Britain or elsewhere could be possible. However, blue hydrogen produces residual carbon emissions and therefore may not be compatible with 2050 UK climate goals. In addition, since blue hydrogen would rely on imported methane, it would also not be consistent with the Energy Strategy priority of replacing fossil fuels with indigenous renewables[2].
- CCUS availability will also limit the potential for BECCS in Northern Ireland in the near term. In the longer term, the emissions could be shipped. However, BECCS entails a higher rate of capture per unit of hydrogen produced than blue hydrogen. Therefore the impact of additional costs associated with shipping will be higher.

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[2] DFE (2021), *Energy Strategy for Northern Ireland*, https://consultations.nidirect.gov.uk/dfe/energy-strategy-for-northern-ireland-consultation-1/supporting_documents/energystrategyforNIconsultationonpolicyoptions.pdf

BOX 1: POTENTIAL FOR CCUS IN NORTHERN IRELAND

There are potential CO_2 storage sites at Raithlin, Portpatrick/Larne and Peel basins on the east coast of Northern Ireland, and at Lough Neagh. However, these sites are not being developed at present[3].

It may be possible to ship carbon to UK carbon storage sites in the long run. Shipping costs would include investments in liquefaction facilities, buffer storage and loading infrastructure, as well as the capital and operating costs associated with the shipping itself.

Additional costs of shipping could be relatively modest in the long run. For example, the CCC estimate the additional costs of shipping CO_2 at around £10-20/tCO_2[4]. Element Energy analysis for BEIS suggest costs of shipping port to port could be as low as £10/ tCO_2 in their central scenario[5].

Taking into account the carbon intensity of production, these shipping costs could add around £6-£9/MWh to the cost of blue hydrogen production in Northern Ireland once the infrastructure to enable this is in place[6].

We note that DFE assumes a large role for hydrogen production using SMR with CCUS (Figure 1). This would imply:

- development of CO_2 storage or shipping facilities;
- negative emissions generated elsewhere in the UK economy[7], to offset the residual emissions; and
- a continued reliance on imported natural gas. For example, 4TWh of SMR production (DFE high gasification scenario) would require around 6TWh of natural gas each year[8].

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3 Lewis et al. (2009). Assessment of the potential for geological storage of carbon dioxide in Ireland and Northern Ireland. Energy Procedia, 1(1), 2655-2662

4 CCC (2020), *Letter from Lord Deben Climate Change Committee to Edwin Poots MLA*, https://www.theccc.org.uk/publication/letter-lord-deben-climate-change-committee-to-edwin-poots-mla

5 Element Energy (2018), *Shipping CO_2 – UK Cost Estimation*, Studyhttps://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/761762/BEIS_Shipping_CO2.pdf

6 Based on an assumed CO2 capture rate of 90-94% efficiency for SMR or ATR production plants.

7 Northern Ireland contributes to the UK Net Zero target under the Climate Act 2008, but it does not have a specific climate target in legislation. Northern Ireland Assembly (2021), *Northern Ireland and Net Zero*, http://www.niassembly.gov.uk/globalassets/documents/raise/publications/2017-2022/2021/aera/1421.pdf

8 We assume that natural gas can be converted to low carbon hydrogen in the SMR process at a rate of 1. 1.355 kWh of methane per kWh of hydrogen. This estimate is based on the assumptions on the efficiency of conversion of natural gas to hydrogen from Element Energy (2018) *Hydrogen Supply Chain Evidence*, https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/760479/H2_supply_chain_evidence_-_publication_version.pdf

Figure 1 DfE's 2050 projections of hydrogen production in Northern Ireland

	Diverse		High gasification		High electrification	
	TWh	Proportion of total	TWh	Proportion of total	TWh	Proportion of total
SMR + CCUS	3.01	53%	3.98	54%	1.45	51%
Biomass gasification + CCUS	1.21	21%	1.61	22%	0.58	20%
Green hydrogen	0.76	13%	0.83	11%	0.44	16%
Power-to-gas	0.74	13%	0.98	13%	0.36	13%
Total	5.72		7.41		2.83	

Source: DfE Energy Transition Model

2.1.1 Green hydrogen production options

Curtailed wind

Low carbon hydrogen could be produced from curtailed wind. This has the advantage of making the most of existing renewables electricity capacity. However, the quantity of curtailed wind is uncertain.

To give an indication of the scale of low carbon hydrogen that could be produced from curtailment, we estimate the quantity of hydrogen that would be produced with a curtailment rate of 10%-20%[9,10]. Based on this, we estimate that hydrogen produced from curtailed wind could meet up to 223-502 GWh of low carbon hydrogen demand in 2030 and 489-1,100 GWh of low carbon hydrogen demand in 2050. This would equate to between 9-24% of the total low carbon hydrogen projected to be produced in Northern Ireland in 2050 by DFE and the CCC. This is similar to the proportion of green hydrogen in the DFE scenarios (Figure 1).

New dedicated renewables

Investment in new dedicated renewables for electrolysis could also allow low carbon hydrogen to be produced.

This would require a significant increase in installed capacity over and above what is required to meet targets associated with decarbonisation of electricity. The

[9] At present, combined curtailment and constraints result in curtailment of about 15%. https://www.eirgridgroup.com/site-files/library/EirGrid/2020-Qtrly-Wind-Dispatch-Down-Report.pdf; http://www.eirgridgroup.com/site-files/library/EirGrid/Annual-Renewable-Constraint-and-Curtailment-Report-2018-V1.0.pdf

[10] There is a wide range of estimates for the proportion of wind that might be curtailed in high renewable systems. Analysis for SEM is available here : David Newberry (2020), *Implications of the National Energy and Climate Plans for the Single Electricity Market of the Island of Ireland*, https://www.econ.cam.ac.uk/research-files/repec/cam/pdf/cwpe2072.pdf; Analysis for the UK is available here: CCC (2019), Integrating variable renewables into the electricity system, https://www.theccc.org.uk/wp-content/uploads/2019/05/Net-Zero-Technical-Annex-Integrating-variable-renewables.pdf ; NIC (2020), Net Zero Opportunities for the power sector, https://nic.org.uk/app/uploads/Net-Zero-6-March-2020.pdf; BEIS (2020), Modelling 2050: Electricity System Analysis, https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/943714/Modelling-2050-Electricity-System-Analysis.pdf

potential required wind capacity associated with both DFE and CCC scenarios for low carbon hydrogen demand in Northern Ireland is set out in Figure 2[11].

Figure 2 Required wind production capacities to meet low carbon hydrogen demand in Northern Ireland

		2030			2050				
		H2 demand (GWh)	Required wind for H2 demand (MW)*	Increase on 2019 wind capacity of 1.4GW (%)	H2 demand (GWh)	Required wind for H2 demand (MW)*	Increase on 2019 wind capacity of 1.4GW (%)	Total wind required for H2 and electricity demand (MW)	Increase on 2019 wind capacity of 1.4GW (%)
CCC (2020)	Balanced	228	113	8%	4,513	2,236	154%	5,181	357%
	Headwinds	274	136	9%	6,646	3,292	227%	6,237	429%
	Tailwinds	153	76	5%	3,537	1,752	121%	4,697	323%
	Engagement	26	13	1%	2,650	1,313	90%	4,258	293%
	Innovation	39	19	1%	3,363	1,666	115%	4,611	317%
DfE (2020)	Diverse	1,342	665	46%	5,200	2,531	174%	5,476	377%
	Electrification	734	364	25%	2,862	1,395	96%	4,340	299%
	Gasification	2,065	1,024	70%	6,815	3,318	228%	6,263	431%
Range		**0 – 2 TWh**	**0 – 1 GW**	**1% - 70%**	**2.6 – 6.8TWh**	**1.3 – 3.1 GW**	**90% - 228%**	**4.6 – 6.3 GW**	**293%-431%**

Source: *Frontier Economics*

Note: *These estimates are based on electrolysis efficiency of 74% (CCC, 2018) and load factor for onshore and offshore wind of 31.14% (BEIS, DUKES 2020). Note that this assumes no supply from curtailed wind.*

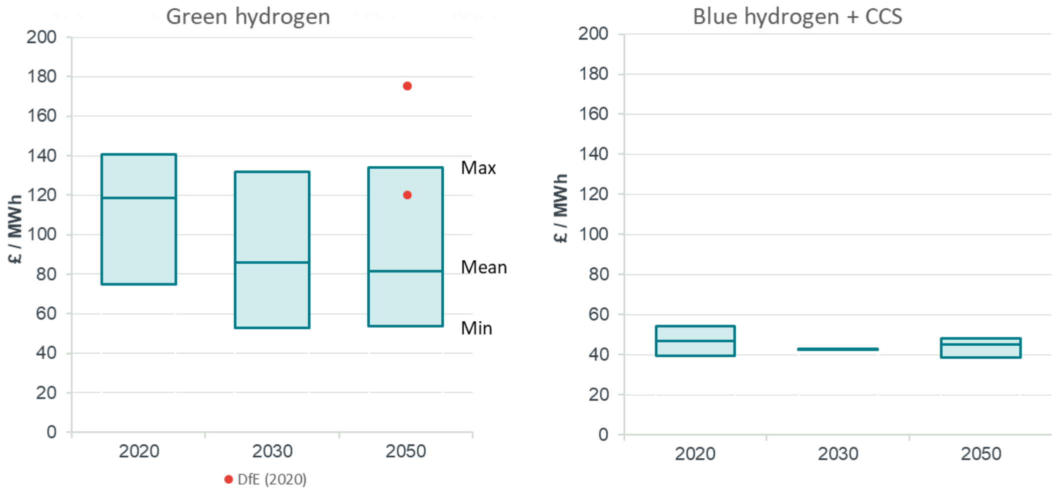
2.1.2 Relative costs of domestic production options

To compare the costs of different hydrogen production options, we gathered estimates of hydrogen production costs from various sources[12]. Figure 3 shows summary statistics (minimum, mean and maximum) of these estimates for green hydrogen across 2020, 2030 and 2050.

[11] The efficiency of electrolysis from wind is assumed to be 74%, based on CCC (2018) Hydrogen in a Low carbon economy, https://www.theccc.org.uk/publication/hydrogen-in-a-low-carbon-economy . Other inputs come from BEIS (2020) *Digest of UK Energy Statistics*, https://www.gov.uk/government/statistics/digest-of-uk-energy-statistics-dukes-2020

[12] See Annex for further details of cost sources including CCC (2020), CERRE (2019), Hydrogen Council (2020), IRENA (2020), IEA (2019), and Element Energy (2019)

Figure 3 Low carbon hydrogen production costs based on literature review



Source: Frontier Economics meta-analysis of published studies, see accompanying annex pack for details

While cost projections are inherently uncertain, Figure 3 illustrates that:

- On average, production costs of green hydrogen are expected to decline by 33% in the 2020-30 period, from £120/MWh in 2020 to £80/MWh in 2030.
- Blue hydrogen may be significantly less costly over the entire period. This is likely to hold, even when CO_2 shipping and carbon price costs are included[13].
- DfE’s 2050 estimates of production costs of green hydrogen are substantially higher than other forecasts. This is partly because the modelling assumes that electrolysis uses solar at a relatively low load factor. Given Northern Ireland’s resources, it may be more cost-effective to rely on wind generation for electrolysis.

It is worth noting that biomethane could also play a role alongside low carbon hydrogen. The CCC cites research that estimates that up to 2 TWh of electrical or heat energy could be provided from organic waste, manure and silage, depending on how easy it is to access this waste[14]. To put this in context, total demand for low carbon hydrogen in the CCC’s main Balanced Pathway scenario is 4.5 TWh (see Figure 2 above).

2.2 Networks

It is likely that the existing Northern Irish gas distribution grids, which are relatively modern and built using primarily polyethelene pipe, can carry hydrogen with relatively small adaptation costs. The situation is less clear at transmission level

13 Further details are included in the Annex pack.

14 *NI Biogas Research Action Plan 2020*, https://www.researchgate.net/publication/304039671_Biogas_Research_Action_Plan_for_Northern_Ireland/link/5764546708ae1658e2ede9ea/download, cited in CCC (2019), Reducing emissions in Northern Ireland, https://www.theccc.org.uk/publication/reducing-emissions-in-northern-ireland/

(where significant research is ongoing in GB)[15]. Further understanding of this issue in the Northern Irish context would be valuable.

2.3 Storage

Hydrogen production capacity will need to be supplemented by hydrogen storage, depending on the uses to which the gas is put:

- to smooth out short-term (e.g. within-day) production and demand fluctuations;
- to meet the supply resilience needs of customers (for example industrial customers, who cannot easily stop and start processes); and
- to ensure that the system can meet seasonal swings in heating and electricity demand.

Linepack

Linepack is likely to be a source of short term storage. The volume of linepack in Northern Ireland will depend on the extent of hydrogen network conversion or development (at the transmission and distribution level). To give a sense of scale, at UK level, the within day flexibility provided by linepack is greater than the within-day flexibility provided by pumped storage power stations by a factor of 20[16].

Supply resilience

Additional storage may be required on customer or producer sites to ensure supply resilience. This could include storage of hydrogen in pressurised tanks, storage of hydrogen in liquid form as ammonia, methanol or Liquid Organic Hydrogen Carriers[17].

Seasonal storage

To manage seasonal swings in heating and electricity demand, salt caverns offer a promising option. Northern Ireland may have strong potential in this area at Islandmagee near Larne. This site is capable of storing approximately 1,173 GWh, and of delivering 61GWh/day of hydrogen (DfE's data suggest only 570 GWh of hydrogen demand being supplied from storage in 2050 in the Diverse scenario, well below Larne's capacity)[18].

15 For example, National Grid's FutureGrid project: https://www.nationalgrid.com/uk/gas-transmission/insight-and-innovation/transmission-innovation/futuregrid

16 UKERC (2019), *Flexibility in Great Britain's gas networks: analysis of linepack and linepack flexibility using hourly data*, https://d2e1qxpsswcpgz.cloudfront.net/uploads/2020/03/ukerc_bn_linepack_flexibility.pdf

17 CCC (2018) *Hydrogen in a low carbon economy*, https://www.theccc.org.uk/publication/hydrogen-in-a-low-carbon-economy/

18 ENTSOG (2020) *Ten year development plan* (p. 768), https://www.entsog.eu/sites/default/files/2020-11/ENTSOG_TYNDP_2020_Annex_A_Projects_Details.pdf . The ENTSOG study presents an estimated working volume 420mcm. We have converted this to GWh by assuming the 420mcm refers to standard cubic meters of gas (1atm, temperature of 15^{O}C).

- DfE estimates that maximum daily demand for hydrogen or heating in 2050 is 20.4 GWh or 46.5 GWh respectively in the Diverse scenario. These are below Larne's maximum withdrawal rate of 61 GWh[19].
- A cold, low wind spell could also be covered by the potential storage site at Larne. If no hydrogen were to be produced for two weeks in January 2050, an additional 458 GWh of hydrogen would be required from storage to supply residential and non-residential demand for heating. This can comfortably be stored in Larne in addition to the base annual requirement.

Blending as a near term measure

In the near term, as the market develops and before significant storage is in place, blending low carbon hydrogen with methane could also help producers manage uncertainties and fluctuations in demand.

- It is estimated that around 20% of hydrogen (by volume) could potentially be blended into the gas grid, without the need to make adjustments to the gas network infrastructure or swapping out household-level appliances.
- Since hydrogen is less energy dense than natural gas, even if the hydrogen is zero carbon, carbon savings will be limited to around 7%.
- This may be helpful in the near term, but would not be consistent with Net Zero in the long term.

2.4 Imports

As an alternative to investing in domestic production capacity, low carbon hydrogen could be imported. Although this would not be compatible with the DfE's Energy Strategy principle of replacing fossil fuels with indigenous renewables, it could provide a useful complement to domestic production and storage. This is a strategy being followed by several European jurisdictions[20]. A key enabler for international imports will be the development of an international system for accrediting low carbon hydrogen. Technological progress around hydrogen carriers and conversions will also be required for imports to be able to compete on costs.

- **Near term.** While there is currently no international liquid market for low-carbon hydrogen, by 2030, there may be some access to imports from locations such as Australia, Chile and the Middle East[21]. However, this will depend on both technological progress and international standardisation.
- **Long term.** In the longer term, international imports of green hydrogen could be an attractive low-cost option if demand for hydrogen in Northern Ireland increases. Alternatively, imports from GB may be possible where transportation costs will be lower (for example via the SNIP).

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[19] DFE (2021), *Northern Ireland Energy Strategy, 2050*, https://www.economy-ni.gov.uk/articles/northern-ireland-energy-strategy-2050

[20] For example: 2x40 GW Green Hydrogen Initiative, https://www.hydrogen4climateaction.eu/2x40gw-initiative

[21] Hydrogen Council (2021), *Hydrogen Insights*, https://hydrogencouncil.com/wp-content/uploads/2021/02/Hydrogen-Insights-2021.pdf

2.5 Conclusions

Conclusions on hydrogen supply are set out in Figure 4.

Figure 4 Conclusions on hydrogen production

	Long term potential: Feasibility	Long term potential: Cost competitiveness in a Net Zero scenario	Long term potential: Key facilitators	Near term priorities
Green hydrogen production	▪ Significant wind energy opportunities in Northern Ireland to facilitate green hydrogen production. Over 2GW of additional wind would potentially be required by 2050. ▪ Curtailed wind alone is unlikely to be sufficient.	▪ Green hydrogen is likely to be more costly than blue hydrogen, even including shipping costs and a carbon price.	▪ Policy support for green hydrogen will be required.	▪ Demonstration of green hydrogen production.
Blue hydrogen production	▪ No carbon capture and storage sites are currently under development in Northern Ireland. However, in the longer term it may be possible to ship captured carbon at a cost of £10-20 tCO_2.	▪ Blue hydrogen is likely to be cost-competitive in the early years, but its long term compatibility with Net Zero is less clear.	▪ Policy support for blue hydrogen will be required. ▪ Development of infrastructure for shipping CO_2 will be required.	▪ Action will depend on learning from FOAK plant deployment in the Scotland and England and cost/time to develop shipping infrastructure.
Storage	▪ Northern Ireland has significant potential for long term storage at Larne.	▪ Long term storage will enable the use of low carbon hydrogen, particularly in power and heating.	▪ Progress on the development of Larne Storage.	▪ Further development work on the potential for H_2 storage at Larne.
Networks	▪ Conversion of gas networks to hydrogen is likely to be feasible. There is more uncertainty over transmission.	▪ Transporting hydrogen via existing or new pipelines may be competitive, depending on demand patterns.	▪ Development of regulatory frameworks.	▪ Further investigation into the feasibility of gas transmission conversions in the Northern Ireland context.
Imports	▪ Imports may be a useful and cost-effective backstop.	▪ Imports are likely to be competitive with domestic production.	▪ Import infrastructure. ▪ International agreements to accredit low carbon hydrogen.	▪ Support international agreements to accredit low carbon hydrogen.

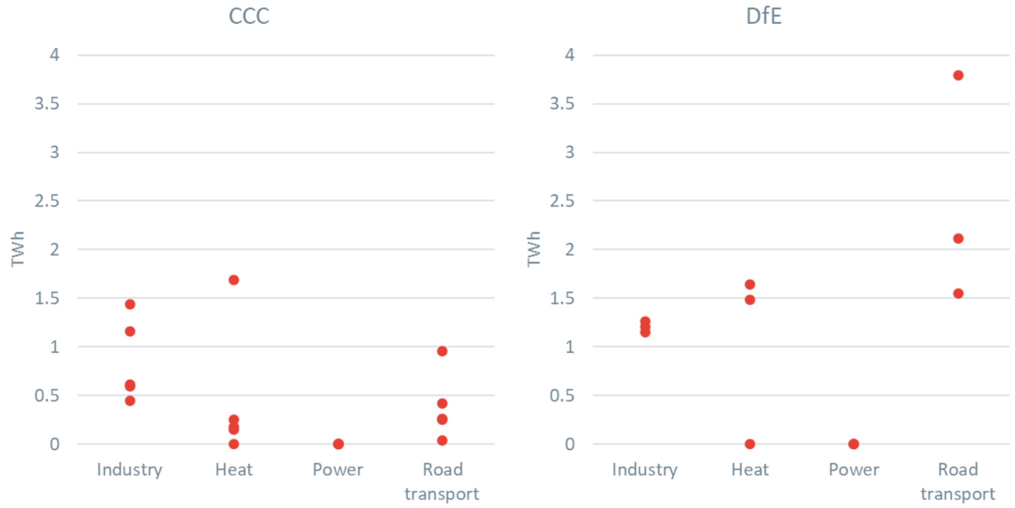
Source: Frontier Economics

3 KEY FINDINGS: DEMAND FOR LOW CARBON HYDROGEN

This section assesses the potential and likely cost-effectiveness of low carbon hydrogen as a Net Zero abatement option in Northern Ireland.

Figure 5 sets out the DFE and CCC scenarios. These illustrate that there is a relatively large variation in projected low carbon hydrogen demand, particularly in the heat and transport sectors. There may be other hard-to-decarbonise sectors where hydrogen is useful in the longer term (e.g. shipping and aviation), but these are not considered by the DfE analysis.

Figure 5 Overview of demand by sector in CCC and DFE analysis



Source: DfE Energy Strategy modelling and CCC Sixth Carbon Budget (2020)

To understand the drivers of this variation, and what it might imply for near term priorities, we now look into each sector in more detail. For each sector, we consider:

- long term demand scenarios;
- near term implications; and
- cost-effectiveness.

3.1 Road transport

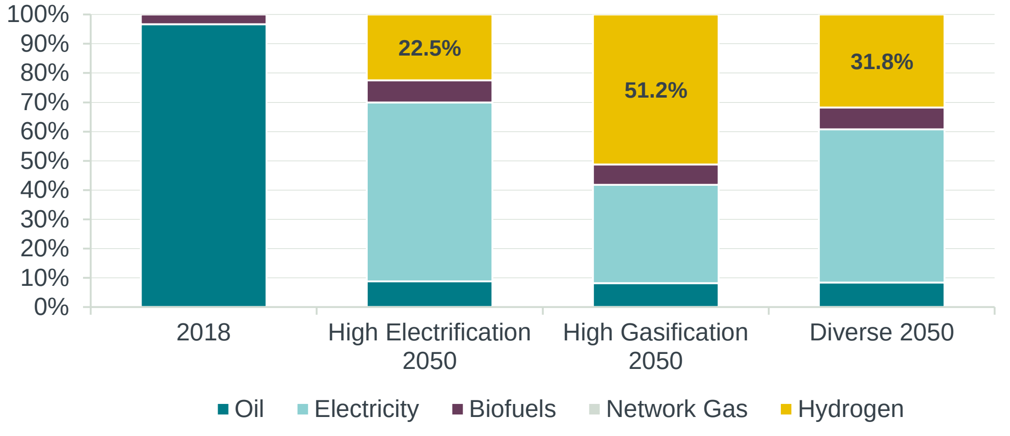
Fuel cell vehicles (FCEVs) using low carbon hydrogen have the potential to replace petrol and diesel heavy vehicles.

Low carbon hydrogen is widely considered to be a useful decarbonisation option for heavy duty transport because there are few alternative options.[22,23,24] While electrification is possible, HGVs and long distance buses are difficult to electrify due to their heavy weight and long journey distances.

3.1.1 Long term demand scenarios

DfE's modelling suggests that approximately 22-50% of transport final demand could be provided by hydrogen by 2050 in Northern Ireland. This equates to between 1,550 and 3,800 GWh of hydrogen in 2050.

Figure 6 Low carbon hydrogen demand in transport in Northern Ireland, 2050



Source: Frontier Economics based on DfE modelling

DfE assumes a role for hydrogen in passenger car transport that is higher than many other European-level studies [25,26] with 32% of fuel use for cars being met by low carbon hydrogen in 2050 in the gasification scenario (Figure 7) and as much as 26%, even in the Diverse scenario. Generally, low carbon hydrogen is not thought to be an option at scale for passenger vehicles because:

- electrification of passenger vehicles is progressing rapidly, and has the potential to be a cost-effective and practical option; and
- the refuelling infrastructure required for cars is likely to be more dispersed than that for HGVs and buses. This could add substantial costs to a low carbon hydrogen vehicle scenario, particularly in a world where utilisation of the

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22 CCC (2020), *Sixth Carbon Budget* includes scenarios with up to around 80% of HGV as FCEV in 2035 in their most ambitious hydrogen scenario

23 EC (2020) estimates that around 25% of HGVs and 20% of LGV will be FCEV in 2050 (https://eur-lex.europa.eu/legal-content/en/TXT/?uri=CELEX:52020DC0562)

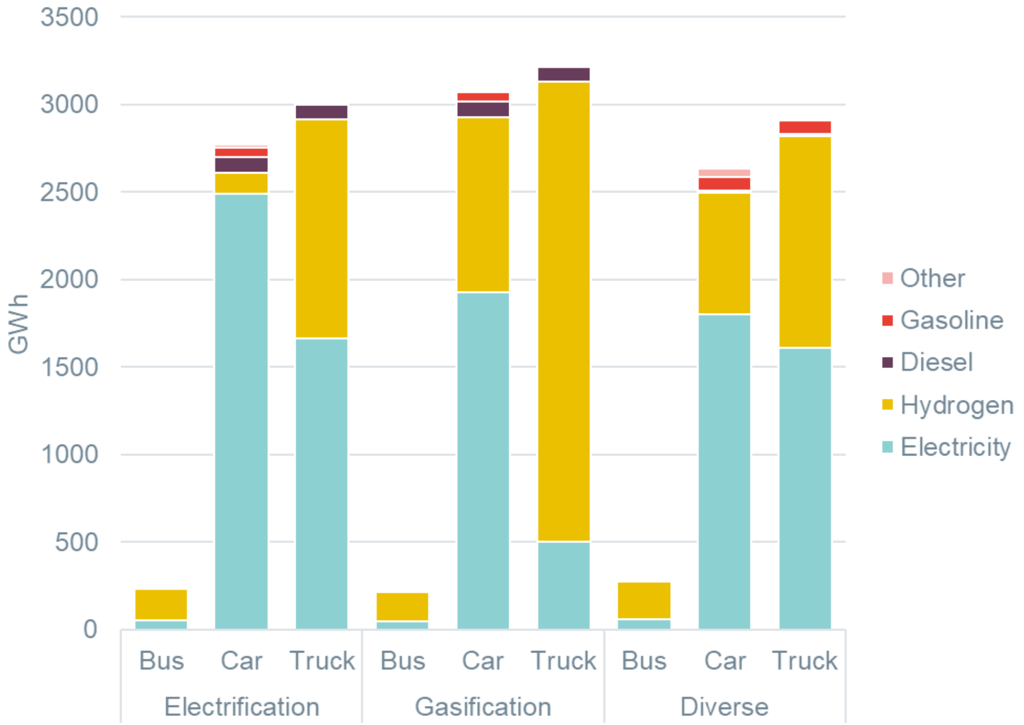
24 Navigant (2019) estimates up to 50% of HGV and 10% of LGV will be FCEV in 2050 (https://gasforclimate2050.eu/wp-content/uploads/2020/03/Navigant-Gas-for-Climate-The-optimal-role-for-gas-in-a-net-zero-emissions-energy-system-March-2019.pdf)

25 EC (2020) estimates that between 5-15% of passenger cars could be FCEV in 2050, but none in 2030 (https://eur-lex.europa.eu/legal-content/en/TXT/?uri=CELEX:52020DC0562)

26 Navigant (2019) estimates that a maximum of 5% of passenger cars will be FCEV (https://gasforclimate2050.eu/wp-content/uploads/2020/03/Navigant-Gas-for-Climate-The-optimal-role-for-gas-in-a-net-zero-emissions-energy-system-March-2019.pdf)

hydrogen refuelling infrastructure is quite low, because many users have chosen electrification.

Figure 7 DFE scenarios for fuel use by vehicle type in Northern Ireland in 2050

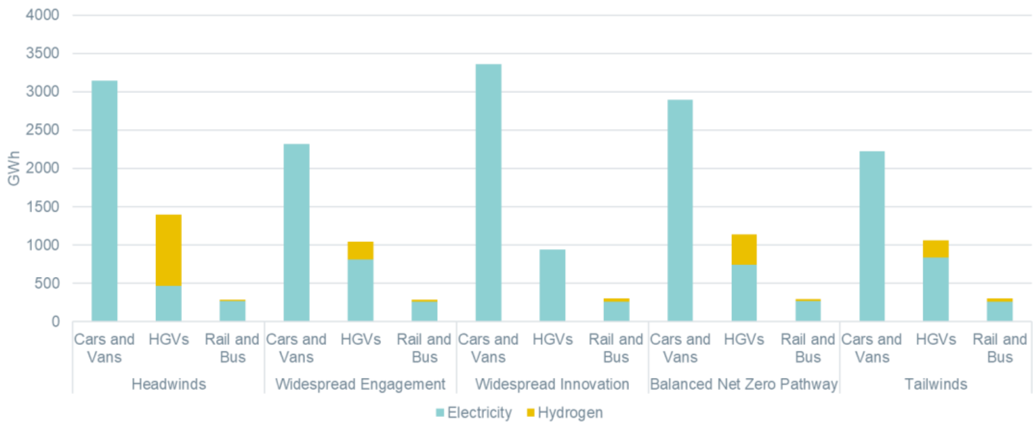


Source: Frontier Economics based on DfE modelling

Note: DfE does not provide a definition of vehicle types that are included in 'Car' and 'Truck', for example whether LCVs are grouped with cars or trucks.

In contrast to the DfE modelling, the CCC scenarios for Northern Ireland show a significantly smaller role for hydrogen in HGVs, and no hydrogen deployment for passenger cars and vans (Figure 8).

Figure 8 CCC scenarios for fuel use by vehicle type in Northern Ireland in 2050



Source: Frontier Economics based on CCC Sixth Carbon Budget (2020)

Note: The CCC also expects a minor amount of petroleum demand from surface transport in 2050 (not included in this chart). It also expects up to an additional 2TWh of hydrogen demand from shipping.

3.1.2 Near term potential

While low carbon hydrogen is likely to be important for heavy transport in the long run, FCEVs are expensive and not widely commercially available today. In addition, there is no refuelling network to support vehicle take-up.

Therefore, in the 2020s, take-up is more likely to be from public transport, not least because this can rely on centralised urban depot refuelling (with some localised storage) and may be able to access public funding for early demonstration projects. For example, the Translink/Wrightbus/Energia project is trialling hydrogen buses in Belfast[27].

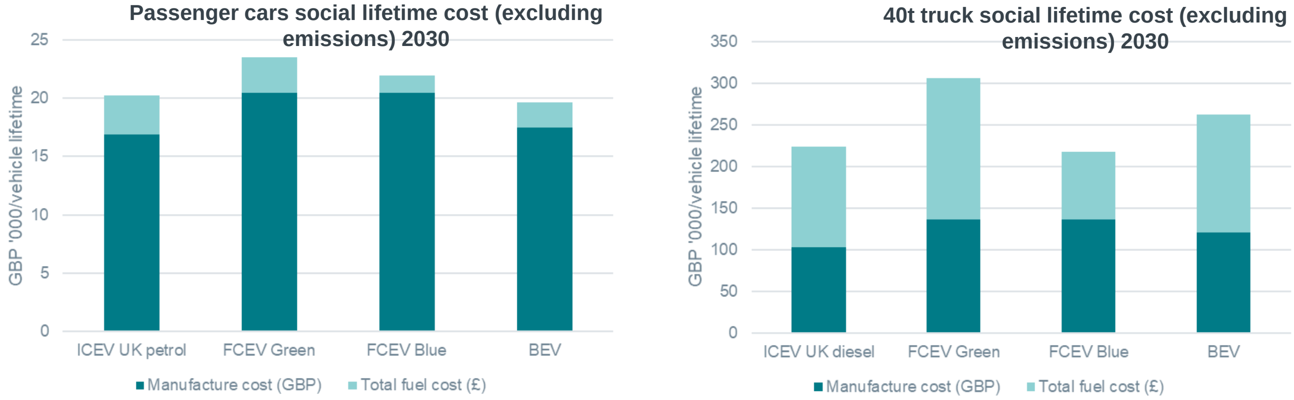
In addition, some consumer-focused brands may convert their HGV fleets to FCEV if they are able to charge a 'green premium' for this.

3.1.3 Relative costs of abatement options

The relative costs of low carbon vehicles including manufacture and fuel costs are illustrated in Figure 9. While there is a high degree of uncertainty around the costs of future options, this illustrates that:

- hydrogen is less likely to be a cost-effective abatement option for passenger vehicles (which can be more easily electrified); and
- for heavy goods vehicles, while they are currently very expensive, hydrogen FCEVs are likely to be cost-effective on a path to 2050.

Figure 9 Relative costs for different transport options in 2030



Source: Frontier Economics based on published studies, see accompanying annex pack for details. Note: the cost of air quality and carbon emissions are not included in this chart.

[27] Tramslink/Wrightbus/Energia launched three hydrogen fuel cell double decker buses in 2020 funded by the NI Department for Infrastructure and OZEV. They are powered by green hydrogen produced by an on-shore North Antrim windfarm. The overall capital investment is around £4 million. https://www.translink.co.uk/corporate/media/pressnews/hydrogenbus, https://www.translink.co.uk/corporate/media/pressnews/hydrogenbuscontract

The costs of the refuelling network are also relevant to consider. This is likely to be more cost-effective for heavy goods vehicles and public transport in the near term than for cars and vans.

- Some HGV applications and many public transport applications have defined routes and therefore require fewer refuelling points. However, due to the large amount of cross-border travel, this may also need to be co-ordinated with ROI.
- Cars and vans have less defined routes than trucks and would therefore require a more dispersed geographic coverage of refuelling stations. This introduces additional cost and co-ordination issues.

3.1.4 Conclusions on transport

Once the cost gap between FCEV and conventional vehicles decreases, hydrogen is likely to play an important role in decarbonising heavy duty transport and buses because they have few alternative decarbonisation options. As a consequence, road transport is likely to be a key source of hydrogen demand in Northern Ireland in the mid-to-long term (Figure 10).

Figure 10 Conclusions on low carbon hydrogen in transport

Long term potential			
Sector	**Feasibility**	**Cost competitiveness in a Net Zero scenario**	**Key facilitators**
Passenger cars		▪ Likely to remain more expensive than BEVs throughout the 2030s. Some users may be willing to pay for ability to travel long ranges (where electrification is less suitable)	▪ Geographically dispersed refuelling infrastructure required
Trucks	▪ Low carbon hydrogen can be used in a range of road vehicles as an alternative to conventional ICE vehicles or electric vehicles	▪ Could be a cost-effective long term options for HGV where electrification is more costly due to weight and recharge time penalties	▪ Refuelling infrastructure required along key defined routes
Buses		▪ May have cost-effective applications in buses alongside electrification	▪ Refuelling infrastructure in urban depots
Near term priorities			
Early demonstration projects will support the role out of refuelling infrastructure, beginning with depot-based bus refuelling and HGV applications with defined routes (that therefore require fewer refuelling points)			

Source: Frontier Economics

3.2 Industry

Low carbon hydrogen has the potential to replace natural gas for high heat applications in industry[28,29].

3.2.1 Long term demand scenarios

Figure 11 sets out the overall role of hydrogen in final energy demand in industry in Northern Ireland in 2050, as modelled by DFE and the CCC.

Figure 11 shows that low carbon hydrogen plays a relatively significant role across all scenarios, ranging from 18%-24% of energy demand in industry in Northern Ireland. This is because some parts of heavy industry have few alternative decarbonisation options to hydrogen.

- Electrification may not be technologically possible for some parts of high heat industry. Other parts of industry (e.g. low heat) are more likely to electrify as a cheaper alternative to hydrogen[30].
- Post-combustion CCUS can be possible, but it may be unattractive in some applications as it adds process complexity. In addition, it is not clear whether CO_2 storage will be available in Northern Ireland[31]. Shipping captured carbon will affect its cost-effectiveness.

CCC analysis suggests that there may be less hydrogen used in Northern Irish industry than in the rest of the UK. In Northern Ireland, heavy industry is not present in defined clusters. If industry adopts hydrogen, then there will be a question over how best to arrange production and transport to serve geographically dispersed customers (i.e. centralised hydrogen production and hydrogen network build or decentralised green hydrogen production with more electricity network build).

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28 Hydrogen Council (2020) states that electrification is the lowest-cost decarbonisation option for low-grade heat, while for mid- and high-grade heat, hydrogen is a decarbonisation option (alongside biomass and CCUS). (https://hydrogencouncil.com/wp-content/uploads/2020/01/Path-to-Hydrogen-Competitiveness_Full-Study-1.pdf)

29 Navigant (2019) also concludes that industrial low temperature heat will mostly be based on electricity, while high temperature heat can be provided by hydrogen (plus some biomethane). (https://gasforclimate2050.eu/wp-content/uploads/2020/03/Navigant-Gas-for-Climate-The-optimal-role-for-gas-in-a-net-zero-emissions-energy-system-March-2019.pdf)

30 Element Energy (2020), *Deep Decarbonisation Pathways for UK Industry,* https://www.theccc.org.uk/publication/deep-decarbonisation-pathways-for-uk-industry-element-energy/

31 While there may be potential sites, these are not being developed at present. Lewis et al. (2009). Assessment of the potential for geological storage of carbon dioxide in Ireland and Northern Ireland. Energy Procedia, 1(1), 2655-2662.

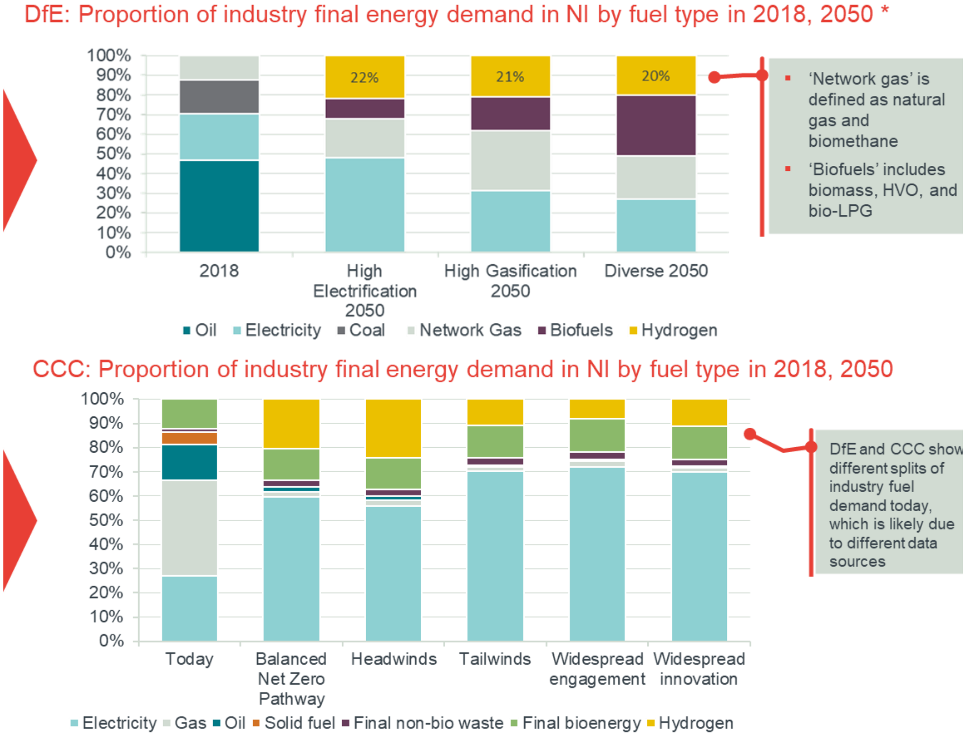
Figure 11 Proportion of industry final energy demand in Northern Ireland by fuel type in 2018, 2050

DfE industry modelling

- Industry currently accounts for 23% of primary energy demand in Northern Ireland
- DfE's modelling suggests that approximately one-fifth of industrial energy demand will be provided by hydrogen by 2050
- DFE's modelling is not based on a top down assessment of energy use in industry as a whole in Northern Ireland*.

CCC industry modelling

- The CCC's scenarios range from 8% - 25% of industrial demand met by hydrogen in 2050
- This is based on a site-level analysis of NI industry using publicly available data
- For the UK as a whole, the CCC estimates that 18% - 31% of industry demand could be met by hydrogen, which suggests that it will play a smaller role in NI than in GB



Source: DFE (2021) and CCC (2020)

3.2.2 Near term potential

Hydrogen is unlikely to play a role at scale in Northern Ireland industry in the near term (up to 2030). This is because the type of industry that is most technologically suited to hydrogen (large scale heavy industry) tends to be industry that requires highly resilient supply with a proven track record of several years.

Early hydrogen producers will not be able to provide such a track record, particularly if the main type of producer in Northern Ireland is electrolysis in the near term. This is because electrolysis is less reliable than methane reformation due to its renewables-based intermittent production.

Some smaller industrial sites may be able to deploy hydrogen in the near term, particularly if they are able to monetise a 'green premium' associated with marketing their products as green and/or where there is scope for small-scale sites that could build on-site electrolysers with localised storage.

In the near term, the focus is therefore likely to be on demonstration, rather than on large scale roll out to industry. There could also be some uptake among high-margin consumer-focused brands who can charge a 'green premium' on their products (for example food and drink manufacturers could install small on-site electrolysers).

Out to 2050, as hydrogen production gains a stronger track record and storage increases, industry will be more able to convert their processes to hydrogen.

3.2.3 Relative costs

The CCC has commissioned a bottom up analysis of carbon abatement cost and potential in Northern Ireland[32]. Figure 12 summarises the analysis on cost. In interpreting this figure, it is important to note that these measures should not be seen as substitutes – for example, energy efficiency alone is not an option to get to Net Zero, and electrification will often not be feasible in high heat applications (though post combustion CCUS may be).

Figure 12 shows significant variation in the abatement costs associated with each option. This variation is driven by uncertainty over technology development and future fuel costs.

Figure 12 Cost of carbon abatement technologies for Northern Ireland industry in 2050

Source: CCC (2020)

Note: Bioenergy includes BECCS, which is why it appears as relatively high cost in these figures. Note that these options are not substitutes and some may not be suitable in all applications.

In the Annex, we set out case studies on individual industrial sites. These give examples of where hydrogen may be useful. For example, high-heat cement kilns can likely only be decarbonised by conversion to a hydrogen kiln or CCUS-based processes. One such case study is shown in Figure 13, for Lafarge Cement. While there is a large degree of uncertainty around these estimates, this illustrates that low carbon hydrogen is a likely solution for some, but not all emissions. It also shows that where green hydrogen is used, the costs are comparable to CCUS.

[32] CCC (2020) Sixth Carbon Budget, https://www.theccc.org.uk/publication/sixth-carbon-budget/

Figure 13 Abatement cost and potential in the cement industry Northern Ireland

- The Lafarge Cement located in Cookstown factory is the largest industrial emitter in Northern Ireland. It is responsible for **16%** of all manufacturing and construction emissions in NI.
- Hydrogen could partially substitute natural gas in the kiln combustion system, abating a maximum of **33%** of the plant's emissions.

Option	Carbon abatement costs (£/t CO2)	% of emissions abated
Blue H2 Kiln	76	31%
Green H2 Kiln	110	33%
CCS - Calcium Looping	110	31%

- CCS is currently the only viable solution for addressing process emissions.
- In the EE model, biomass fuel switching occurs only if combined with CCS.

- The EE model suggests that blue hydrogen kilns are the most cost-effective technology to abate cement combustion emissions.
- Green hydrogen kiln are as cost-effective as CCS.

Source: *Frontier, based on Element Energy (2020), Deep-Decarbonisation Pathways for UK Industry, https://www.theccc.org.uk/publication/sixth-carbon-budget/*

3.2.4 Conclusions

Industry is unlikely to be an early adopter of hydrogen at scale. But, hydrogen is likely to be a really important part of the long term solution in some parts of heavy industry. Our conclusions are set out in Figure 14.

Figure 14 Conclusions on low carbon hydrogen in industry

Long term potential			
Sector	**Feasibility**	**Cost competitiveness in a Net Zero scenario**	**Key facilitators**
Industry	▪ Low carbon hydrogen is one option for decarbonising high-heat industrial processes that cannot be electrified or that are expensive to electrify ▪ The main alternative is post-combustion CCUS	▪ Could be a cost-competitive solution for industry where: □ Electrification is not viable □ Post-combustion CCUS is either infeasible due to the lack of CO_2 storage near NI, or expensive because of CO_2 shipping costs □ Post-combustion CCUS requires process adjustments and may be an unattractive option for some sites	▪ Resilience / security of supply for hydrogen production ▪ Suitable levels of storage to mitigate the impact of production outages ▪ Cost reductions for hydrogen applications ▪ If CCUS is expensive/not viable, then hydrogen will be a more attractive decarbonisation option for industry

Near term priorities

- Early demonstrations could come from small scale industrial sites that can install on-site electrolysers with localised storage. The industries most likely to take up this option are those that can monetise a 'green premium' associated with marketing their products as green.
- Building up a reliable track record for hydrogen production in NI will give larger industrial sites the confidence to switch to hydrogen in the longer run.

Source: Frontier Economics

3.3 Buildings

Low carbon hydrogen can be an alternative or a complement to electrification to decarbonise buildings on a path to Net Zero. In particular, for buildings on the gas grid, there are two key low carbon hydrogen options.

- Natural gas boilers can be replaced by hydrogen boilers. Unlike heat pumps, these can provide a similar consumer experience to current heating systems.
- Hydrogen can also be used with hybrid heat pumps. A hybrid heat pump combines an electrically-driven heat pump with a gas boiler. The gas used could be low carbon hydrogen[33]. Hybrid heat pumps are useful for managing the high system costs associated with seasonal peaks in electricity demand: the gas boiler can be used on the coldest days of the year[34].

[33] Natural gas or biomethane could also be used.

[34] Imperial College (2018), *Analysis of Alternative UK Heat Decarbonisation Pathways,* https://www.theccc.org.uk/wp-content/uploads/2018/06/Imperial-College-2018-Analysis-of-Alternative-UK-Heat-Decarbonisation-Pathways.pdf

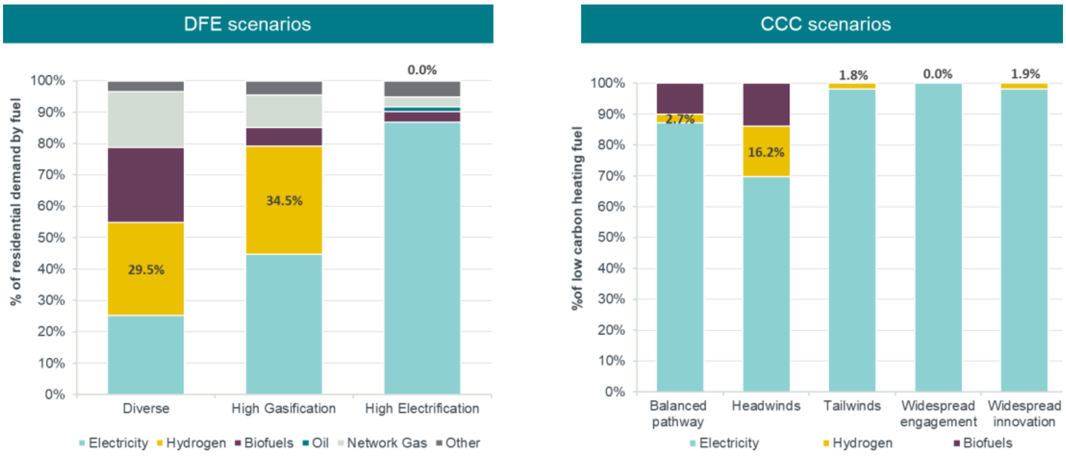
3.3.1 Long term demand scenarios

There is significant variation across DFE and CCC scenarios in the proportion of heating demand that is made up by low carbon hydrogen in 2050. Figure 15 shows that:

- DFE estimates that up to 35% of fuel use for heating could be provided by hydrogen by 2050, though it also considers scenarios with substantially less low carbon hydrogen; and
- CCC scenarios see up to 16% being met by low carbon hydrogen, with around 30% met by low carbon gas as a whole.

Both scenarios take into account the fact that conversion to low carbon hydrogen will be driven partly by the number of homes already connected to the gas grid. However the CCC scenarios include a high proportion of hybrid heat pumps. Where hybrid heat pumps are a significant proportion of demand, it is also worth noting that the proportion of households using low carbon gas may be significantly higher than the proportion of fuel consumed.

Figure 15 Proportion of residential final demand in Northern Ireland by fuel type in 2018, 2050



Source: DFE (2021) and CCC (2020)

The variation across scenarios is driven by:

- **Uncertainty over the future penetration of the gas grid in Northern Ireland.** Gas grid roll out is a key driver for the future of low carbon hydrogen in heating. For buildings remaining off the gas grid, electrification is likely to be the most practical and cost-effective abatement option[35]. Northern Ireland has a relatively new and modern gas network, consisting primarily of polyethylene (PE) pipe, which is easier to convert to hydrogen, compared to the gas grid in the rest of the UK. However, Northern Ireland has a much lower penetration of buildings connected to the gas grid than the rest of the UK. DFE cites a figure

[35] For example, Delta Energy and Environment (2018), *Technical Feasibility of Electric Heating in Rural Off-Gas Grid Dwellings,* https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/762596/Technical_Feasibility_of_Electric_Heating_in_Rural_Off-Gas_Grid_Dwellings.pdf; Element Energy (2019), *Development of Trajectories for Residential Heat Decarbonisation*, https://www.theccc.org.uk/wp-content/uploads/2020/12/Element-Energy-Trajectories-for-Residential-Heat-Decarbonisation-Executive-Summary.pdf

of 30% for 2018[36]. This proportion may grow rapidly: the Utility Regulator, estimates that once GDNs complete the network development up to the end of the GD23 price control (expected to be 2029), approximately 65% of properties in Northern Ireland could have access to natural gas should they choose to connect to the network[37]. This compares to over 80% of residential properties already connected in the rest of the UK[38].

- **Uncertainty over relative costs of low carbon gas and electricity for homes on the gas grid.** For buildings on the gas grid there is likely to be a choice between low carbon gas and electrification. This choice will be a function of several factors, all of which are relatively uncertain.
  - **Cost.** This includes the cost of the fuels, the cost of equipment in customers' homes as well as energy system wide costs (for example, associated with seasonal storage, network investment costs etc).
  - **Feasibility.** Some properties may not be possible to electrify (at least without incurring very high costs). For example, energy efficiency measures are generally important for heat pumps to be effective, and these may not be possible in all properties. However, we note that significant improvements in energy efficiency will be part of any Net Zero strategy.
  - **Consumer acceptability and hassle.** Consumer preferences for the different low carbon options are quite uncertain at present. All will require a degree of disruption as households switch technologies (though within-home disruption may be higher for some electrification options).
  - **System-wide coordination requirements.** A high degree of coordination is required for switching to hydrogen. Networks will have to switch over on an area-by-area basis, which means that all customers will need to be ready to switch over simultaneously. The exact scale of co-ordination required will depend on the specifics of network configuration and the degree to which switchovers can be staggered according to smaller customer groups. Hydrogen ready boilers may also help with this. Some level of coordination may also be required for electrification options given that there may be a requirement to ensure sufficient electricity capacity is in place.
  - **Technological development.** Advances in technology across the value chain may alter costs, feasibility and hassle for the consumer.

3.3.2 Near term potential

Converting the gas grid to low carbon hydrogen is not likely to be practical in the near term, beyond demonstration projects, as the supply facilities (including

[36] DFE (2021), *Future Energy Decarbonisation Scenarios*, https://www.economy-ni.gov.uk/sites/default/files/consultations/economy/Future-Energy-Decarbonisation-Scenarios-report-Northern-Ireland.PDF

[37] Utility Regulator (2020), *Gas Distribution Networks GD23 Price Control*, https://www.uregni.gov.uk/sites/uregni/files/media-files/2020-11-6%20GD23%20Final%20Approach-%20Final.pdf

[38] Element Energy (2021), *Development of trajectories for residential heat decarbonisation to inform the Sixth Carbon Budget*, https://www.theccc.org.uk/publication/development-of-trajectories-for-residential-heat-decarbonisation-to-inform-the-sixth-carbon-budget-element-energy/

production and seasonal storage) and in-house technologies are not yet in place. In the near term, blending could be an option.

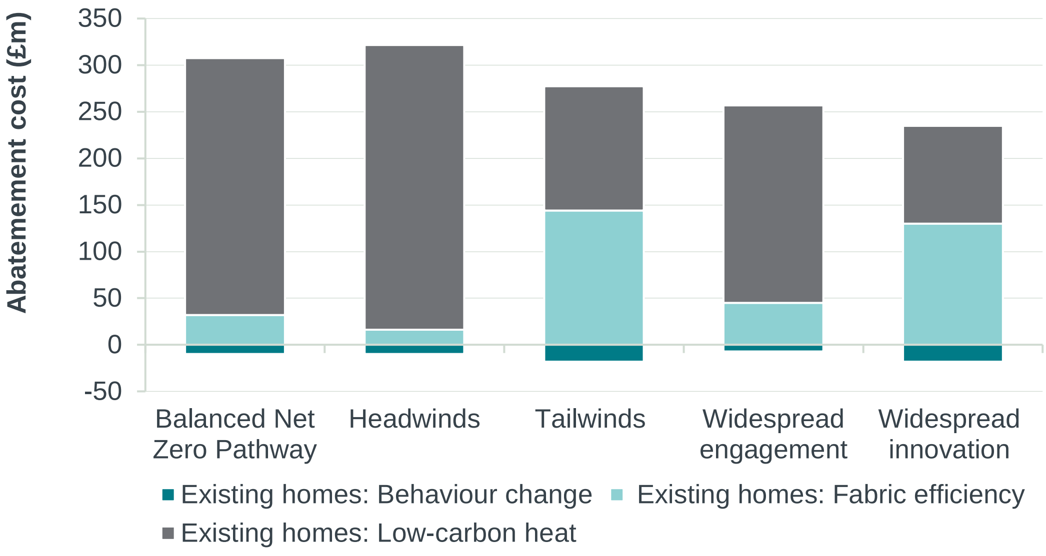
The Utility Regulator will next year determine appropriate new gas connection targets for the GD23 period in Northern Ireland. For customers who are likely to remain off the gas grid, it is likely to make sense to proceed with electrification (heat pumps).

3.3.3 Relative costs

The relative costs of different abatement options will differ according to building characteristics, heat usage patterns and connection to the gas grid. Alternative abatement options are likely to be complements as well as substitutes and all scenarios are likely to include a range of measures.

Figure 16 shows total abatement costs in 2050 for residential heating, based on CCC analysis. Costs in the Headwinds scenario (which includes the highest usage of low carbon hydrogen) are around 11% higher than in the CCC's main Balanced Pathway scenario. This is a relatively small cost difference, in the context of the significant uncertainty around all the factors that will determine the choice between low carbon heating options as described above.

Figure 16 Residential heating abatement costs in Northern Ireland by scenario, CCC 2050



Source: CCC (2020)

3.3.4 Conclusions on heating

Figure 17 sets out our conclusions on heating.

Figure 17 Conclusions on heating

Long term potential			
Sector	**Feasibility**	**Cost competitiveness in a Net Zero scenario**	**Key facilitators**
Heating	▪ Low carbon hydrogen can be used to heat homes on the gas grid, either with hydrogen boilers or hybrid heat pumps	▪ Could be a cost-effective long term options for homes on the gas grid as part of a mix of solutions that also includes electrification	▪ Demonstration projects ▪ Roll out of hydrogen ready boilers ▪ Development of seasonal storage (Larne).
Near term priorities			
▪ For homes remaining off the gas grid, electrification will be the main decarbonisation option. It makes sense to continue to roll out low carbon electrification options such as heat pumps to these properties. ▪ In line with CCC advice, new gas boilers should be hydrogen- ready by 2025 to keep options open for a longer term switchover. ▪ Learning from demonstration projects carried out elsewhere in the UK will be useful.			

Source: Frontier Economics

3.4 Power

Low carbon hydrogen can be used in power plants to provide a flexible source of low carbon generation, as an alternative to post combustion CCUS.

3.4.1 Long term scenarios

Overall, there is a high degree of uncertainty over the future role of low carbon hydrogen in the Northern Irish power sector.

Clearly the primary route to decarbonisation of the electricity system is the deployment of more renewable capacity. However, as an intermittent resource, this capacity will need to be complemented by dispatchable plant (including interconnectors) to maintain security of supply. This backup capacity may also be able to provide a source of power in the winter as electricity demand becomes more temperature sensitive with the electrification of some heating load. If production is largely green hydrogen, its use in the power sector clearly needs to be accompanied by a storage solution.

The use of hydrogen in the power sector in the DFE and CCC scenarios is very low (see Figure 5 on page 13 above). However, the CCC highlights the opportunity for hydrogen to replace natural gas power generation by the 2040s[39].

There are three gas-fired power stations in Northern Ireland, which have the potential to be converted to low carbon hydrogen:

- Kilroot (which is transitioning from a coal-fired plant) is considering the use of hydrogen. Although the gas-fired power generation will initially be by natural gas, "it will also be capable of using gas alternatives, such as biogas and hydrogen, as they become available to the market[40]."

[39] CCC (2019), *Reducing emissions in Northern Ireland*, https://www.theccc.org.uk/publication/reducing-emissions-in-northern-ireland/

[40] https://kilrootenergypark.co.uk/the-masterplan-vision

- Ballylumford and Coolkeeragh - these have not yet made any similar considerations public.

Whether or not low carbon hydrogen is used in these plants, or in new gas-fired plants, will depend on a number of factors, including:

- the availability of other low carbon flexibility generation resources, such as gas with CCUS or interconnection;
- the availability of sufficient production; and
- the availability of storage to allow low carbon hydrogen generation to contribute to meeting winter peaks in demand and troughs in renewable electricity infeed.

While Northern Ireland has good resources available for both production and storage, there may be trade-offs, for example, using production and storage capacity as fuel for generation or as fuel for heating.

3.4.2 Near term potential

2030 is likely to be the earliest that natural gas plants could fully convert to hydrogen[41]. However, existing power plants may be able to accept blended hydrogen and methane without converting turbines for a transitional period.

3.4.3 Costs

Several studies compare the cost-effectiveness of hydrogen and CCUS for power generation.[42,43,44] They have mixed findings, which reflects the uncertainty over how the cost of each option will develop in the future.

- For both retrofit and new build, low carbon hydrogen options are often found to be cheaper than CCUS at UK level.
- This is often based on the assumption that blue hydrogen is available. The situation in Northern Ireland may be different for two reasons:
  - the predominance of green hydrogen may push up the price of the low carbon hydrogen options; and
  - the lack of local carbon storage may push up the costs of the CCUS options.

3.4.4 Conclusions

Our conclusions are set out in Figure 18.

41 Element Energy (2019), *Hydrogen for Power Generation*, http://www.element-energy.co.uk/wordpress/wp-content/uploads/2019/11/Element-Energy-Hy-Impact-Series-Study-3-Hydrogen-for-Power-Generation.pdf

42 Element Energy (2019), *Hydrogen for Power Generation*, http://www.element-energy.co.uk/wordpress/wp-content/uploads/2019/11/Element-Energy-Hy-Impact-Series-Study-3-Hydrogen-for-Power-Generation.pdf

43 Uniper Technologies (2018), *BEIS- CCUS Technical Advisory*, https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/759538/2018_ESD_329.pdf

44 Hydrogen Council (2020), *Path to Hydrogen Competitiveness*, https://hydrogencouncil.com/wp-content/uploads/2020/01/Path-to-Hydrogen-Competitiveness_Full-Study-1.pdf

Figure 18 Conclusions on low carbon hydrogen in power

Long term potential			
Sector	**Feasibility**	**Cost competitiveness in a Net Zero scenario**	**Key facilitators**
Power	▪ Hydrogen can be used to decarbonise power turbines in gas-fired power plants, although the technology is not expected to be available before 2030 ▪ The main alternatives are using biomethane instead of natural gas, or applying post-combustion CCUS	▪ The cost of hydrogen and CCUS turbines are uncertain: there is no clear optimal technology today ▪ CCUS turbine cost and feasibility will depend on the availability of CO_2 transport and storage in Northern Ireland ▪ Biomethane's relative cost and feasibility will depend on the available sustainable supply of feedstocks	▪ If CO_2 transport and storage is unavailable or expensive, and/or biomethane cannot be sustainably produced at the level necessary for use in power generation, then hydrogen turbines are likely to be a good decarbonisation option for power turbines ▪ Storage is required to ensure hydrogen is available for dispatchable power generation
Near term priorities			
▪ In the near term, there are no technologies available to decarbonise thermal power plants (pre-2030).			

Source: Frontier Economics

4 CONCLUSIONS

We have reviewed the available evidence and projections provided by DfE, CCC and other sources. The evidence suggests the following conclusions.

Supply is most likely to come from green hydrogen and imports

- Given the DfE's emphasis on using indigenous renewable resources in Northern Ireland, and the lack of carbon storage sites currently under development, the focus is likely to be on green hydrogen (albeit blue hydrogen as an interim solution should not be ruled out, should the DfE's emphasis change or new carbon storage potential is identified).
- The majority of green hydrogen is likely to be produced from additional renewables, with curtailed wind likely to account for a modest proportion of production.
- Meeting all low carbon hydrogen demand with indigenous renewables could require very high levels of additional dedicated wind capacity. In time, it may also be useful to import low carbon hydrogen as a complement to indigenous production, which could provide additional supply resilience.
- Northern Ireland may be well placed for storage of hydrogen, with significant potential at the salt cavern at Larne.

Heavy transport and high heat industry are likely to be key sectors for demand, with greater uncertainty on the scale of the role in heating and power

- Hydrogen has the potential to play a long term role for hard-to-electrify sectors including some parts of industry and heavy transport. It may also have a role in flexible power generation and wider uses in heating, particularly for buildings on the gas grid. The scale of that role will depend on a number of factors that are currently very uncertain, including future cost and technological developments.
- Electrification and low carbon gas are likely to be complementary decarbonisation solutions. In all scenarios there is likely to be a substantial long term role for electrification in low heat industry, light vehicles, and residential heat, even where hydrogen plays a significant role.

The conclusions on each sector are summarised in Figure 19.

Figure 19 Summary of long term hydrogen demand

Sector	Feasibility	Cost competitiveness in a Net Zero scenario	Key facilitator
Transport	▪ Likely route to HGV and public transport decarbonisation	▪ FCEV most likely to be cost-competitive in the HGV sector due to high BEV cost for heavy loads	▪ Vehicle availability, resilience of supply & refuelling network
Industry	▪ Likely route to high temperature heat decarbonisation	▪ Fuel switching to hydrogen is likely to be cost-effective for certain parts of industry, for example high heat processes	▪ Resilience of supply and hydrogen / electricity transport
Heating	▪ Possible route to decarbonisation, most likely for on gas grid properties	▪ Could be a cost-effective long term options for homes on the gas grid as part of a mix of solutions that also includes electrification	▪ Seasonal storage and gas grid conversion programme
Power generation	▪ Need low carbon flexibility – mix of hydrogen generation and/or gas CCUS most likely options	▪ Cost-effectiveness depends on availability of CCUS and cost of CO_2 transport and storage (for post-combustion capture)	▪ Resilience of supply ▪ Availability of CCUS

Source: Frontier Economics

It is also worth noting that there may be other hard-to-decarbonise sectors where hydrogen is useful in the longer term (e.g. shipping and aviation), but these are not considered by the DfE analysis.

Action to enable hydrogen is required in the near term

The key focus in the near term will be on demonstration projects and building up markets that have long term cost-effective potential (Figure 20).

Figure 20 Summary of near term priorities

Sector	Near term priorities
Supply	▪ Enable some blending to help catalyse the market by providing a stable source of demand for early investors in production.
Transport	▪ Focus on public transport as a first step towards developing infrastructure that can be used for wider heavy transport.
Industry	▪ Enable niche applications (e.g. in high margin, branded industry) or in high temperature applications where there is a resilience solution.
Heating	▪ Role for demonstration
Power generation	▪ Role for demonstration

Source: Frontier Economics

www.frontier-economics.com