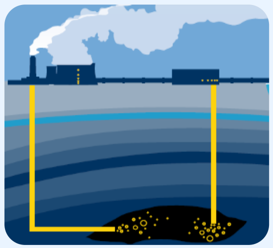








Dual Fuel Hub feasibility study

Final report

UK Power Networks & Cadent

September 2019

Element Energy Ltd

Ben.Madden@element-energy.co.uk
Mike.Dolman@element-energy.co.uk
Sophie.Lyons@element-energy.co.uk
William.Darby@element-energy.co.uk

Contents

Dual Fuel Transport Hubs could exploit synergies between electricity and gas networks to provide benefits to end users and energy networks

Context and concept for a Dual Fuel Transport Hub

- The increasing adoption of plug-in electric vehicles has the potential to create substantial new loads on distribution networks in the UK. Hydrogen-fuelled vehicles, while not as technically or commercially mature, offer an alternative for zero emission mobility, and could help to avoid costly upgrades to these networks.
- The central concept of a "Dual Fuel Transport Hub" is **a refuelling Hub** which exploits the potential **synergies available between the gas and electricity sectors**, using various technologies to manage the capabilities of the gas and electricity networks, whilst meeting **demand for zero-emission (electric and/or hydrogen) vehicles**. This concept would be most attractive when the Hub provides the following benefits to various stakeholders:
  - **For end users (e.g. vehicle users):**
    - Lower overall costs, compared to the costs associated with a single technology
    - Lower impact on operations, compared to the impact of using a single technology
  - **For UK Power Networks (value to network customers):**
    - Resolution, reduction or avoidance of constraints and/or costs for the electricity network
  - **For Cadent:**
    - Future revenues from continued demand for gas or hydrogen delivered via the grid
  - **For the UK as a whole:**
    - Increased adoption of zero-emission vehicles as a result of lower costs and reduced barriers to adoption

This feasibility study aims to define and assess specific Hub concepts that provide these benefits

For the purposes of the analysis, we assume that the existence of a sustainable business case for end users is a prerequisite for a sustainable business case for a hub operator (note that the end user could be the hub operator in some cases)

This study assesses the value of Dual Fuel transport hub concepts in terms of their costs and benefits relative to "single-fuel" solutions

A dual fuel transport hub could be defined by the following characteristics:

- **Technologies using multiple vectors (e.g. gas, electricity and hydrogen) in one place, to meet demand for transport refuelling.**
  - From the perspective of the network operators, the following questions can be considered:
    - What technologies can be used to make this beneficial from a system perspective?
    - To what extent is a multi-vector solution applicable at a local scale vs at a system-level scale?
    - As such, is there a need for local "Hubs" or should Dual Fuel solutions be implemented at a higher level?

- **Multiple types of vehicles (e.g. hydrogen + electric).**
  - For this to be a viable option, the questions to be addressed are:
    - In what situations is this likely to be attractive for end users?
    - What conditions could make a dual fuel solution more attractive than a single-fuel alternative?

The questions above have informed the approach and analysis throughout this feasibility study; the following slides present the high level conclusions.

1. Fleets of buses / trains (and possibly trucks) are expected to be most relevant for dual fuel hub concepts

Conclusions

- For a dual fuel hub to be of interest to UK Power Networks / Cadent, a minimum of MW-scale demand level is needed. This implies a minimum fleet of hundreds of cars, or several tens of buses, or a small fleet of trains.
- As of early 2019, there are relatively few fuel cell electric vehicles (FCEVs) operating in the UK (20 buses, c.100 cars across the whole country).
- However, various initiatives are underway that are expected to lead to expanded fleets of FCEVs and BEVs in the context of increasing focus on zero emission transport solutions. For example, 100+ new fuel cell buses are due to be deployed in the UK by the early 2020s (via funded demonstration projects), and two of the UK's leading bus manufacturers (**ADL** and **Wrightbus**) are now offering fuel cell vehicles. Furthermore, the *H2Bus Europe* initiative could bring hundreds more vehicles in the coming years.
- There is also a growing interest in fuel cell trains, with organisations such as **Alstom**, **Eversholt Rail**, and **Vivarail** announcing hydrogen fuel cell train designs for the UK in recent months.
- Heavy goods vehicles (trucks) are another promising market for fuel cell solutions and several technology development and demonstration activities are underway in Europe, Asia, and North America. Initial engagement with innovative truck fleet operators (e.g. **DHL** and **UPS**) indicates some interest in trialling fuel cell technology, particularly in London where there is increasing demand for zero emission fleets. However, as of early 2019 there is little certainty on the availability of fuel cell trucks in the UK, which limited the extent to which this potential source of hydrogen demand could be considered in this study.

2. There could be a case for dual fuel hubs, particularly where costs to upgrade the electricity network to meet additional demands are high

Conclusions

- In the context of a dual fuel hub that could alleviate issues on the electricity network, **bus depots in London** are of particular interest. Based on the policies in the **Mayor's Transport Strategy**, all new single deck buses introduced to London from 2020 will be zero emission, and this will extend to all new buses (including double deck vehicles) from 2025. This implies a relatively high and concentrated uptake of zero emission buses from the early 2020s.
- While fuel cell bus technology has been demonstrated (in London and elsewhere), **further validation** of the latest generation vehicles is needed in preparation for wider scale deployment in the 2020s. The **demonstration activities already underway** are designed to meet this need.
- This study has found that a dual fuel hub in which a mixed fleet of fuel cell electric and battery electric vehicles are deployed can offer benefits relative to electric-only solutions in some circumstances. The most promising opportunities from a network perspective lie where the costs of providing charging infrastructure for fleets of battery electric vehicles are high (e.g. due to the need for network reinforcement) and / or where fuel cell vehicles offer a superior solution from an operational perspective (for some routes a switch from diesel to battery electric buses may necessitate a larger overall fleet, whereas fuel cell buses are generally a one-for-one replacement for diesel). This means that the case for a dual fuel hub will be **highly location-specific** and dependent on the customers' needs and other local demands on the network.
- This study did not identify specific opportunities for UK Power Networks or Cadent to develop a dual fuel hub that would provide significant direct network benefits. However, in the context of growing demands for zero emission vehicles, this concept could be a good solution for some fleet operators to avoid heavy loading of electricity networks in constrained areas, which would benefit the wider network.

3. The scope to use the gas network for on-site H_2 production appears limited for a range of practical, economic, and environmental reasons

Conclusions

- Having explored the potential for a dual fuel hub to link the electricity and gas distribution networks, this study found no clear opportunities which would be appropriate for the distribution network operators to exploit in the short term. The gas network can alleviate pressure on the electricity network as a means of delivering energy to customers – for example, rather than producing hydrogen on site by electrolysis (which would add to electricity demands), hydrogen could be generated from natural gas from the existing gas grid.
- However, there are several issues with such on-site solutions, including (i) space is often at a premium at refuelling sites which restricts the scope for installing any on-site production equipment, (ii) the costs (capex and opex) of decentralised production technologies tend to be relatively high, and (iii) the carbon intensity of the hydrogen produced this way is high relative to fuel produced from renewables.
- The alternative method of meeting demands from fuel cell vehicles is to **produce hydrogen at scale at a centralised production facility** (with access to low cost, low carbon energy) and deliver it to refuelling stations, either via tube trailers or in a pipeline. Pipeline delivery includes dedicated hydrogen pipelines (one concept being developed in the HyNET project), and potentially using existing natural gas networks (although this would require equipment to separate hydrogen blended with natural gas and purify it at the refuelling site, a technique not yet demonstrated in the field).

4. Centralised low carbon hydrogen production could unlock dual fuel opportunities and thus lead to (indirect) network benefits

Conclusions

The centralised renewable hydrogen production model is one of the most promising options for providing low cost, low carbon hydrogen to a range of applications and is being pursued by several major players in the hydrogen sector, including in the UK. While not directly within the scope of a dual fuel hub originally envisaged (i.e. solving localised constraints with localised dual fuel technologies), these types of solutions are potentially relevant to:

- **UK Power Networks** – centralised hydrogen production and distribution systems are highly scalable and the economics tend to improve with increasing scale. Therefore, should such a system be established in the UK Power Networks area (e.g. initially to serve London's fleet of fuel cell buses or another "anchor demand"), this could provide a promising alternative fuel delivery system to zero emission vehicles in the region (i.e. fuel cell vehicles would become a more viable option for other fleet operators seeking to adopt zero emission solutions, which could lead to a greater mix of technologies and therefore overall reduced demands on the electricity network, compared to a battery electric dominated future).
- **Cadent** – there may be opportunities to use existing gas pipelines to transport renewable hydrogen (and thus reduce the carbon intensity of gas supplies) via power-to-gas concepts, depending on the location of the centralised hydrogen production plant (although the economic case for using hydrogen in this way is currently challenging). In addition, large scale gas reformation with carbon capture and storage (one option for low carbon production) would contribute to the sustained use of the gas network.
- **Wider system benefits** – centralised production of hydrogen via electrolysis coupled directly to renewables could offer synergies with large-scale renewables such as offshore (and onshore) wind, by reducing the overall capacity required for connections to the main electricity network. This could enable a higher overall installed capacity of renewable energy in the UK.

Contents

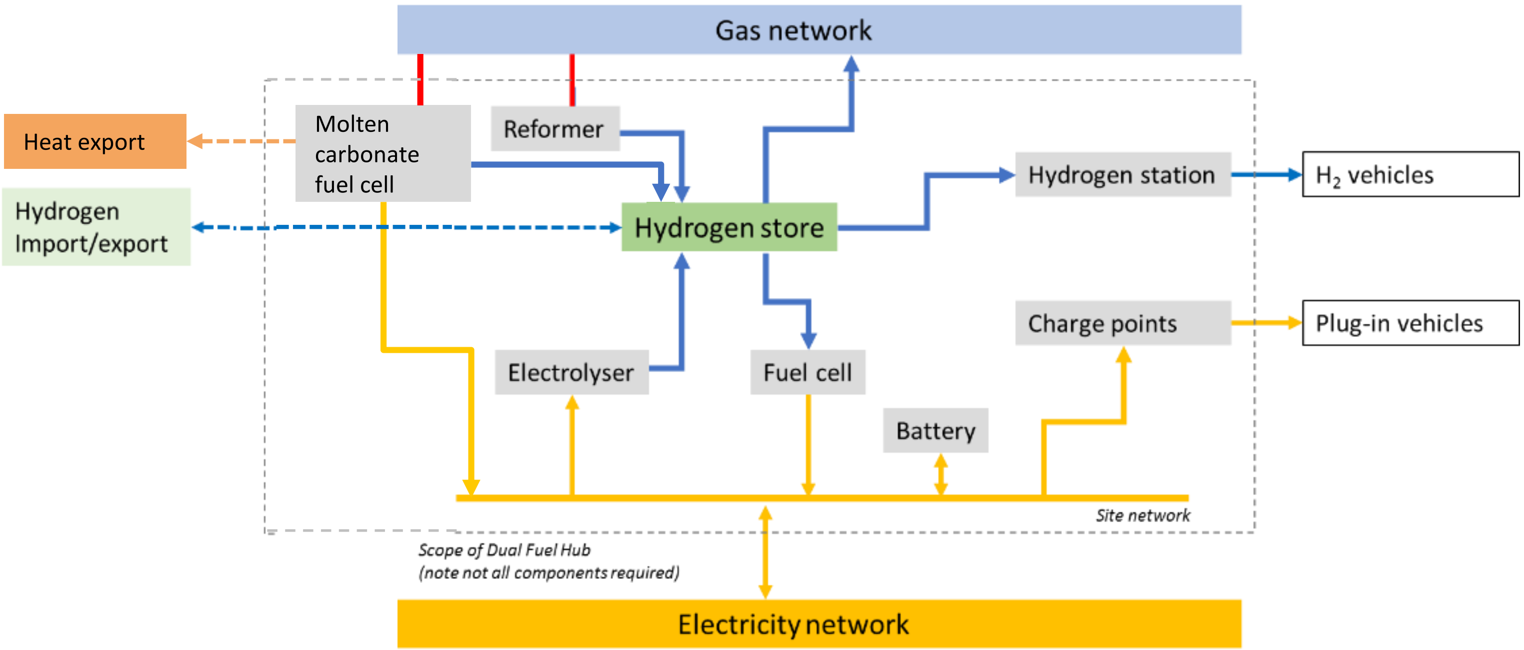
The report considers the key opportunities for a Dual Fuel Hub and presents an analysis of the costs and benefits of specific configurations

Overview of the report

1	**Introduction**	▪ Context and overview of report
2	**End user markets**	▪ Summary of economic analysis and market sizing for potential end users i.e. different vehicle types ▪ Refuelling needs for potential end users: timing, location, level of demand
3	**Distribution network opportunities**	▪ High level assessment of the value of services that a Dual Fuel Hub could provide to the electricity and gas networks
4	**Defining Dual Fuel Hub concepts**	▪ Defining possible Dual Fuel Hub concepts; selection of "archetypes" for further analysis
5	**Techno-economic and spatial assessment**	▪ Detailed assessment of the costs and benefits of selected archetypes relative to "single-fuel" alternatives; overview of potential locations
6	**Conclusions**	▪ Conclusions specific to the techno-economic assessment ▪ Broader conclusions regarding possible variations on the archetypes and the implications for the Dual Fuel Hub concept
	Appendices ▪ **Technology review** ▪ **Market review**	▪ Cost and performance data and projections for technologies relevant to a Dual Fuel Transport Hub; examples of deployment to date ▪ Detailed analysis of potential end user markets

This study investigated and developed potential concepts for a *dual fuel transport hub*

Dual Fuel Transport Hub concept – overview



- The Hub concept brings together electric and hydrogen vehicle fuelling solutions.
- A mix of technologies used to convert gas or electricity into a transport fuel and potentially also to convert between the two networks (e.g. via electricity generation from gas or electrolytic hydrogen injection to the gas grid).
- This type of concept exploits the potential synergies available between the gas and electricity sectors, e.g. balance demand between the networks; sell on the flexibility benefits to various network stakeholders.

The original scope of work envisaged three phases – this has been reduced to two due to lack of clear short-term opportunities

Dual Fuel Hub project overview

Phase 1: Understand Hub opportunity

- Evaluate stakeholder requirements
- Technology review
- Market review

Phase 2: Develop design concepts

- Develop Dual Fuel Hub design concepts
- Techno-economic analysis
- Assess business case / customer value proposition

Phase 3: Deployment project realisation

- Location and design
- Project delivery plan

Due to a lack of a clear short-term opportunities to develop a Dual Fuel Hub demonstrator, Phase 3 of the study will not proceed at this stage.

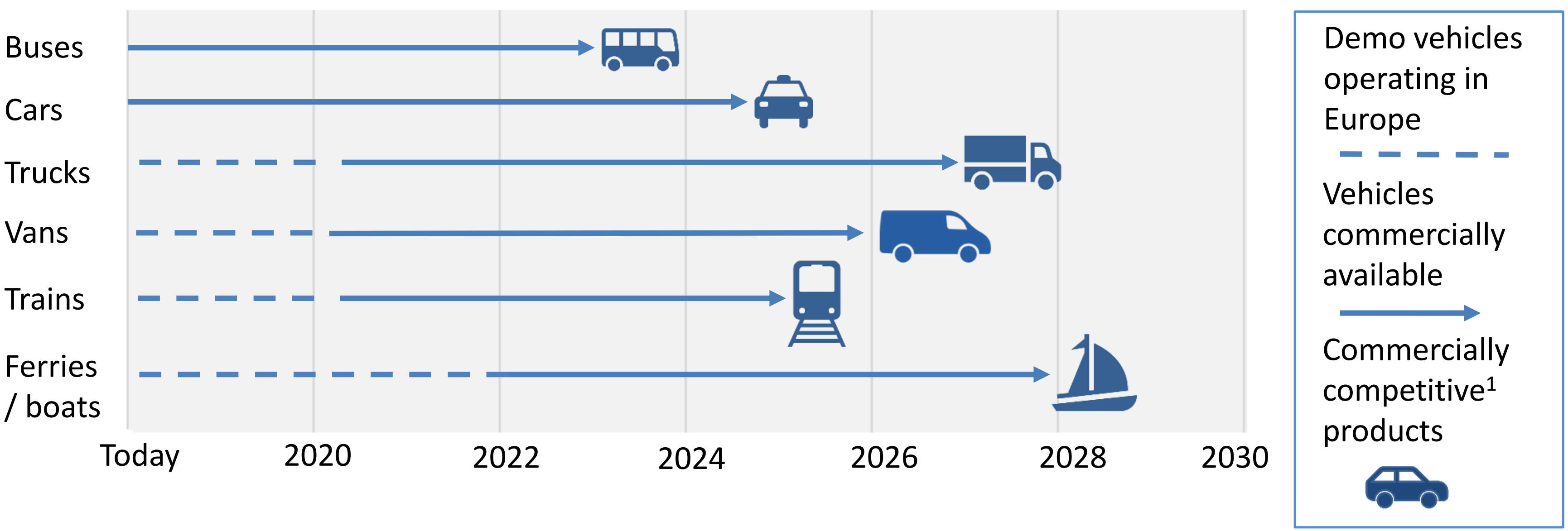
Contents

Dual Fuel Hub end users will be largely determined by the overall availability of hydrogen vehicles to operate alongside electric vehicles

Possible zero emission end users considered in this document (based on likely market availability by 2022)

Plug-in electric	Hydrogen
Cars & vans (various use cases)	Cars & vans (various use cases)
Buses	Buses
Trucks	Trucks
Trains	Trains
Ferries	Ferries

Indicative timescales for availability of hydrogen fuel cell vehicles in the UK



1 - Commercially competitive products refers to hydrogen transport modes which are **competitive with other forms of low/zero emission transport.**

Uptake scenarios for electric and hydrogen vehicles help to inform which vehicle types could be potential end users for a Dual Fuel Hub

Indicative scale of daily demand for electricity and hydrogen at local ('Hub') level

- To assess the high-level demand opportunity for a Dual Fuel Hub for different vehicle types, we have assessed the potential scale of local refuelling demand under different uptake scenarios for electric and hydrogen vehicles. The scale of local demand is based on the following:
  - Typical daily fuel consumption per vehicle
  - Number of vehicles likely to be deployed within a "Hub area" in the early-mid 2020s (e.g. this could translate to the potential uptake within a specific depot, or within a certain area). This is informed by the overall uptake scenarios in the Market Review[1].

Scalability of Hub opportunity

- We can also use the uptake scenarios for total UK uptake of these vehicles on a 2030 timescale to assess the wider scalability of the Hub opportunity offered by specific vehicle types, i.e. the potential number of Hubs based on vehicle demand.

The tables in the following slide(s) set out the typical demand per vehicle, the potential number of locally deployed vehicles under a given uptake scenario in the early-mid 2020s, and the total number of vehicles that could be deployed in the UK by 2030 (Element Energy scenarios developed based on a range of published studies). This facilitates a comparison of the factors identified above (in bold on the following slide).

[1] *For the detailed analysis supporting these tables, please refer to the full Market Review in the Appendices.*

Demand for hydrogen at a Hub could range from 100 kg per day to 3 tonnes per day, depending on the types of end user

Assessing scale of potential demand for hydrogen end users (INDICATIVE SCENARIOS)

Hydrogen vehicles	Cars (fleets)	Vans (fleets)	Buses	Trucks	Trains[1]	Ferries[2]
Average daily hydrogen demand per vehicle (kg H_2/day)	1.0	1.5	13	11	280	650
Estimate for number of 'locally deployed' vehicles likely to use one refueling Hub in 2025	50	50	40	40	10	5
Estimated demand for a refueling Hub (kg H_2/day)	**50**	**80**	**500**	**450**	**2,800**	**3,250**
Total vehicles by 2030 (central estimate)	10,000	14,000	1,000	1,000	100	50
Implied potential number of Hubs	**200**	**300**	**25**	**25**	**10**	**10**

Assumptions	Cars	Vans	Buses	Trucks	Trains	Ferries
Fuel consumption (kWh/km)	0.33	0.67	2.7	2.4	9.3	43.3
Fuel consumption (kg/km)	0.01	0.02	0.08	0.07	0.3	1.3
Daily mileage per vehicle (km)	96	77	165	154	1,000	500

[1] Based on hydrogen self-powered option; demand for a bi-modal train will vary depending on share of non-electrified miles

[2] Demand estimate based on a fuel-cell & diesel medium ROPAX ferry for 450 passengers (Innovate UK H2 Roadmaps)

Simultaneous charging of electric fleets could lead to localised average additional power demand in depots ranging from 200 kW to 22 MW

Assessing scale of potential demand for electric vehicle end users (INDICATIVE SCENARIOS)

Electric vehicles	Cars (depot based)	Vans (depot based)	Buses	Trucks	Trains[1]	Ferries[2]
Average daily electricity demand per vehicle (kWh/day)	15	28	280	180	4,400	17,400
Estimate for number of 'locally deployed' vehicles likely to use one refueling Hub in 2025	50	50	100	50	10	10
Estimated daily electricity demand for a refueling Hub (kWh/day)	770	1,400	28,000	8,500	44,000	174,000
Average additional power demand for a refueling Hub (MW)	**0.2**	**0.2**	**4.7**	**1.1**	**7.3**	**21.7**
Total vehicles by 2030 (central estimate)	100,000	100,000	5,000	5,000	100	100
Implied potential number of Hubs	**2,000**	**2,000**	**50**	**120**	**10**	**10**

Assumptions	Cars	Vans	Buses	Trucks	Trains	Ferries
Fuel consumption (kWh/km)	0.2	0.4	1.7	1.1	8.0	34.6
Daily mileage (km)	96	77	165	154	550	500
Simultaneous vehicle charging period (hours)	5	6	6	8	6	8

[1] Based on battery self-powered option; demand for a bi-modal train will vary depending on share of non-electrified miles

[2] Demand estimate based on a battery & diesel medium ROPAX ferry for 450 passengers

Assessment of the relative economics for different vehicle types also informs the feasibility of a Dual Fuel Hub for that end user group

Comparing relative vehicle economics in mid 2020s

Technologies have been scored on a comparative scale for the different fleets, from “least attractive” to “most attractive” vehicle offer, compared to the counterfactual technology. This takes into account capital costs as well as the overall TCO.

-2	-1	0	1	2
Worse than most other electric / hydrogen technologies	Worse than some other electric / hydrogen technologies	Median technology	Better than some other electric / hydrogen technologies	Better than most other electric / hydrogen technologies

Summary of relative vehicle economics

	Cars (fleets)	Vans	Buses	Trucks	Trains	Ferries
Electric vehicles*	2	1	1	0	-1	-2
Hydrogen vehicles*	0	0	1	-1	-1	-2

Overall, electric and hydrogen cars, vans and buses are likely to offer the best end user proposition in the mid 2020s. Electric options for these vehicle types are likely to be more attractive than hydrogen vehicles, mainly due to their lower purchase costs. However, charging times and power requirements could constrain demand.

*Where vehicles are not yet available “off-the-shelf”, these metrics are based on estimates in the literature and bottom-up technology costs for demonstration vehicles

Refuelling requirements for different vehicle types vary in timing and location; fleet refuelling is often constrained to specific depot sites

User requirements (high level summary)

End users	Typical refuelling schedule	Typical refuelling location	Fuel customer
Buses	Whole fleet refuelled at the end of the last shift (evening)	Bus depot	Fleet operator
Urban and localised HGV routes	Often at start or end of shift (early morning or evening)	Fleet depot	Fleet operator
Long haul HGVs	Often at start or end of shift (early morning or evening)	Motorway services and/or dedicated refuelling facilities	Fleet operator
Taxis, vans and private cars	Flexible – 24/7 fuel availability often required	Public refuelling stations or charging at driver homes	Individual driver or fleet operator
Trains	Between services / overnight	Refuelling at depot	Train operator
Ferries	Between services / overnight	Refuelling at depot	Ferry operator

The preferred time of day and location for refuelling creates boundaries for consideration in the definition of a Dual Fuel Hub.

Contents

Avoiding the cost of upgrades is likely to be the single largest network 'benefit' that could be accessible to Dual Fuel Hub operators

Avoided upgrade costs vs 'Reinforcement deferral' DSR market

Revenue stream / benefit	Value	Current requirements	Relevant technologies	Current market size
DSR (UK Power Networks) – Reinforcement deferral	Maximum available (4 year contract) up to £90k per year per constraint	~1MW and above, up to 11kV Typically 1–3 hours (evening peak)	Electrolysers Batteries	117 MW in 2019 (increasing to 206 MW in 2022)[1]
Avoided grid upgrade costs	Up to £2.5m for avoiding a primary sub upgrade (for an additional load of 5 MW above the existing capacity)	Avoid new demand exceeding existing network capacity	Replacing EV charging with hydrogen refuelling (various production methods)	Dependent on underlying demand profile
Gas network benefits	The overall benefit to gas network operators would be from opportunities to increase the future utilisation of the gas network in meeting transport-related demand.			

- Reinforcement deferral is currently the highest value revenue stream available to loads connected to the UK Power Networks network, with potential value estimated at up to £90k per year for a contract period of 4 years.
- In comparison, if a Dual Fuel Hub could avoid primary substation upgrades to accommodate an additional load, the avoided costs (both for the operator and UK Power Networks) could be in the region of £millions due to the high costs that can be associated with upgrades to the London network.
- **As such, avoided upgrade costs could be the most valuable 'market' relevant to Dual Fuel Hubs.**

[1] UKPN Flexibility Roadmap, available here (Figure 5, p23).

The cost of network reinforcements to accommodate the needs of a 100% electric bus depot in the London area could be around £0.5m per MVA

Network upgrades and associated costs

- If the capacity required by charging vehicles cannot be accommodated by the existing network, the fleet operator will have to contribute to the cost of network reinforcements.
- For current business-as-usual connections, in cases where reinforcements would be required for additional loads **in excess of ~1MW** capacity (e.g. more than 20 buses or trucks charging at 50kW simultaneously), such reinforcements would involve upgrades at the primary substation level.
- In London, total network reinforcement costs are very dependent on location and due to the high loading of many primary substations and the high cost of civil works, upgrade costs could be as high as **£0.5 million per MVA** (on average) at the primary substation level**.** For an additional load of 5MW (e.g. 100 buses charging simultaneously), this could lead to up to around **£2.5 million to be paid by the customer** for their share of the upgrade**.**
- In addition, in some areas the **waiting time for network upgrades may be several years.**

For capacity requirements above 1MW, the share of the total grid upgrade cost paid by the bus depot could be around 3% per vehicle

Depot cost of upgrade as a share of the total grid upgrade cost

Capacity requirements in excess of existing headroom > 1MW

- For this case, it is likely that the primary substation will need to be upgraded e.g. from 15 MVA to 30 MVA. In order to gain the additional capacity required, the customer would pay for the following[1]:
  - Primary substation upgrade (e.g. 15 MVA to 30 MVA): customer pays for their **own increase in capacity** (including the headroom before the upgrade). The remaining costs are socialised.
- The customer share of the total upgrade cost will therefore scale linearly with the number of vehicles charging simultaneously at a given rate. (e.g. 50 kW per vehicle) and can be calculated as follows:
- $$\frac{\text{Additional capacity } \textbf{required} \text{ by the customer}}{\text{Additional capacity } \textbf{installed} \text{ (next sub station level up)}} = \frac{\text{e.g. 50 kW per vehicle}}{\text{15,000 kW (for primary substation upgrade)}}$$
- **<u>For vehicles charging simultaneously at 50 kW per vehicle, the share of the total upgrade cost equates to ~3% per vehicle.</u>**

Capacity requirements in excess of existing headroom < 1MW

- For additional capacity below 1MW (e.g. fewer than 20 buses charging at 50kW), a new secondary substation e.g. from 500 kVA to 1.5 MVA may be sufficient; in this case, the customer will pay for a large share of the costs, but the total network costs are likely to be lower.

[1] Simplified version of the total costs incurred

Contents

The following end users, technologies and network benefits were considered for the assessment of possible Dual Fuel Hub configurations

Potential end users

- Electric cars
- Electric vans
- Electric buses
- Electric HGVs
- Battery electric trains
- Electric ferries
- Hydrogen cars
- Hydrogen vans
- Hydrogen buses
- Hydrogen HGVs
- Hydrogen trains
- Hydrogen ferries

Potential technologies

- Charging points
- Batteries for stationary energy storage
- Electrolysers
- Reformers
- Fuel cells (especially molten carbonate fuel cells)*
- Hydrogen injection
- Hydrogen recovery
- Hydrogen storage
- Hydrogen compression
- Hydrogen refuelling stations

An overview of the key characteristics and market readiness of these technologies is provided in the Technology Review (see Appendices).

Potential network benefits

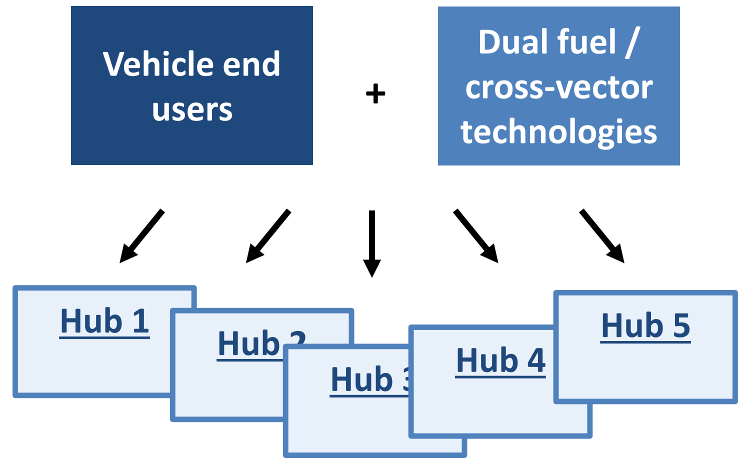
- Reinforcement deferral
- Demand turn up (National Grid balancing services)
- Avoided/delayed electricity network upgrade costs e.g. by reducing the time constrained demand for electric vehicles
- Demonstration of possible future role of the gas network

* Due to their ability to generate electricity, heat, and hydrogen from natural gas.

Approach to defining and assessing Dual Fuel Hub concepts

Overview of approach to defining and assessing Dual Fuel Hub concepts

1. **Identify Hub configurations consisting of relevant combinations of potential technologies and end users, based on the following:**
   - Timing and location of refuelling needs, constraints to be resolved, and technology capabilities
   - Scale of end user demand in relation to scale of constraint



2. **High level assessment of Hub configurations in terms of:**
   - Chance of success
     - Strength of end user proposition (accounting for vehicle economics, the benefit of a Dual Fuel solution, and the cost of component technologies)
     - Technology readiness level (for vehicles and for component technologies)
   - Value to network customers (based on network benefits)
   - Degree of network-relevant innovation
   - Scalability (based on size of relevant vehicle markets and how replicable the concept is)

The high level assessment resulted in the selection of two key Hub configurations to be defined in detail and considered for full techno-economic analysis. The following slides show how these were selected from a list of eight options.

Opportunities for a Dual Fuel Hub exist where a combination of technologies could deliver benefits compared to a single technology

Identifying opportunities for a Dual Fuel Hub

- The central concept of a "Dual Fuel Transport Hub" is **a refuelling Hub** which exploits the potential **synergies available between the gas and electricity sectors**, using various technologies to manage the capabilities of the gas and electricity networks, whilst meeting **demand for zero-emission (electric and/or hydrogen) vehicles**.
- This concept is most attractive when the following benefits are provided to various stakeholders:
  - **End users (e.g. vehicle users):**
    - Lower overall costs, compared to the costs associated with a single technology
    - Lower impact on operations, compared to the impact of using a single technology
  - **UK Power Networks (value to network customers):**
    - Resolution, reduction or avoidance of constraints and/or costs for the electricity network
  - **Cadent:**
    - Future revenues from continued demand for gas or hydrogen delivered via the grid
  - **UK as a whole:**
    - Increased adoption of zero-emission vehicles as a result of reduced barriers to adoption

By considering the compatibility of the timing, scale and location of network constraints to be resolved, with vehicle refuelling needs, and technology capabilities, we have identified possible ways in which technologies and end users could be combined in a Dual Fuel Hub to maximise the benefits across different stakeholders. These possible Hub concepts are described in the tables in the following slides.

Potential "mixed use" Dual Fuel Hub configurations (1/2)

	End user case	Relative fuel demand (Electric: hydrogen)	Potential gas network opportunity & key technologies	Potential electricity network benefit
1	Zero emission bus[1] fleet (dual fuel depot with electric bus charging + hydrogen refuelling)	Low: high	Hydrogen injected to the grid upstream and extracted from a blend in the gas grid close to (or at) the point of demand	Delayed/avoided reinforcement costs by reducing the time-constrained demand for charging of electric vehicles
2	Zero emission bus[1] fleet (dual fuel depot with electric bus charging + hydrogen refuelling)	Low: high	Hydrogen injection to the grid upstream & hydrogen production onsite via grid gas reformation (as a proxy for higher % blending & extraction in future)	Delayed/avoided reinforcement costs by reducing the time-constrained demand for charging of electric vehicles
3	Zero emission bus[1] fleet (dual fuel depot with electric bus charging + hydrogen refuelling)	High: low	Gas-driven molten carbonate fuel cell (onsite) to provide additional electricity needs at peak times + generate hydrogen	Delayed/avoided reinforcement costs by reducing the simultaneous demand on the electricity grid (time-constrained vehicle refuelling)
4	Zero emission urban deliveries depot – vans and HGVs (electric, range-extended hydrogen + electric vehicles) + demand for heat & power	High: low	Gas-driven molten carbonate fuel cell (onsite) to provide additional electricity needs at peak times + generate hydrogen	Delayed/avoided reinforcement costs by reducing the simultaneous demand on the electricity grid (time-constrained vehicle refuelling)

[1]Bus fleet could also be a different heavy duty fleet (e.g. trains or ferries) in a constrained network setting where electric vehicles would be more cost-effective than hydrogen vehicles before the network upgrade cost is considered, and where a combination of electric and hydrogen powertrains that avoids the upgrade requirement could therefore be the most cost-effective solution overall. However, buses are likely to be the most relevant scale for a dual fuel option.

Potential "mixed use" Dual Fuel Hub configurations (2/2)

	End user case	Relative fuel demand (Electric: hydrogen)	Potential gas network opportunity & key technologies	Potential electricity network benefit
5	Mixed use refuelling hub for plug-in electric cars & hydrogen taxi fleet (e.g. motorway services near airport with high taxi demand)	High: low	Gas-driven molten carbonate fuel cell (onsite) to provide additional electricity needs at peak times + generate hydrogen	Delayed/avoided reinforcement costs by reducing the simultaneous demand on the grid for rapid charging of electric vehicles
6	Mixed use refuelling hub for plug-in electric cars & hydrogen taxi fleet (e.g. motorway services near airport with high taxi demand)	Low: high	Hydrogen injected to the grid upstream and extracted from a blend in the gas grid close to (or at) the point of demand	Delayed/avoided reinforcement costs by reducing the demand for rapid charging of electric vehicles
7	Mixed use refuelling hub for plug-in electric cars & hydrogen taxi fleet (e.g. motorway services near airport with high taxi demand, or depots)	Low: high	Hydrogen injection to the grid upstream & hydrogen production onsite via grid gas reformation (as a proxy for higher % blending & extraction in future)	Delayed/avoided reinforcement costs by reducing the demand for rapid charging of electric vehicles
8	Rapid charging & hythane refuelling for HGVs (e.g. at motorway services)	Low: low (high gas demand)	Hydrogen injected to the grid upstream; blended gas taken from the grid and directly used in vehicles (transition technology before full hydrogen vehicles)	Delayed/avoided reinforcement costs by reducing the demand for rapid charging of electric vehicles

The following slide compares the eight Hub configurations by assessing various factors

Overall scoring categories to identify Hub concepts for further analysis

- **Chance of success**, i.e. are the component technologies likely to be deployed within the relevant timescale? Is there likely to be sufficient interest from potential project partners?

- **Value to network customers & wider benefits**, i.e. what is the scale of the overall network benefit and (secondary factor) what is the scale of the emissions benefits from increased zero emission vehicle uptake?

- **Level of network-relevant innovation**, i.e. are either the gas or the electricity network being used in new ways with the potential to address challenges for the network in a timely way?

- **Scalability**, i.e. to what extent can this concept be replicated across the UK; to what extent can the knowledge that would be gained during the project be shared more widely?

The following slide shows the scoring of each configuration for each of these factors, based on the characteristics of the end users and technologies in each Hub concept, and other additional factors.

Overall assessment of “mixed use” Hub configurations

	End user cases	Key technologies
1	Bus depot: electric bus charging + hydrogen refuelling	Hydrogen injected to the grid upstream and extracted from a blend in the gas grid close to (or at) the point of demand
2		Hydrogen injection upstream; onsite grid gas reformation (as a proxy for higher % blending & extraction in future)
3		Gas-driven molten carbonate fuel cell (onsite) to provide additional electricity needs at peak times + generate hydrogen
4	Urban deliveries depot: electric, range-extended hydrogen + electric vans & HGVs + heat & power	Gas-driven molten carbonate fuel cell (onsite) to provide additional electricity needs at peak times + generate hydrogen
5	Mixed use refuelling hub for plug-in electric cars & hydrogen taxi fleet (e.g. services near airport)	Gas-driven molten carbonate fuel cell (onsite) to provide additional electricity needs at peak times + generate hydrogen
6		Hydrogen injected to the grid upstream and extracted from a blend in the gas grid close to (or at) the point of demand
7		Hydrogen injection upstream; onsite grid gas reformation (as a proxy for higher % blending & extraction in future)
8	Rapid charging & hythane refuelling for HGVs (e.g. at motorway services)	Hydrogen injected to the grid upstream; blended gas taken from the grid and directly used in vehicles (transition technology before full hydrogen vehicles)

	1	2	3	4	5	6	7	8
Chance of success	1	2	**3**	**2**	2	1	2	1
Value to network customers & wider benefits	3	2-3	**2-3**	**2-3**	1	1	1	1
Level of network-relevant innovation	3	1	**2**	**2**	2	3	1	2
Scalability	1	1	**2**	**3**	3	2	2	2

In addition to the "mixed fleet" concepts, 100% hydrogen fleets could present "Dual Fuel" transport hub opportunities

Two main concepts have been assessed in detail (in the next chapter)

The **mixed fleet** concept below was selected for further analysis as a result of the screening process:

Network opportunities

1. **Onsite hydrogen & electricity production from the gas grid** in a molten carbonate fuel cell, to minimise grid electricity demand for zero-emission fleets in network-constrained areas (city centre applications)

   Refuelling hub: Electric & hydrogen buses or logistics fleets

UK Power Networks: Avoided/delayed network upgrades in constrained areas

Cadent: Demonstrates the transitionary and future role of the gas grid in a "smart" balanced network

The study also considered the possible network benefits of **hydrogen only** refuelling options which may have different roles for Cadent and UK Power Networks:

2. **Offsite hydrogen production to accommodate renewables**; hydrogen delivered by a dedicated pipeline or by road ("virtual pipeline") to meet demand for zero-emission transport in network-constrained areas and thus avoid network upgrades for electric vehicles.

   Refuelling hub: Hydrogen buses, trucks or trains

UK Power Networks: Avoided/delayed network upgrades in constrained areas; access to electrolyser grid services

[Cadent: Demonstrates future demand for hydrogen grid]

Contents

This chapter presents the costs and benefits of specific Dual Fuel Hub archetypes, and identifies cases where these could be beneficial

Chapter overview

Dual Fuel Hub "archetype"	Content
i) Fuel cell tri-generation: Electric & hydrogen bus depot using a Molten Carbonate Fuel Cell to generate hydrogen, electricity and heat **ii) Off-site renewable electrolysis:** Large scale offsite renewable electrolysis to supply hydrogen for trains (or other large fleet demand)	• Definition of possible Dual Fuel Hub archetypes based on options down-selected from Phase 1 of the study • Economic analysis from hydrogen supplier and fleet operator perspectives to assess customer value proposition • Comparison of overall capex and opex with diesel and electric counterfactuals • Comparison of overall emissions with diesel and electric counterfactuals • Assessment of potential benefits to UK Power Networks and Cadent • Overview of potential locations for a Dual Fuel Hub

Contents

Molten Carbonate Fuel Cells (MCFCs) can generate hydrogen, electricity and heat from natural gas

Overview of MCFCs

- MCFCs **create electricity** using **natural gas** and **water** inputs. **Hydrogen** and **heat** are also produced as part of the process. As the production of hydrogen increases, the amount of electrical power decreases.
- In 2010, global annual production of MCFCs was 30MW at an **installed cost of c. £5,500/kW**. The National Renewable Energy Lab predicts that if production reaches c. 150MW, the installed capex could drop to c. £2,400/kW[1]. However, note that the 2018 Fuel Cell Industry Review (E4Tech) recorded global shipments of MCFCs at c.25MW in 2017 and 2018.
- Material corrosion results in a stack lifetime of c. 5 years. However, Fuel Cell Energy (the main supplier) have forecasted an increase in the lifetime of their stacks, from 5 to 10 years by the early 2020s[1].

Performance characteristics of a Fuel Cell Energy 300kW Molten Carbonate Fuel Cell

Variable	Units	Pure Electric Mode	Combined Electric and H_2 mode	Comments for Performance in Combined Electric and H_2 mode
Stack DC gross output	kWe	**300**	**274.9**	-
Net H_2 Production	kgH_2/day	**0**	**125**	-
Net electrical power output	kW	**258**	**183**	Requires a 5% increase in fuel input
Net Electrical Efficiency	%	**46.4**	**27.6**	-
Net Hydrogen Production Efficiency	%	**0.0**	**26.2**	-
Net Heat Recovery Efficiency	%	**32.7**	**23.2**	If waste heat is used to raise hot water (lower if steam is raised)
Total Efficiency	%	**79.1**	**77.0**	**-**

[1] R. Remick and D. Wheeler, "Molten carbonate and phosphoric acid stationary fuel cells: Overview and gap analysis," 2010.

Archetype 1: Electric & hydrogen bus depot using a Molten Carbonate Fuel Cell to generate hydrogen, electricity and heat

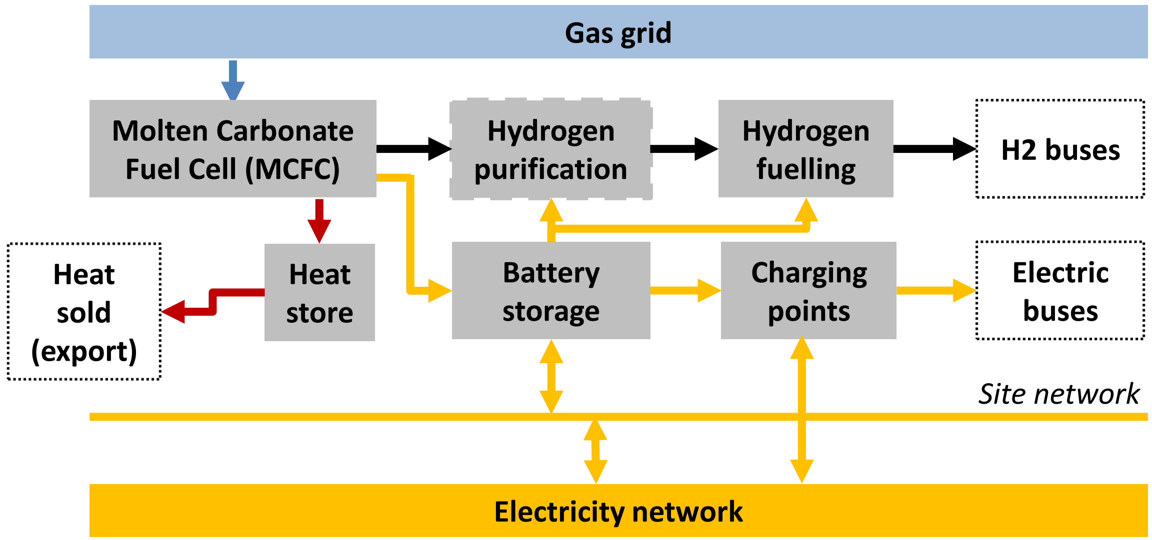
Archetype 1 characteristics

End-user characteristics

- Total fleet: 50 buses, total mileage 8,000 km per day, operation from 6am til 9pm
- 30 electric buses & 20 hydrogen buses
- 9 MWh electricity per day, 260 kg H2 per day

Electric technology characteristics

- 10 MWh battery storage (for electricity generated by MCFC); 90% round trip efficiency
- One charging point per bus & upgrades to the "in-building" network to accommodate charging points



Hydrogen technology characteristics

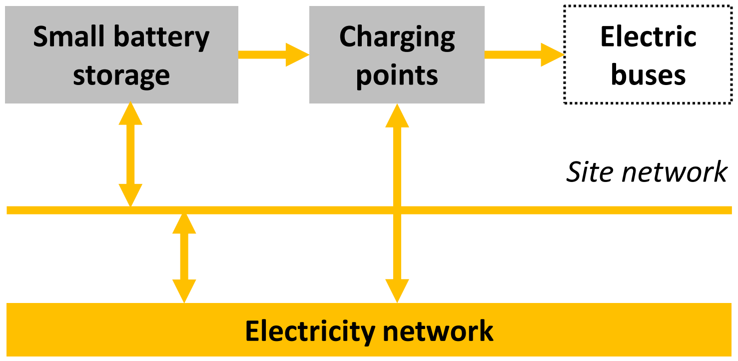
- MCFC: 1MW capacity (up to 400 kg/day)
- Hydrogen purification (Pressure Swing Adsorption): up to 500kg/day PSA unit
- Combined efficiency in maximum hydrogen production mode: 77% (including usable heat generated)
- Hydrogen fuelling, including compression, storage and dispensing, 500 kg/day capacity

Archetype 1: The counterfactuals are a diesel hybrid bus fleet, and an electric-only bus fleet

Archetype 1 characteristics

Electric counterfactual characteristics

- Total fleet: 55 buses, total mileage 8,160 km per day; operation from 6am to 9pm. <u>5 additional electric buses are assumed to be required</u>, compared to diesel and dual fuel, due to the range limitations of electric buses and/or the challenges of simultaneous charging. This also leads to <u>"additional dead mileage" compared to diesel</u>, in extra trips to and from the depot for re-charging.
- 15 MWh electricity per day
- One charging point per bus & upgrades to the "in-building" network to accommodate charging points
- Electricity network is upgraded to meet additional capacity requirements for buses to charge overnight (1.6 MW over 9 hours) at a cost of <u>£5 million</u> (of which the fleet operator share is £0.5 million)
- 1.6 MWh battery storage to allow peak-time charging of additional vehicles, access to grid revenues, cheaper electricity; 90% round trip efficiency.



Diesel counterfactual characteristics

- Total fleet: 50 buses, total mileage 8,000 km per day
- 3,000 litres of diesel per day

Archetype 1: cost assumptions (1/3)

Parameter	Assumption	Notes
Cost of capital	10%	Standard assumption for private investment.
Electricity price	14p/kWh	Based on government projections for commercial demand in mid 2020s.
Gas price	3p/kWh	Based on government projections for mid 2020s.
Electric double decker buses		
Bus capex per bus	£350k	Estimated capex in mid 2020s based on current prices.
Depreciation period	15 years	Typical bus lifetime. Note that bus routes in London are tendered on a 5 + 2 year basis.
Powertrain overhaul per bus	£80k	Representative costs of powertrain overhaul. We assume one major overhaul is required at the mid-point of the bus lifetime.
Maintenance per bus	£12k per year	Includes drivetrain maintenance and regular maintenance.
Fuel consumption	180 kWh / 100 km	Total consumption including heating / cooling.
Hydrogen double decker buses		
Bus capex per bus	£350k	Targeted future capex based on achieving scale-up of demand and production in Europe.
Depreciation period	15 years	Typical bus lifetime. Note that bus routes in London are tendered on a 5 + 2 year basis.
Powertrain overhaul per bus	£90k	Representative costs of powertrain overhaul. We assume one major overhaul is required at the mid-point of the bus lifetime.
Maintenance per bus	£16k per year	Includes drivetrain maintenance and regular maintenance.
Fuel consumption	8 kg / 100 km	Total consumption including heating / cooling.

Archetype 1: cost assumptions (2/3)

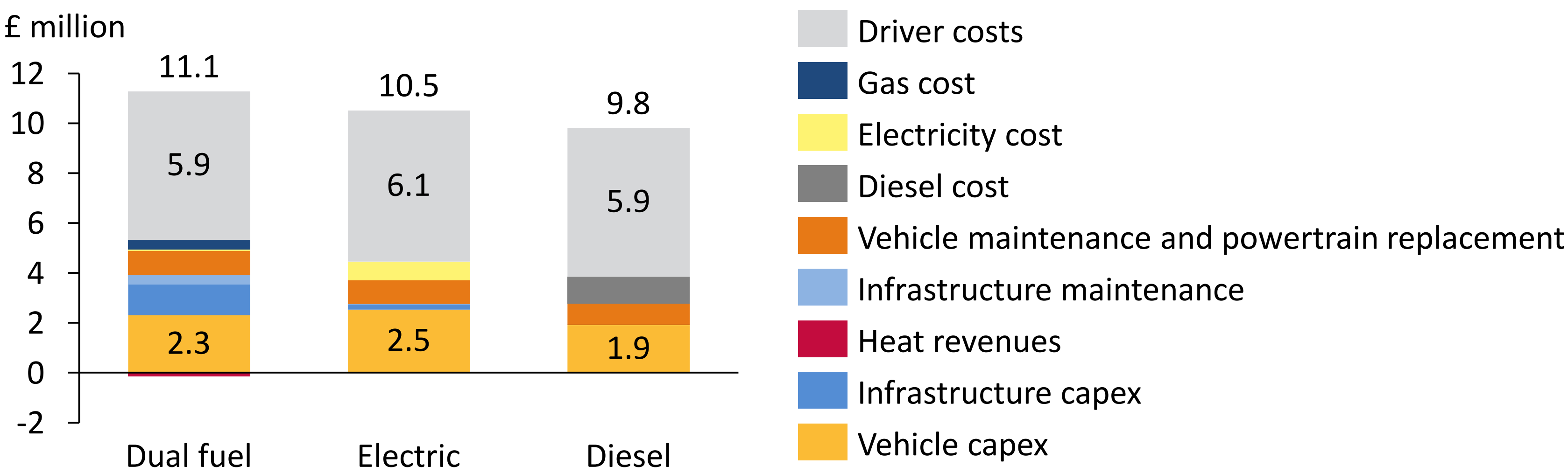
Parameter	Assumption	Notes
Diesel price	£1/litre	Including fuel duty, excluding VAT; Bus Service Operator Grant not included here).
Diesel double decker buses		
Bus capex per bus	£290k	Based on discussions with manufacturers.
Depreciation period	15 years	Typical bus lifetime. Note that bus routes in London are tendered on a 5 + 2 year basis.
Powertrain overhaul per bus	£20k	Representative costs of powertrain overhaul. We assume one major overhaul is required at the mid-point of the bus lifetime.
Maintenance per bus	£16k per year	Includes drivetrain maintenance and regular maintenance.
Fuel consumption	37.5 L / 100 km	Total consumption including heating / cooling.
Infrastructure		
Molten carbonate fuel cell capex	£5 million	Total cost for a 1MW system, based on average installed costs of systems to date. MCFC capex may fall with increasing production volumes but as of 2019 total global shipments remain relatively low.
MCFC depreciation period	10 years	Assumes an improvement to stack life vs 2010 figures.
MCFC fixed opex	5% of capex per year	Estimate based on a range of stationary fuel cell applications.
Pressure Swing Adsorption purification unit capex	£300k	For up to 500 kg/day capacity. Based on discussions with suppliers.
Hydrogen refuelling station (500 kg/day capacity) including storage and compression	£1.8 million	Installed costs; in line with FCH2JU targets for mid 2020s.
HRS depreciation period	15 years	In line with FCH2JU targets for mid 2020s.
HRS fixed opex	3% of capex per year	In line with FCH2JU targets for mid 2020s.

Archetype 1: cost assumptions (3/3)

Parameter	Assumption	Notes
Infrastructure		
Charging points capex	£10k per unit + £8k per bus (in-depot electricity upgrades)	One unit per bus.
Charging points depreciation period	15 years	Assumed to last over lifetime of bus.
Charging points fixed opex	5% of charging point capex per year	Standard estimate based on other infrastructure costs.
Battery storage capex	£57/kWh	Includes balance of plant; based on battery projection costs from Bloomberg New Energy Finance, June 2018 (+ balance of plant)
Battery storage depreciation period	10 years	Assumed to require one replacement during bus lifetime.
Battery storage fixed opex	5% of capex per year	Standard estimate based on other infrastructure costs.
Total network upgrade costs for fully electric fleet	£5 million	Assumption based on a range quoted by UK Power Networks.

The net annual costs for a MCFC dual fuel fleet (including annualised capex) represent around a £1.3m premium compared to a diesel fleet

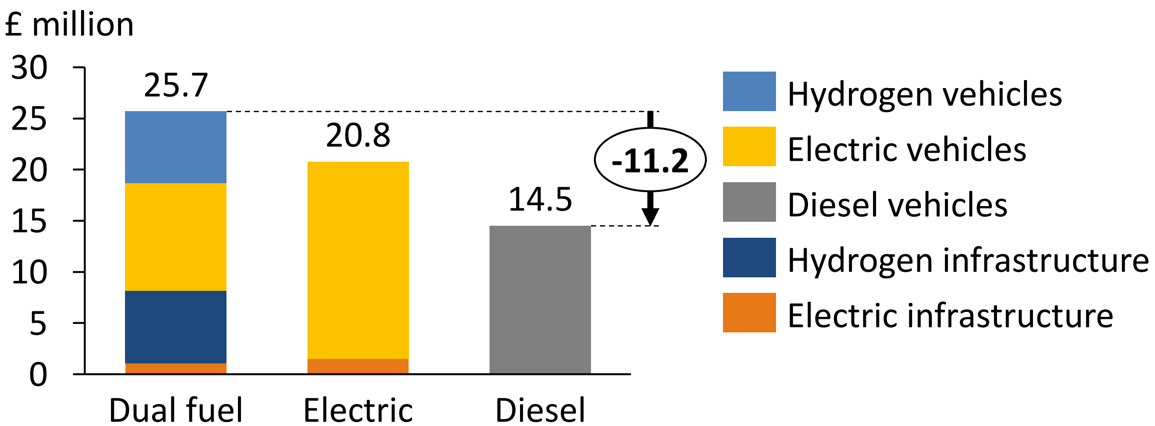
Net annual costs - fleet operator owned infrastructure (10% cost of capital)



- The capital costs, operational costs and revenues are combined into overall annual costs by calculating the cost of repaying a loan over the technology lifetime (e.g. 15 years), using a 10% cost of capital.
- Overall, the net annual costs are driven largely by the driver costs and the total bus capex (which are both assumed to be higher in the case of electric vehicles, due to the additional vehicles and dead mileage). As such, a dual fuel solution could be more cost-effective than an electric-only option, **if the cost of hydrogen (and the associated infrastructure) is sufficiently low**. However, in this case, the dual fuel solution is more costly than the electric-only option overall, largely due to the high MCFC cost.
- **The next slide considers the impact of different hydrogen prices on the fleet operator net annual costs, and considers the possible annual cashflows for a third party "Dual Fuel Hub" supplier providing hydrogen at different prices.**

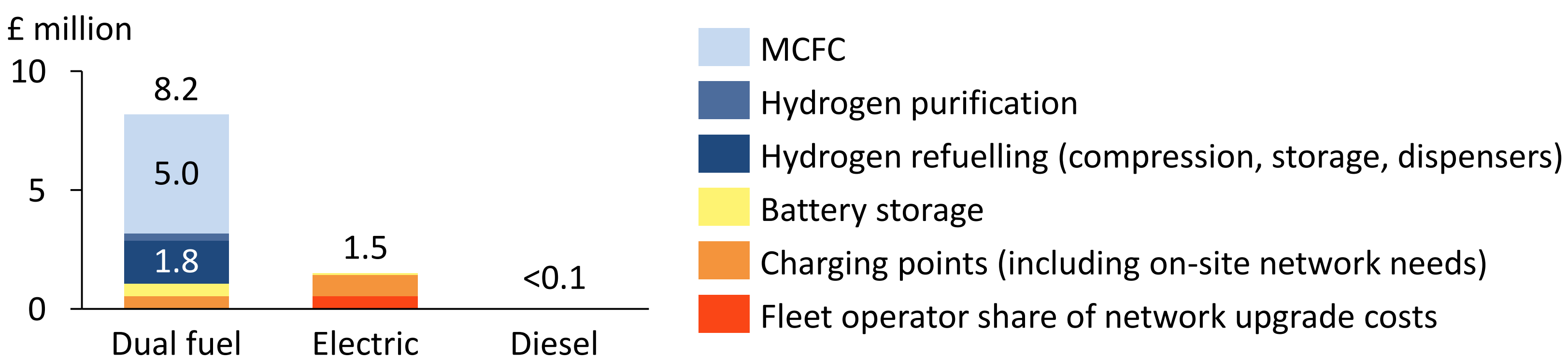
From a fleet operator's perspective, the total capital cost premium for this "Dual fuel solution" would be in the region of £11 million

Capex breakdown for different bus fleets, including infrastructure and vehicles



- Total capex premium relative to diesel is estimated as £11.2 million for dual fuel, and £5.7 million for electric only.
- **Vehicle costs** are the main component of this in both cases, but the hydrogen infrastructure costs are also significant.

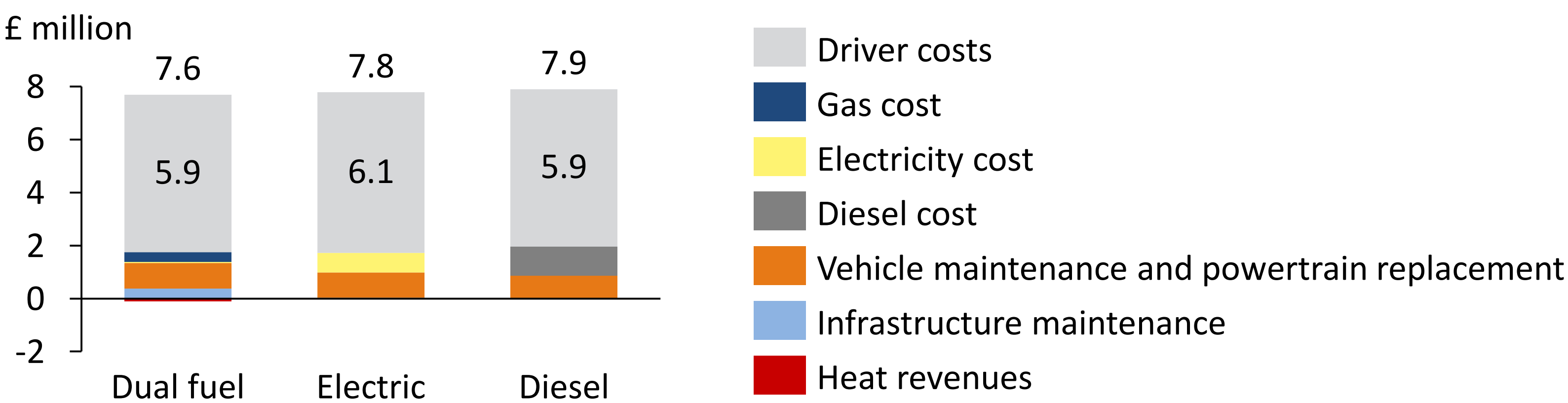
Capex breakdown for refuelling infrastructure



- The **hydrogen refuelling equipment** itself accounts for the greatest share of the infrastructure costs

However, on the basis of operating costs and revenues, this solution could save hundreds of thousands of pounds a year compared to diesel

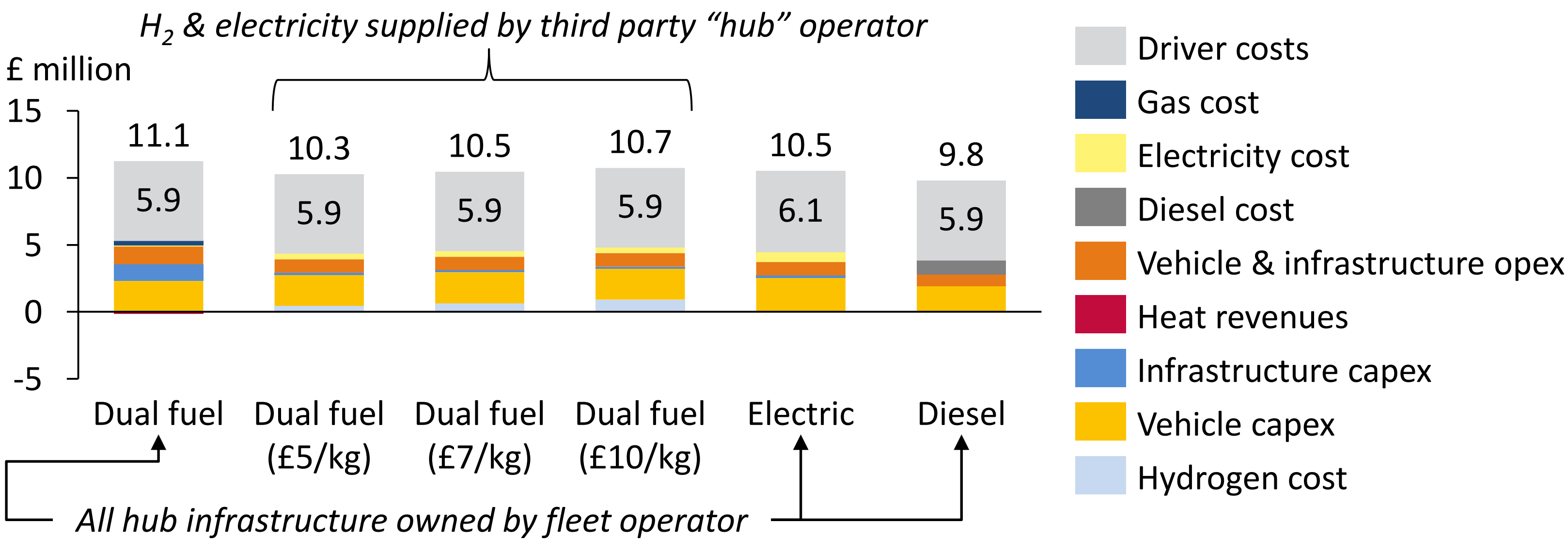
Breakdown of net annual operating costs including fuel, infrastructure and vehicles



- **Driver costs** dominate the overall operating costs for bus fleets, due to the high number of operational hours per year. In the case of fully electric fleets, 5 extra buses are assumed to be required due to range restrictions, and additional "dead mileage" is incurred in additional trips to and from the depot for recharging. This increases the total driver costs, as well as the total fuel cost, without increasing the total revenue from customers, and gives the Dual Fuel solution an advantage over the electric-only solution. This could also apply to other fleets with intensive duty cycles.
- **Fuel costs** are lowest in the Dual Fuel case due to the relatively low cost of gas compared to electricity and diesel, even after accounting for the efficiency losses of the MCFC (vs. direct use of electricity).
- If there is a local demand for heat, the Dual Fuel hub could benefit from **revenues for heat** generated by the fuel cell. Here, 5p/kWh is used as an upper bound, which is optimistic and does not account for the costs of delivering the heat. However, **even in this "best-case scenario", these revenues are very low** in the context of the overall fuel costs, reflecting the low value of heat compared to transport fuel.

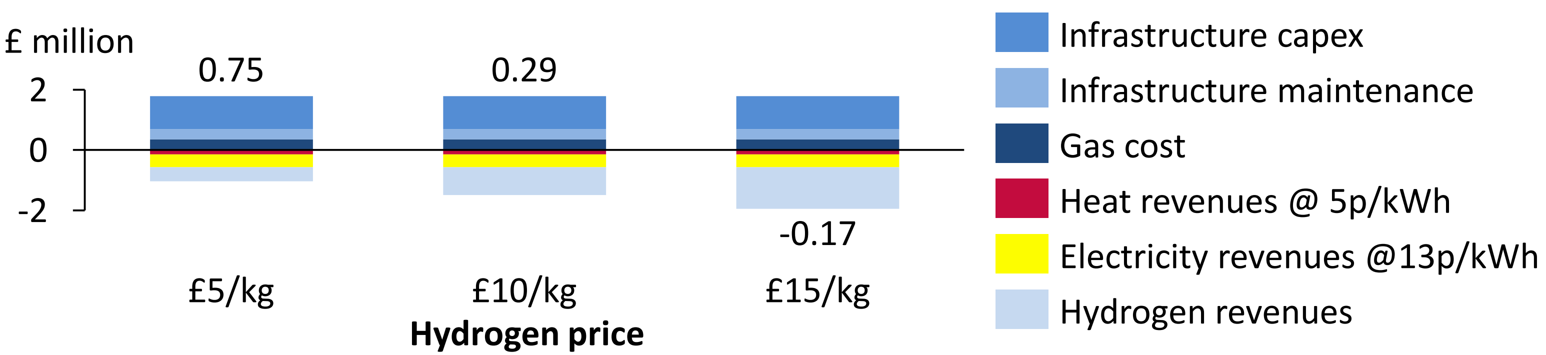
To compete with an 100% electric fleet, a third-party fuel supplier would need to make hydrogen available below £7/kg

Net annual costs for Dual Fuel fleet operators purchasing hydrogen at various prices (10% cost of capital)



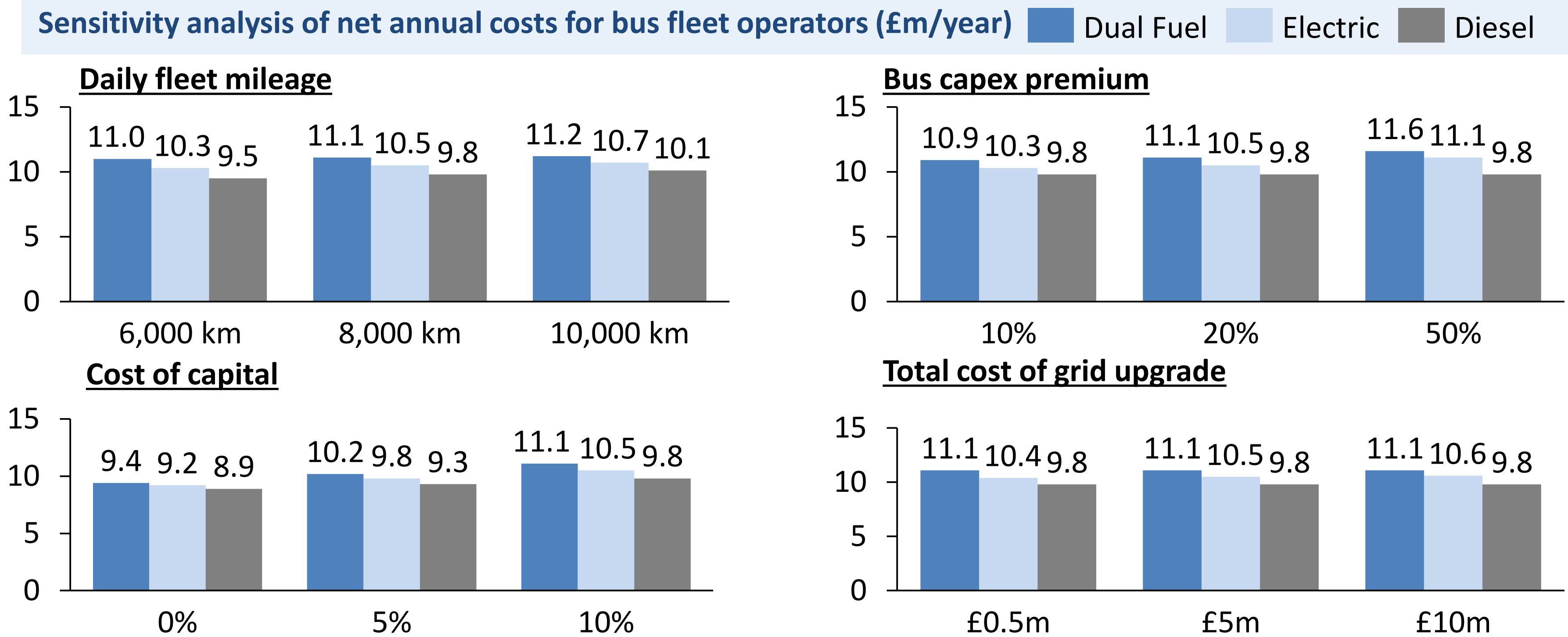
Net annual costs for a third party hub operator selling hydrogen, heat & electricity from an MCFC

- However, a third party **MCFC operator** would need to sell hydrogen at **£15/kg for a positive cashflow**



When using an MCFC, the dual fuel solution is the most costly option, but the total cost gap closes for fleets with high daily mileage

Sensitivity analysis of net annual costs for bus fleet operators (£m/year)

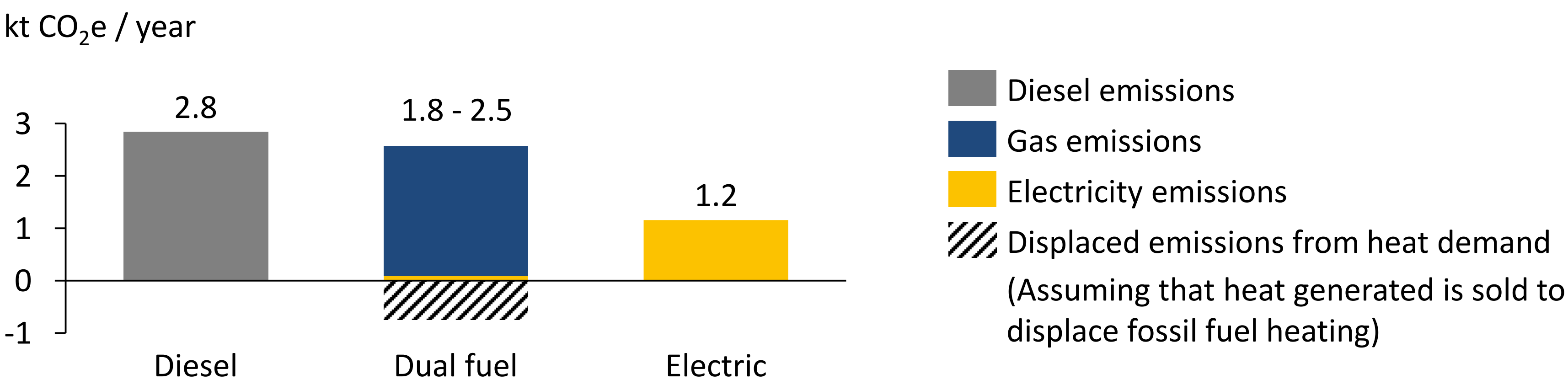


Key impacts on business case for Dual Fuel bus fleet with a MCFC producing electricity and hydrogen onsite

- As fleet daily mileage increases, the total cost gap between dual fuel and diesel closes, and the advantage of electric-only fleets reduces. However, the dual fuel option is still the most costly.
- The total cost of the dual fuel fleet and the electric-only fleet relative to the diesel fleet (and in relation to each other) also depends strongly on the total fleet capex; in this analysis we assume that a few additional electric buses are required vs hydrogen buses, and that the capex per bus is the same for electric and hydrogen buses. The total cost of the grid upgrade has relatively little impact on the total cost for the electric-only fleet.

On a well-to-wheel basis, the MCFC-based dual fuel solution offers lower carbon emissions savings than electric vehicles

Well-to-wheel emissions for different fleet types



Overall, an electric-only fleet would offer much greater emissions savings than a dual fuel fleet, assuming that the gas used by the MCFC is 100% natural gas. However, in a future with a decarbonised gas grid (e.g. with biomethane and/or hydrogen), emissions from an equivalent system could be closer to the electric-only fleet case. In areas with a constrained electricity network, co-locating hydrogen refuelling with onsite electricity generation from a fuel cell could be an attractive solution to meet high levels of demand for zero-emission fleet vehicles.

Key assumptions

- The lower bound for the dual fuel emissions is calculated based on assuming that the heat is supplied to an end-user to displace a gas driven heating technology that is 85% efficient.
- Gas emissions factor: 0.212 kgCO_2eq./kWh (includes production and transport emissions).
- Electricity emissions factor (projected value for marginal UK grid electricity in 2025): 0.22 kgCO_2eq./kWh
- Diesel emissions factor: 2.63 kgCO_2eq./L – for an average biofuel blend

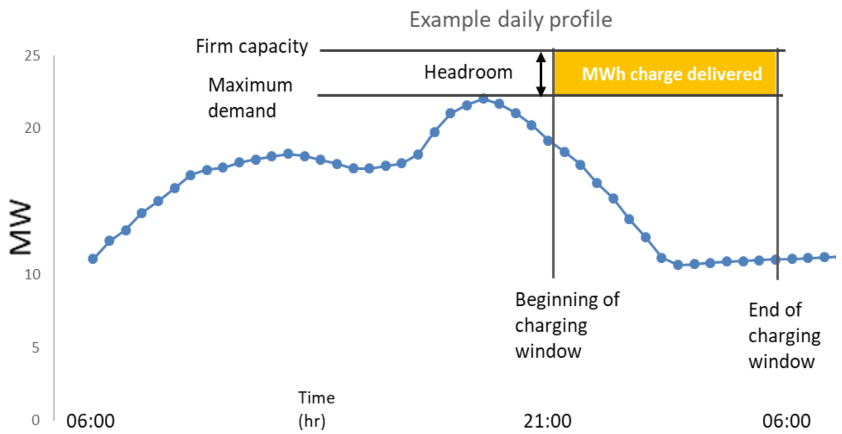
The potential scale of avoided upgrade costs for a “dual fuel” solution depends on the existing network loading

Capacity constraints for grid connections

- To understand the potential network benefits of “dual fuel” solutions, we need to consider the areas with potential demand for electric vehicles (specifically, fleet vehicles looking to charge simultaneously) and the **capacity of the existing electricity network** in these areas to **accommodate additional demand from electric vehicle fleet charging**.
- Seven substations with capacity constraints were identified in areas with large numbers of fleet depots (and thus potential for high levels of additional electricity demand for fleet vehicles) – **see slides 58-60.**
- The capacity for these specific substations can be assessed in a few different ways (illustrated on the following slides):
  - **24/7 firm connections**
    - Currently, when new electric fleets request connections on the UK Power Networks network, they are constrained by the headroom on a substation
    - Capacity is determined by the existing headroom at the **underlying peak demand** (even if this is outside of the expected charging period)
  - **Timed connections**
    - Capacity is determined by the underlying peak demand **during the specific charging period**
  - **Smart charging**
    - The available connection capacity can follow the underlying profile “filling in the gaps”

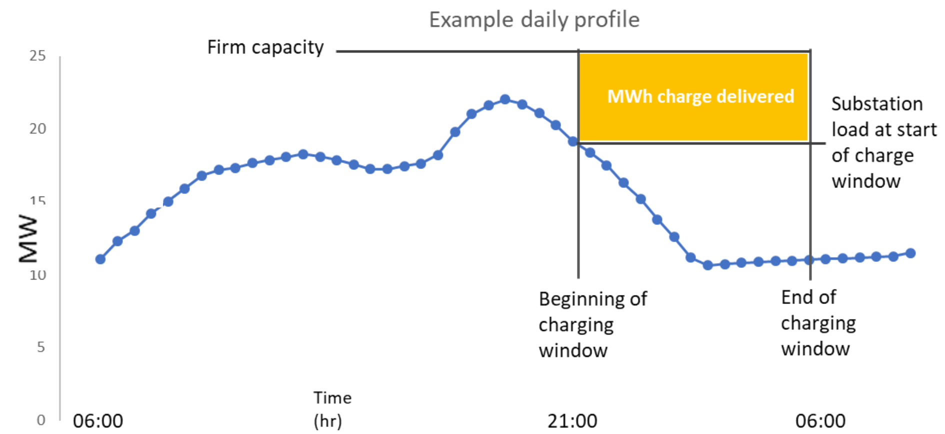
Non-profiled connections are the default case for fleets seeking new connections, but profiled connections have also been demonstrated

24/7 firm connection



- A 24/7 firm connection limits the amount of energy which could potentially be supplied to an electric fleet, based on the capacity of the gap between the peak demand of the consumption profile and the total or firm capacity of the substation which is called the headroom.
- With this type of connection, the amount of electrical power delivered is limited by the capacity of the grid connection installed and the length of the charging window.

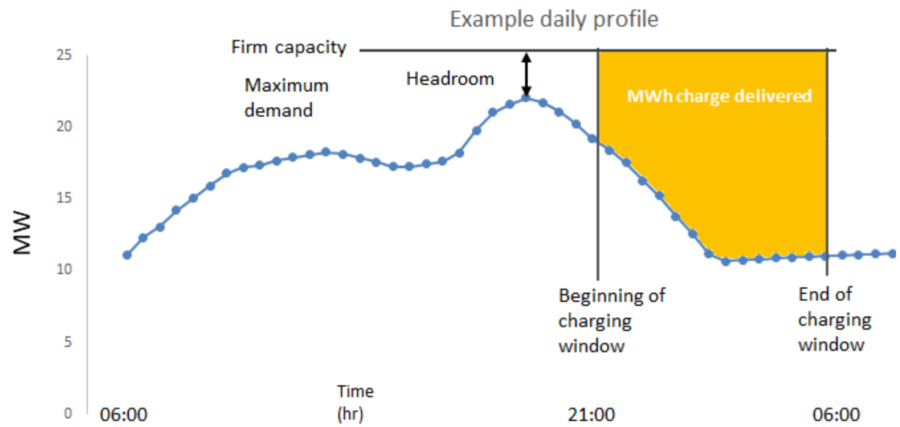
Timed connection



- A timed connection allows the depot to take up the spare power capacity in the substation at the start of the charge window and maintain that charge rate throughout the charge cycle.
- On this charge cycle, the amount of electrical power delivered is limited by the length of the charging window and the gap between substation load at the start of charging and the firm capacity of the substation.
- This would supply more energy to the fleet than a 24/7 firm connection.

“Smart charging” could maximise the number of vehicles which could be accommodated on a substation

Smart charging assumptions

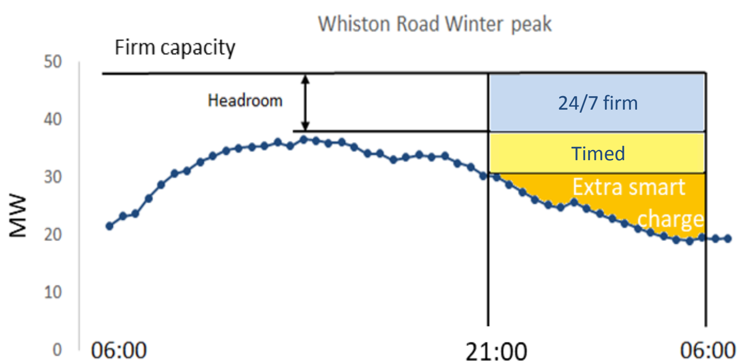


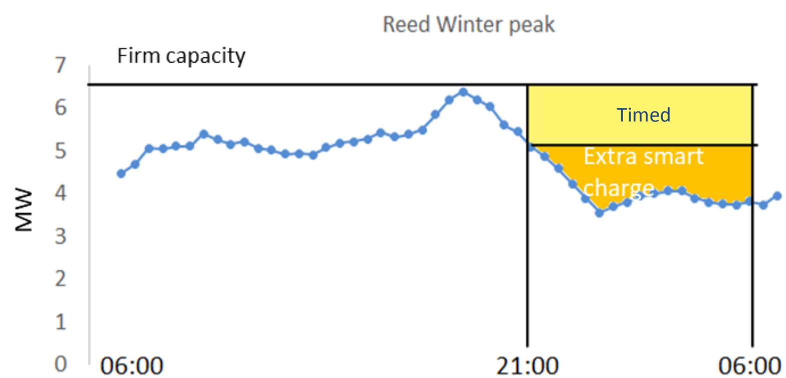
- Smart charging maximises the energy delivered to vehicles at the depot while not exceeding the firm capacity of the substation.
- The electrical demand of the chargers is moderated with the other demands on the substation to keep the power delivered by the substation at its firm capacity for the duration of the charging cycle.
- The amount of energy which could be delivered depends on the length of the charging window and the size of other loads on the substation during the charging window.

Load profiles differ significantly between different substations, meaning that the capacity for new timed connections varies

Examples for specific substations

- A ‘peak load’ winters day is a day selected from the UK Power Networks substation data, based on the highest recorded loading for the substation over the year.
- The electrical profiles of substations can be significantly different and would mean that electrical fleets wishing to connect to the substation would benefit from different grid connections.
- The charts below illustrate these differences for Whiston Road and Reed substations:



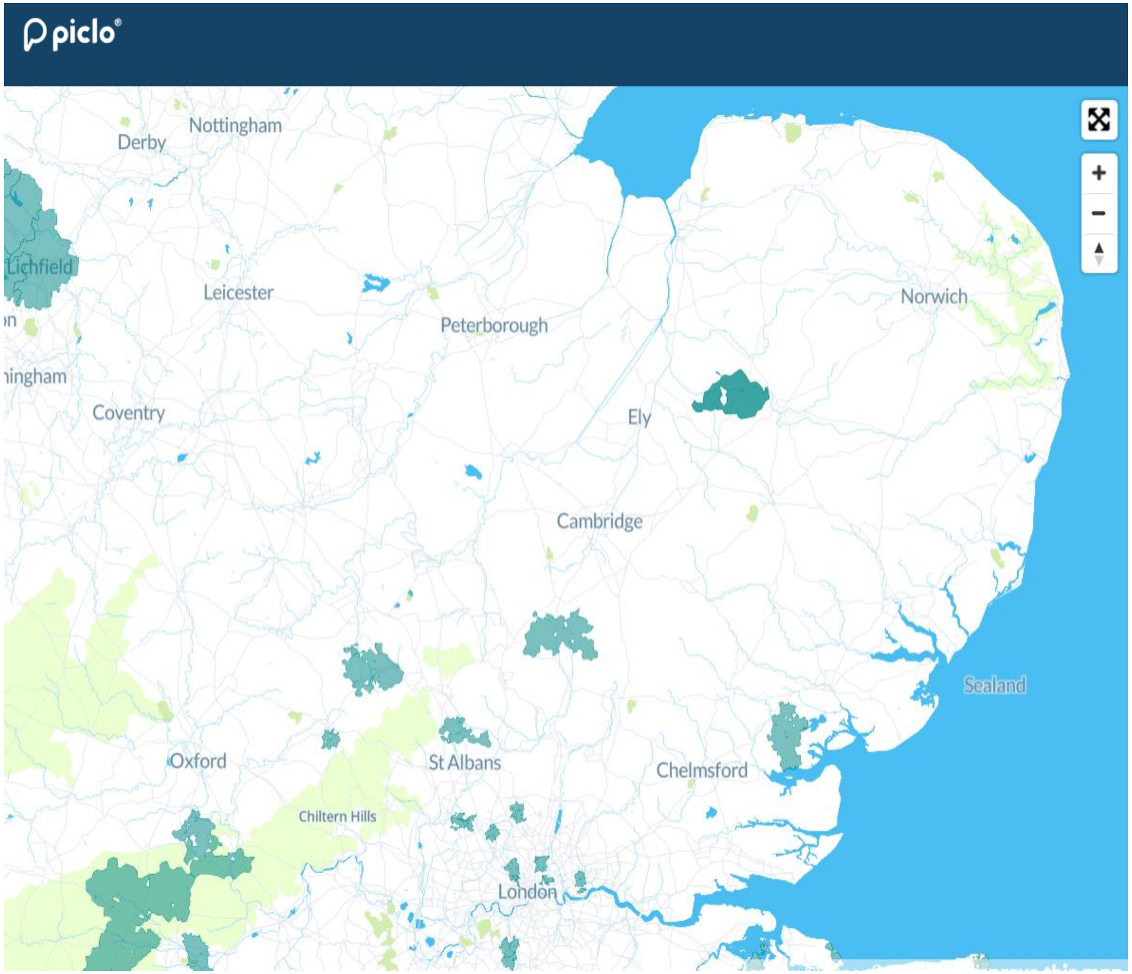


- Note: in some cases, a timed connection with a **later start time** may allow more vehicles to be charged, despite the shorter charging window, if the overall available energy in that window is greater due to the increased available capacity at night.
- For example, the Reed substation (right) would have sufficient energy to charge **20 more buses** on a profiled connection window starting at 12PM (rather than 9PM), due to the increased MW capacity of the connection.

Capacity constraints within the UK Power Networks & Cadent areas were identified by considering areas where UK Power Networks is tendering for reinforcement deferral

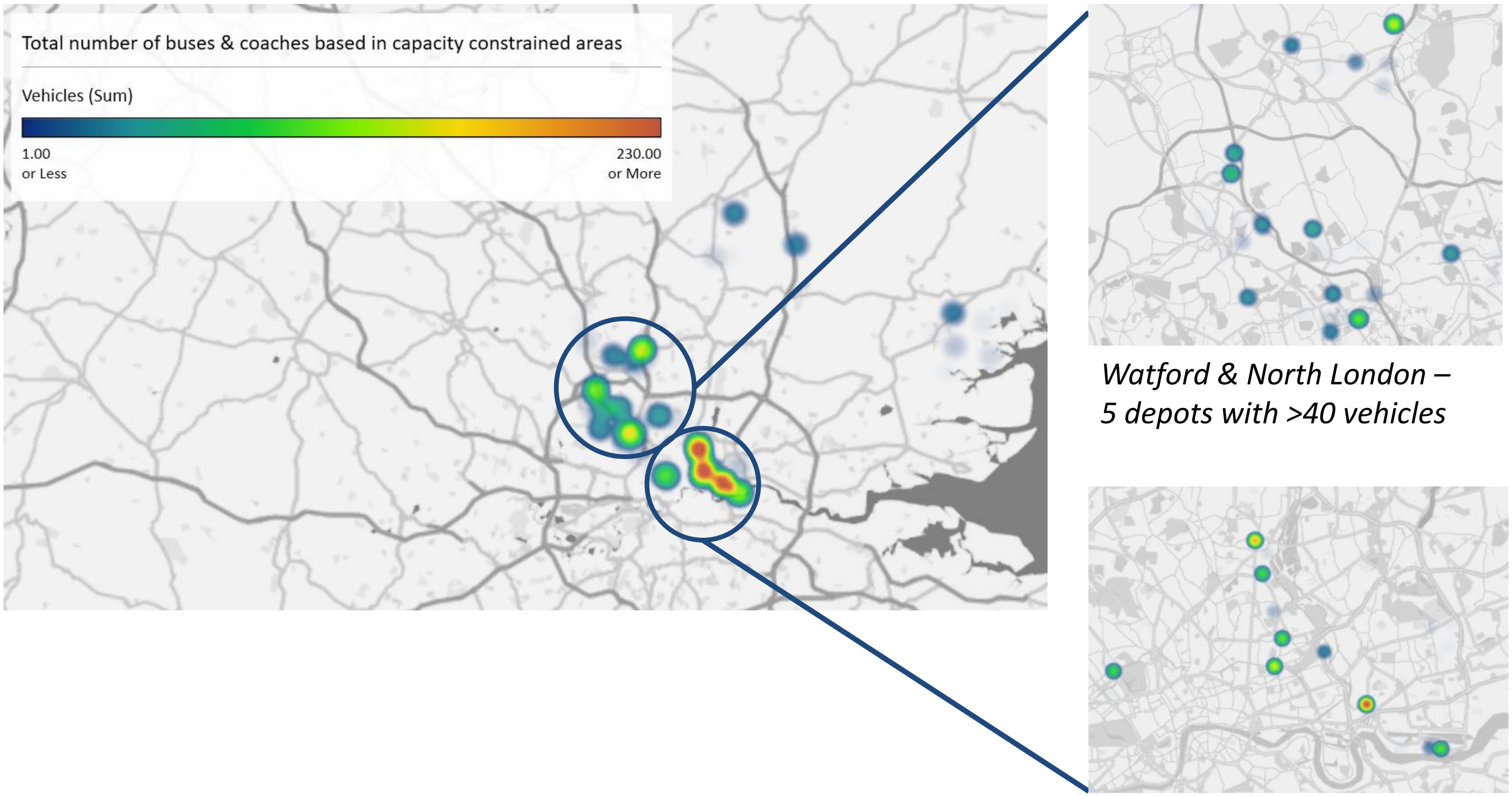
Piclo data shows the areas with existing constraints on primary substations

- The map shows the areas in which UK Power Networks is seeking reinforcement deferral to ease the local capacity constraints.
- Additional loads for electric vehicles in these areas would be likely to trigger upgrades to primary substations (depending on the overall profile and the capacity for timed or profiled connections).
- By identifying bus and HGV depots in these areas, we can assess the scale of potential demand for Dual Fuel solutions which could avoid the need for network upgrades.



Bus and coach depots within constrained areas were identified, with the greatest numbers of buses concentrated in London

Bus/coach depots in constrained areas form several “clusters” in London and Hertfordshire



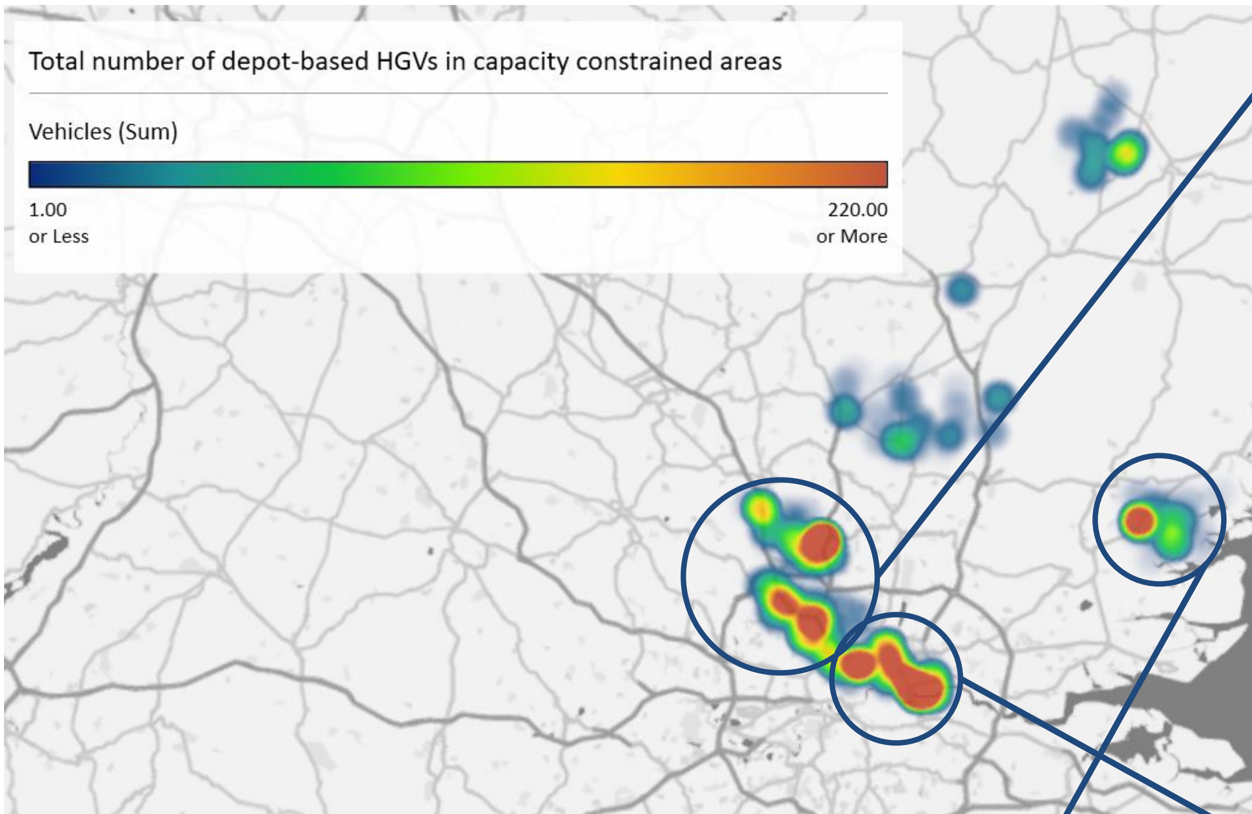
Watford & North London – 5 depots with >40 vehicles

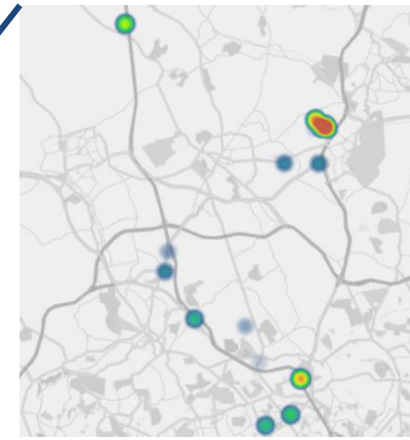
Central London - 7 depots with >40 vehicles

Source: Vehicle Operator Licensing data
https://www.vehicle-operator-licensing.service.gov.uk/search/find-lorry-bus-operators/

Location data for HGV fleets in constrained areas revealed several clusters of depots which could offer opportunities for a Dual Fuel hub

HGV depots in constrained areas





Watford & North London – 11 depots with >40 vehicles

Colchester / Chelmsford – 4 depots with >40 vehicles

Central London - 16 depots with >40 vehicles

Source: Vehicle Operator Licensing data
https://www.vehicle-operator-licensing.service.gov.uk/search/find-lorry-bus-operators/

Estimated number of buses and fleets based in depots in capacity-constrained areas

The following depots could be considered as potential end-users for a Dual Fuel hub

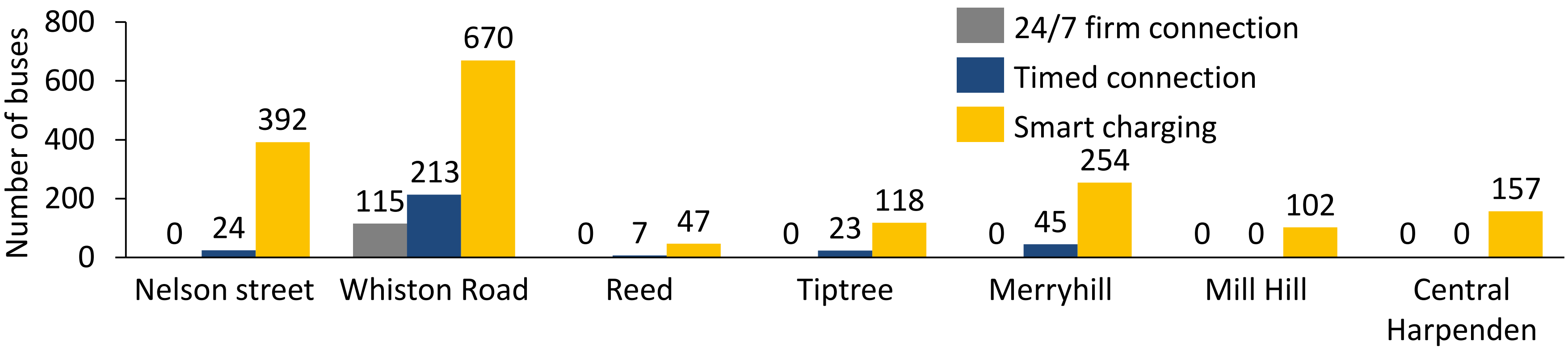
Bus operator	Depot(s)	Number of buses
Metroline & London Sovereign	Edgware	189
Arriva	Hackney	201
Arriva	Tottenham & Stamford Hill	273
East London Bus & Coach Company	West Ham	230
Arriva & Mullanys Coaches	St Albans Road, Watford	117
Universitybus Ltd	Hatfield	100

Fleet operator	Depot	Number of HGVs
UPS Ltd	Kentish town	140
DHL Supply Chain Ltd	Hatfield business park	115
Royal Mail	Hatfield business park	100
Yodel	Hatfield business park	110

Source: Vehicle Operator Licensing data
https://www.vehicle-operator-licensing.service.gov.uk/search/find-lorry-bus-operators/

Of the seven substations assessed, only Whiston Road could accommodate more than 50 electric buses on the basis of a simple profiled connection

Number of buses accommodated under different connection types



Key assumptions

- 'Peak load' winters day is a day selected from the UK Power Networks substation data, based on the highest recorded loading for the substation over the year.
- The charging time for each of the profiles is 9 hours from 9PM to 6AM.
- The daily charging demand is 300 kWh per bus (based on a daily mileage of 160 km, fuel consumption 180 kWh per 100 km).

Conclusions

- Assuming that only "profiled connections" are available for fleets, most new connections for large electric fleets on constrained substations are likely to require upgrades at the primary substation level.
- ***However,*** if "smart" charging (e.g. smoothing demand using a battery for peak demand days) is made available as an option, many substations would be able to accommodate hundreds of electric fleet vehicles without requiring upgrades.

Dual fuel bus fleets could be attractive compared to electric fleets if low cost hydrogen is available but MCFCs are unlikely to provide this

Archetype 1: Key conclusions for a Dual Fuel bus fleet using a MCFC to generate electricity and hydrogen

- Overall, largely due to the high costs of MCFCs (and the emissions associated with a gas-based technology), a Dual Fuel fleet with onsite production using this technology is unlikely to be attractive to a fleet operator from an economic or emissions benefit perspective. **An electric-only fleet** (charging from the grid) is **likely to be more cost-effective even when costs of upgrading the network are accounted for**, as well as offering higher overall emissions savings. In fact, the analysis suggests that when comparing these two specific cases, the cost of upgrading the electricity network is relatively insignificant (over the project lifetime) compared to the impacts of other cost components such as driver costs, and the relative price of hydrogen and electricity (notably including the cost of the MCFC in the Dual Fuel case).
- However, the case for a Dual Fuel bus operator supplied by a third-party electricity and hydrogen supplier could be commercially attractive (compared to an electric-only fleet) under the following conditions:
  - Bus capex is equivalent for hydrogen and electric buses
  - A few additional vehicles are required for electric bus fleet due to the range limitations (possible for more energy-intensive bus-routes), leading to higher dead mileage and increased driver costs
  - Total price of dispensed hydrogen below £7/kg
- While at current technology costs the MCFC production route is unlikely to result in hydrogen costs below £7/kg, alternative routes could be considered in which hydrogen is available at a cost of £5/kg or lower.
- Archetype 2 considered the costs of large-scale hydrogen production and distribution, using a fleet of trains as an “anchor demand”, and shows that hydrogen could be available at £5–6 per kg under certain conditions (see slides 35 and 36).

Contents

Archetype 2: Large scale offsite renewable electrolysis to supply hydrogen for trains (or other large fleet demand)

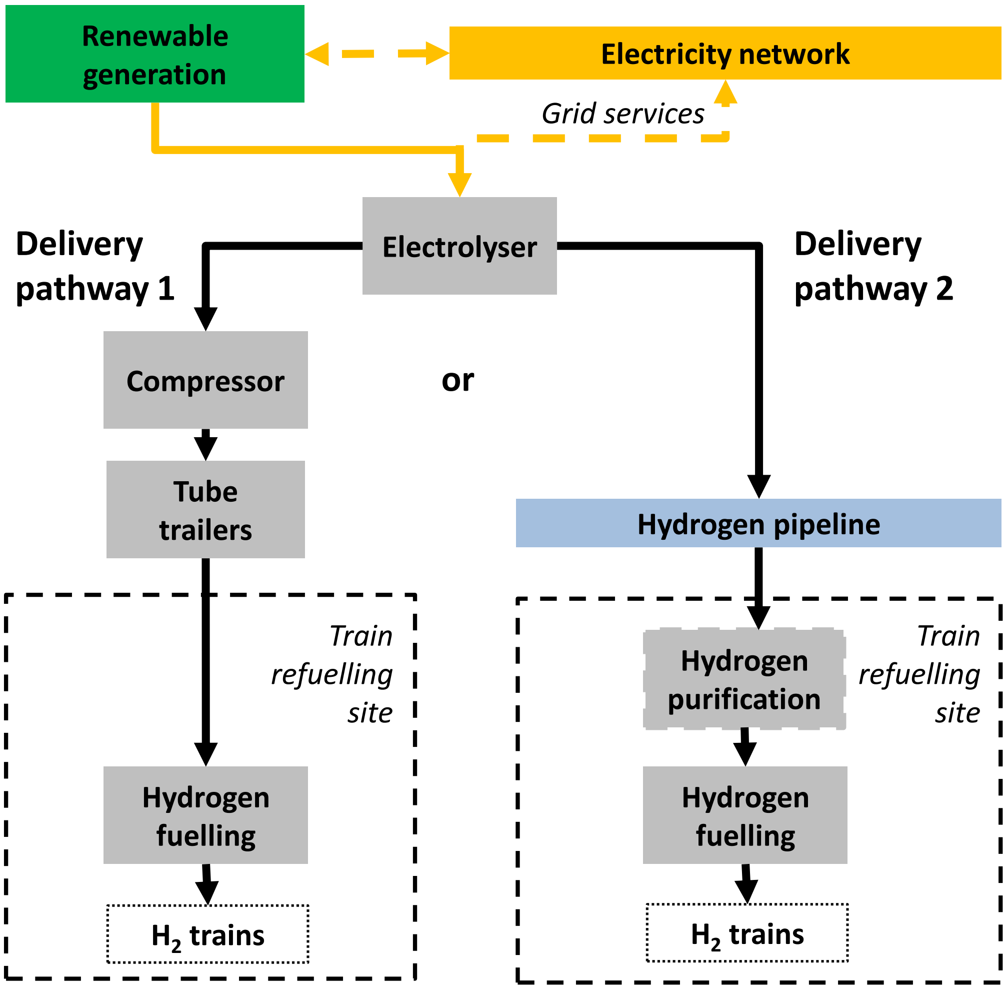
Archetype 2 characteristics

End-user characteristics

- Total fleet: 10 hydrogen trains, total mileage 10,000 km per day; 28 kg H_2 per 100km; 360 days per year
- 2.8 tonnes of hydrogen per day

Hydrogen supply options

- Hydrogen fuelling, including compression and dispensing, 3 tonnes/day capacity.
- All assets not on the train refuelling site are assumed to be owned by a third party:
- Electrolyser & compression: 10 MW; 4.3 tonnes/day capacity at 100% load factor
- 8 tube trailers (& 4 tractors) for delivery to site (200km round trip delivers 750kg per tube trailer) OR dedicated pipeline, 5km



Note that tube trailer delivery and pipeline delivery routes have different onsite and offsite compression needs

Archetype 2: The counterfactual is a self-powered diesel train fleet; 100% battery electric trains are assumed not to be applicable

Archetype 2 counterfactual characteristics

Diesel counterfactual characteristics

- Total fleet: 10 diesel trains, total mileage 10,000 km per day; 120 L diesel per 100 km; 360 days per year
- 12,000 litres of diesel per day

- Battery electric trains may be suitable to replace some diesel routes, but in general are unlikely to be more cost effective than hydrogen trains in longer distance applications, due to the lower energy density of batteries (and hence a higher number of additional carriages required for the powertrain).

Archetype 2 counterfactual assumptions

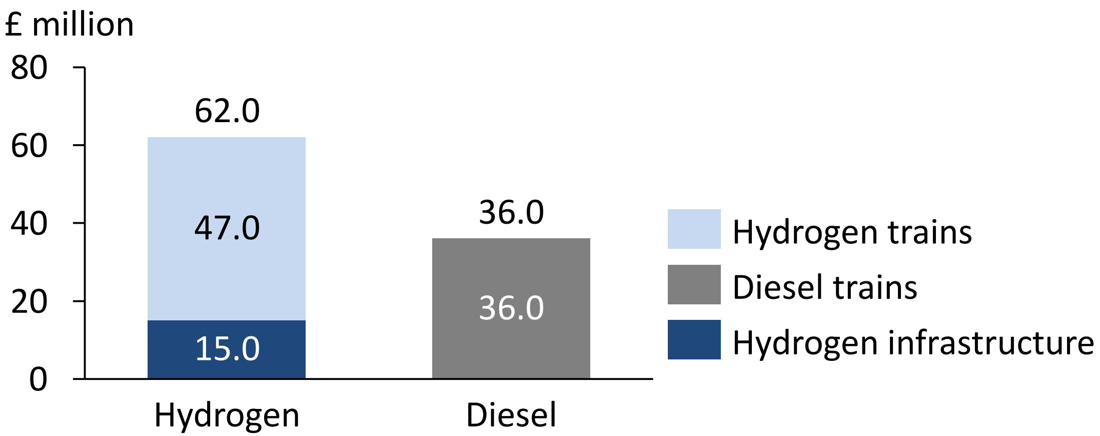
Parameter	Assumption	Notes
Diesel train cost	£3.6 million	Based on discussions with Alstom
Diesel train depreciation period	20 years	Based on discussions with Alstom
Diesel train maintenance	£140k per year	Based on discussions with Alstom
Diesel price	£0.52/L	Red diesel (price includes partial fuel duty rebate, exclusive of VAT)

Archetype 2: cost assumptions

Parameter	Assumption	Notes
Cost of capital	10%	Standard assumption for private investment
Hydrogen train capex (per train)	£4.7 million	Based on discussions with Alstom
Hydrogen train depreciation period	10 years	Based on discussions with Alstom – note this is half that of diesel trains
Hydrogen train powertrain overhaul during lifetime (per train)	£1 million	Based on discussions with Alstom
Hydrogen train regular maintenance (per train)	£126k per year	Based on discussions with Alstom
Hydrogen station capex (including compression and storage)	£15 million	In line with FCH2JU targets for mid-2020s, for high capacity stations
Hydrogen station maintenance cost	3% of capex per year (£450k/year)	In line with FCH2JU targets for mid-2020s
Hydrogen station electricity consumption	5 kWh/kg	For dispensing and compression
Electricity cost at hydrogen station	14 p/kWh	
Electrolyser & compressor capex	£10 million	Total installed cost
Electrolyser & compressor maintenance	2% of capex per year	In line with FCH2JU targets for mid-2020s
Depreciation period	15 years	In line with FCH2JU targets for mid-2020s
Electricity consumption for compression	6 kWh/kg	For high pressure transport
Tube trailers & tractors for deliveries – total capex	£2.4 million	Based on 4 tractors and 8 trailers
Tube trailers & tractors - depreciation period	15 years	Based on industry consultation
Tube trailer delivery opex (drivers, fuel & logistics)	£550k/year	Based on a 200 km round trip for deliveries
Pipeline cost	£5 million	Based on £1 million per km
Pipeline depreciation period	45 years	

From the train operator's perspective, the total capital cost premium for ten hydrogen trains would be in the region of £26 million

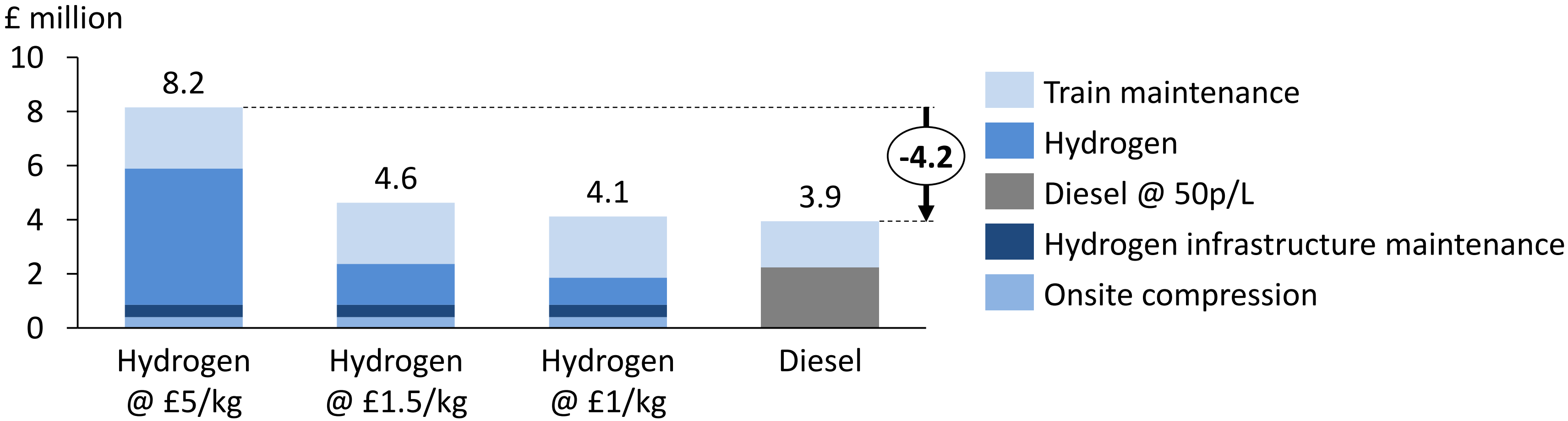
Capex breakdown for hydrogen and diesel train fleets, including onsite infrastructure and vehicles



- The total capex premium relative to diesel is estimated as £26 million for hydrogen trains.
- **Refuelling station costs** are high and are assumed to constitute the largest component of the capex premium for the train operator. However, **train costs** are also a significant component of the capital cost premium: note that hydrogen trains are assumed to have a depreciation period of 10 years, vs 20 years for the diesel trains.
- Hydrogen is assumed to be supplied by a third party who owns and operates the electrolyser and the associated hydrogen delivery vehicles (or pipeline).

Due to the low price of diesel for trains, to be competitive on an operating cost basis, very low cost hydrogen would need to be available

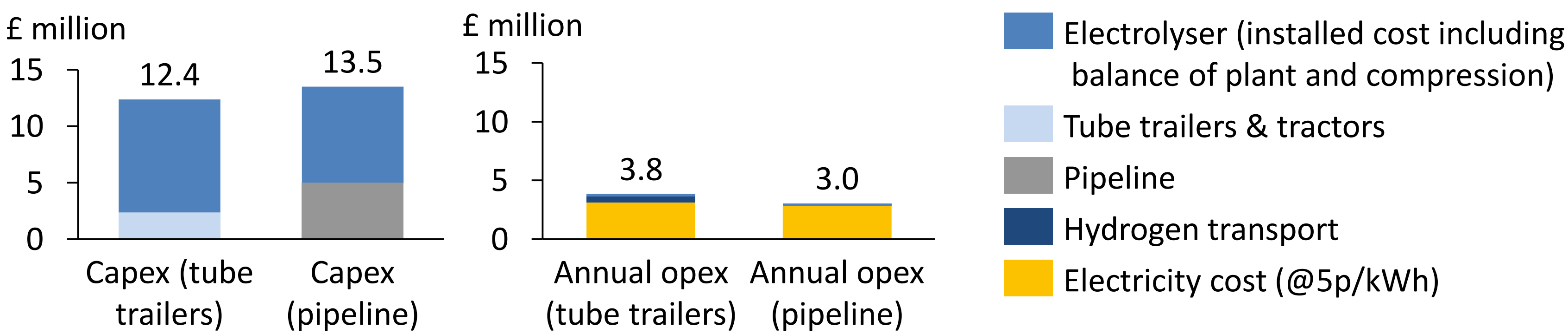
Annual operating costs for hydrogen and diesel train fleets, including fuel, infrastructure and vehicles



- **The graph shows the annual operating costs for a train fleet, including train and infrastructure maintenance, and fuel, for different costs of supplied hydrogen. Capital costs are not included.**
- Diesel trains can run on "red diesel", which is intended for non-road applications, and benefits from a fuel duty rebate and is therefore much cheaper (fuel duty is 57.95p/litre for diesel for road vehicles). This means that in order to compete with diesel on an operating cost basis, for a fleet of 10 trains hydrogen would need to be available to the operator at £1/kg or below.
- **The next slide** shows that for a hydrogen supplier to achieve a positive net annual cashflow (based on electrolysis with an electricity cost of 5p/kWh), overall hydrogen revenues would need to be in the region of £6/kg, and as such **a significant subsidy would be required to make hydrogen available at a competitive price for trains**. Renewable hydrogen could be eligible for RTFCs (Renewable Transport Fuel Certificates), which could have a value between £2 and £7 per kg for hydrogen.

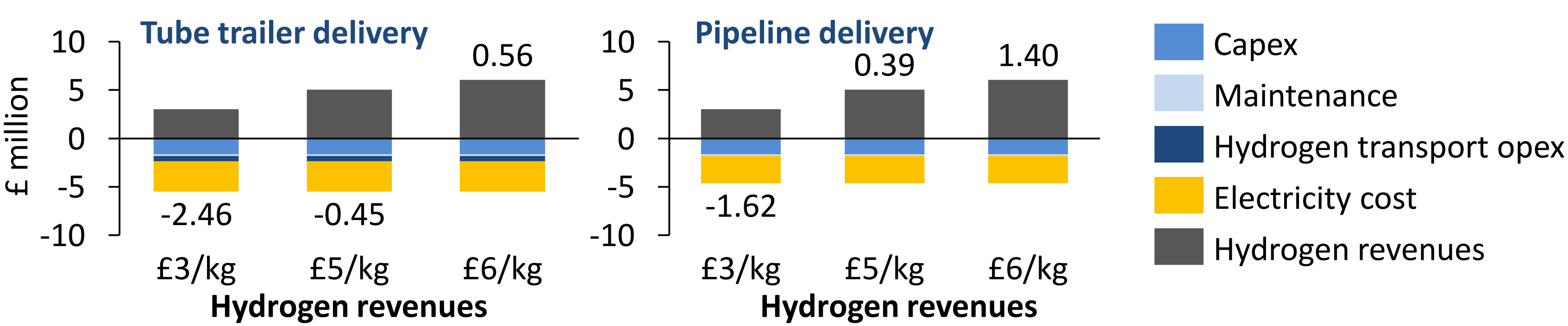
The price of hydrogen available for trains will depend on the costs to the hydrogen supplier, and revenues available e.g. from RTFCs

Total capex and opex breakdown for third party hydrogen supplier



Net annual cashflow for third party hydrogen supplier with different H_2 revenues (10% cost of capital)

- The capital costs are combined with the operational costs and revenues by calculating the cost of repaying a loan over the technology lifetime (e.g. 15 years), assuming a 10% cost of capital, to give the overall net annual cashflow for the hydrogen supplier. On this basis, total revenues of around £5-6/kg hydrogen would be required for a net positive annual cashflow, depending on the delivery method.



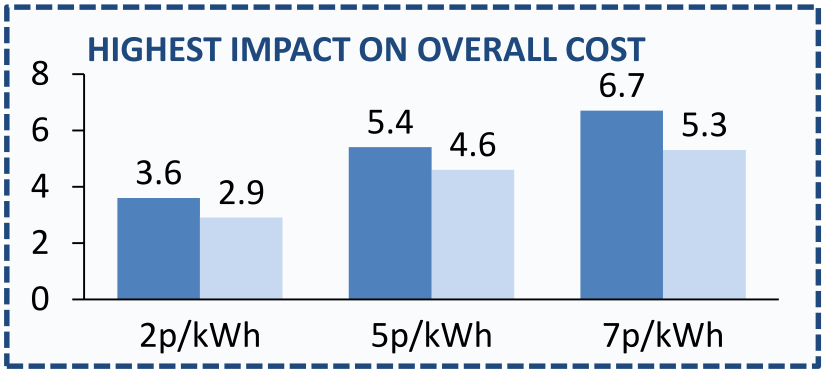
Pipeline lifetime assumed to be 45 years; other technology lifetimes 15 years

Electricity prices have a high impact on the overall cost of electrolytic hydrogen; very low prices are required for a competitive production cost

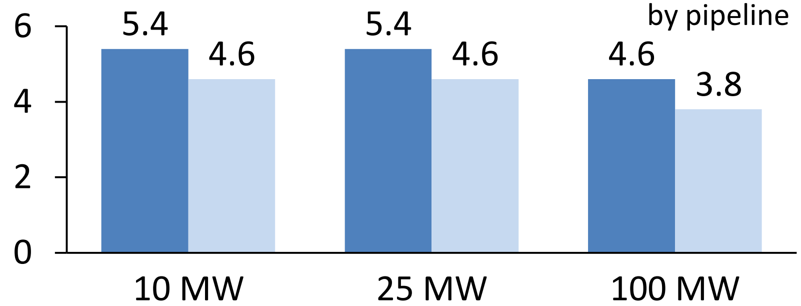
Sensitivity analysis of costs of fuel cell grade hydrogen delivered to a hydrogen refuelling station (£/kg)

Hydrogen delivered by tube trailers
Hydrogen delivered by pipeline

Electricity price

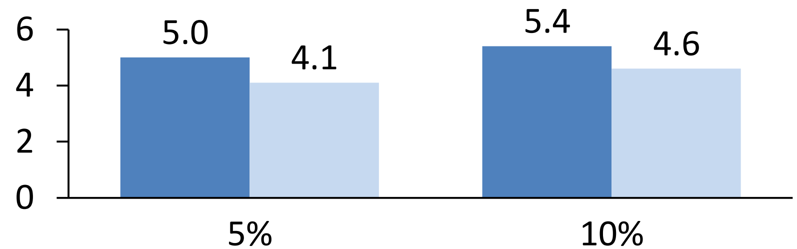


Electrolyser size (cost per MW reduces with scale)*



Pipeline cost

Cost of capital

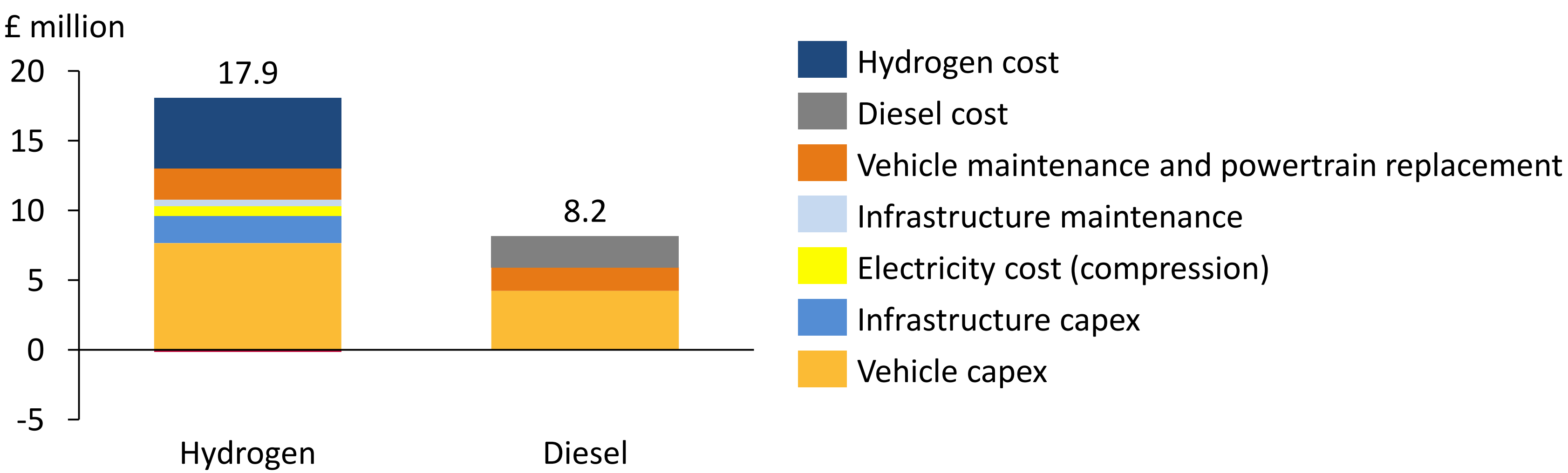


- Pipeline delivery likely to be more cost-effective than tube trailer delivery (for pipeline costs up to £10m)
- Low electricity prices (e.g. from renewable generation which cannot connect to the grid cost-effectively) are essential to achieve low hydrogen prices from electrolysis. Lower costs of capital and increased scale of hydrogen production could also reduce the overall cost.

*Total hydrogen production increases in line with the scale of the electrolyser, assumed to serve other demands.

When hydrogen is sold at £5/kg, the net annual costs for a train operator represent approximately a £10m premium compared to a diesel fleet

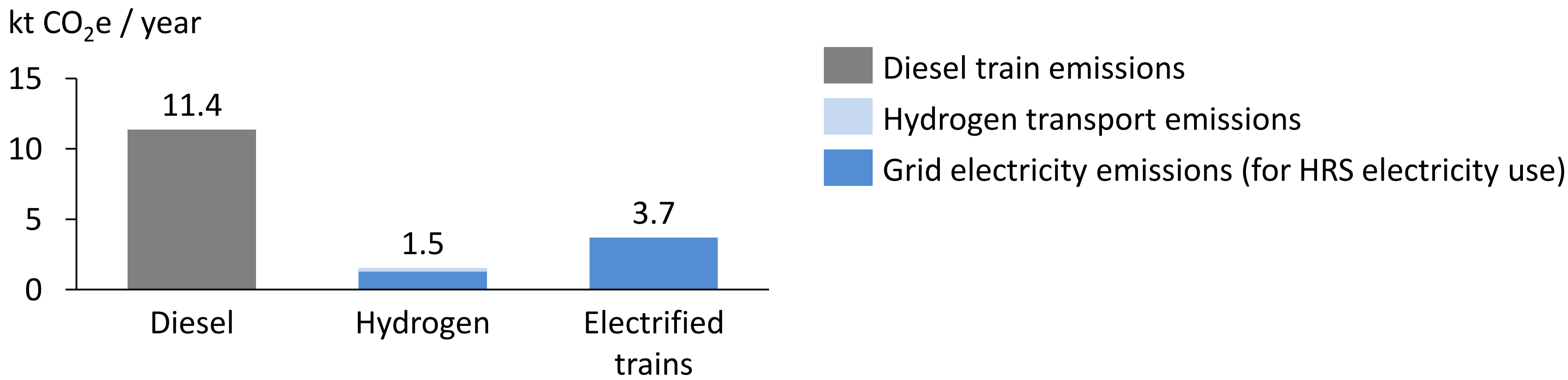
Net annual costs - fleet operator owned infrastructure (10% cost of capital)



- The capital costs, operational costs and revenues are combined into overall annual costs by calculating the cost of repaying a loan over the technology lifetime (e.g. 15 years), using a 10% cost of capital.
- Based on these assumptions, a fleet of 10 hydrogen trains would have a premium of £10m per year over 10 equivalent diesel trains. The following factors are key contributors to this cost premium:
  - Low cost of diesel for trains (c.50p per litre) means that electricity must be available well below 5p/kWh in order for large scale electrolysis to be competitive on an opex basis.
  - The high cost premium (and lower depreciation period) of hydrogen trains compared to diesel means that the vehicle capex premium is very high.
  - HRS costs add to the premium (no new infrastructure needed for diesel trains).

Hydrogen trains could save in the region of 10 kt CO_2 emissions per year compared to diesel equivalents

Well-to-wheel emissions for different fleet types



- Compared to equivalent self-powered diesel trains, 10 hydrogen trains using renewable hydrogen could offer emissions savings of 9.9 kt CO_2 per year.
- The emissions of electrified trains have also been estimated for comparison, based on grid electricity emissions factor, and assuming an energy consumption saving of 50% compared to hydrogen trains for an equivalent route. On this basis, 10 hydrogen trains using renewable hydrogen in 2025 would offer an emissions saving of around 2 kt CO_2 per year compared to an electrified route.

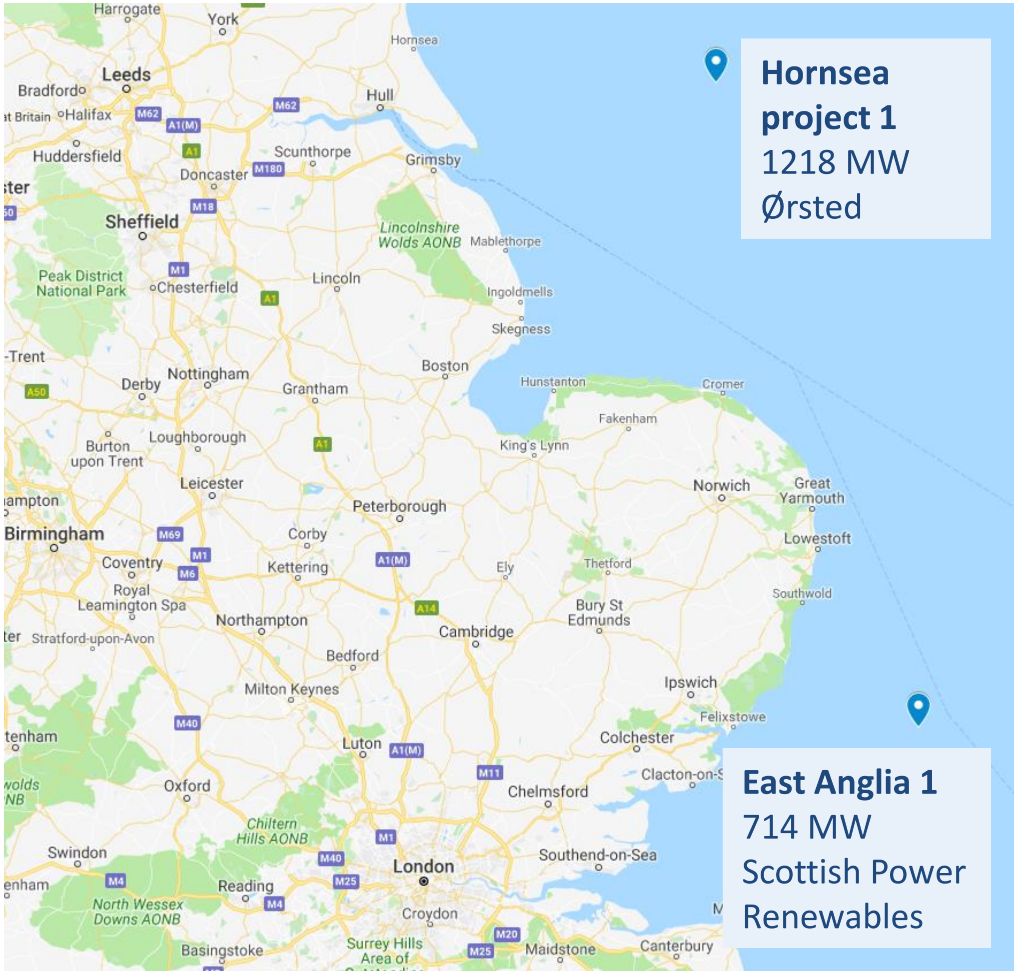
Key assumptions

- For electrolysis: zero emissions (from 100% renewable electricity)
- Grid electricity emissions factor (for on-site compression & electrified train lines) - projected value for marginal UK electricity generation in 2025: 0.22 kgCO_2eq./kWh
- Diesel emissions factor: 2.63 kgCO_2eq./L – for an average biofuel blend

New offshore wind projects could present opportunities for electrolysis at scales up to 100s of MW

The map shows two offshore wind farms currently under construction

- Using offshore wind power to drive electrolysis could help with balancing of electricity demand and supply.
- At scales of 100 MW or above, the cost of hydrogen from electrolysis would be driven mainly by the electricity price, which could potentially be very low during periods of low demand. This approach could provide low carbon hydrogen at price parity with diesel (even if it is delivered by road).
- Large scale electrolysis could also be used for power to gas; Project Centurion aims to demonstrate this concept with a 100 MW electrolyser in the North West.



Conversations with Alstom indicate that there are several potential opportunities for hydrogen trains in the Cadent and UK Power Networks areas

There are potential (but separate) opportunities in the Cadent and UK Power Networks areas

- Alstom plans to deploy 50 hydrogen trains by 2025, in "batches of 10-20".
- Key criteria for hydrogen train deployment:
  - Low speed, cross-country routes (<100 mph)
  - Suitable for back-to-base refuelling model (c. 1,000 km)
  - **Cheap, low carbon supply of hydrogen available**
- Based on Alstom mapping exercises and initial discussions with ROSCOs:
  - Cadent area: "5 potential opportunities".
  - UK Power Networks area: Potentially Kent Downs and/or Brighton. East Anglia have recently replaced all their diesel trains so are unlikely to be relevant.

While fuel cell trains have high cost premiums compared to diesel, they could provide an “anchor demand” for low carbon hydrogen

Archetype 2: Key conclusions for a hydrogen train fleet fuelled by hydrogen from offsite electrolysis

- Compared to equivalent self-powered diesel trains, 10 hydrogen trains using renewable hydrogen could offer emissions savings of around 10kt CO_2 per year.
- This would come at a significant cost premium (£10m per year, assuming 10% cost of capital and 5p/kWh electricity for the electrolyser). A large part of this is due to the fact that even with electricity at 5p/kWh, electrolytic hydrogen would not compete on a cost basis with red diesel, which is currently used for trains.
- This solution would not be commercially attractive under the conditions assessed here, and funding to subsidise both the capital costs (trains and infrastructure) and the operating costs (e.g. specifically total cost of hydrogen) would be required to enable such a project.
- However, if this could be realised, a hydrogen train fleet (or in fact any hydrogen fleet with a similar scale of hydrogen demand, such as 50 or more hydrogen buses) could act as a significant “anchor demand” that could justify large-scale centralised production and distribution of renewable hydrogen. Large-scale production and demand unlocks economies of scale for both production and distribution (though efficient tube trailer logistics or via dedicated pipelines), resulting in overall lower costs of hydrogen (estimated at £5–6/kg in this analysis assuming that low cost electricity is available to the electrolyser, e.g. by coupling directly to renewables).
- This could enable additional uptake of hydrogen vehicles in the area (e.g. for buses), bringing additional “indirect” benefits including further emissions savings vs diesel, and potentially avoided costs of electricity network upgrades to enable electric vehicle charging (see previous slide).
- This “anchor demand” concept could also apply to other forms of large scale, low carbon hydrogen production, such as reformation of natural gas with carbon capture and storage.

Contents

Overall, fleets of buses / trains (and possibly trucks) are expected to be most relevant for dual fuel hub concepts

Conclusions

- For a dual fuel hub to be of interest to UK Power Networks / Cadent, a minimum of MW-scale demand level is needed. This implies a minimum fleet of hundreds of cars, or several tens of buses, or a small fleet of trains.
- As of early 2019, there are relatively few fuel cell electric vehicles (FCEVs) operating in the UK (20 buses, c.100 cars across the whole country).
- However, various initiatives are underway that are expected to lead to expanded fleets of FCEVs and BEVs in the context of increasing focus on zero emission transport solutions. For example, 100+ new fuel cell buses are due to be deployed in the UK by the early 2020s (via funded demonstration projects), and two of the UK's leading bus manufacturers (**ADL** and **Wrightbus**) are now offering fuel cell vehicles. Furthermore, the *H2Bus Europe* initiative could bring hundreds more vehicles in the coming years.
- There is also a growing interest in fuel cell trains, with organisations such as **Alstom**, **Eversholt Rail**, and **Vivarail** announcing hydrogen fuel cell train designs for the UK in recent months.
- Heavy goods vehicles (trucks) are another promising market for fuel cell solutions and several technology development and demonstration activities are underway in Europe, Asia, and North America. Initial engagement with innovative truck fleet operators (e.g. **DHL** and **UPS**) indicates some interest in trialling fuel cell technology, particularly in London where there is increasing demand for zero emission fleets. However, as of early 2019 there is little certainty on the availability of fuel cell trucks in the UK, which limited the extent to which this potential source of hydrogen demand could be considered in this study.

Dual fuel hubs could play a role for ZE fleets, particularly where costs to upgrade the electricity network to meet additional demands are high

Conclusions

- In the context of a dual fuel hub that could alleviate issues on the electricity network, **bus depots in London** are of particular interest. Based on the policies in the **Mayor's Transport Strategy**, all new single deck buses introduced to London from 2020 will be zero emission, and this will extend to all new buses (including double deck vehicles) from 2025. This implies a relatively high and concentrated uptake of zero emission buses from the early 2020s.
- While fuel cell bus technology has been demonstrated (in London and elsewhere), **further validation** of the latest generation vehicles is needed in preparation for wider scale deployment in the 2020s. The **demonstration activities already underway** are designed to meet this need.
- This study has found that a dual fuel hub in which a mixed fleet of fuel cell electric and battery electric vehicles are deployed can offer benefits relative to electric-only solutions in some circumstances. The most promising opportunities from a network perspective lie where the costs of providing charging infrastructure for fleets of battery electric vehicles are high (e.g. due to the need for network reinforcement) and / or where fuel cell vehicles offer a superior solution from an operational perspective (for some routes a switch from diesel to battery electric buses may necessitate a larger overall fleet, whereas fuel cell buses are generally a one-for-one replacement for diesel). This means that the case for a dual fuel hub will be **highly location-specific** and dependent on the customers' needs and other local demands on the network.
- This study did not identify specific opportunities for UK Power Networks or Cadent to develop a dual fuel hub that would provide significant direct network benefits. However, in the context of growing demands for zero emission vehicles, this concept could be a good solution for some fleet operators to avoid heavy loading of electricity networks in constrained areas, which would benefit the wider network.

The scope to use the gas network for on-site H_2 production appears limited for a range of practical, economic, and environmental reasons

Conclusions

- Having explored the potential for a dual fuel hub to link the electricity and gas distribution networks, this study found no clear opportunities which would be appropriate for the distribution network operators to exploit in the short term. The gas network can alleviate pressure on the electricity network as a means of delivering energy to customers – for example, rather than producing hydrogen on site by electrolysis (which would add to electricity demands), hydrogen could be generated from natural gas from the existing gas grid.
- However, there are several issues with such on-site solutions, including (i) space is often at a premium at refuelling sites which restricts the scope for installing any on-site production equipment, (ii) the costs (capex and opex) of decentralised production technologies tend to be relatively high, and (iii) the carbon intensity of the hydrogen produced this way is high relative to fuel produced from renewables.
- The alternative method of meeting demands from fuel cell vehicles is to **produce hydrogen at scale at a centralised production facility** (with access to low cost, low carbon energy) and deliver it to refuelling stations, either via tube trailers or in a pipeline. Pipeline delivery includes dedicated hydrogen pipelines (one concept being developed in the HyNET project), and potentially using existing natural gas networks (although this would require equipment to separate hydrogen blended with natural gas and purify it at the refuelling site, a technique not yet demonstrated in the field).

Centralised low carbon hydrogen production could unlock dual fuel opportunities and thus lead to (indirect) network benefits

Conclusions

The centralised renewable hydrogen production model is one of the most promising options for providing low cost, low carbon hydrogen to a range of applications and is being pursued by several major players in the hydrogen sector, including in the UK. While not directly within the scope of a dual fuel hub originally envisaged (i.e. solving localised constraints with localised dual fuel technologies), these types of solutions are potentially relevant to:

- **UK Power Networks** – centralised hydrogen production and distribution systems are highly scalable and the economics tend to improve with increasing scale. Therefore, should such a system be established in the UK Power Networks area (e.g. initially to serve London's fleet of fuel cell buses or another "anchor demand"), this could provide a promising alternative fuel delivery system to zero emission vehicles in the region (i.e. fuel cell vehicles would become a more viable option for other fleet operators seeking to adopt zero emission solutions, which could lead to a greater mix of technologies and therefore overall reduced demands on the electricity network, compared to a battery electric dominated future).
- **Cadent** – there may be opportunities to use existing gas pipelines to transport renewable hydrogen (and thus reduce the carbon intensity of gas supplies) via power-to-gas concepts, depending on the location of the centralised hydrogen production plant (although the economic case for using hydrogen in this way is currently challenging). In addition, large scale gas reformation with carbon capture and storage (one option for low carbon production) would contribute to the sustained use of the gas network.
- **Wider system benefits** – centralised production of hydrogen via electrolysis coupled directly to renewables could offer synergies with large-scale renewables such as offshore (and onshore) wind, by reducing the overall capacity required for connections to the main electricity network. This could enable a higher overall installed capacity of renewable energy in the UK.

Contents

Market review: overview

Overview

- This section provides a review of the potential end users for a Dual Fuel Hub, and of any services that the Hub could provide to the electricity and gas networks. The following aspects are considered:

End-user markets for plug-in electric and hydrogen vehicles

1. **Current and future economics (based on total cost of ownership relative to petrol or diesel equivalents)**
2. **Estimates of potential UK market size to 2030**

Grid-service markets and cost considerations

1. **Potential revenue streams from grid services**
2. **Value of avoided upgrade costs**

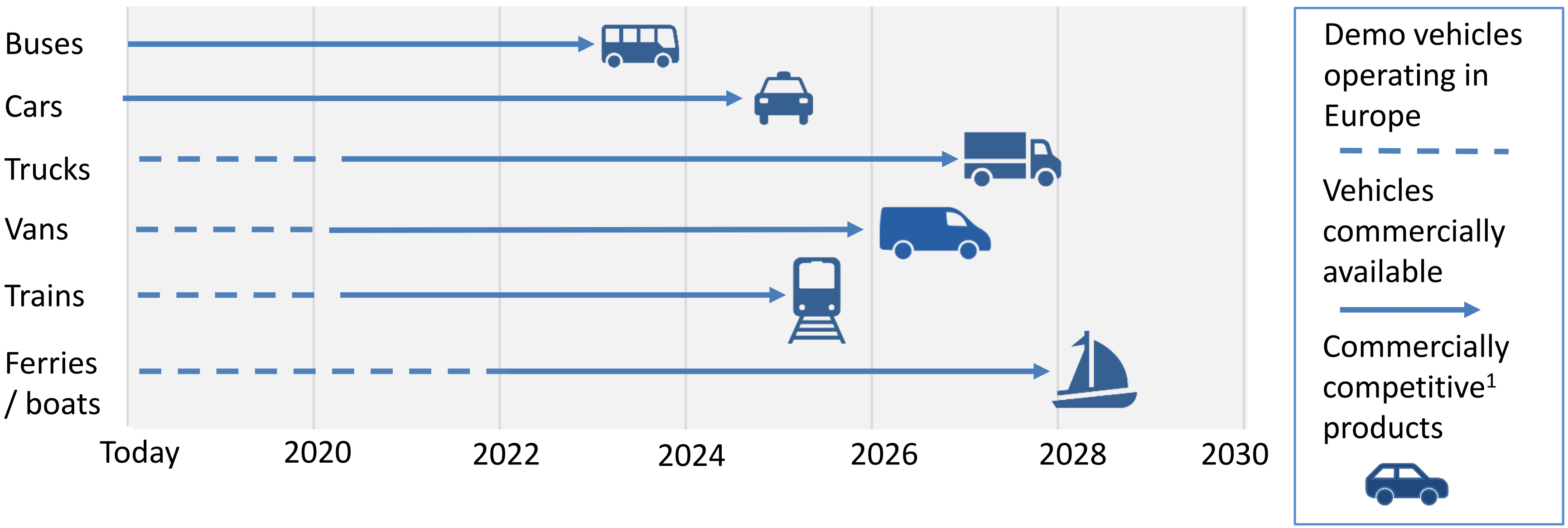
- The purpose of the market review is to inform the project team of the potential services provided by a Dual Fuel Hub to be deployed in the early 2020s, both in terms of meeting refuelling demand from end users and in terms of the potential benefits to the electricity and/or gas networks, to allow the **feasibility and value** of these markets to be compared.

Dual Fuel Hub end users will be largely determined by the overall availability of hydrogen vehicles to operate alongside electric vehicles

Possible zero emission end users considered in this document (based on likely market availability by 2022)

Plug-in electric	Hydrogen
Cars & vans (various use cases) Buses Trucks Trains Ferries	Cars & vans (various use cases) Buses Trucks Trains Ferries

Indicative timescales for availability of hydrogen fuel cell vehicles in the UK

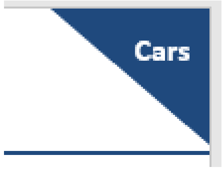


1 - Commercially competitive products refers to hydrogen transport modes which are **competitive with other forms of low/zero emission transport.**

Assessing end-user markets for plug-in electric and hydrogen vehicles

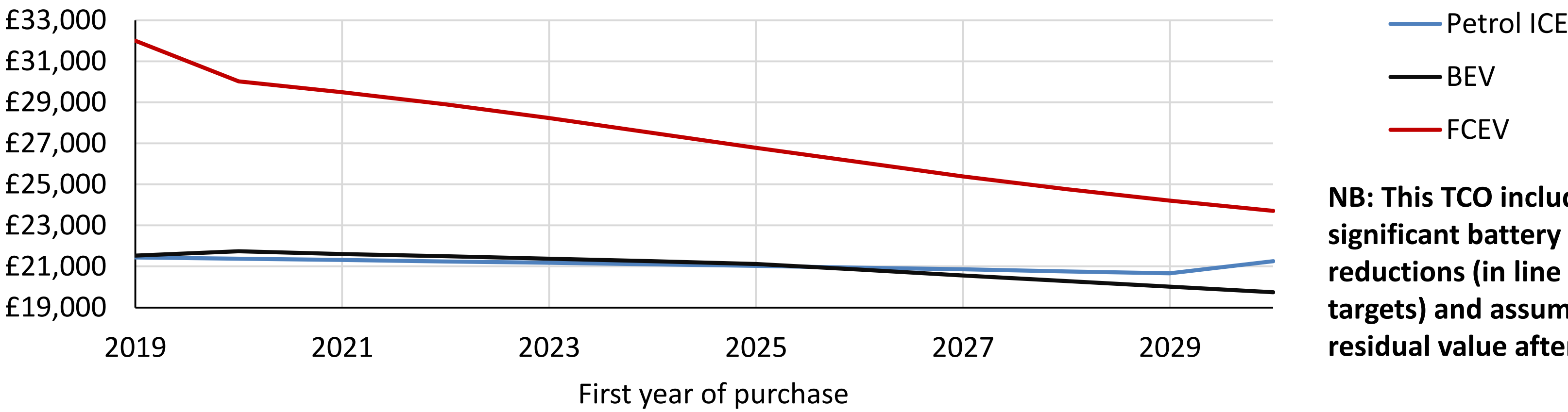
Overview

- This section assesses the **current and future economics** and **estimated UK market size** for the vehicle types indicated on the previous slide.
- The following pages provide a summary of Element Energy's existing expertise on the markets for these vehicle types, supplemented by additional information from a high-level review of external studies. For some vehicle types, there is limited information available on cost and performance, reflecting the current absence of plug-in electric and hydrogen options. Best-available estimates are provided where appropriate. In addition, specific economic analysis of ZE bus options is included (buses represent one the most promising prospects for dual fuel hub applications).
- The relevant vehicle type is highlighted in the corner of each slide in this part of the report:



The total cost of BEV and FCEV ownership relative to ICE vehicle ownership could reduce significantly over the next 10 years

4 year Total Cost of Ownership (TCO) for private consumer cars (annual mileage 12,500 km)



NB: This TCO includes significant battery cost reductions (in line with OEM targets) and assumes 50% residual value after 4 years

- Under the current plug-in car grant, the TCO of a BEV over a 4 year ownership period is very similar to that of an equivalent Petrol ICE car. The TCO case for BEVs is likely to continue to improve towards 2030, as costs reduce and vehicle efficiencies improve. The TCO for FCEVs is also expected to reduce significantly, although based on this analysis, for the average private consumer they may still have a significant TCO premium compared to a Petrol ICE in 2030.
- The scenario shown in the graph assumes that a reduced grant for plug-in vehicles and FCEVs (up to £1,000) is maintained in 2020-2030.

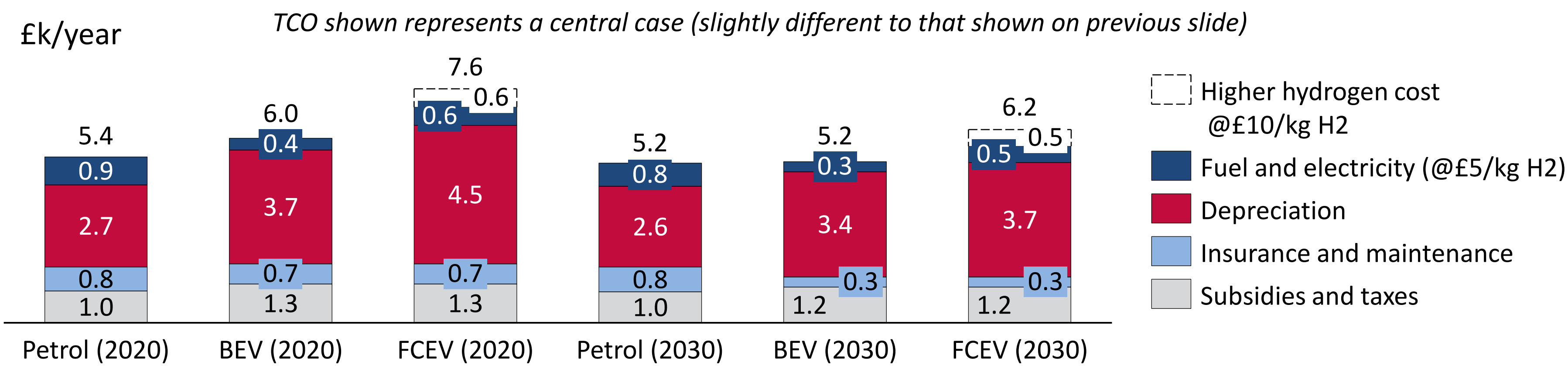
Key assumptions

- Capital cost reductions based on bottom-up technology costs (including battery cost reductions) & OEM projections.
- Second hand BEV and FCEV markets are assumed to be in place (vehicles have residual value after 4 year period)
- Fuel prices: Based on Government Green Book projections (for domestic electricity price and petrol price); hydrogen assumed to be c.£10/kg in 2020, reducing to c.£6/kg in 2030 in the analysis shown above.

BEV: Battery Electric Vehicle; FCEV: Fuel Cell Electric Vehicle; ICE: Internal Combustion Engine
Based on Element Energy's Cost and Performance model (in line with costs used by Department for Transport)

For the majority of car owners, BEVs tend to be more attractive on a TCO basis than FCEVs, due to their lower capital costs and fuel costs

Annualised TCO for private consumer cars (for annual mileage 12,500 km and a 4 year ownership period)

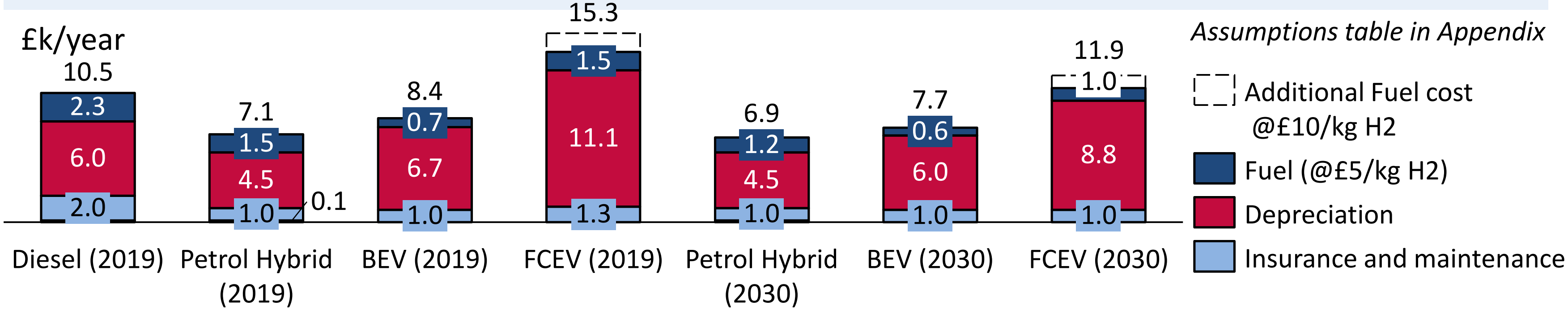


- TCOs above are shown for **C-segment (medium-sized) cars.** A residual value of **50% after 4 years** is assumed.
- Based on this analysis, BEVs are close to being competitive with petrol ICE vehicles on a TCO basis in 2020, largely due to the lower fuel price per km relative to petrol (due to the higher efficiency of BEVs as well as the relative fuel prices). Access to overnight charging (e.g. at home) is likely to be required for continued increase in uptake from private consumers.
- FCEVs are at an early stage of commercialisation and are being produced in relatively low volumes. However, assuming that demand increases globally, the increased production volumes will result in reduced vehicle prices, and therefore capital costs in 2030 are expected to be lower.
- Once FCEV capital costs are reduced, the cost of hydrogen will become more important; competitively priced hydrogen (e.g. £5/kg or lower) will be a key factor to enable FCEVs to be cost-competitive with BEVs on a TCO basis. Expected improvements in vehicle efficiencies will also contribute to this, by bringing down the total cost of fuel. Uptake of FCEVs will rely on sufficient infrastructure development as well as a lower TCO.

Based on Element Energy's Cost and Performance model – central case

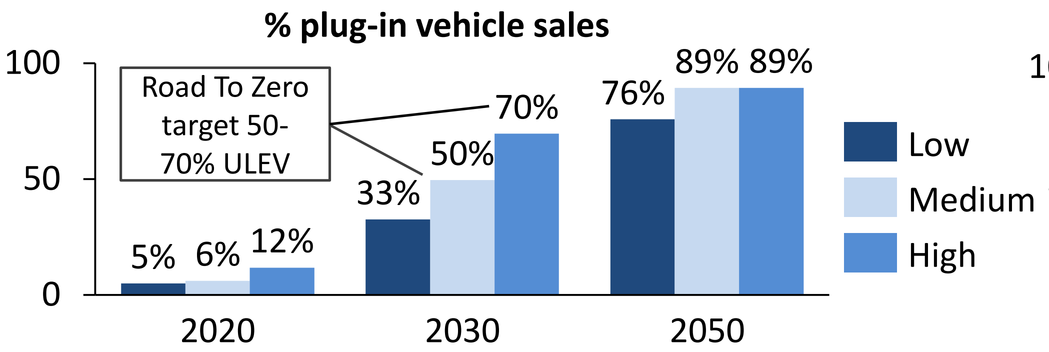
For commercial fleets with high utilisation (e.g. private hire vehicles) FCEVs may be more attractive than BEVs due to operational advantages

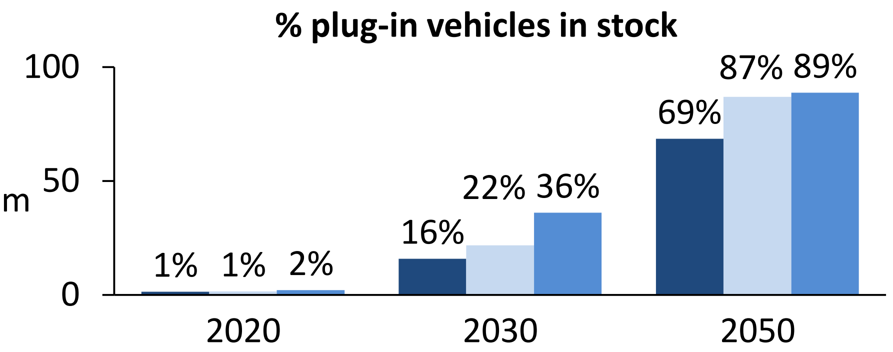
Annualised TCO for private hire vehicles (for annual mileage 30,000 km and a 4 year ownership period)



- The results above assume that private hire vehicles (PHVs) have a residual value of **33% after 4 years**.
- Zero emission vehicles will offer greater benefits to fleet operators than to private car owners. In some cities, zero-emission vehicles offer other benefits such as freedom from utilization restrictions (in Paris, and in London from 2020), and exemption from the congestion charge in London.
- PHVs typically have a much higher annual mileage than consumer owned vehicles; as a result a vehicle with a higher range is required, compared to the average vehicle represented on the previous slide. BEV PHVs could be close to cost-competitive with petrol hybrids, but would require a high density and availability of rapid charging in order to operate with the required level of flexibility for operation.
- Operational factors may make **FCEVs more commercially attractive than suggested by the above comparison.** For example, for taxi operators requiring high levels of utilisation, **FCEVs offer greater flexibility than BEVs due to the shorter refuelling times** (note that this is the key motivation for Green Tomato Cars in London) and therefore offer the **potential for greater revenues from operation,** outweighing the TCO disadvantages.
- By 2030, based on fuel cell price projections, FCEVs could reach a purchase price of £53,000; it is likely that they would still mainly be a viable option for applications which place high value on flexibility as well as zero emissions.

Our consumer choice model (ECCo) has been used to calculate ZEV stock corresponding to different levels of ambition in the Road to Zero





- ECCo combines **vehicle cost and performance projections** with **primary consumer research** (including fleet users as well as private consumers) to determine the rate of electric and fuel cell vehicle uptake under different scenarios.

Input settings	Low	Medium[1]	High[2]
Battery costs	Central	Central	Low, in line with OEM targets
Subsidies/taxes	As announced	As announced, plus £1,000/£500 grant for BEV/PHEVs in 2020, and VED supplement increases by £50 a year 2020-2030 for diesel ICE/HEVs	As announced, plus £1000/£500 grant for BEV/PHEVs 2020-2030, and VED supplement increases by £50 a year 2020-2030 for diesel ICE/HEVs
Overnight charging access	Constant	Increases to 100% by 2030	Increases to 100% by 2030
New car average CO_2 target	65gCO2/km in 2030 and 42gCO2/km in 2050	Decreases to 0 gCO_2/km between 2021 and 2050	Decreases to 0 gCO_2/km between 2021 and 2050
Vehicle availability	ICEs removed from showroom in 2035, HEVs in 2040	ICEs and HEVs gradually removed from showroom after 2030.	ICEs and HEVs gradually removed from showroom after 2030

Fuel cell vehicle (FCEV) sales

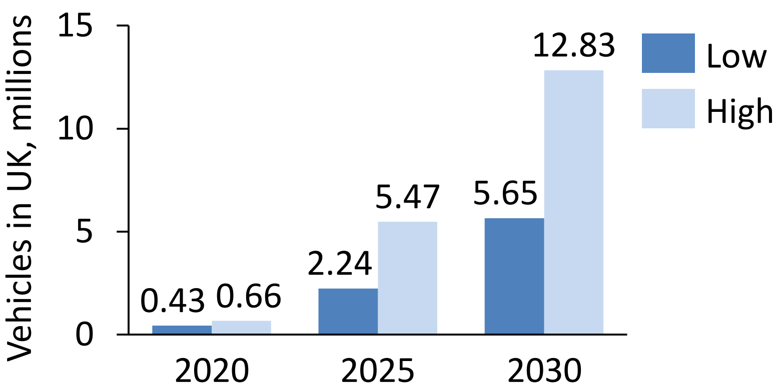
- FCEV costs decrease more over time in the High scenario than in the Low scenario. Estimated FCEV uptake within ECCo depends partly on the **relative utility of FCEVs compared to BEVs** (i.e. the difference in range, and **whether consumers have access to overnight charging**). The resulting sales share is low; <1% by 2030 in all scenarios shown.

1. In line with Road to Zero target lower bound of 50% ULEVs in 2030 **2.** In line with Road to Zero target upper bound of 70% ULEVs in 2030. ZEV: Zero emission capable vehicle; ICE: Internal combustion engine vehicle; HEV: Hybrid electric vehicle

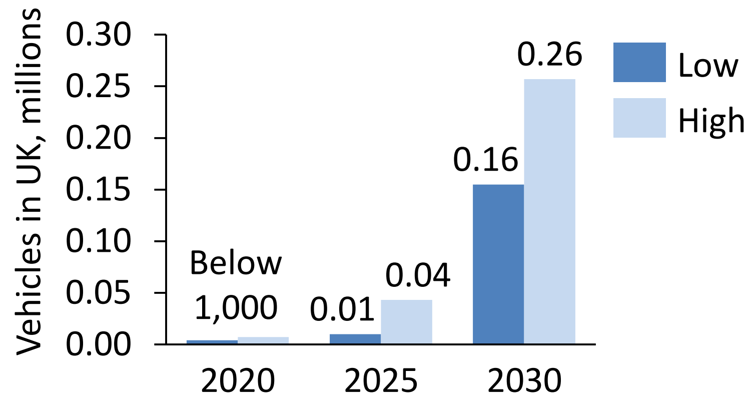
Under these scenarios, the number of zero emission cars in the UK could be in the millions by 2025

Estimated market size (total UK stock of electric and hydrogen cars)

Potential UK electric car stock (BEVs, PHEVs and RE-EVs)



Potential UK FCEV stock



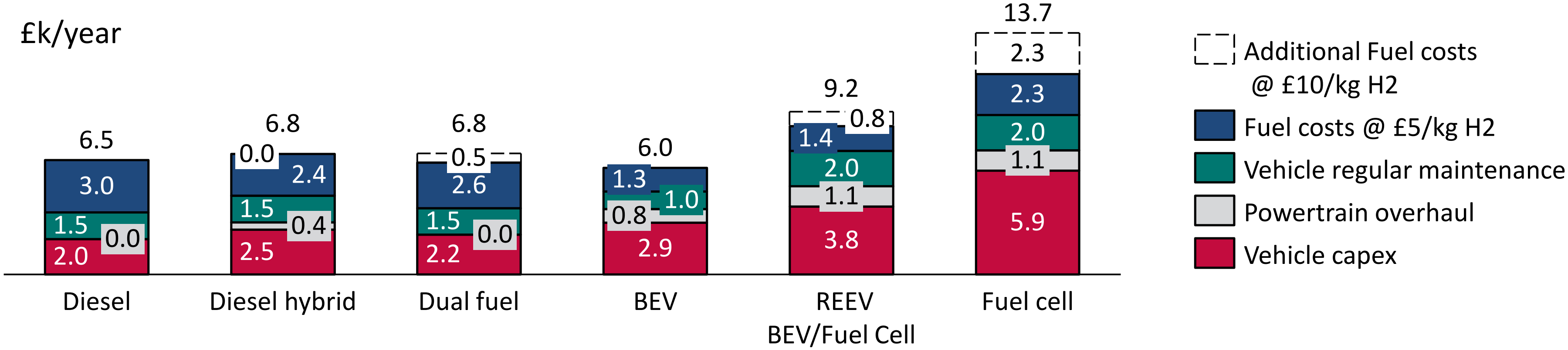
- Even in the low scenario (based on no additional policy support) according to the ECCo analysis **the number of zero emission cars in the UK could be in the millions by 2025.**
- In the short term, FCEV stock is likely to be lower than suggested by this analysis (e.g. **in the low 1,000s by 2025**), due to the lower than expected supply of FCEVs from OEMs to the UK to date (which is not accounted for in ECCo). However, in the longer term, uptake could potentially exceed the estimates shown here; **the Hydrogen Council (an industry grouping) targets 5 million FCEVs in the EU by 2030** in their 2017 'Scaling Up' report and the UK is likely to account for a significant share of this.
- **Access to overnight charging** is a key differentiating factor between the Low and High ECCo scenarios, and is a major enabling factor for plug-in vehicle adoption. This explains the greater difference between the two scenarios for electric cars, compared to FCEVs. **The impact of charging access on uptake emphasises the value of facilitating overnight charging or refuelling; a Dual Fuel Hub could play a role in providing this.**

Sources: Element Energy for UK Power Networks, 2018: Charger Use Study - Recharge the Future (ECCo modelling)

The supply of zero emission or low emission vans is currently limited, but a range of options could be available by the mid 2020s

Annualised TCO for vans (for annual mileage 24,000 km and a lifetime of 12 years) – <u>for future supply options</u>

Assumptions table in Appendix



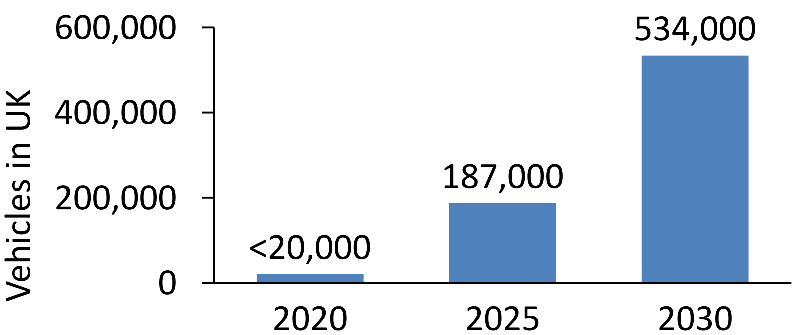
- Currently, the only zero emission options for vans are a small number of BEVs, and converted BEVs fitted with a fuel cell range extender. Converted dual fuel hydrogen & diesel vans offer another alternative to diesel.
- BEV vans are competitive on a TCO basis but uptake is likely to depend on the vehicle range, the availability of overnight charging and the requirements of specific fleet operations. Operations with high demand for flexibility and rapid depot-based refuelling may prefer a fuel cell option, and even operations with more predictable refuelling times may prefer a range extender electric vehicle (REEV, with the option to use hydrogen) to a fully electric van. In addition, charging infrastructure costs are not included in the above.
- It should be noted that in the absence of existing models on the market, there is a very high level of uncertainty around the TCO for the fuel cell van.
- **The overall business case for use of BEV or hydrogen vans will be very dependent on the value of flexibility in terms of the additional miles provided and how this translates to revenue for fleet users.**

Cost estimates based on internal analysis, with component costs taken from the ETI Zero Emission HDV database

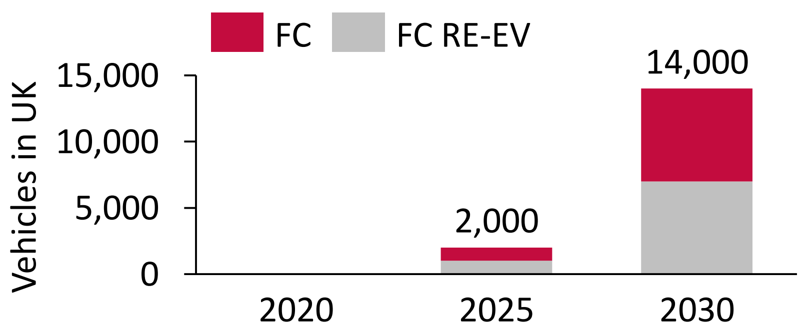
Our consumer choice model (ECCo) suggests that the number of electric vans in the UK could be in the hundreds of thousands by 2025

Estimated market size (total UK stock of electric and hydrogen vans)

Potential UK electric van stock (BEVs + PHEVs)



Potential UK fuel cell van stock (FC vans and FC RE-EVs)



- The market sizing for vans is also based on our consumer choice modelling tool, ECCo, which combines vehicle cost and performance projections with primary consumer research (including different types of fleet users) to determine the rate of electric vehicle uptake under different scenarios.
- The market projections shown here are based on no assumed changes to current policy; it is assumed that the plug-in van grant is removed after the 2019/20 tax year. <u>Note that the specific van TCO on the previous slide is not directly used to inform the ECCo market projections shown here.</u>
- On this basis, **hundreds of thousands of plug-in hybrid electric and pure electric vehicles could be on UK roads by the mid 2020s**.
- The market availability of FCEV and Fuel Cell Range-Extender Electric Vans is uncertain, with no firm commitments from OEMs to date (although concept vehicles have been released), but based on potential consumer demand **for a product offering greater flexibility (& not relying on the availability of overnight charging infrastructure)**, hydrogen vans on the road could number in the low thousands by 2025.

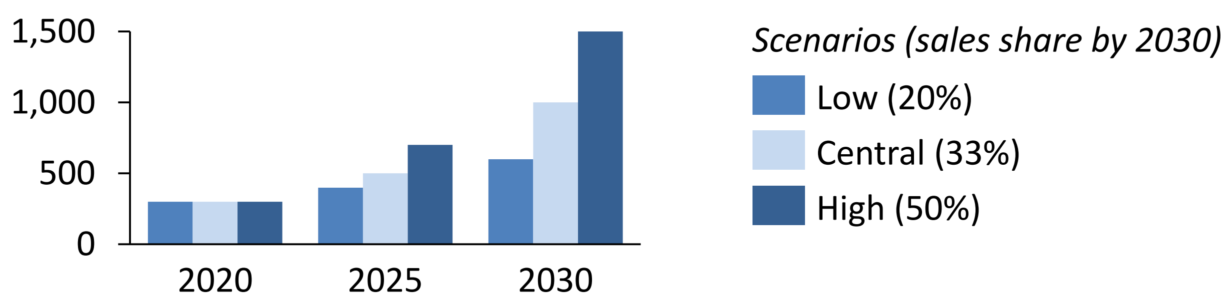
Sources: Element Energy for UK Power Networks, 2018: Charger Use Study - Recharge the Future (ECCo modelling)

With demand driven by ambitious city-level strategies to improve air quality, zero emission bus sales could reach 1,000 per year by 2030

Potential demand for zero emission buses in the UK

- Air quality and emissions regulations and targets in UK cities are driving increased demand for zero emission buses, including hydrogen fuel cell buses and battery electric buses. The UK is one of the largest markets for buses in Europe, with around 3,000 buses registered per year[1], and **in 2017 over 20% of buses registered were Low Carbon Emission technologies** (including diesel hybrids and gas buses as well as zero emission technologies).[1]
- London is leading the way for adoption of zero emission technologies, and the Mayor's Transport Strategy sets out a plan for all new single deck buses in London to be zero emission from 2020, with the policy of only buying zero emission vehicles extended to double deck buses from 2025. In addition, the UK government has mandated five other cities to implement Clean Air Zones (CAZs).
- London alone accounts for around 15% of annual bus sales[2]. Taking the other CAZ cities into account, it is feasible that total demand for zero emission buses in the UK could be in the region of **1,000 buses per year by 2030.**

Scenarios for zero emission bus sales in the UK



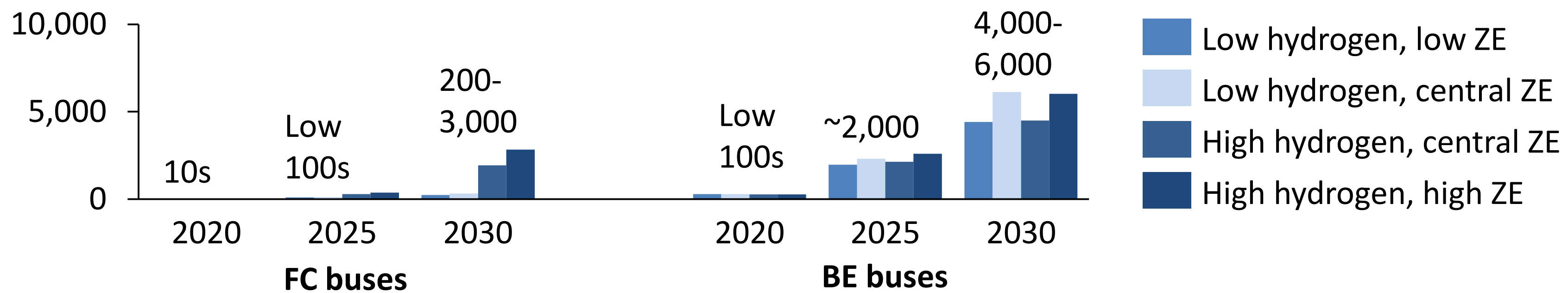
[1]Low Carbon Vehicle Partnership – National Policy Outlook 2018/19 [2]DfT Vehicle registration data (table VEH065)

The share of electric and hydrogen buses is uncertain and is likely to depend on bus operator experiences as deployment ramps up

Share of electric and hydrogen buses in UK zero emission fleet

- The share of hydrogen buses in the zero emission fleet will depend partly on increased availability from manufacturers, and on cost reductions being achieved as expected with greater volumes; electric buses are currently more widely available, and currently have lower capital costs.
- With a sufficient level of aggregated demand (of the order of hundreds of vehicles per manufacturer) fuel cell buses could be available for a similar capital cost as equivalent electric buses. Companies such as Wrightbus have stated that supplying 150 FC buses per year would be feasible if bus operators were to place orders of this size, and that production capacity would ramp up in line with demand growth.
- As such, it is possible that by 2030 the supply of hydrogen buses could meet the majority of demand for zero emission buses. Relative demand is likely to depend on bus operator experiences of the two technologies (as well as on relative TCOs – see the following slides).
- **The following scenarios can be considered for the zero emission bus mix (cumulative sales shown below):**
    - Low hydrogen: 5% FC buses, 95% BE buses, from 2020–2030
    - High hydrogen: 7% FC buses in 2020 – 50% FC buses in 2030

Total ZE bus deployment in the UK (cumulative sales)



ZE: Zero emission; BE: Battery electric; FC: Fuel cell (hydrogen)

The economic analysis for buses considers the costs of delivering bus services with different zero emission powertrains

Zero emission bus economic analysis – introduction

- The business case for a Dual Fuel Hub will depend on its ability to offer cost-effective fuel for vehicle users.
- London's (regulated) bus market is an area where demand for fuels for zero emission vehicles are expected to grow significantly by the mid-2020s.
- We have undertaken a techno-economic analysis to assess the costs of running a fleet of buses with different powertrain types for a generic bus depot of c. 50 vehicles.
- This captures most of the key factors: capital costs of buses & any new infrastructure, fuel costs, maintenance costs (buses and infrastructure), powertrain overhaul costs, a representation of driver costs, etc.
- However, this is not an exhaustive analysis and some costs are excluded / assumed to be constant between powertrain types. We have excluded certain one-off costs (e.g. for retraining staff to operate and maintain new powertrain types, workshop upgrades) and not accounted for any risk premium that may need to be added. Other costs (such as value of land taken up by new infrastructure and infrastructure decommissioning) are also excluded from this generic analysis as these are highly site-specific.
- The underlying assumptions are taken from a previous study and were validated through discussions with operators and suppliers.
- The following analysis focuses on double deck buses (which account for >70% of the total fleet in London).

We focus this analysis on three powertrain options and depot-based refuelling / recharging solutions

Bus types in scope

Given the Mayor of London's ambition to transition to fully zero emission buses over the next two decades, this analysis focuses on the following powertrain technologies:

- **Diesel hybrid** – diesel hybrid buses represent the incumbent "low emission bus" technology for new double deck buses in London.
- **Battery electric** – trials of pure battery electric double deck buses are on-going. There remains some uncertainty over the availability of electric buses that can act as one-for-one replacements for diesel hybrid and meet the demands of all routes in London, due to the difference in range compared to diesel buses.
- **Fuel cell electric** – until recently no fuel cell double deck bus was available. However, both Wrightbus and Alexander Dennis are now offering such vehicles. The range of fuel cell buses is comparable to diesel.

Note that in this analysis we have attempted to represent depot-based recharging / refuelling solutions only.

Source: Andrew Macintosh / ADL

Source: Wrightbus

The next slide compares the total costs of operating electric and fuel cell bus depots, based on the following key assumptions

Vehicle and infrastructure costs

- **Diesel hybrid buses** – Current prices are around £290k; no significant cost reductions expected as the technology is already commercial. Infrastructure costs are negligible.
- **Battery electric buses** – Current DD prices are around £400k, which could come down to £350k by the mid-2020s due to battery cost reductions. An allowance of £10k per bus is included to represent the cost of in-depot charge points. Any costs of electricity grid upgrades are excluded for the purposes of this analysis.
- **Fuel cell electric buses** – Current capital costs for FC buses are in the region of £550k. However, at production volumes of c.100s of buses per manufacturer (which could be achieved in the early to mid 2020s), the capital costs for a bus could reach £350k. No capital cost for infrastructure is included, as this is assumed to be within the all-inclusive hydrogen price.

Total fleet size and dead mileage

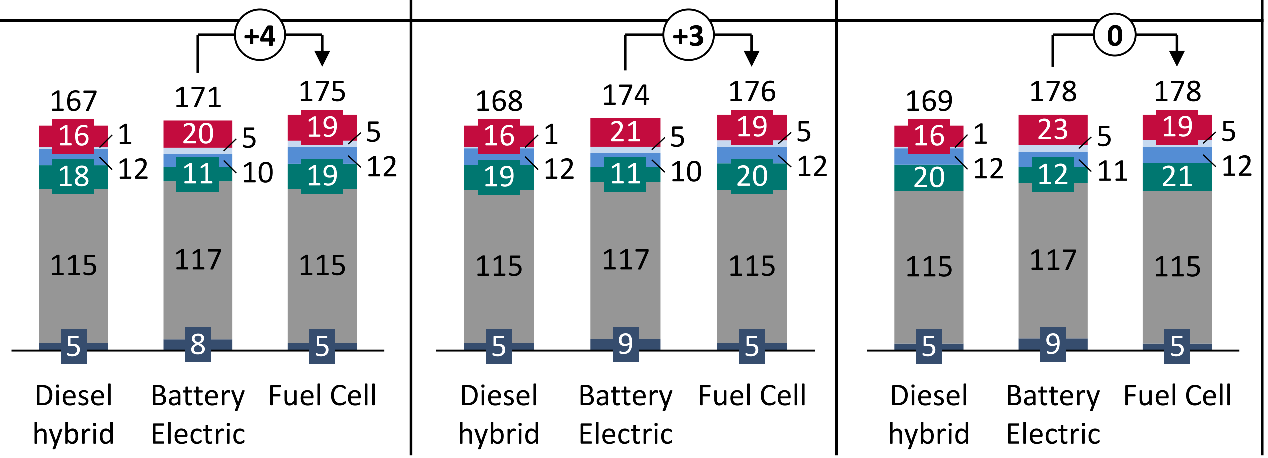
- For some bus routes, in order to meet the total contracted mileage, additional electric buses could be required compared to the number of fuel cell buses needed (partly due to the range of BE buses, and partly due to the time and space limitations on charging overnight).
- The scenarios presented in the next slide represent a range of cases for the contracted mileage and hence the assumed additional vehicles needed in the case of battery electric (BE) buses.
- The analysis also includes an assumption of slight increases in dead mileage (and driver costs) for the larger BE fleet sizes (on the basis that more trips between the depot and start / end of the route would be needed for buses not able to complete a full day's service without being recharged).

The need for additional BE buses to provide the same service could lead to very similar TCOs before taking into account grid upgrade costs

Total cost of operating a fleet of c.50 buses over 14 years (£m) – for purchase in mid 2020s

Average contracted daily mileage per vehicle (indicative)	**175 km**	**185 km**	**200 km**
Increase in fleet size with battery electric buses	**5%**	**10%**	**20%**

Difference in total cost (£m) – represents the approximate cost that could be incurred for electricity network upgrades whilst still allowing the BE option to be economically competitive, as upgrade costs are excluded from the results.



Bus capex | Powertrain overhaul | Bus maintenance | Fuel costs | Driver costs | Infrastructure & other costs

- Battery electric buses are likely to be a lower cost zero emission option than fuel cell electric vehicles in situations where they can be used as a one-for-one replacement for diesel buses. This is most likely for routes with lower daily mileages.
- However, for routes with higher average daily mileages, if additional buses and driver time (amounting to ~£2–4m of the TCO) are likely to be needed for battery electric buses to deliver the same service as diesel vehicles, the fuel cell option could become the lowest cost solution. Before considering network upgrade costs, this is likely to be marginal, but upgrade costs could be in the region of £2–5 million for a whole depot in constrained areas. **A mixed fleet could be a solution to avoid these costs.**
- NB: in practice, various other considerations (e.g. relating to space needs for infrastructure, operational issues, etc.) will also come into play when operators are selecting a preferred zero emission bus solution.

BE: Battery electric; FC: Fuel cell (hydrogen)

Baseline assumptions – intended to represent potential costs in the mid-2020s

Parameter	Assumption	Notes
Peak vehicle requirement	50	Assumption (total PVR for all routes run from depot).
Average contracted daily km per bus	175 km	Based on a typical London depot
Cost of finance	5%	Representative figure.
Bus lifetime	14 years	In practice, bus routes in London are tendered on a 5 + 2 basis.
DH bus capex (£/bus)	290k	Current DD diesel hybrid bus; no significant cost reductions expected as the technology is already commercial.
BE bus capex (£/bus)	350k	Estimated price of a DD battery electric bus, based on a reduction to current observed prices (around 400k, with a limited range) due to battery cost reductions.
FC bus capex (£/bus)	350k	Indicative price for a DD FC bus based on *at scale* price indications from selected bus OEMs. The current price is around 550k.
Powertrain overhaul cost (£/bus)	20k (Diesel hybrid); 80k (BE); 90k (FC)	Representative costs of powertrain overhaul. We assume one major overhaul is required at the mid-point of the bus lifetime.
Average diesel demand (DH)		Total consumption including heating / cooling.
Average electricity demand (BE)	170 kWh/100km	Total consumption including heating / cooling.
Average hydrogen demand (FC)	8.0 kg/100km	Total consumption including heating / cooling.
Diesel price	£1/litre	Typical average diesel price.
Electricity price	13p/kWh	Typical average electricity cost. In practice the average annual tariff will depend on the ratio of peak to off-peak charging and other factors.
Hydrogen price	£5/kg	Relatively aggressive all-in hydrogen price (i.e. includes cost of infrastructure). **Such prices are only likely to be available given sufficient scale and certainty of demand.**

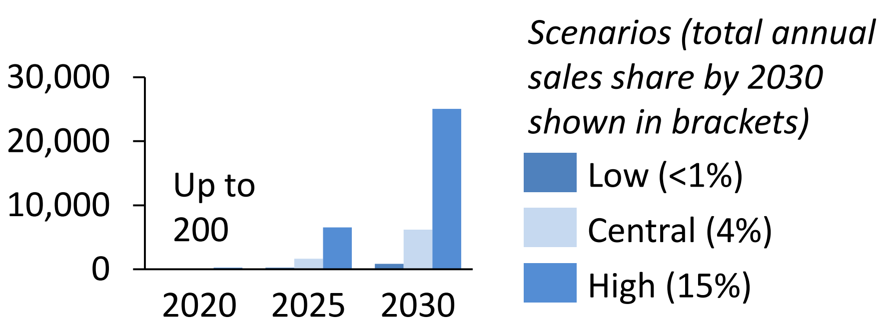
PVR: peak vehicle requirement; BE: Battery electric; FC: Fuel Cell; DD: Double deck

There is a strong demand for zero emission trucks but the market size to 2030 will depend on the models that become available

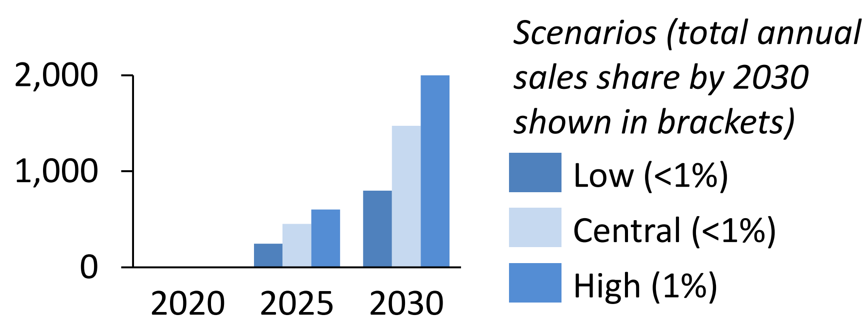
Potential demand and supply of zero emission trucks in the UK

- HGV operators are also under pressure to reduce their emissions to help meet air quality and greenhouse gas emissions regulations and targets in UK cities and on a national basis. Manufacturers are starting to respond to demand for ZE HGVs, and options are in development globally for both BE and FC drivetrains.
- **Battery electric trucks are likely to be best suited to applications such as local deliveries**, with vehicles <25t travelling relatively short distances and returning to a depot overnight, while in the long term **hydrogen could be more suitable for heavy duty haulage applications which require long ranges and fast refuelling.** However, with the potential for significant technological innovations and cost reductions in both powertrains, there is significant uncertainty around the long term supply and demand for each technology.
- The following scenarios show the total numbers of BE and FC trucks on the road under different adoption rates. The low scenario represents the "baseline" case where development is slow and there are no dedicated UK grant schemes for zero-emission trucks; the central and high cases would require rapid increases in model choice, pilot schemes, and dedicated incentives for ZE trucks to be put in place.

ZE truck stock scenarios (total stock, including rigid and articulated HGVs)



BE trucks

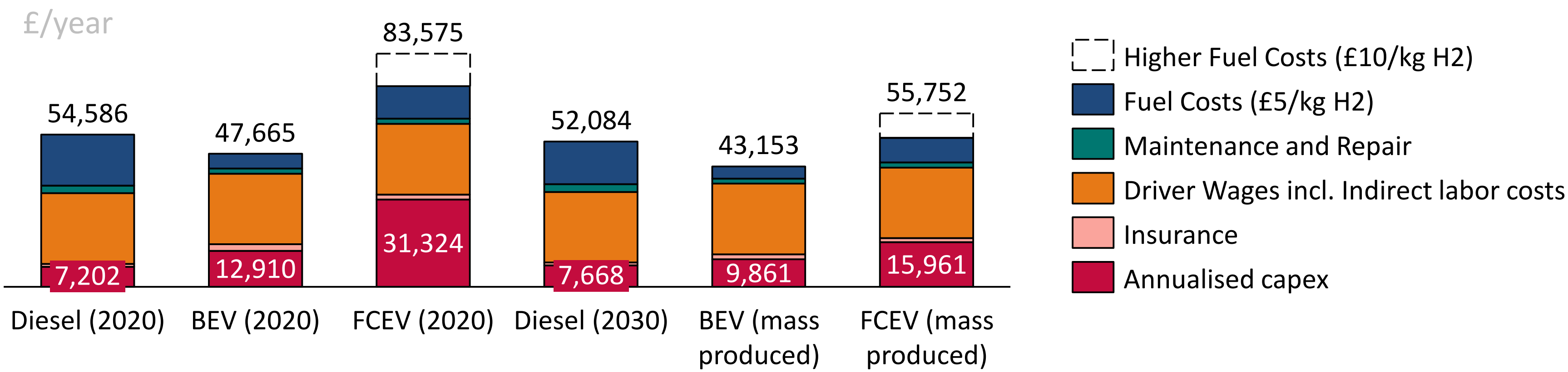


FC trucks

Scenarios developed by Element Energy based on previous studies for Transport for Greater Manchester, Transport Scotland, and the GLA. Note that stock scenarios are made up of different adoption rates for different classes of truck.

BE trucks are likely to offer a more competitive TCO than FCEVs, but applications may be limited by range and charging time requirements

Annualised TCO for 25t regional delivery truck (for annual mileage 52,000 km and a lifetime of 10 years)



- At present, regional BEV or FC delivery trucks are not commercially available, but a number of manufacturers have prototype offerings and are likely to have market ready products by the early 2020s.
- BEV trucks, once commercially available, could be cost competitive with diesel trucks in the near future, as the lower running costs offset the initially higher capital cost. However, there are concerns that the range of BEV trucks will not be large enough to meet some duty cycles. In addition, grid upgrade costs for recharging large numbers of BE trucks are not included here, as they are highly location specific, and could make a significant difference to the overall cost.
- For fuel cells trucks, there are likely to be much higher one-off engineering costs associated with integrating all of the fuel cell components and hydrogen storage into European trucks (which have strict size limits) than for short range BE trucks. One estimate which was developed was for ~£310,000 [2.] in 2020, which is ~330% more than an equivalent diesel truck. If the initial capital costs are this high, then this may delay or decelerate market introduction of FC trucks.
- At mass market volumes, FC trucks could reduce in price to become commercially competitive with conventional truck drivetrains. Their commercial competitiveness will then be sensitive to the price of hydrogen used, as shown above.

[1.] CE Delft report commissioned by the ICCT, Zero emissions trucks, 2013

[2.] Element Energy HGV cost analysis for Transport for Greater Manchester, 2017

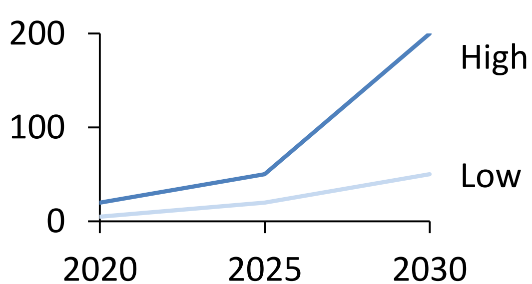
Ferries and other maritime applications are at demonstration stage or earlier, but activity in this area is ramping up

Potential demand for zero emission ferries in the UK

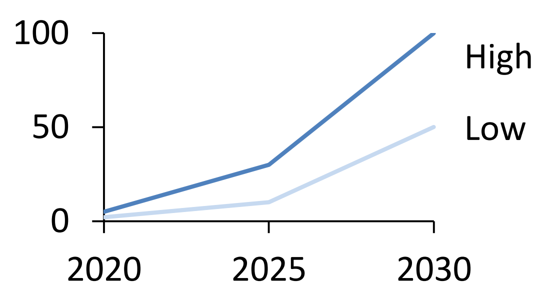
- The marine sector has historically faced limited regulation (relative to road transport), but is now starting to feel the pressure of regulations as policy makers recognise the contribution of this sector to overall emissions. In particular, pressure is being applied to marine vessels in ports in urban areas which suffer from air pollution issues.
- Pure electric and hydrogen technologies could provide zero emission options for propulsion and/or auxiliary power on ships, but are both still **in early demonstration stage.** Both technologies have been demonstrated in a number of small in-land and near coastal vessels. Demonstration projects on small ferries are under development, and larger vessels are generally at the design study stage.
- There are more operational examples to date for pure electric options, and therefore roll-out estimates are slightly higher for electric vessels than for hydrogen. Hydrogen passenger ships could start to become commercially available from 2020[1]. Deployment prior to 2025 is expected to be limited to a small number of early proof of concept vessels.
- Scenarios for UK deployment have been developed in line with the Hydrogen Roadmaps for Innovate UK.

Potential UK deployments of zero emission marine and other waterborne applications

Battery electric vessel deployment



Hydrogen vessel deployment



[1]'Hydrogen scaling up' H2 Council (2017)

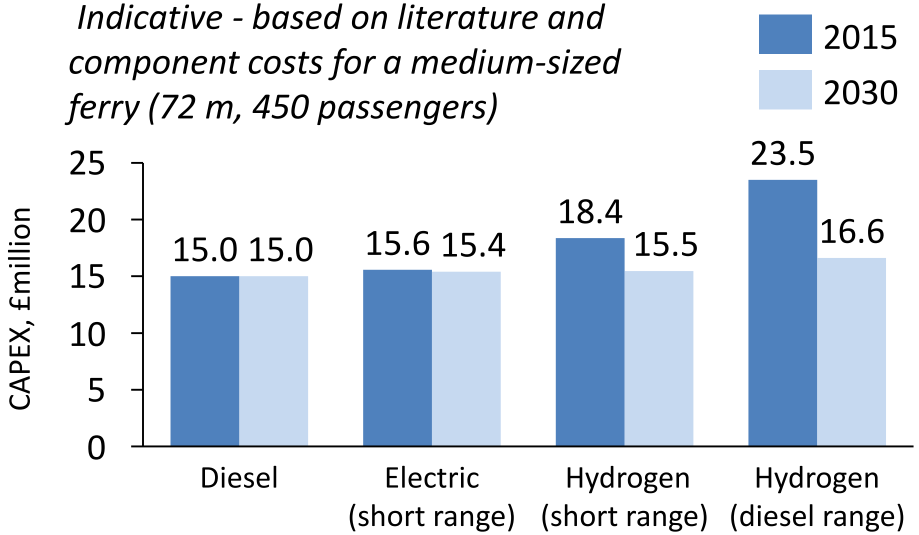
Zero emission ferries would require low fuel costs to be competitive with diesel, due to capital cost premiums

Capital cost of ferries (all of comparable size)

- Based on component costs, low-emission ferries could range from approx. £1m to £7.5m more expensive than conventional diesel ferries of comparable size, as indicated below. **Infrastructure costs and engineering/design costs could significantly increase this premium.**
- However, **fuel costs are likely to dominate the total cost of ownership** as ferries have relatively long lifetimes (c. 30 years), high power and high utilisation factors. The increase in capex could potentially be compensated for by lower fuel costs due to increased efficiencies of electric and hydrogen technologies; the reduced tax for diesel in ferries means that very low costs would be required (e.g. well below £5 kg for hydrogen).

Capital cost estimates (see breakdown in Appendix)

Indicative - based on literature and component costs for a medium-sized ferry (72 m, 450 passengers)



- **Hydrogen options**: Short range hydrogen (comparable to battery electric) or diesel range equivalent assuming fuel cell at £1,500/kW in 2015 (£442/kW in 2030) and additional costs for hydrogen tank
- **Electric options**: 1,000 kWh (full electric) or 250 kWh (hybrid electric) battery at £250/kWh in 2015 (£100/kWh in 2030) with additional costs for motor and inverter
- Note: these costs do not include infrastructure costs, which are expected to be over £1 million for all low-emission ferry types[1], or any design/engineering costs.

1 – to cover electric connection for electric ferries, and hydrogen station plus connection for hydrogen ferries. Upgrade of the local grid expected to be over £1m , source UK Power Networks guide to fleets, 2017

UK interest in hydrogen trains has increased following the challenge set by Government to remove diesel from passenger trains by 2040

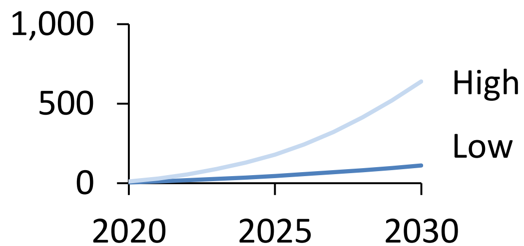
Potential demand for zero emission trains in the UK

- The total in-service UK train fleet is expected to increase by 40–80% (from around 14,000 vehicles) by 2050, to meet increasing demand. Electric trains comprise 72% of the national fleet and over 80% of committed new vehicles. The remaining vehicles (around 3,900) are self-powered diesel trains.
- In 2018 the Minister for Transport **challenged the industry to take all diesel engines off passenger trains by 2040**. While there is still some potential for increased use of pure electric (overhead charging) trains, the business case for electrification is weak in some cases (e.g. for quiet regional services).[1]
- The UK government has also encouraged **increased use of bi-mode trains** (capable of using more than one source of electrical power), where hydrogen fuel cells and batteries are of interest as alternatives to diesel for the on-board power source. Battery-catenary hybrids are beginning to enter commercial use in China.
- Hydrogen fuel cells and batteries also present a lower emission option for **self-powered trains,** and could be of particular interest to reduce local emissions for low mileage routes, e.g. in freight shipyards. The first two hydrogen passenger trains (from Alstom) are now in operation in Germany (with more to be deployed in 2021), and several projects to trial the technology are being developed in the UK.[2]

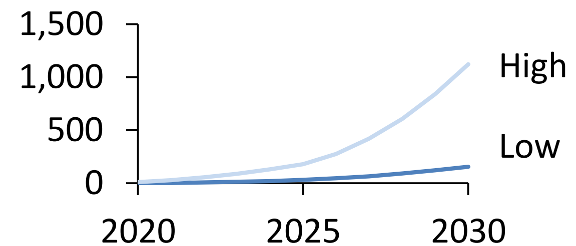
Uptake scenarios

- Both bi-mode and self-powered technologies could be adopted
- In total, 50–400 UK hydrogen and battery powered train sales per year by 2030

Potential UK stock of self-powered hydrogen & battery trains



Potential UK stock of bi-mode hydrogen & battery trains



[1]Rail Delivery Group, Long Term Passenger Rolling Stock Strategy for the Rail Industry (2018)
[2]ICCT, Beyond road vehicles: survey of zero-emission technology options across the transport sector (2018)

Opportunities for a Dual Fuel Hub from bi-mode and self-powered hydrogen and battery trains would depend on specific characteristics

Assessing possible opportunities for a Dual Fuel Hub

Self-powered trains

- A mixed “fleet” of battery electric and hydrogen self-powered trains could be an optimal solution for some routes, if the local network has some capacity for overnight charging but not enough for the whole fleet. This would depend on the profile of existing network demand. This scenario would rely on a low cost supply of hydrogen e.g. produced or supplied via the gas grid. However, in this case a fully hydrogen solution could potentially be a lower cost (and/or more practical) option.

Bi-mode

- The batteries for battery – catenary hybrid trains would be charged via the catenary; unlikely to be suitable for a Dual Fuel solution.[1]
- Hydrogen – catenary hybrid trains would be refuelled at a depot. The opportunity for this to be part of a Dual Fuel solution would have to come from combining this with other applications e.g. identifying an opportunity for hydrogen technologies to help resolve electricity constraints caused by other end users.

Relative costs highly dependent on route & depot characteristics

- Overall, the low number of deployed battery and hydrogen trains, along with the **highly route-specific nature of train costs**, mean that **quantitatively assessing and comparing different solutions is not feasible at this stage**. The high specificity also suggests that any zero emission **train deployments by the mid 2020s are likely to be focused on exploring single-fuel solutions**, indicating that the opportunity for a Dual Fuel application is low.
- An example TCO estimate for hydrogen powered trains is provided in the Appendix.

[1] https://www.railjournal.com/in_depth/battery-train-energises-race-to-replace-diesel

Uptake scenarios for electric and hydrogen vehicles help to inform which vehicle types could be potential end users for a Dual Fuel Hub

Indicative scale of daily demand for electricity and hydrogen at local ('Hub') level

- To assess the high-level demand opportunity for a Dual Fuel Hub for different vehicle types, we have assessed the potential scale of local refuelling demand under different vehicle uptake scenarios. The scale of local demand is based on the following:
  - Typical daily fuel consumption per vehicle
  - Number of vehicles likely to be deployed within a "Hub area" in the early-mid 2020s (e.g. this could translate to the potential uptake within a specific depot, or within a certain area). This is informed by the overall uptake scenarios in the Market Review.

Scalability of Hub opportunity

- We can also use the uptake scenarios for total UK uptake of these vehicles on a 2030 timescale to assess the wider scalability of the Hub opportunity offered by specific vehicle types, i.e. the potential number of Hubs based on vehicle demand.

The tables in the following slide(s) set out the typical demand per vehicle, the potential number of locally deployed vehicles under a given uptake scenario in the early-mid 2020s, and the total number of vehicles that could be deployed in the UK by 2030. This facilitates a comparison of the factors identified above (in bold on the following slide).

Demand for hydrogen at a Hub could range from 100 kg per day to 3 tonnes per day, depending on the types of end user

Assessing scale of potential demand for hydrogen end users (INDICATIVE SCENARIOS)

Hydrogen vehicles	Cars (fleets)	Vans (fleets)	Buses	Trucks	Trains[1]	Ferries[2]
Average daily hydrogen demand per vehicle (kg H_2/day)	1.0	1.5	13	11	280	650
Estimate for number of 'locally deployed' vehicles likely to use one refueling Hub in 2025	50	50	40	40	10	5
Estimated demand for a refueling Hub (kg H_2/day)	**50**	**80**	**500**	**450**	**2,800**	**3,250**
Total vehicles by 2030 (central estimate)	10,000	14,000	1,000	1,000	100	50
Implied potential number of Hubs	**200**	**300**	**25**	**25**	**10**	**10**

Assumptions	Cars	Vans	Buses	Trucks	Trains	Ferries
Fuel consumption (kWh/km)	0.33	0.67	2.7	2.4	9.3	43.3
Fuel consumption (kg/km)	0.01	0.02	0.08	0.07	0.3	1.3
Daily mileage per vehicle (km)	96	77	165	154	1,000	500

[1] Based on hydrogen self-powered option; demand for a bi-modal train will vary depending on share of non-electrified miles
[2] Demand estimate based on a fuel-cell & diesel medium ROPAX ferry for 450 passengers (Innovate UK H2 Roadmaps)

Simultaneous charging of electric fleets could lead to localised average additional power demand in depots ranging from 200 kW to 22 MW

Assessing scale of potential demand for electric vehicle end users (INDICATIVE SCENARIOS)

Electric vehicles	Cars (depot based)	Vans (depot based)	Buses	Trucks	Trains[1]	Ferries[2]
Average daily electricity demand per vehicle (kWh/day)	15	28	280	180	4,400	17,400
Estimate for number of 'locally deployed' vehicles likely to use one refueling Hub in 2025	50	50	100	50	10	10
Estimated daily electricity demand for a refueling Hub (kWh/day)	770	1,400	28,000	8,500	44,000	174,000
Average additional power demand for a refueling Hub (MW)	**0.2**	**0.2**	**4.7**	**1.1**	**7.3**	**21.7**
Total vehicles by 2030 (central estimate)	100,000	100,000	5,000	5,000	100	100
Implied potential number of Hubs	**2,000**	**2,000**	**50**	**120**	**10**	**10**

Assumptions	Cars	Vans	Buses	Trucks	Trains	Ferries
Fuel consumption (kWh/km)	0.2	0.4	1.7	1.1	8.0	34.6
Daily mileage (km)	96	77	165	154	550	500
Simultaneous vehicle charging period (hours)	5	6	6	8	6	8

[1] Based on battery self-powered option; demand for a bi-modal train will vary depending on share of non-electrified miles
[2] Demand estimate based on a battery & diesel medium ROPAX ferry for 450 passengers

Assessment of the relative economics for different vehicle types also informs the feasibility of a Dual Fuel Hub for that end user group

Comparing relative vehicle economics in mid 2020s

Technologies have been scored on a comparative scale for the different fleets, from “least attractive” to “most attractive” vehicle offer, compared to the counterfactual technology. This takes into account capital costs as well as the overall TCO.

-2	-1	0	1	2
Worse than most other electric / hydrogen technologies	Worse than some other electric / hydrogen technologies	Median technology	Better than some other electric / hydrogen technologies	Better than most other electric / hydrogen technologies

Summary of relative vehicle economics

	Cars (fleets)	Vans	Buses	Trucks	Trains	Ferries
Electric vehicles	2	1	1	0	-1	-2
Hydrogen vehicles	0	0	1	-1	-1	-2

Overall, electric and hydrogen cars, vans and buses are likely to offer the best end user proposition in the mid 2020s. Electric options for these vehicle types are likely to be more attractive than hydrogen vehicles, mainly due to their lower purchase costs. However, charging times and power requirements could constrain demand.

Contents

Technology review: overview

Overview

- This document provides a review of the technologies which could be included in a Dual Fuel Hub**. For each technology,** the following aspects are considered:

  1. **Technology overview**
  2. **Key suppliers (focused mainly on suppliers with a UK presence) or relevant research / demonstration projects**
  3. **Technology cost and performance information**

- The purpose of the technology review is to provide the project team with the most up to date information and assumptions on the status of relevant technologies.

Contents

Rapid charging points for cars and vans can charge batteries to 80% in c. 30 minutes, and are currently found mainly on motorways

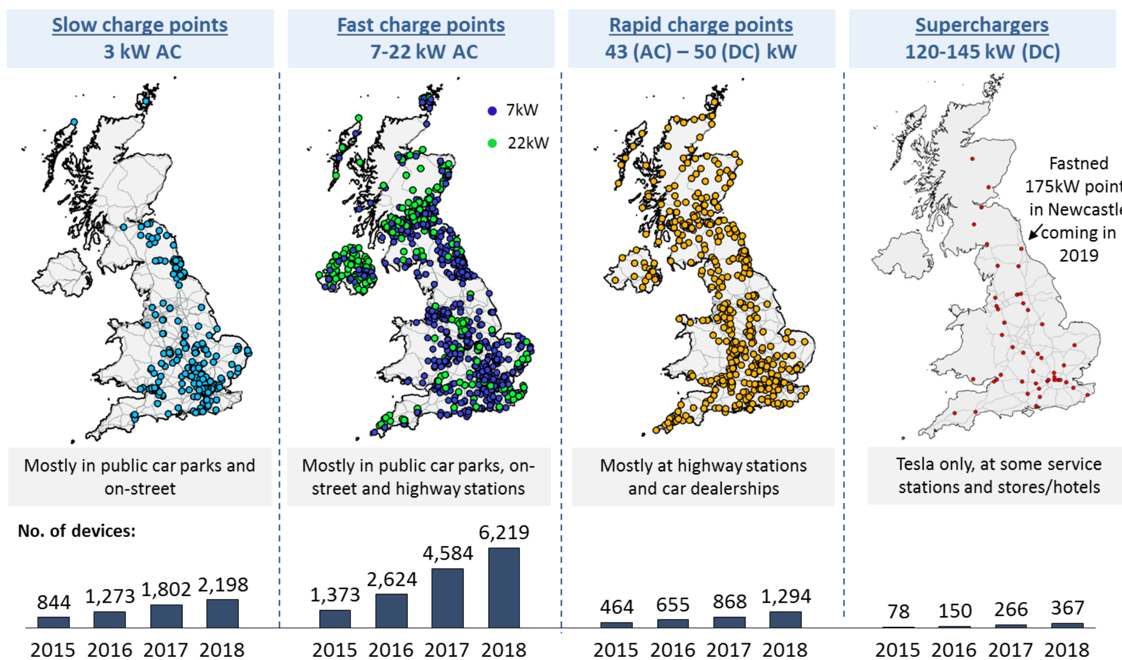
Electric Vehicle Charging Points

- Electrical charging points use electricity from the grid or from local generation to power both light duty vehicles (LDVs) and heavy duty vehicles (HDVs). The **battery size for these different vehicle types greatly differ** (<70kWh for LDVs and >100kWh for HDVs) and, as a consequence, they have **different infrastructure requirements**.
- This report explores charging options for Light Duty Vehicles (LDVs) and Heavy Duty Vehicles (HDVs) in turn.

Charging Points for Light Duty Vehicles

- There are over 11,000 devices installed at over 6,600 locations in the UK, **categorised as slow**, **fast**, **rapid** and **superchargers**[1].

- **Rapid-charging** is capable of **recharging an LDV to 80% in c. 30 minutes** (battery size dependent)[2].
- There are **two main focuses** for rapid charging with LDVs:
  - Ensuring **long distance journeys are enabled through intercity & city connections**.
  - **Serving sufficient vehicles per day without queues**.
- This is likely to be more compatible with a "Dual Fuel Hub" concept than other types of LDV charging points which are only capable of recharging vehicles at slower rates and therefore offer less flexibility.



[1] Charge point device numbers provided by Zap-Map.com, December 2018 (numbers under maps from September 2018

[2] Most rapid EVCPs have both AC (43kW) and DC (50kW or more) ports; most BEVs would use the DC ports whereas most PHEVs would use the AC, but get 3/7kW (on board charger limit).

Rapid charging operators for LDVs can be broadly divided into four categories

OEMs (Vehicle and battery)

- Focused on providing complementary services to help vehicle or hardware sales
- E.g. Tesla providing high spec charging for their customers.
- This often involves partnerships with charge points providers (e.g. free home charging or credits on public charge points) at point of vehicle purchase

Utilities

- Focused on expanding consumer base and diversifying business models.
- Have the ability to offer bundle products to consumers which combine home and public charge point use.
- Also have engineering and project management experience to carry out large roll outs of charge points (e.g. public tender or fleet).

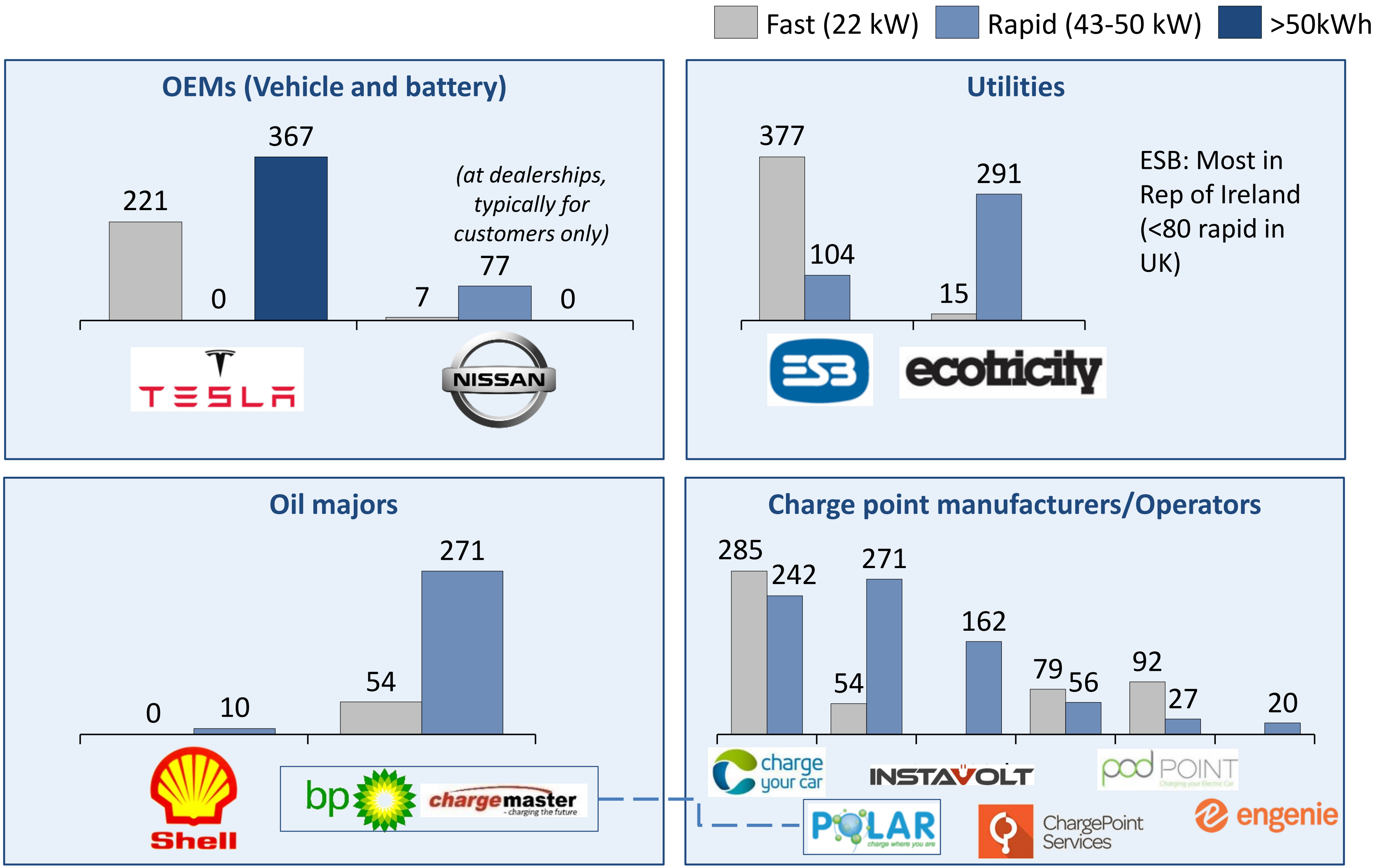
Oil majors

- Focus is on diversifying business model to adapt to changing fleet make up.
- Can utilise prime highway locations to enter the rapid charging market which fits with their current operational model as they have partnerships in place with retail outlets on site.
- Access to capital means they are able to expand rapidly through acquisition (e.g. Shell buying Newmotion, First Utility)

Charge point manufacturers/Operators

- Traditional early market entrants, typically 'start ups' looking to build market share.
- Varying operational models; own and operate, service provider, hardware provider etc.
- Can partner with any of the other three categories to form partnerships or join offerings.
- Control the majority of the current charging network.

LDV charge point operators have a total of ca. 1,700 rapid/ultra rapid EVCPs currently in operation in the UK



Omitting operators with < 10 rapid EVCPs. CYC and Chargemaster: effectively same company since merger between Chargemaster and Electromotive (owns CYC). CYC do not own EVCPs, only operate e.g. for Transport Scotland

There are two main LDV operating models which public charging providers operate under: full operator (B2C) and service provider (B2B)

Full operator — Business to Customer

- Funds infrastructure costs (plus option of additional ground rent or profit/revenue share)
- Charges users directly for usage either through subscription or per kWh

Service provider — Business to Business

- Provides charge points to host for a fee
- Manages operation, payment, faults and data analysis
- Revenue distributed back to host (or charge point offered free of charge)

	Full operator	Service provider
Examples	INSTAVOLT, ecotricity, POLAR (The EV charging network), engenie	pod POINT, chargepoint, newmotion
Benefits to operator	Targeting high utilisation rates to make return from supply of energy	Targeting roll out of charge points and acquisition of customers for service fees
Benefits to host	Revenue share or ground rent Attract customers	Provide charge points for social reasons (LAs) or to attract customers

Typical hosts: Fuel court operators | Local authorities and public car parks | Workplace | Rapid charging hubs | Restaurant / retail locations | Hotels

Charging rate: Ultra –rapid | Rapid | Fast | Slow

Charging location: En-route | Destination (short) | Destination (long) | Workplace

Rapid charging sites are increasingly fully privately funded with this trend expected to continue

Costs of rapid charging for LDVs

- The **cost of charging** in the UK varies between different providers, **between 24p/kWh and 42p/kWh,** depending on the network and location of the charging point.
- **Costs for individual chargers** can be seen in the table[1] (*right*) for varying capacity. Note that the **power ratings of rapid chargers is expected to increase** from the current standard, 50kW, to 150kW and eventually 350kW. This is needed to accommodate **increased LDV throughput** and to **meet the demand of larger batteries**.
- However, additional chargers will eventually require **significant investments in grid connections**. For example, for a given location two rapid chargers require c. €10k of investment, however the next eight require up to c. €345k. This can be seen in the table (*right*).

Charger Capacity[1] (kW)	Charge Time to 80% & Battery Size	Production Cost (€ '000s)		Installation Cost (€ '000s) (a)
		2017	2030	
50	30 mins 25kWh battery	30	22	5
150	-	60	41	
350	20 minutes 75kWh battery	120	100	

(a) Excludes grid connections, civils and greenfield site preparation costs. These can be seen below.

	Item	Initial stage (2 chargers)	Mature Stage (8 or more chargers)
Brownfield site	Grid connection	€ 10,000	€ 345,000
	Civils	€ 64,000	€ 82,000
Greenfield site	Access roads	€ 50,000	€ 50,000
	Site works	€ 100,000	€ 100,000
	Professional fees	€ 33,000	€ 33,000
	Grid connection	€ 5,000	€ 340,000
	Civils	€ 64,000	€ 82,000
Brownfield site	TOTAL	€ 74,000	€ 427,000
Greenfield site	TOTAL	€ 252,000	€ 605,000

[1] Element Energy and Cambridge Econometrics, "Low-carbon cars in Europe : A socio- economic assessment," 2018.

Electric buses are typically recharged using a mixture of overnight charging and opportunity charging; future electric HGVs may also use overnight charging

Charging options for Heavy Duty Vehicles

- The main type of electric HDV currently in commercial operation is **battery electric (BE) buses**. Trucks are also classified as HDVs but there are currently no commercially available electric trucks.
- Bus **depots are now being retrofitted with rapid charging points** to allow for **two to six hour of electrical charging per night**. However, due to the limited range of electric buses, a **combination of this overnight charging and on-route top-ups** (opportunity charging) may be required for some routes.
- Allowing for both of these means that the bus **battery does not need to be as large or heavy** – this allows for **optimal operation of the bus route**. These opportunity charging points have **very high power charging** (100's of kWs) which allow for **short bursts of 10 minutes** to top up the bus's battery.

- There are a few alternative charging methods currently being developed by major players in the market:
  - **Conductive charging** uses overhead lines to top up the bus on-route.
  - **Inductive charging** uses a magnetic field to charge the battery using plates below the bus.
  - **Central terminals** at the start of multiple bus routes are equipped with rapid chargers.

[1] Element Energy, "BE Bus Charging Infrastructure," 2017.
[2] https://cleantechnica.com/2018/08/27/european-electric-car-sales-increased-42-in-h1-2018-vs-h1-2017/
[3] https://www.store-dot.com/business-units

Suppliers of HDV depot charge points also offer opportunity charging infrastructure such as pantographs

HDV Charge Point Suppliers

Supplier	Location	Notable UK Contract	Summary	Source
ABB	Switzer-land	ABB supplied for a fleet of Volvo electric buses operated by Transdev Blazefield from 2018. This includes three HVC 300P charging stations and an electricity substation at a bus station in Harrogate, UK LINK	ABB offer overnight charging for BE bus fleets alongside remote diagnostics and management. Their designs are flexible to allow for both floor and roof mounted chargers.	https://new.abb.com/ev-charging/products/depot-overnight-charging
heliox	Nether-lands	Not found UK contract details. Largest outside is the 100 buses / 13Mw project at Amsterdam airport LINK	Heliox have introduced charging infrastructure which reduces charging time by 67% and employ smart systems to reduce operating costs.	https://www.heliox.nl/markets/public-transport
SIEMENS	Germany	City of York – park and ride LINK	Siemens offer a range of charging options, including off-board top-down and on-board bottom-up Pantographs and charging via connectors at depots.	https://www.siemens.com/uk/en/home/products/mobility/road-solutions/electromobility/ebus-charging.html

- BYD (a bus manufacturer) have their own charging equipment which they use at BYD depots.
- Nexans are bringing a product to UK market, from French company IES.

The majority of charging will occur at depots where substation upgrades represent the most significant capital cost

Cost and status of HDV charging

- HDVs require **high power charging points due to their large batteries** (c. 300–400kWh)[2]. Although currently in the range of 30–150kW, some HDV depot charging points can reach can reach 200kW (and could provide power up to 350kW in future). As a consequence, **LDVs cannot be charged at these depots due to the high power rating and health and safety issues**[1].
- The number of charging points per depot impacts the overall costs to the fleet operator, as network upgrades are often required. More than 10 chargers in one depot will typically require a secondary substation upgrade and more than 100 chargers will require a primary substation upgrade. **Substation upgrades can be very costly** to both the fleet operator and the network.
- As a result, costs associated with HDV charging are around **£5k – 30k per charging point** and **c. £25k per vehicle for upgrades to the necessary grid infrastructure** for BE buses, with equivalent costs for **BE trucks in the same order of magnitude**[1]. A more detailed breakdown of charger costs is shown in the table (right).
- There are **c. 1,250 HDV depot charging points in operation across Europe** serving BE buses and trucks. **Standards for bus recharging are expected in 2019.** Standards for trucks will follow (electric trucks being less commercially available than BE buses[1]).

Cost Component[5]	Cost (£,000's)
1-2MW grid infrastructure	60 – 2,000
Installation	4.5
11 or 22kW Charge Point	2.2
50kW Charge Point	27
150kW Charge Point	53
350kW Charge Point	105

[1] A. Stewart and R. Riley, "Nissan Zero Emission HDV Market and Recharging Infrastructure," 2018.

[2] C. Cluzel and A. Hope–Morley, "Transport Energy Infrastructure Roadmap to 2050: Electricity Roadmap," 2015.

Contents

As well as storing energy, batteries can provide multiple grid services including frequency response

Batteries – An Overview

- Batteries **convert electricity to chemical energy for storage before converting it back** when there is demand. The capacity of batteries playing a role in the electricity market today depends on the application; **10s kWs for domestic** batteries and **100s MWs for commercial** batteries.

- To date, the majority of batteries in the electricity market have been used to maintain a grid frequency of 50Hz via "**frequency response**" due to their sub-second response times. Mechanisms include Firm Frequency Response (FFR) and Enhanced Frequency Response (EFR). However, the **FFR market is finite and is becoming increasingly competitive**[1]; consequently, prices have fallen from £22/MWh (2015/16) to less than £12/MWh (2017/18)[2].

- To exploit additional revenue streams, the potential for other **balancing mechanisms** is currently being explored. The penetration of renewable energy sources means that **flexible storage is required to match the demands** of the grid[1].

- Beyond stationary storage, **electric vehicles also have the potential to provide flexibility to the grid** by providing storage options or the ability to increase demand. These mechanisms **still require exploration**.

[1] https://www.energy-storage.news/news/national-grid-dont-put-all-your-eggs-in-the-frequency-response-basket
[2] https://theenergyst.com/can-balancing-mechanism-replace-ffr-price-erosion/

There are several British businesses offering energy storage options in the UK

Stationary Battery Storage – Suppliers

Supplier	Location	Example Products	Summary	Source
ARENKOGROUP	UK	Arenko is working with GE to deliver a 41MW battery energy storage system, GE's largest as of 2018. 	Arenko was founded in 2014, and has since delivered several grid-scale energy storage projects in the UK between 6MW (10MWh) and 41MW.	https://arenko.group/ http://planning.walsall.gov.uk/swift/MediaTemp/63084-56465.pdf
ukpowerreserve SUPPORTING A RENEWABLE FUTURE	UK	UKPR uses lithium ion batteries to deliver a range of solutions such as frequency response and voltage regulation. 	UK Power Reserve, established in 2010, is the UK's second largest developer of battery storage, with 120MW installed nationally, for a total portfolio of 1.013GW (this includes 893MW of fast-ramping small-scale gas power plants).	https://ukpowerreserve.com/snap-shots/test-case-study/
EDF ENERGY	France, UK, Brazil, USA & China	- Powervault 3 - Domestic Battery - 4.1 – 8.2kWh - Compatible with Solar PV 	EDF offers commercial battery storage to large companies and home owners for on-site storage.	https://www.edfenergy.com/large-business/energy-solutions/battery-storage
FLUENCE A Siemens and AES Company	USA & Germany	- Advancion - Focused on dependability - 2 – 100MW+ - 30 mins to 8+ hours of energy 	Fluence is the result of a joint venture between Siemens and AES. They have more than 10 years of experience deploying and operating energy storage. They have 701MW of storage, current and future contracts for 75 projects and they operate in 17 different countries, including the UK.	http://fluenceenergy.com/our-story/

Historical savings in the cost of batteries are expected to continue beyond 2025

Battery Costs

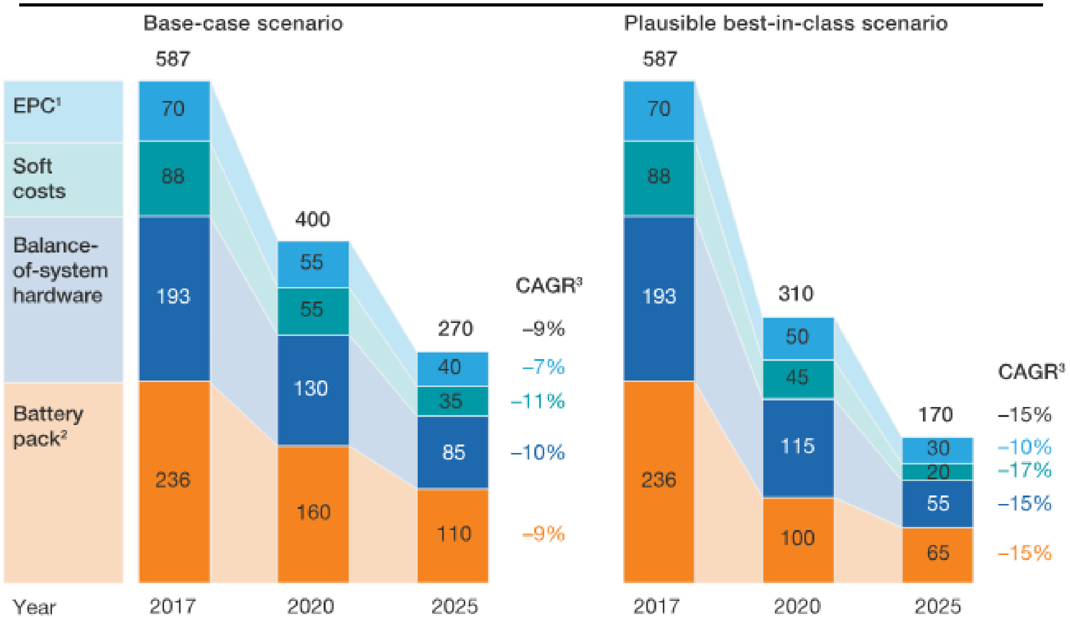
- An increasingly **competitive energy storage market** is continuing to **drive down the costs** associated with battery technology. Improvements in cost are concentrated in four key areas (*below*), including; customer acquisition and development costs (**soft costs**), **battery pack costs**, balance of system (**BOS**) costs and engineering, procurement and construction (**EPC**) costs[1].

- These improvements have led to a **72% cost reduction between 2012 and 2017**[1].

- This has been predominantly driven by increased investment into batteries **due to an increasing global demand for consumer electronics and electric vehicles**. There have also been **cost reductions for key battery components** due to design and manufacturing efficiency improvements. Finally, **soft and EPC costs have fallen** due to increased **market experience** and **streamlined processes**[1].

- In the base case of McKinsey's analysis, the installed battery cost is **expected to fall by c. 46% by 2025** due to improvements in technology, the scale of manufacturing[1] and a 40% reduction in lithium-ion costs[2].

Cost of a 1MW energy-storage system with a 1 hour duration by segment[1]
$/kWh



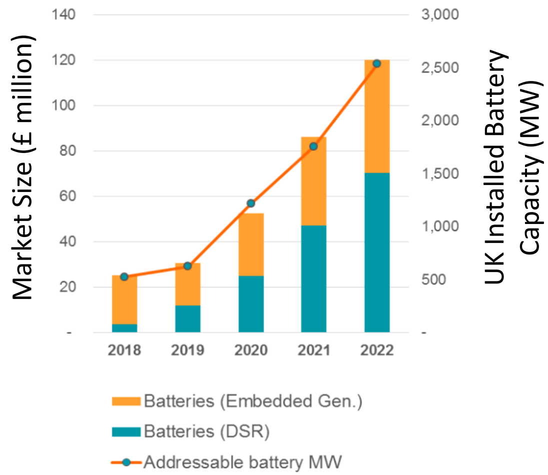
[1]Engineering, procurement, and construction.
[2]Battery-pack cost includes battery-management system, cells, and modules.
[3]Compound annual growth rate, 2017 to 2025.

The total installed capacity of batteries in the UK is expected to increase, despite associated investment risks

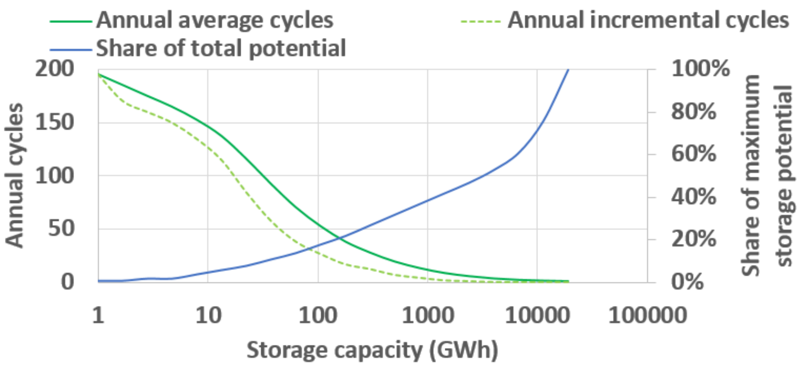
Batteries – Capacity and Market Forecasts

- Due to the expected reductions in cost outlined above, there is an **upward trend in the deployment of batteries for storage**. Policy Exchange has estimated that such a flexible energy system could **save the UK c. £8bn by 2030**[1].
- Furthermore, analysis by EDF suggests that the total market size for batteries will **increase to c. £120m by 2022** (*right*), with battery storage becoming an increasingly viable option for organisations who want to flex their energy consumption[1].
- This is further corroborated by analysis by National Grid who expect an **additional 6–50GWh of storage in the early 2020s**, with a similarly **large addition again in the late 2020s** with the development of more mature business models. This is expected to be **led by EFR and FFR** before the **subsequent co-location of storage with renewable energy generation**[2].
- However, with the further deployment of storage, **less additional storage capacity will be utilised** (*as seen right*). This means that **investing in this area will become less attractive as the market grows**[3].

UK Battery Capacity and Market Size[1]



Annual Charging and Discharging Cycles Decrease with Increasing Deployed Capacity[3]



[1] https://www.edfenergy.com/large-business/talk-power/blogs/the-business-opportunity-for-battery-storage
[2] https://www.energy-storage.news/news/national-grid-dont-put-all-your-eggs-in-the-frequency-response-basket
[3] C. Cluzel, F. Tahir, M. Joos, S. Slater, and S. Baltac, "Study on EV Batteries Progress meeting," 2018.

Contents

Electrolysis is a mature technology that is finding new applications as part of the transition to low carbon economies in Europe and beyond

Water Electrolysis – An Overview

- Electrolysers convert electrical energy to chemical energy by **using electricity** to split water into hydrogen and oxygen.
- Electrolysers have been used in industrial applications for **decades**, mainly in continuous-load (steady-state) operations.
- There is growing interest in electrolysers as a source of low carbon hydrogen as part of the broader *hydrogen economy* vision – i.e. increasing use of hydrogen as an **energy vector** across a range of applications, including **transport, energy storage, electricity and heat generation**.
- To play a full role in supporting the uptake of renewable electricity generation, electrolysers for energy storage applications must be **flexible** and able **to accept variable input power**, ideally with rapid response times.

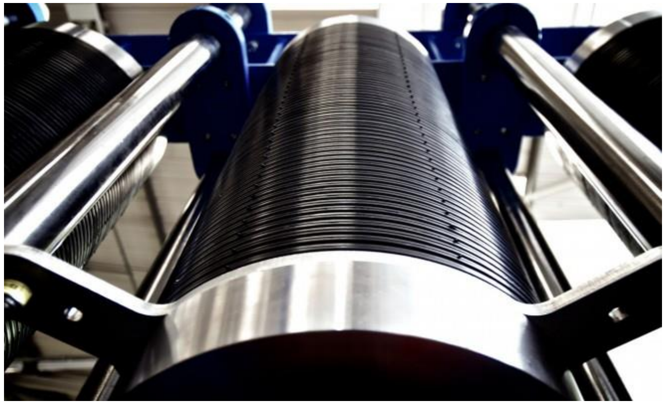
Water electrolysis reactions

Oxidation of water at the (positive) anode:
$2H_2O_{(l)} \rightarrow O_{2(g)} + 4H^+ + 4e^-$

Reduction of protons at the (negative) cathode:
$2H^+ + 2e^- \rightarrow H_{2(g)}$

Overall: $2H_2O_{(l)} \rightarrow O_{2(g)} + 2H_{2(g)}$

Source: NEL Hydrogen



Source: ITM Power

The main types of electrolysis systems now available are based on alkaline and proton exchange membrane technologies

Electrolysis – Technology Options

- Today, two main electrolytic technologies are used:
  - **Alkaline electrolysers** are the most **mature** technology and have been in commercial operation since the 1920s. They form the **majority of currently installed capacity**, used for systems greater than 100kW.
  - **Proton Exchange Membrane (PEM) electrolysis** has been developed over the last 10 years. The scale of PEM projects is **growing**, with the first 10MW project proposed in the Rhineland refinery between ITM Power and Shell. There is **ongoing R&D** to improve efficiency and reduce costs.

- This technology is reliable – with one supplier reporting that only 3% of their sold cells have required replacement since 2009[1]. Electrolysers are typically designed for an operational lifetime of at least ten years, however this is dependent on factors including frequency of use and the maintenance regime.

- Other technologies, such as Anion Exchange Membrane (**AEM**) and Solid Oxide Electrolysis (**SOE**) have a lower technology readiness level than PEM / alkaline systems. SOE operates at higher temperatures and promises lower costs and increased efficiency relative to low temperature systems.

Technology	Status	Size of Systems	2018 System Costs (£/kW)
PEM	Commercial	0.2kW – 10MW as of 2018	700 – 1,060[3,4]
Alkaline	Commercial[2]	1.8kW – 100MW+ as of 2018	518 – 650[3]
AEM	Commercial in limited applications	0.7 – 4.5kW as of 2014	N/A
Solid Oxide	In research and development phase	N/A	N/A

[1] E. Anderson, "PEM Electrolyzer Reliability Based on 20 years of Product Experience in Commercial Markets," *Proton*, no. February, 2016.
[2] https://www.gasworld.com/worlds-largest-h2-energy-system-study-commences/2011500.article.
[3] L. Bertucciolo, A. Chan, D. Hart, F. Lehner, B. Madden, and E. Standen, "Development of Water Electrolysis in the European Union," *FCH JU*, no. February, 2014.
[4] M. Dolman, B. Madden, and W. Nock, "Hydrogen fuel cell buses in London beyond 2020," 2018.

There are many international suppliers of electrolysers, for both PEM and alkaline technology

Electrolysis – Suppliers (1/2)

Supplier	Location	Example Products	Summary	Source
McPhy Driving clean energy forward	France	- 2.8–63 kW - New PEM technology in development. 	McPhy has installed >3,000 electrolysers globally (mostly small scale). A 6MW system has been installed at an Audi plant in N. Germany.	McPhy Company Presentation
nel	Norway	- NEL A150 - 220kW – 2MW - 100-1000 kgH_2/day 	Nel has installed hundreds of electrolysers in >50 countries over the last few decades. Nel opened the world's first public hydrogen fuelling station in Iceland in 2003 and has been engaged in hydrogen fuelling projects since.	https://nelhydrogen.com/
GREENHYDROGEN.DK	Denmark	- A60 electrolyser - MW scale - 130 kgH_2/day 	Green Hydrogen has a decade of experience in developing electrolysers. Their first commercial hydrogen fuel station was installed in 2018.	http://greenhydrogen.dk/technology/hyprovide-250tm/
thyssenkrupp	Germany	- BH-210 electrolyser - 125 kW 	ThyssenKrupp has installed >600 electrochemical plants worldwide. The majority of their experience is with large industrial units.	https://www.thyssenkrupp.com/en/company/
HydrogenPro	Norway	- Single units up to 1,500 kgH_2/day 	HydrogenPro has installed their technology in >300 sites (mainly chemical, metallurgical and energy applications) since 1994.	https://www.hydrogen-pro.com/

ITM Power is the only UK based electrolysis manufacturer

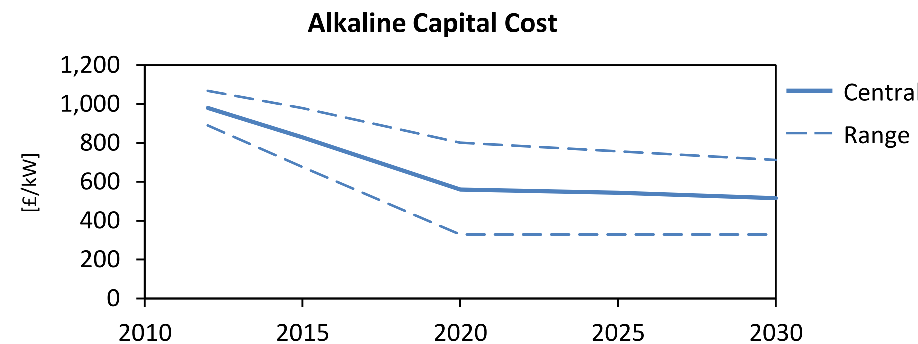
Electrolysis – Suppliers (2/2)

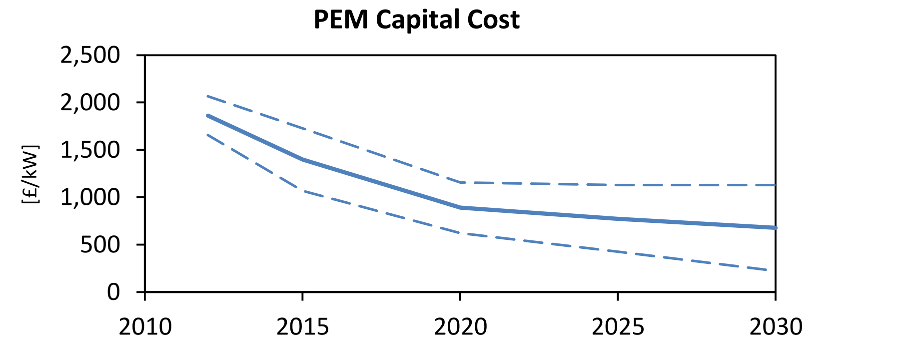
Supplier	Location	Example Products	Summary	Source
ITM POWER Energy Storage | Clean Fuel	UK	- HGas - 0.1-100MW - 45-40,000 kg/day 	ITM Power manufacture electrolysers for multiple applications. They currently operate the UK's largest HRS network; these use their electrolysers on-site.	http://www.itm-power.com/product/hgas
HYDROGENICS SHIFT POWER | ENERGIZE YOUR WORLD	Canada	- HySTAT 60 - 20-1,000 kg/day 	Hydrogenics has delivered >500 electrolyser projects worldwide. This includes on-site production systems for 45 hydrogen fuelling stations.	https://www.hydrogenics.com/wp-content/uploads/renewable-projects-references---fueling-stations.pdf
SIEMENS	Germany	- SILYZER 300 - 2,400-48,000 kg/day 	Siemens develop PEM electrolysers. They have several models within their SILYZER product line. These electrolysers are used in the industry, mobility and energy sectors with decades of experience.	https://www.siemens.com/global/en/home/products/energy/renewable-energy/hydrogen-solutions.html
PROTON ON SITE | nel	US	- M Series - 225-902 kg/day 	Proton, now wholly owned by Nel, specialise in PEM electrolysers. They have supplied five working stations; three in the US and two in Germany.	https://www.protononsite.com/hydrogen-fueling
AREVA H_2Gen	France	- ELYTE 5 – 120 - c. 600kW, modular 	Areva is involved in hydrogen mobility demonstration projects.	http://www.arevah2gen.com/en/

Low cost electrolytic hydrogen relies on low-cost energy, further technological advancements and economies of scale

Electrolysis – Capex and Opex

- Although alkaline electrolysers are more mature than PEM systems, the capital costs of both technologies are expected to converge over the next decade. This is due to:
  - A **faster learning rate** for PEM electrolysers.
  - Increasing **system sizes** and **economies of scale**. E.g. Nel is close to developing a semi-automated production line for PEM stacks.
- With reductions in Capex, operational costs, such as that for **electricity, dominate the cost of hydrogen**. Access to low-cost electricity is critical for an investible case.
- There are currently **no mechanisms** to support tariffs tailored to low-carbon hydrogen production[1].





System Cost [a)]			2012	2015	2020	2025	2030
£/ kW	Alkaline[1]	Central	979	828	561	543	516
		Range	890-1,070	680-980	330-800	330-770	330-680
	PEM[1]	Central	1,860	1,397	890	774	676
		Range	1,660-2,070	1,070-1,730	620-1,160	430-1,130	220-1,130

[a)] Incl. power supply, system control, gas drying. Excl. grid connection, external compression, external purification and storage

[1]L. Bertucciolo, A. Chan, D. Hart, F. Lehner, B. Madden, and E. Standen, "Development of Water Electrolysis in the European Union," *FCH JU*, no. February, 2014.

The electrical efficiency of electrolysers drives the performance of the system

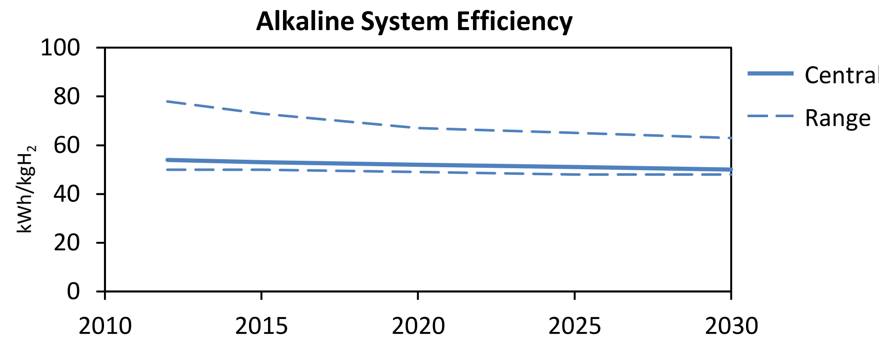
Electrolysis – Characteristics

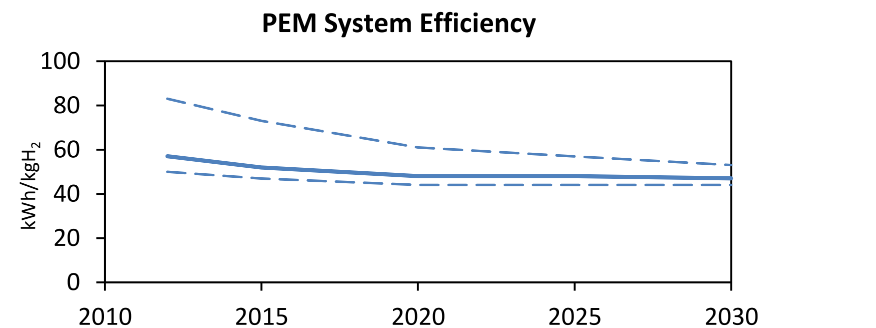
- Although the efficiency of PEM electrolysers is increasing faster than that for alkaline technology, both are **limited to a maximum theoretical efficiency of 39 kWh/kgH_2**.

- These efficiency improvements have arisen due to advances in the **removal of impurities**, increased system **pressures** and improved **electrode construction**.

- The high electricity demand for water electrolysis means that system efficiency is a **key parameter in reducing the price** of hydrogen.

- Electrolysers, both PEM and alkaline, are **highly flexible**. They can be ramped up and down rapidly allowing for **services to the grid** such as balancing[1].





Electricity input [a]			2012	2015	2020	2025	2030
kWh$_{el}$/kgH_2	Alkaline[2]	Central	54	53	52	51	50
		Range	50-78	50-73	49-67	48-65	48-63
	PEM[2]	Central	57	52	48	48	47
		Range	50-83	47-73	44-61	44-57	44-53

[a] Incl. power supply, system control, gas drying. Excl. external compression, external purification and storage

[1] D. Hart, J. Howes, B. Madden, and E. Boyd, "Hydrogen and Fuel Cells: Opportunities for Growth: Mini roadmaps," no. July, 2016.

[2] L. Bertucciolo, A. Chan, D. Hart, F. Lehner, B. Madden, and E. Standen, "Development of Water Electrolysis in the European Union," *FCH JU*, no. February, 2014.

Contents

Hydrogen reformers produce the majority of the world's hydrogen but need to be combined with CCUS to be a low carbon production option

Reforming – An Overview

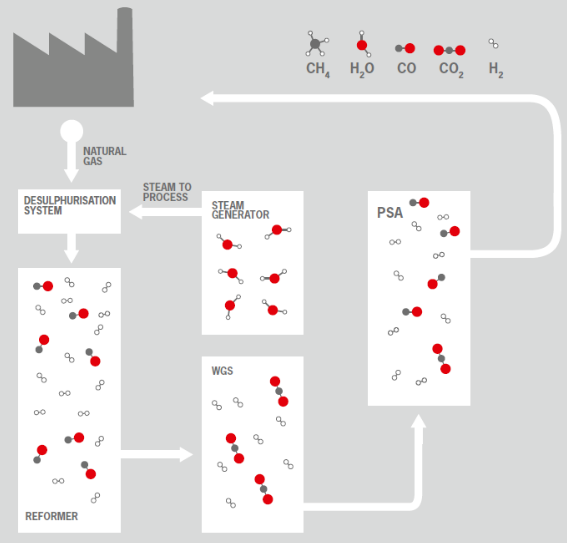
- Steam Methane Reformation (**SMR**) converts a stream of pre-desulfurized **natural gas**, **LPG** or **biogas** to **syngas**, using stoichiometric quantities of **steam** and a **specialised catalyst**.
- Syngas consists of hydrogen and carbon monoxide. The latter is converted to more hydrogen and carbon dioxide via the **water gas shift** (**WGS**) reaction. **Any impurities are then removed** via **pressure swing adsorbers** (**PSA**) to produce a pure stream of hydrogen.
- SMR has been a **fully commercialised** industrial process since its conception in the early 20th century. It now **produces the majority of the world's hydrogen,** primarily meeting industrial demand (large scale production facilities exist in the UK) and smaller customers such as refuelling stations. There is also **interest in smaller scale plants for dedicated production for use in transport** (c. 500kgH_2/day), but the **economic case needs strengthening**.
- For low carbon hydrogen from SMR, the carbon emissions must be captured and stored or used (CCUS). Alternatively, **co-locating hydrogen production with biomethane production** could reduce costs by taking advantage of green hydrogen production incentives (via Renewable Transport Fuel Certificates).
- Auto Thermal Reformation (**ATR**) is an alternative hydrogen production method. It **directly uses pure oxygen** in the reaction between methane and water. This is also a **commercially available process**, but has a shorter history than SMR.

Steam Methane Reformation

Reformation reaction:
$CH_4 + H_2O \rightarrow 3H_2 + CO$

Water Gas Shift Reaction:
$CO + H_2O \rightarrow H_2 + CO_2$

Overall: $CH_4 + 2H_2O \rightarrow 4H_2 + CO_2$



There are several well established reformer suppliers, many of whom are now looking at small scale units

Reformers – Suppliers

Supplier	Location	Summary	Source
Linde	Germany	Linde produces SMR plants with a range of capacities and has installed more than 200 units worldwide. One of their newest products, HydroPrime is a modular, on-site hydrogen reformer. One unit produces c. 500kgH_2/day. This is their smallest SMR option. These units are controlled remotely and have a purity of 99.99%+.	https://www.linde-engineering.com/en/process_plants/hydrogen_and_synthesis_gas_plants/gas_generation/steam_reforming/index.html
HYGEAR	Nether-lands	HyGear has a range of hydrogen products, including small scale SMR options. Their patented technology, HY.GEN, provides on-site production at refuelling stations for transport and industrial sites. The throughput for these units varies between 20kg/day and 4,300kg/day.	http://hygear.com/technologies/hy-gen/
Air Products United Kingdom & Ireland	UK & Ireland	Air Products is a global company and the world's leading hydrogen supplier and the operators of the world's largest hydrogen pipeline network in the USA (the Gulf Coast Pipeline) for industry. One of their products is PRISM, a modulable hydrogen generator. They are designed to be able to produce 5,000Nm^3/h. These can be used in a variety of applications, including the chemicals industry and hydrogen refuelling.	http://www.airproducts.com/~/media/Files/PDF/products/supply-options/gas-generation/en-prism-hydrogen-generation-systems-datasheet.pdf?la=en
Air Liquide creative oxygen	France	Air Liquide vary their designs to provide low Opex, high efficiency or lowest total-lifetime costs. This can be achieved through varying degrees of modulation. They also offer small hydrogen capacities. For their large assets, output varies between 21,500 and 430,000kg/day, whereas for their smaller assets, it varies between 21,500 and 86,000kg/day.	https://www.engineering-airliquide.com/steam-methane-reforming-hydrogen-production

Economies of scale result in lower hydrogen production costs for larger scale reformers

Reforming – Efficiency Characteristics

- To produce the hydrogen, a feedstock of natural gas and electricity is required. Currently, the **utilisation of natural gas is around 47kWh/kgH_2** (LHV) and the **utilisation of electricity is c.0.6kWh/kgH_2**[1].

- As this is a mature technology, **improvements in efficiency are expected to be minimal**. By 2025, the natural gas utilisation is expected to **decrease by 1.1kWh/kgH_2** whilst the **electricity consumption is expected to remain constant**[1].

Reforming – Cost Characteristics

- The SMR and associated balance of plant (BoP) **Capex decrease with scale**, as can be seen in the table (*below*).

- The BoP includes the pre-treatment of the gas stream (i.e. pre-desulfurization) and downstream purification (i.e. PSA).

Capacity[2, 3, 4] (kgH_2/day)	SMR Capex (£/(kgH_2/day))	BoP Capex (£/(kgH_2/day))
560	3,300	1,400
2,240	1,900	1,000

[1] Carbon Trust, "Technology Innovation Needs Assessment," no. January, 2013.
[2] M. Dolman, B. Madden, and W. Nock, "Hydrogen fuel cell buses in London beyond 2020," 2018.
[3] HyGear Quote- See Email – Flag as confidential
[4] The Linde Group, "HYDROPRIME ® . Modular hydrogen generators using steam-methane reforming."

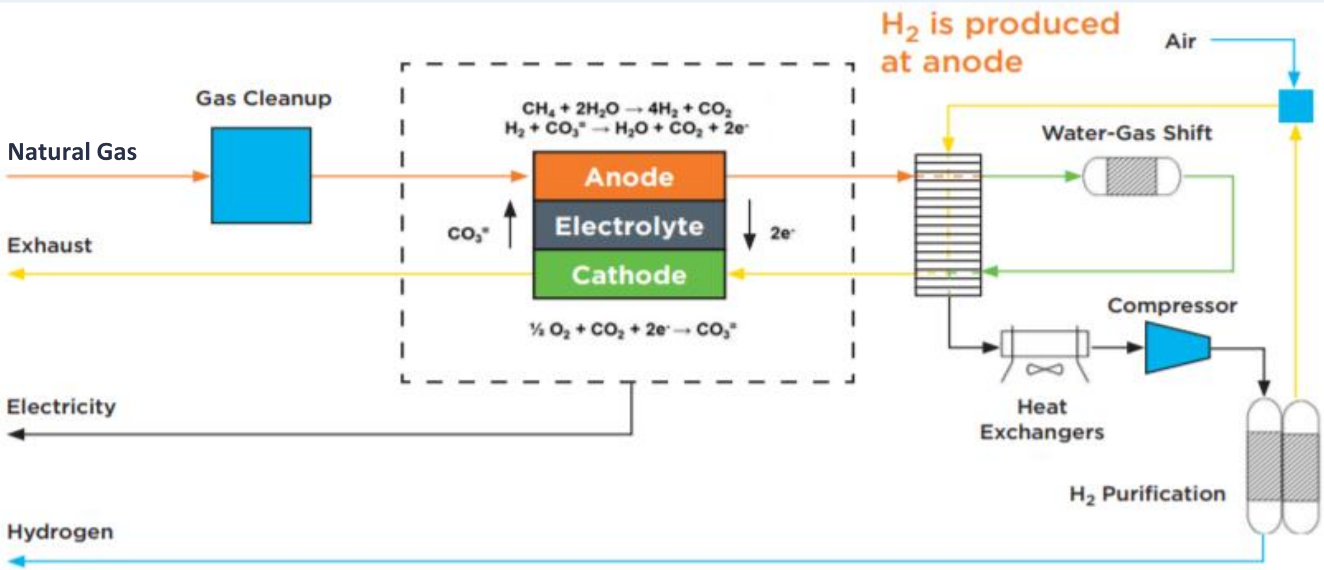
Contents

Molten Carbonate Fuel Cells (MCFCs) are capable of creating hydrogen, electricity and heat in variable proportions from a natural gas fuel source

MCFCs - An Overview

- MCFCs **create electricity** using **natural gas** and **water** inputs. **Hydrogen** and **heat** are also produced as part of the process.
- The **ratio** of production of **electricity, hydrogen** and **heat** can be **modulated**. As the amount of **hydrogen produced increases**, the **electric power output** and the **usable heat decrease**. These relationships are **non-linear** and are explored in the following slide.
- MCFCs operate at **temperatures above 600°C**, using an electrolyte mixture of molten carbonate salt[1].
- This high operational temperature **increases the inherent efficiency** of the technology and **avoids the need to use precious metals as catalysts**; this reduces Capex and environmental impacts.

MCFC Process Diagram[2]



[1] https://www.doitpoms.ac.uk/tlplib/fuel-cells/mcfc_history.php
[2] U.S. Department of Energy, "Tri-Generation Success Story: World's First Tri-Gen Energy Station - Fountain Valley," 2013.

The output from MCFCs can be varied to meet demand or to improve the economics of the business case

MCFCs – Characteristics

- The **hydrogen**, **heat** and **electrical outputs** from MCFCs can be **varied**, according to their demand & associated prices. This is achieved by:
  - First producing **hydrogen** & **heat** in the **reformer.**
  - **The hydrogen** can be **reacted** at the **anode** for the production of **electricity** & more **heat**;
  - **OR the hydrogen** can be **separated** into a pure stream;
  - **OR** a **combination** of the above.
- The chart (*right*) demonstrates this effect for a 300kW MCFC system. As the **production of hydrogen increases**, the amount of **electrical power decreases.** This **relationship** is **non-linear** and is **accounted** for by the **increased** amount of **heat** which can be **recovered** at **lower volumes** of **hydrogen production.**
- The **demand & prices** of **hydrogen** and **electricity** will **dictate** the **ratio** of their **output** by the MCFC. This will have a **strong influence** on the **business case** which can be improved if a buyer for the heat can be found.

MCFC reactions

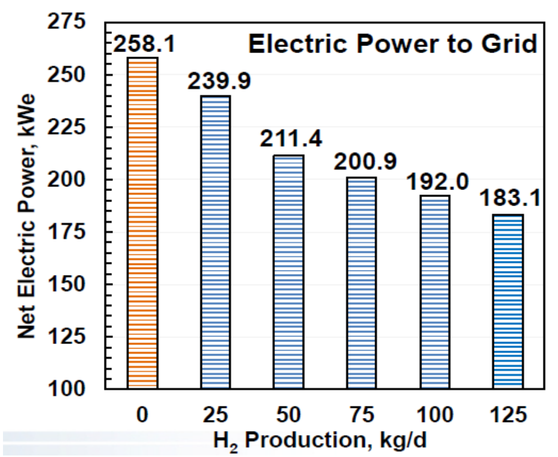
Internal Reformer:
$CH_4 + 2H_2O \rightarrow 3H_2 + CO$

Oxidation at the (positive) anode:
$H_2 + CO_3{}^{2-} \rightarrow H_2O + CO_2 + 2e^-$

Reduction at the (negative) cathode:
$O_2 + 2CO_2 + 4e^- \rightarrow 2CO_3{}^{2-}$

Overall FC Reaction: $O_2 + 2H_2 \rightarrow 2H_2O$

Electricity reduces with increased H_2 output[2]

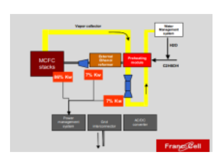


[1] R. Remick and D. Wheeler, "Molten carbonate and phosphoric acid stationary fuel cells: Overview and gap analysis," 2010.

[2] S. Ahmed, D. Papadias, R. Ahluwalia, T. Hua, and H.S. Roh, "Performance and Cost Analysis for a 300kW Tri-generation Molten Carbonate Fuel Cell System," 2015.

Fuel Cell Energy is the major global OEM involved in MCFC technology, other companies listed are technology integrators or licensees

MCFC – Suppliers

Supplier	Location	Example Products	Summary	Source
fuelcellenergy	US	- SureSource 1500 - 1.4MW - Suitable for waste-water treatment, manufacturing and hospitals 	In 2013, Fuel Cell Energy (FCE) supplied the first MCFC (300 kW) to Regents Street's redevelopment and to the Walkie Talkie building in 2015, both in London. In total, they have completed more than 80 installations worldwide.	https://investor.fce.com/Investors/default.aspx http://www.renewableenergyfocus.com/view/35074/logan-energy-installs-britain-s-biggest-fuel-cell-at-regent-street-development/
FuelCell Energy Solutions Saubere, effiziente, zuverlässige Energie	Germany	- As above 	FCE Solutions is a joint-venture between FCE and Fraunhofer IKTS. In 2015, they installed the first commercial MW class (1.4MW) MCFC in Europe, in Mannheim, Germany.	http://www.renewableenergyfocus.com/view/42756/fuelcell-energy-solutions-and-e-on-to-develop-mw-scale-projects-in-european-market/
POSCO ENERGY	South Korea	- As above 	Opened a prototype MCFC 125 kW system in 2010. POSCO also have a licence, manufacturing and distribution agreement with Fuel Cell Energy for MCFCs. The POSCO manufacturing plant has a production capacity of 100 MW per annum.	https://www.ieafuelcell.com/documents/MCFC_international_status_2015_web.pdf
FrancoCell	France	- Use sugar cane ethanol as a feedstock - High efficiency of 56%+ 	Franco Cell has conducted preliminary feasibility studies on a multi-megawatt MCFC. Their strategy is to deploy MCFCs in locations isolated from the electricity grid.	S. J. Mchphail, L. Leto, M. Della Pietra, V. Cigolotti, and A. Moreno, "International Status of Molten Carbonate Fuel Cells Technology," 2015.

The poor efficiency associated with dual electricity and hydrogen production is increased by recovering excess heat

Performance characteristics of a Fuel Cell Energy 300kW Molten Carbonate Fuel Cell

Variable	Units	Pure Electric Mode	Combined Electric and H_2 mode	Comments for Performance in Combined Electric and H_2 mode
Stack DC gross output	kWe	**300**	**274.9**	-
Net H_2 Production	kgH_2/day	**0**	**125**	-
Net electrical power output	kW	**258**	**183**	Requires a 5% increase in fuel input
Net Electrical Efficiency	%	**46.4**	**27.6**	-
Net Hydrogen Production Efficiency	%	**0.0**	**26.2**	-
Net Heat Recovery Efficiency	%	**32.7**	**23.2**	If waste heat is used to raise hot water (lower if steam is raised)
Total Efficiency	%	**79.1**	**77.0**	-

- In 2010, global annual production of MCFCs was **30MW** at an installed cost of **c. £5,500/kW**. The **National Renewable Energy Lab** predicts that if production reaches **c. 150MW**, the installed capex could drop to **c. £2,400/kW** [1]. If production reached **c. 750MW/year** costs could reach **c. £1,500/kW** which would make **MCFC's Capex comparable to incumbent combined heat and power** technologies[1].

- Material corrosion results in a stack lifetime of c. 5 years. However, FCE have **forecasted an increase in the lifetime** of their stacks, **from 5 to 10 years** by the early **2020s**. This would **reduce operational and maintenance costs** by **c. 40%** [1].

[1] R. Remick and D. Wheeler, "Molten carbonate and phosphoric acid stationary fuel cells: Overview and gap analysis," 2010.

Contents

The current hydrogen injection focus is on blends with natural gas up to 20% by volume

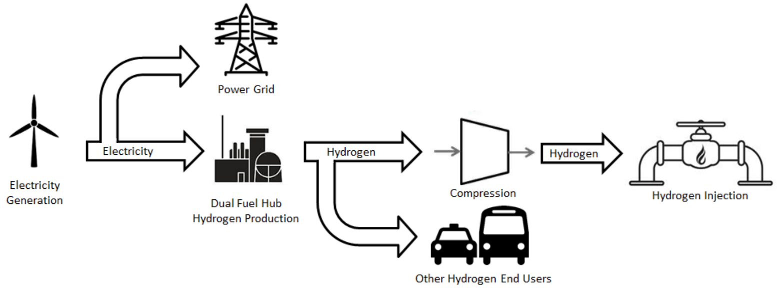
Hydrogen Injection – An Overview

- There is growing interest in using hydrogen to decarbonise the UK's gas grid amongst gas network operators and the UK Government. Concepts such as those envisaged by the *H21 North of England* initiative being developed by Cadent and Northern Gas Networks are based on large-scale production of low carbon hydrogen (mainly from natural gas with CCS), combined with dedicated hydrogen pipelines and wholesale conversion of gas distribution networks to hydrogen.

- Such concepts will require years of detailed planning and implementation of these types of projects is not expected before the mid to late 2020s. In the nearer term, research is underway into the feasibility of blending hydrogen with natural gas, and thus using the existing gas grid as a means of storing hydrogen produced from renewables. "Power-to-gas" involves generating hydrogen from excess / low cost renewable electricity and injecting the gas produced into existing networks, typically blended with natural gas. This is potentially relevant for a Dual Fuel Hub and therefore the focus of this section.

- There are **limitations on the percentage of hydrogen by volume (%H_2vol) that can be injected** into the grid **due to compatibility** with existing equipment, such as heating and gas turbines[1]. While the Gas Safety (Management) Regulations 1996 stipulate that the hydrogen content of gas in the network should be <0.1% (molar), it has been established in some locations that a blend of **10%H_2vol is feasible**[2]. Projects such as HyDeploy[3] and GRHYD are looking at how and where this can be increased **to 20%H_2vol**.

- After the hydrogen has been produced, it is **mixed with natural gas from the existing network**. The mixture is blended using **specialised equipment to ensure that the %H_2vol does not exceed local or national limits**. The pressure is then adjusted to match that of the grid, either using compressors to increase the pressure or it is dropped using expansion valves[3].



Power-to-gas concept

[1] Carbon Connect, "Next steps for the gas grid," 2017.
[2] K. Altfeld and D. Pinchbeck, "Admissible hydrogen concentrations in natural gas systems," 2013.
[3] https://hydeploy.co.uk/about/technology/

Several projects are investigating the feasibility, safety, and cost implications of injecting hydrogen into existing gas networks

Hydrogen Injection – Projects

Project	Years	Project Summary	Source
Project CLoCC	2015 – 2018	CLoCC is a national grid project aimed to optimise the process and costs associated with forming a grid connection. This was achieved through a web-based customer connections platform to improve the application process, "off-the-shelf" standardised designs for grid connections (suitable for a range of gases and flow rates) and designs for new commercial processes for non-traditional customers. The results of this project are discussed in the following slide.	http://projectclocc.com/about-us/
HyDeploy	2017 – 2020	HyDeploy is a British project exploring whether blends of natural gas and hydrogen up to 20%vol. are a feasible way of reducing CO_2 emissions from heating and cooking without the need for changes in appliances. This is being run on a private network at Keele University – the first of a kind in the UK. This project will be continued in HyDeploy2, focusing on two public networks in the north of England.	https://hydeploy.co.uk/
NATURALHY	2004 – 2009	NaturalHy was a European Commission funded project to assess the feasibility of using the existing natural gas network for hydrogen delivery. The main conclusions relevant to hydrogen injection related to the safety of hydrogen in the network (i.e. minimal embrittlement).	G.Tiekstra (2008) The NaturalHY project: first step in assessing the potential of the existing natural gas network for hydrogen delivery.
GRHYD Renouvelons nos énergies	2014 – 2021	GRHYD is a French project, coordinated by Engie in conjunction with 10 other partners. Its objective is to assess the technical and economic validity of hydrogen and natural gas blends into the grid. There are two primary demonstration projects, one to assess the mixture at a CNG bus station (increasing from 6%H_2vol. to 20%H_2vol.) and the second to test a small residential gas network with this blend.	http://grhyd.fr/presentation/

Projects such as CLoCC have focussed on making unconventional gas connections to the grid accessible and economical

Hydrogen Injection – Costs

- Given the nascent stage of the power-to-gas industry, there is limited real-world experience and therefore **limited cost data**. The table (*right*) therefore details injection **costs for biomethane as a proxy** (based on internal Element Energy data).
- There are also **capital costs** associated with the **blending process**. It is designed to increase the energy density of the gas and to ensure that the volume of hydrogen does not exceed safe levels.
- CLoCC, a National Grid project, has sought to **reduce the cost of a National Transmission System (NTS) injection connection to below £1 million**. This has been achieved via the **standardisation of injection equipment**. The available array of equipment will be compatible with unconventional gases at a range of flow rates[1].
- In addition, the project **reduced consulting times from three years to less than a year**[1].

Cost Component (Pipeline Length)	Cost (£,000's)
NTS Injection Connection (1km)	2,500
LTS Connection (1km)	700
IP Connection (1km)	340
IP Connection; Double Capacity (3km)	940
MP Connection (0.25km)	65
MP Connection; Double Capacity (2km)	415

[1] http://projectclocc.com/about-us/

Contents

Tube trailers are a commonly used method of transporting compressed (or liquified) gases by road

Tube Trailers – An Overview

- "Tube trailers" are a form of **mobile hydrogen storage** and a commonly used way of transporting gases from production sites to points of demand. They consist of **banks of cylinders** (tubes) connected together with **pipework** and **valves** mounted on trailers that are **pulled by articulated lorries** (tractor units).

- Hydrogen can be **decanted from tube trailers into static storage**, or the trailers can be **decoupled from the tractor unit at the demand site** (trailer swapping).

- Gaseous hydrogen is typically **transported at pressures of several hundred bar** – e.g. 200 bar tube trailers have been used for many years, 500 bar solutions are also available and some gas companies are working on even higher pressure levels. Note that hydrogen **can also be transported as a liquid**. To liquefy the gas, its temperature is lowered to -253°C which typically requires c. 12kWh/kgH_2 (i.e. **there is a relatively high energy cost** of going to liquid hydrogen).

- Different pressure vessels can be used **from Type I** (all metal construction) to **Type IV** (all composite) (see section on hydrogen storage). The choice of material is a **balance between costs and performance** – e.g. steel cylinders are lower cost than composites but have a higher mass and therefore a the weight percentage of hydrogen that can be transported is lower (given vehicle weight limits).

- The capital cost of hydrogen tube trailers is typically from **several hundred £k to c.£1m depending on the specification**. The FCH JU published targets for tube trailer capex: €550k (for 800kgH_2) in 2020 and €450k (for 1,000kgH_2) by 2023.[1]

An Air Products 500 bar tube trailer (source: Air Products)

A 500 bar tube trailer from Linde with a capacity of 1,100kgH_2 (source: Linde)

A bespoke tube trailer designed for small roads on the Orkney Islands (source: www.bighit.eu/about/)

[1] Source: *FCH JU Multi Annual Work Plan 2014-2020*, Table 3.1.1.5, p.37.

Suppliers of tube trailers also provide an array of hydrogen storage solutions

Tube Trailers – Overview of Selected Suppliers

Supplier	Location	Summary	Source
CHESTERFIELD SPECIAL CYLINDERS	UK	Chesterfield Special Cylinders has developed a 500 bar hydrogen trailer for high pressure refuelling. This trailer also facilitates the transportation of 200 bar hydrogen cylinders.	http://www.chesterfieldcylinders.com/products#renewable-energy
CALVERA	Spain	Calvera can provide tank configurations and the necessary cylinder for volume and weight specifications. Their collector hoses include anti-vibration design for maximum safety.	http://www.calvera.es/en/business-lines/industrial-gas/trailer-container-for-h2/
HEXAGON	Norway, USA & Germany	Hexagon has developed a patented “TITAN” trailer for the bulk transportation of hydrogen using storage modules. They also have a lightweight container, “SMARTSTORE”, which can be transported by standard trailer equipment.	https://www.hexagonlincoln.com/
BOC Member of The Linde Group	UK	BOC has dedicated trailers for both compressed (CGH_2) and liquefied (LH_2) hydrogen. For the LH_2, the tanks are specially insulated to maintain a temperature of -253°C. For CGH_2, the containers (cylinders, cylinder bundles, tanks and pipes) are all pressure-tight.	https://www.boconline.co.uk/en/processes/hydrogen-energy/complete-hydrogen-solutions/hydrogen-distribution-storage.html
Air Liquide creative oxygen	France	Air Liquide offers many sizes of high-pressure gas cylinders and tube trailers made of aluminum and stainless steel.	https://industry.airliquide.co.uk/supply-modes/cylinders

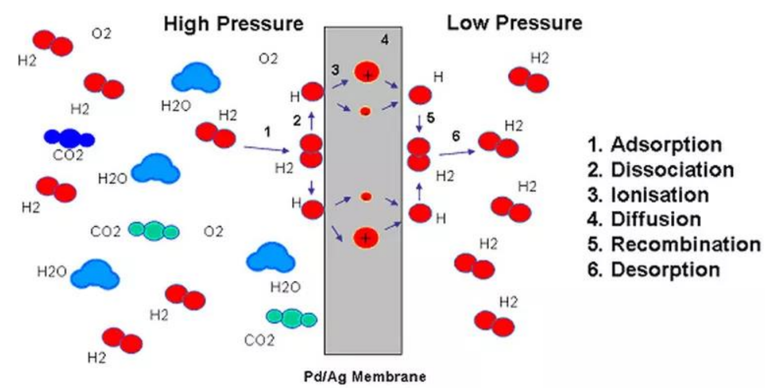
Contents

Although hydrogen separation technology is in commercial use, work is required to realise this for recovery from the gas grid

Hydrogen Recovery – An Overview

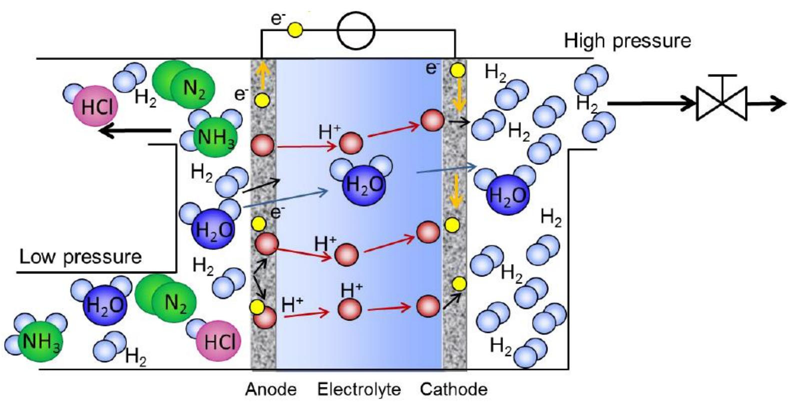
- Hydrogen injected into the natural gas grid can be **recovered once it has reached the point of demand**. This method of delivery requires **separation and extraction** from the **natural gas blend**.
- The two most promising methods of separation include:
  - **Membrane separation** technology (TRL 5).
  - **Electro-chemical membrane** technology (TRL 5).
- **Membrane separation** uses pressure gradients to filter gases across a **Palladium membrane**. Extremely **high hydrogen purity** is possible, but **elevated temperatures** are required due to **hydrogen poisoning** effects. It is currently used in **the electronics industry** to purify hydrogen to fuel cell grade[1].
- **Electro-chemical membrane** technology uses a **proton exchange membrane** with an **applied voltage** to **oxidize and reduce** hydrogen and separate it from a **mixed gas feed stream**[2]. There are **no commercial electrochemical hydrogen** separators **available currently**[1].
- Membrane separation achieves **higher hydrogen purity** but electro-chemical separation can **extract more hydrogen** from **a low concentration of hydrogen** in a gas stream.

Membrane Separation



Source: Sigma-Tech

Electro-Chemical Separation



Source: Memphys

[1] Liemberger, Werner & Halmschlager, Daniel & Miltner, Martin & Harasek, Michael. (2018). Efficient extraction of hydrogen transported as co-stream in the natural gas grid – The importance of process design.

[2] K. Perry. (2007) "Electrochemical hydrogen pumping using a high-temperature polybenzimidazole membrane"

All technologies are currently at the laboratory prototype stage using public funding for these research projects

Hydrogen Recovery – Research Projects

Project	Years	Summary	Source
NATURALHY	2004 - 2009	The first funded European Commission project to **assess the feasibility** of using the **existing natural gas network for hydrogen delivery**. **Carbon-based membranes** were found to be able to **separate hydrogen** from mixtures with high flow rates to give **c. 98% purity**. **Purity above 99.999%** was obtained with **lab scale** thin **Pd-based** membranes.	G.Tiekstra (2008) The NaturalHY project: first step in assessing the potential of the existing natural gas network for hydrogen delivery.
FERRET	2014 - 2017	An FCH JU funded research project **trialling new Pd-supported** membranes which would **decrease the capital cost of separation** equipment and **increase the amount of hydrogen** which can **be separated from a given gas blend to c. 3.4Nm^3/hr**.	http://www.ferret-h2.eu/disseminations/communications
MEMPHYS	2017 - 2019	An FCH JU funded research project to develop hydrogen purification technologies based on **electro-chemical membrane** technology. Some **targets** of the project are: for a production rate of **>5 kgH$_2$/day**; an energy consumption of **<5kWh/kgH$_2$**; and a Capex of **<£1,300/kgH$_2$/day**	http://www.memphys.eu/downloads/
Project HyGrid	2016 - 2019	Another FCH JU funded project with **aims** to **develop, build and demonstrate** an integrated electrochemical and membrane separation technique for hydrogen from the natural gas grid. The project targets include: – A cost of **<£1.3/kgH$_2$** from a hydrogen concentration of <10% by volume – A production rate of **>25kgH$_2$/day**[1] Multiple **tests have been performed on a prototype electro-chemical** membrane for hydrogen **concentration streams of <2%**. These experiments required an **energy intensity of electro-chem separation was 4.7 kWh/kgH$_2$** to achieve the **target recovery rate of 60%**[2]. At present, **no results from the fully integrated separator** have been published, but **modelled results** suggest that the project **targets can be met**[1].	[1] https://hygrid-h2.eu/sites/hygrid.drupal.pulsartecnalia.com/files/documents/HyGrid-2nd-Public_presentation_Nov2017_final.pdf [2] HyGrid Newsletter Issues 3 (2018) page 7 of 19

http://www.saespuregas.com/Products/Gas-Purifier/Hydrogen/Palladium-Membrane/Home.html

Contents

Hydrogen can be stored in various forms

Hydrogen Storage – An Overview

- Hydrogen storage is important for **seasonal energy demand**, **transport** (HRS and FCEVs) and in **industry**.
- These applications are **constrained by different requirements**; i.e. power ratings, energy capacity, energy density, safety and cost (Capex and Opex).
- For the Dual Fuel Hub, the **most relevant storage solutions** include **pressurised tanks** and **liquid storage**. Liquid organic hydrogen carriers (**LOHCs**) are also **under development** and could be relevant.

Storage Method[1,2]	Description	Capacity	Commercialisation
Pressurised Tanks	H_2 is compressed to a range of pressures in storage tanks.	0.1 – 10 MWh/tank	Very Mature
Liquid Storage	H_2 is stored cryogenically as a liquid.	1 – 100 GWh/tank	Commercially used
LOHC	H_2 bonds to a molecule for storage and is released using heat and a catalyst at the point of demand.	<160 MWh/tank for bulk storage	Close to commercialisation

- **Other storage options** include **underground storage** (large scale) and **metal hydrides** (developing technology) but these are **not so relevant** for the Dual Fuel hub.

[1] SBC Energy Institute, "Hydrogen-Based Energy Conversion," 2014.
[2] Hydrogenious, "Hydrogenious Technologies GmbH – a pioneer in chemical hydrogen storage," 2017.

There are four main types of pressure vessels

Pressure vessel tank types – overview

Pressure vessels are classified into four main types, as summarised below.

Type	Features	Maximum pressure
Type I	• All-metal construction, typically steel (or aluminium). • Widely available, relatively low cost. • Relatively high mass per unit storage volume. • Commonly used in CNG vehicles.	175 – 200 bar
Type II	• Mostly steel or aluminium with a glass-fibre composite overwrap. • Structural loads shared between metal vessel and composite materials. • Higher cost than Type I but lighter weight.	260 – 300 bar
Type III	• Tanks made from a metal liner with full composite overwrap (e.g. aluminium with a carbon fibre composite). • The composite materials carry the structural loads	300 – 700 bar
Type IV	• All-composite construction using a polymer liner with carbon fibre or hybrid carbon/glass fibre composite. • Relatively expensive but lower tank mass per unit volume	700 bar

Source: based on http://www.compositesworld.com/articles/pressure-vessel-tank-types.

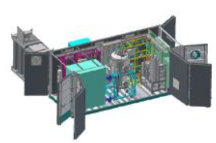
Many hydrogen storage suppliers specialise in a cylinder type, although Faber and Calvera provide a spectrum of options

Hydrogen Storage – Pressurised Tank Suppliers (non-exhaustive list)

Supplier	Location	Example Products		Summary	Source
Pressurised Tank Suppliers					
HEXAGON	Norway, USA & Germany	- Pressure: 500 bar - Length: 2.424m - Weight: 229kg - Capacity: 10.7kgH_2		Hexagon has specialised in filament-wound fuel tanks since 1963. They now produce Type 4 hydrogen cylinders up to a maximum pressure of 950 bar.	https://www.hexagonlincoln.com/resources/brochures
LUXFER	UK	- Pressure: 350 bar - Length 2.19m - Weight: 141kg - Capacity: 7.72kgH_2		Luxfer is the world's largest manufacturer of composite cylinders. Luxfer produces Type 3 & 4 hydrogen cylinders up to 500 bar.	http://www.luxfercylinders.com/products/g-stor-h2#description
CHESTERFIELD SPECIAL CYLINDERS	UK	- Steel cylinders for tube trailers <500 bar		Chesterfield Special Cylinders produces cylinders for a range of gases. They provide Type 1 hydrogen cylinders up to 500 bar.	http://www.chesterfieldcylinders.com/products#renewable-energy
Faber CYLINDERS	Italy	- Pressure: 700 bar - Volume: 53.5L - Type 3, Carbon Fiber		Faber is the only manufacturer of all types of cylinder (1, 2, 3 & 4). This is up to a maximum pressure of 1,100 bar.	http://www.faber-italy.com/eng-product-hydrogen2.asp?cda=50&ca=9999
CALVERA Hydrogen	Spain	- Pressure: 200 – 1,000 bar - All systems are modular and extendible		Calvera provides Type 1, 2 & 3 hydrogen cylinders up to a maximum pressure of 1,000 bar.	http://www.calvera.es/en/business-lines/hydrogen-h2/storage-for-hydrogen/

There are fewer players in the liquefied, solid state and underground storage markets due to scale and developing technologies

Hydrogen Storage – Suppliers (2/2)

Supplier	Location	Example Products	Summary	Source
Liquefied Hydrogen Suppliers				
Linde	Germany	- Volume: 3,000 to >100,000 litres. - Pressure: 18, 22 or 36 bar. 	Linde offer both pressurised cylinders and liquefied hydrogen. They have extensive experience of liquefying gases, including nitrogen, argon and methane.	https://www.the-linde-group.com/en/clean_technology/clean_technology_portfolio/hydrogen_energy_h2/index.html
Air Liquide	France	- Developed tanks for Ariane space launcher. - 28 tons H_2 - Walls 1.3mm thick 	Air Liquide operate in pressurised, liquefied and solid state hydrogen storage. Their involvement in liquefied storage ranges from industry to space travel.	https://energies.airliquide.com/resources-planet-hydrogen/how-hydrogen-stored
Liquid Organic Carriers				
hydrogenious TECHNOLOGIES	Germany	- Their process involves a storage and release box. - The storage box has c. 200kgH_2/day of uptake. - The release box has a release rate of c. 70kgH_2/day 	Formed in 2013 as a spin-off from FAU Erlangen, Hydrogenious focus on commercial systems for industrial hydrogen logistics and supply of fuelling stations.	Hydrogenious, "Hydrogenious Technologies GmbH – a pioneer in chemical hydrogen storage," 2017.

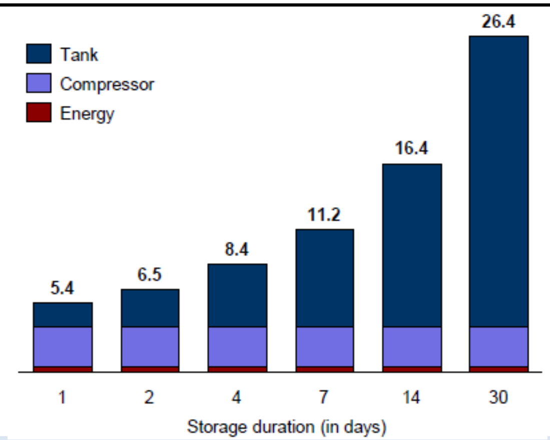
Pressurised storage is suitable for small scale applications in a variety of end use types

Hydrogen Storage – Pressurised Tanks Characteristics

- There are **four cylinder types**; these are defined by material choice (see above) and have different lifetimes, weights and cost.
- These pressurised tanks are most applicable to **small scale** applications and are pressurised between 200–700 bar, allowing for a **variable energy content**.
- They are able to handle **high cycle rates** and **don't suffer from discharge**. However they do suffer from **low energy densities** and **high compression costs**.
- The cost of hydrogen storage is a **large cost component in the hydrogen supply chain**. Research and public funding by the FCH JU and US Department of Energy is looking to reduce these costs to c. €350/kgH_2 or \$333/kgH_2 for storage in vehicles, from 2024.
- The cost of these tanks **increases with pressure and the storage duration** (*right*). This shows that the cost is minimised with high cycle rates.
- In addition to the tanks, manifolds (high pressure piping), storage racks and trailers are required for hydrogen storage.

Variable	State of Art
Max Cycling Rate	High – Minutes to charge and discharge
Propensity to leak	Low
Efficiency	89-91% (350 bar) – includes compression 85-88% (700 bar) – includes compression
Volumetric Energy Density	670-1,300 kWh_{ch}/m^3
Cost[1]	c. £450/kgH_2 for 300 bar c. £1,050/kgH_2 for 500 bar

Levelised cost of storage according to storage duration, with a fixed rate of production[2]
\$/MWh



[1] *Based on storage volumes of c. 300kgH_2 to 1,000kgH_2 per trailer.*
[2] B. Decourt, B. Lajoie, R. Debarre, and O. Soupa, "Hydrogen-Based Energy Conversion," *SBC Energy Inst.*, no. February, 2014.

Liquefied hydrogen storage is associated with high energy density but high costs of liquefaction

Hydrogen Storage – Liquefied Hydrogen Characteristics

- Storing hydrogen as a liquid creates a medium with a **very high energy density**.
- This storage solution benefits from economies of scale and offers a **potential solution for HRS in the future** – pure hydrogen would be transported long distances, avoiding compression costs.
- However, this method is **expensive**. The required infrastructure investment is very high as are the operating costs, due to the need to both cool and maintain the hydrogen cryogenically.
- Due to the propensity for this method to leak, hydrogen **cannot be stored for long periods of time**. There are also explosion **hazards** and risks of fires associated with this solution[1].

Variable	State of Art
Max Cycling Rate	Medium (hours to charge and discharge)
Propensity to leak	High – 0.1-0.5% per day
Efficiency	55-75% (including liquefaction)
Volumetric Energy Density	1,400 – 1,600 kWh_{ch}/m^3
Cost[2]	£4,193/MWh

[1] B. Decourt, B. Lajoie, R. Debarre, and O. Soupa, "Hydrogen-Based Energy Conversion," *SBC Energy Inst.*, no. February, 2014.
[2] D. Sadler and H. Solgaard Anderson, "H21 North of England," 2018.

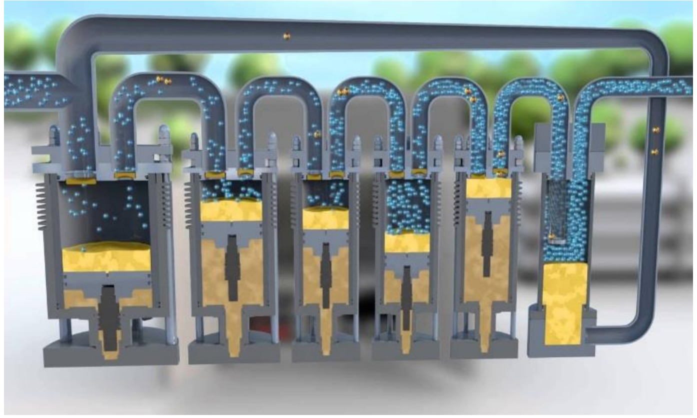
Contents

Compression of hydrogen is a well understood technology, however adaptations are required to improve its suitability for refuelling

Hydrogen Compression – An Overview

- Hydrogen **transport requires pressures of 350 and 700 bar**, however, **hydrogen is typically produced at only 20 to 30 bar**. Compressors meet this need by using electrical energy to increase the pressure of the gas.

- Most compressors are either positive displacement compressors (e.g. reciprocating, rotary & ionic) or **centrifugal compressors**. Positive displacement compressors **suffer from tight tolerances required to minimise leakages of hydrogen**.
  - **Reciprocating compressors** are most commonly used where a **large increase in pressure is required**. A motor moves a piston back and forth to reduce the volume occupied by the hydrogen.
  - **Rotary compressors** use the **rotation** of machinery to compress.
  - **Ionic compressors** (right) use **ionic liquid** instead of pistons and **do not require bearings or seals** (common sources of failure).
  - **Centrifugal compressors** are more common for **pipeline applications** due to their **high throughput** and the **relatively moderate pressure increase required**. This is achieved by rotating turbines at very fast speeds. The **tip speed needs to be three times greater** than that for natural gas due to the low molecular weight of hydrogen[1].



- The compressor **throughput depends on the application**, ranging from tens to thousands of kilograms of hydrogen per day.

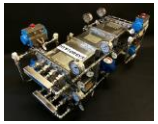
- The technology is **advanced and well understood**. However, improvements are required to **increase the reliability** of compressors in hydrogen transport applications and **reduce their cost**[2].

[1] https://www.energy.gov/eere/fuelcells/gaseous-hydrogen-compression

[2] Hydrogen Europe, "Hydrogen, Enabling a Zero Emission Europe," September, 2018.

Many global companies are developing compressors capable of handling intermittent use, synonymous with refuelling

Hydrogen Compression – Suppliers (1/2)

Supplier	Location	Example Products	Summary	Source
nel	Norway	- HyBoost allows fast refuelling. - 5,000 hour maintenance intervals. - 45 refuels in 12 hours. - Contamination free. 	Nel is a dedicated hydrogen company, working on storage, production and logistical activities since 1927.	U. Borup, "HyBoost – Faster Hydrogen refuelling for Heavy Duty Vehicles," 2018.
Linde	Germany	- IC90 use ionic liquid to provide quick, safe, efficient refuelling. - It is currently used globally. 	Linde believes that ionic compression technology leads the way to the next generation of hydrogen refuelling.	The Linde Group, "Hydrogen technologies: The Ionic Compressor 90 MPa - IC90."
HyET High Yield Energy Technologies	Nether-lands	- HCS100 has no moving parts - Throughput of $10kgH_2$/day - $1,000-2,000/($kgH_2$/day) 	HyET create hydrogen and solar technologies which enable commercially viable, large scale access to decentral renewable energy sources.	https://hyethydrogen.com/hcs100/
HYSTORSYS	Norway	- HYMEHC-10 has no moving parts - Uses waste heat to reduce energy costs - Silent operation - Capacity: $20kgH_2$/day 	Hystorsys' focus is on the use of metal hydrides for compression and storage of hydrogen	http://www.hystorsys.no/

Suppliers are focused on compressors with few moving parts, that are resistant to contamination and operate efficiently

Hydrogen Compression – Suppliers (2/2)

Supplier	Location	Example Products	Summary	Source
Howden	UK, France & USA	- Diaphragm compressor - 100% leak free - 5MPa to 100MPa in two stages 	Howden originally invented compressors in the early 20th century. 700 of their compressors are currently used in hydrogen related activities.	https://www.howden.com/en-gb/applications/compressors-for-hydrogen-fuel-cells
PDC MACHINES.COM	USA	- For HDVs, capacity >2,500kgH_2/day - Discharge up to 100MPa - Ultra-high purity - Easy maintenance 	PDC specializes in providing complete solutions for alternative energy applications. They have nearly 350 compressors employed in the fueling market worldwide.	http://www.pdcmachines.com/alternative-energy-hydrogen-stations/
Sundyne	USA, UK, Spain & France	- Pinnacle LF-2000 - Max pressure 350 bar - Modulable compressor 	Sundyne engineer and manufacture centrifugal compressors for a range of industries including power generation, oil & gas and engineered water.	http://www.sundyne.com/Products/Model-Locator/Pinnacle-LF-2000

Although established, research is required to meet today's demands

Hydrogen Compression – Characteristics

- Most commonly used for HRS, the **size and throughput** of a compressor is **variable** can be designed accordingly.
- The **cost** for compression is dependent on the throughput and **change in pressure**. For throughputs between 250 – 1,000kgH_2/day and an inlet pressure of 1 bar, the capital cost can be found in the table (*right*)[1].
- Although this technology is commercially established, compressors are the **main point of failure** for hydrogen refuelling stations due to **intermittent usage**. One way to ensure high HRS availability is to include redundancy in the design (i.e. specify multiple compressors). This adds costs but is a prudent strategy when high reliability is important (e.g. for fuelling fleets of buses).
- The **efficiency** for these compressors **depends on the change in pressure and the model**. For an increase in pressure from **0.5 to 90MPa**, the efficiency[2,3,4] ranges between **0.63kWh/kgH_2 and 4kWh/kgH_2**.
- Research is currently focussed on **purpose built** compressors with a **higher efficiency**, **reduced contamination** and a **lower cost**. Companies such as Nel, Linde, Hystorsys and HyET are currently developing and beginning to market these products[5].

Outlet Pressure (bar)	Cost ($/(kg$H_2$/day))
70	211 – 323
1,000	338 – 471

[1] Strategic Analysis, "Final Report: Hydrogen Storage System Cost Analysis Sponsorship and Acknowledgements," 2016.
[2] U. Borup, "HyBoost – Faster Hydrogen refuelling for Heavy Duty Vehicles," 2018.
[3] The Linde Group, "Hydrogen technologies: The Ionic Compressor 90 MPa - IC90."
[4] https://hyethydrogen.com/hcs100/
[5] D. Hart, J. Howes, B. Madden, and E. Boyd, "Hydrogen and Fuel Cells: Opportunities for Growth A Roadmap for the UK," 2016.

Contents

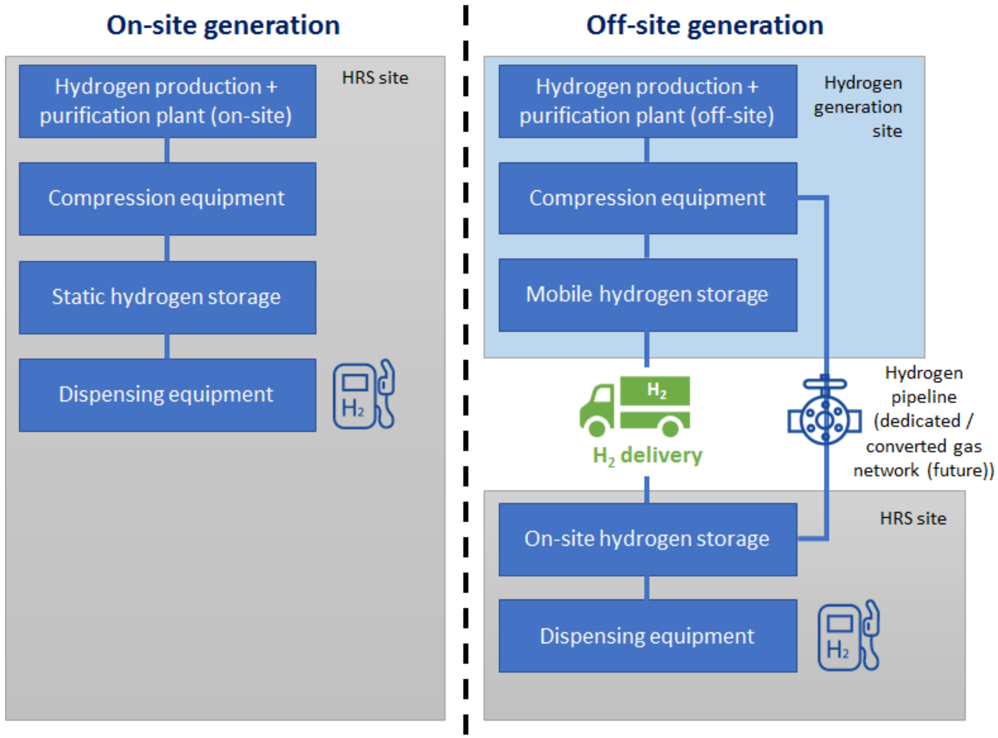
HRS are designed to transfer hydrogen from static storage tanks into on-board vehicle tanks in line with defined protocols

Hydrogen Refuelling Stations – An Overview

- Hydrogen refuelling stations (HRS) transfer hydrogen **from a static storage tank**, via a **hydrogen compressor**, to **on-board vehicle storage** via a **dispensing nozzle**. HRS range in capacity from low tens of kilograms of hydrogen per day to many hundreds of kilograms per day.

- Hydrogen is dispensed until a defined maximum pressure is reached. The hydrogen transport sector has adopted **two standard pressure levels for vehicles**: 350 bar and 700 bar. In general, the higher pressure level is used by smaller vehicles such as passenger cars (where maximising the mass of hydrogen stored per unit volume is a priority), while heavy duty vehicles in Europe (buses, trucks, trains) generally use 350 bar storage.

- Hydrogen refuelling stations are often **classified into two main categories** according to whether the fuel is produced **on site** (on-site generation) or **elsewhere and delivered** to the station (off-site generation).



Notes:
The mobile hydrogen storage can be used as on-site storage (parked tube trailers).
Additional equipment may be needed at HRS site depending on the pressure of delivered hydrogen.

Companies from various sectors are involved in the deployment of refuelling stations

Hydrogen Refuelling Stations – Suppliers / Other Relevant Players (1/2)

Major Players	Country	Summary	Source
Electrolyser suppliers offering turn-key green hydrogen stations			
ITM POWER Energy Storage | Clean Fuel	UK	ITM Power are the largest operator of HRS in the UK. Eight of their stations are currently open to the public; three of these in collaboration with Shell. ITM Power are expecting to have opened four more by early 2019.	https://www.itm-power.com/h2-stations
HYDROGENICS Advanced Hydrogen Solutions	Canada, Denmark, Belgium	Hydrogenics supplied electrolysers to many of the largest electrolytic bus stations in Europe, including Aberdeen, Hamburg and Oslo.	https://www.hydrogenics.com/hydrogen-products-solutions/energy-storage-fueling-solutions/hydrogen-fueling-stations/
McPhy energy	France. Denmark & Italy	McPhy installed the first electrolytic stations in France. The station, in Sarreguemines, refuelled Symbio vehicles with 350 bar hydrogen.	https://mcphy.com/en/our-products-and-solutions/hydrogen-stations/
NEL HYDROGEN	Norway	Nel has installed six electrolytic stations in Scandinavia and is pursuing further opportunities to deploy additional HRS.	https://nelhydrogen.com/products/
SIEMENS	Denmark	Siemens offers turn-key stations, mainly for large capacity stations e.g. for buses and trains.	https://new.siemens.com/global/en/products/energy/renewable-energy/hydrogen-solutions.html
AREVA H_2Gen	Denmark & France	Areva offers turn-key stations based on their PEM electrolyser platform.	http://www.arevah2gen.com/en/h2-industry
Energy companies exploring green hydrogen			
ENGIE	France	Exploring a series of green hydrogen projects, including fuelling stations linked to their hydro-electric assets and electrolytic stations in Paris	https://www.engie.com/en/businesses/hydrogen/

Many of these suppliers are collaborating to optimize the technology and equipment used at the refuelling stations

Hydrogen Refuelling Stations – Suppliers / Other Relevant Players (2/2)

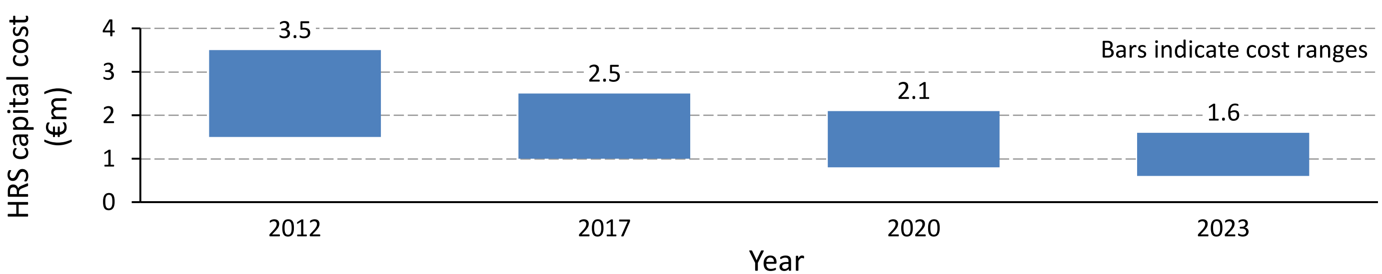
Major Players	Country	Summary	Source
Shell	UK & Nether-lands	Shell is actively pursuing opportunities related to hydrogen. E.g. Shell is one of the founding partners of the H_2Mobility Germany joint venture. In the UK, Shell is working in partnership with ITM Power and is hosting HRS delivered by ITM at several petrol stations.	https://www.shell.com/energy-and-innovation/the-energy-future/future-transport/hydrogen.html
VATTENFALL	Sweden	Vattenfall is an early investor in green hydrogen stations and concepts, including the Hamburg bus refuelling facility.	D. Hustadt and Vattenfall, "Fuel of the Future, HafenCity Hydrogen Station."
Other major of suppliers of equipment (i.e. compressors)			
BOC Member of The Linde Group	UK	BOC (part of the Linde group) delivered the Aberdeen refuelling station for buses which, at the time, was the largest hydrogen bus refuelling station in Europe. Current ITM stations in the UK use Linde's ionic compressor IC series which compresses hydrogen on-site.	https://www.boconline.co.uk/en/processes/hydrogen-energy/complete-hydrogen-solutions/hydrogen-fuelling-technologies.html
Air Liquide creative oxygen	France	To date, Air Liquide has designed and built c. 100 hydrogen refuelling stations. In 2012, Air Liquide opened its first HRS in Dusseldorf, Germany.	https://energies.airliquide.com/clean-transportation-passenger-transport/hydrogen-energy-vehicles
AIR PRODUCTS United Kingdom & Ireland	UK & Ireland	Air Products has been involved in the development of hydrogen infrastructure. Examples include supplying fuel for hydrogen buses in London and Beijing for the 2008 Olympic Games, and fuelling Boeing's unmanned Phantom Eye.	http://www.airproducts.co.uk/Industries/Energy/Hydrogen-Energy/Transportation.aspx
Haskel An Accudyne Industries Brand	UK, USA, France & Spain	Haskel has been investing in the hydrogen market for nearly 15 years. In 2016, they were involved in the refuelling of a Toyota Mirai's demonstrative drive across Europe.	https://www.haskel.com/industries/hydrogen/

HRS capital costs depend on various factors related to the specification of the equipment and installation site

Hydrogen Refuelling Stations – Capital Costs

- While the number of HRS installed in Europe and globally has increased substantially in recent years, as of early 2019 there is no completely standard HRS design / specification.
- Station designs tend to be tailored to the specific requirements of the application in question, with factors such as the number and type of compressors, amount of on-site storage, number of dispensers, etc. varied according to customer needs.
- The capital costs of HRS depend on several factors (daily capacity, back-to-back fuelling capability, refuelling windows, level of redundancy in the design, etc.). Furthermore, in assessing the total installed costs of stations, site preparation costs also need to be taken into account (these vary significantly depending on the condition of the site, utility requirements, etc.).
- Total installed costs for a new HRS typically range from hundreds of thousands to several million pounds. As the graph below indicates, the hydrogen industry aims to reduce the costs of HRS over time as the hydrogen transport market matures.
- Note, that for well utilised HRS, the capital costs of the station are typically a relatively small component of the total cost of dispensed hydrogen (the costs of producing the fuel are a more significant determinant of the total cost). For under-utilised HRS, fixed costs are a more significant consideration in terms of the per-kilogram cost of hydrogen.

HRS cost targets according to the FCH JU MAWP (2014-2020) for 700 bar HRS with 200 to 1,000 kg/day capacity (including on-site storage)



Based on targets published by the FCH JU: *FCH JU Multi Annual Work Plan 2014-2020*, Table 3.1.1.1, p.28.

[1] On a taxed diesel price, including CO_2 costs and fuel consumption dependent.
[2] Appendix B
[3] FCH JU, "Multi-Annual Work Plan 2014 - 2020," 2018.
[4] Appendix C