Chapter

Hydrogen as a Rail Mass Transit Fuel

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Abstract

There is a continually growing need for mass transport and along with customer desire for greater comfort and speed, its consumption of energy will grow faster still. The fiscal cost of energy plus global warming has spurred efficiency improvement and thoughts now concentrate on fuels. In the UK for major lines for trains, this is electricity generated in a benign fashion in large facilities nominally remote from the train and track. Electric trains tend to be lighter, hence more efficient and demand less maintenance than their diesel counterpart. Similar arguments, including pollution emissions apply to city mass transit systems. For medium density and lower density routes, whether fuel cells or the next generation of IC or GT engines are employed, hydrogen is a prime energy candidate and here we examine its feed, production, distribution, and application, including generator location. Hydrogen from steam hydrocarbon reformers have even been installed in ships. Other countries have similar desires to those of the UK, including Saudi Arabia, but their problems are different and outline examples from Australia and Saudi Arabia are included.

Keywords: cost of train emissions, fuel cells, hydrogen fuel, hydrogen generator location, hydrogen production, hydrogen trains

1. Introduction

1.1 Background

Much energy generated ultimately ends as a heat release to the environment. If any associated carbon dioxide is produced, it retains this heat plus any received from other sources such as the sun and this raises ambient temperatures. To minimise the production of carbon dioxide and other emissions, the use of rail for passenger and freight transport is being promoted and rail itself is being decarbonised thus reducing transport energy per passenger-km and benefitting use of trains.

In 2019, rail services globally consumed 0.6 million BPD of oil [1] equivalent to 0.6% of global oil use, and 280 TW-h of electricity (1.2% of global amount). They were responsible for 0.3% of direct carbon dioxide emissions. Rail passengers accounted for slightly less than 10% of global passenger-kilometres, consuming 3% of transport sector energy, reducing mass transport energy use and any carbon dioxide emissions.

The ideal fuel for trains is electricity, as electric trains are lighter, more fuel efficient and have less maintenance needs than trains using other propulsion fuels. Electric motor drives are designed for rapid acceleration and electric trains usually issue less emissions in the vicinity of the track. If the electricity used is "renewable", e.g. from wind, then carbon emissions are virtually eliminated. Nuclear power fits into this category, with the latest designs having long periods between refuelling activities. Ammonia is also a possible fuel supply as it does not contain carbon.

The problem with electric propulsion systems is their cost (CAPEX). This is acceptable for high speed and high usage routes but not for lower usage routes. This applies also to mass transport inner city traffic. For medium sized trains operating on tracks with low density traffic, the trains are usually diesel driven in the UK and are ideal for conversion to use hydrogen as a fuel. There are other applications including shunters and low power drives on large engines which normally use 25kV AC electricity supply through pantographs but still need low speed mobility when operating away from overhead power supply cables.

For the UK, approximately 40% of energy consumption is used for transport of which 1.9% (0.9% of total) is used for trains: see **Table 1**. This gives the parameters used for the UK (total), that for trains only and those for passengers and freight. For year 2018/2019, passenger services used 3.976 TW-hr of electricity and 469 million litres of diesel. The numbers for freight movements were 75 GW-hr and 153 million litres of diesel [2]. For year 2019/2020 passenger trains used 4.186 Tw-hr of electricity and 476 million litres of diesel. Freight services used 70 GW-h of electricity and 172 million litres of diesel [3]. In this later period, CO_{2e} for passenger traffic fell to 35.1 gm/passenger-km from 36.6 and CO_{2e} for freight was 27.5 gm/Te-km rising from 25.3 gm/Te-km where CO_{2e} is the weighted average of CO_2 + CH_4 + N_2O and is a measure of greenhouse gas emissions. Passenger numbers fell slightly (~1.3%). This shows the general increase in rail movements also confirming the movement from hydrocarbon fuels to electricity for rail passenger services and thence ultimately to zero carbon emissions when the electricity is generated using renewables. Last period's freight statistics are a little disappointing, continuing the steady decline from a peak in 2013/2014 but there is a new generation of electric freight engines in the offing and an increase in freight energy consumption can indicate a faster service and a rising economy.

Country	Energy	Unit/year	2019	2018	2017	2016	2015
UK	Total supplied	EJ	7.84	7.96	7.99	8.01	8.11
	Energy/capita	GJ/cap	116.1	118.6	119.8	120.9	123.1
	Carbon dioxide	Million Tonne	387.1	396.9	404.1	415.8	439.7
Trains	CO_{2e} passenger	gm/pass-km	35.1	36.6	40.8	43.8	46.4
	Percent change	%	−4.10	−10.30	−6.85	−5.60	−4.32
	CO_{2e} freight	gm/Te-km	27.5	25.3	26.4	26.2	27.1
	Percent change	%	8.70	−4.35	0.76	−3.32	11.74
Passenger	Electricity	TW-h of fuel	10.592	10.061	9.222		
	Liquid fuel	TW-h of fuel	4.738	4.668	4.916		
Freight	Electricity	TW-h of fuel	0.177	0.190	0.168		
	Liquid fuel	TW-h of fuel	1.712	1.523	1.625		
	Total used	EJ	0.0619	0.0591	0.0573		
	Fraction of total	% of UK Total	0.790	0.743	0.717		
	Carbon dioxide	Million Tonne	3.675	3.512	3.450		
	Fraction of total	% of UK Total	0.949	0.885	0.854		

Table 1.
Energy and Emission Statistics for UK.

The above statistics have been developed against a background that only 38% of UK track is electrified with over 70% of rolling stock being pure electric, highlighting the concentration of its use [4, 5]. Current proposal is that a further 11,700 STkm of track will be electrified leaving only 2,400 STkm of track for all other non-electric users. This implies that only 3–4% of trains require conversion to hydrogen fuelled units. For a total fleet of 14,000 vehicles this equals 420 to 560 vehicles to be considered for conversion. If no further route electrification occurs, then 4,200 vehicles could be considered for conversion thus giving a lower and upper bound range for hydrogen needs.

For the EU (see **Table 2**), there are approximately 64,000 power units of which the top three owners are Germany, UK (included in these numbers) and France whose combined numbers have over 55% of the units. Adding the next two (Poland and the Netherlands) they hold nearly 70% of the total traction stock [6]. Despite EU's endeavours, there is little commonality between the railways of each nation despite having the same rail gauge and loading gauge (UK is different for the latter). For fast trains there has been some success as they are electric units with most using 25 kVAC/50 Hz supply (Germany and Austria are different having 15 kVAC @ 16.67 Hz supply) permitting fast continuous transit, for example, from Italy to the UK. Signalling and control systems are different leading to complications particularly for items involving computer software.

Where practicable, precise statistics are used. Where not available, overall national data is employed. **Tables 1** and **2** (based on [7]) gives the total energy consumption, the per capita energy consumption and the carbon dioxide generated for the three largest EU train users with overall EU and world data to provide comparisons. Train energy consumption is small though decarbonisation of this energy supply is still laudable.

Currently hydrogen comprises 2% of Europe energy mix and the target is to raise this to 14% by year 2050. The estimated investment necessary to achieve this is 470 bn € [8]. France produces one million tonne per year of hydrogen of which 94% comes from fossil fuels [9]. They can inject up to 6% (v/v) hydrogen into their gas grid at this moment and they plan to raise this figure to 10% by 2030. France's railways, particularly SNCF, do not see hydrogen as an affordable and accessible fuel to replace the hydrocarbon services and prefer a combination of electricity and batteries (hybrids where necessary). To compress, store and transport one million tonnes per year of hydrogen will need significant amounts of energy. Their estimate is that to produce this quantity of hydrogen using electrolysis will need 2000 to 4000 by 3Mwe wind turbines or 6+ EPR nuclear stations. However total rail use would be only 3% of this number and only 1% of this is from fossil fuels [10] which need replacing. This is acceptable if there is a hydrogen grid in place which may not be realistic (see later). Despite this, the French railways are committed to decarbonisation of their resources and SNCF wish to eliminate emissions by year 2035. The parties project a 20% increase in traffic over this period (passenger and cargo) and are negotiating the supply of new hydrogen fuelled trains. Alstom can build these trains in France.

France has approximately 30,000 km of track (16.400 km are double tracks) of which 15,100 km are electrified (9,200 km at 25 kVAC and 5,900 at 1.5 kVDC) with 2,600km suitable for fast use. 80% of SNCF routes are electrified but 50% of TER (the regional supplier of rail transport) still use diesel units [11]. In terms of carriage, only 20% of rail trips are by diesel units whereas 40% of TER trips are by diesel units. These numbers give the potential task for decarbonisation.

For year 2019 Germany had 38,465 km of track (41,365 km in year 2015) of which 20,726 km (19,857 km in 2015) were electrified and 18,500 km were double track. 79.3 billion passenger-km and 75.5 million Te-km of freight were

Country	Energy	Unit/year	2019	2018	2017	2016	2015
Germany	Total	EJ	13.14	13.44	13.78	13.62	13.40
	Energy/cap	GJ/cap	157.3	161.7	166.8	165.7	163.8
	Carbon dioxide	Million Tonne	683.8	731.3	760.9	770.5	755.6
Train	Electricity	TW-h of fuel		54.27			Q/η
	Liquid fuel	TW-h of fuel		2.75			
	Total	TW-h		57.0			
	Fraction of total	% of Germany		1.526			Energy
	Carbon dioxide	Million Tonne		10.563			
	Fraction of total	% of DB+ Total		1.444			CO_2
France	Total	EJ	9.68	9.87	9.70	9.76	9.92
	Energy/cap		148.6	151.9	149.6	151.0	154.0
	Carbon dioxide		299.2	307.2	318.1	312.1	306.7
Train	Electricity	TW-h of fuel		22.25	19.25	18.75	19.00
SNCF	Liquid fuel	TW-h of fuel		1.64			
Train	Electricity	TW-h of fuel		9.75			
TER	Liquid fuel	TW-h of fuel		3.96			
	Total	TW-h		37.60			
	Fraction of total	% of France		1.37			
	Carbon dioxide	Million Tonne		7.292			
	Fraction of total	% of France		2.374			
EU	Total	EJ	68.81	69.81	69.91	69.14	68.32
	Energy/cap		134.3	136.4	136.9	135.7	134.7
	Carbon dioxide	Million Tonne	3,330.4	3,466.5	3,527.1	3,498.5	3,486.9
World	Total	EJ	583.90	576.23	560.42	550.60	543.17
	Energy/cap		75.7	75.5	74.2	73.8	73.6
	Carbon dioxide		34,169.0	34,007.9	33,279.5	32,936.1	32,787.2
Train	Electricity	EJ		1.529			1.315
	Liquid fuel	EJ		1.479			1.748

Country	Energy	Unit/year	2019	2018	2017	2016	2015
	Total energy	EJ		3.009			3.062
	Fraction of total	% of world		0.522			0.564
	Carbon dioxide	Million Tonne		186.83			195.97
	Fraction of total	% of world		0.549			0.598

Table 2.
Energy and emission statistics by country.

carried. There is a steady elimination of diesel units, as electrification of track is undertaken and a determination to replace diesel units where electrification is not attractive, with hydrogen powered units. Currently 1300 diesel units are scheduled to be replaced.

Despite the above, 90% of Germany's railways are already electric and 27.5 TW-h of electricity were consumed [12]. The share of various energy sources in Deutsche-Bahn's traction power mix in FY2020 were as follows [13]:

i. Renewable = 61.4%

ii. Black coal = 11.2

iii. Nuclear = 12.0

iv. Natural gas = 8.1

v. Lignite = 7.0

vi. Other = 0.3

1.2 Hydrogen statistics

The production of hydrogen currently consumes approximately 6% of global natural gas and coal and simultaneously produces roughly 830 million tonnes (Te) of carbon dioxide in this process [1]. Global demand for pure hydrogen is around 70 million Te/year and is used mostly for oil refining and chemical manufacture including products such as methanol, acetic acid derivatives and fertilisers. Here we are contemplating using it for propulsion of trains both using internal combustion devices and in fuel cells.

The use of hydrogen as a fuel has been a goal for some time and much research has been performed in trying to produce hydrogen from water by various means, e.g., [14] with the resulting dilute gases burned in heat recirculating burners [15]. These can achieve high efficiency electricity generation with minimum pollution [16]. When higher energy densities are obtained from using renewables, their widespread use may occur but for now and the immediate future the main available methods for generating hydrogen are:

i. Steam – hydrocarbon reforming ideally from natural gas

ii. Gasification – frequently from coal

iii. Electrolysers – splitting water using electricity.

There are other techniques but until affordable methods of carbon capture and storage exist then these will remain as the major producers and for (i) and (ii) emit carbon dioxide. With natural gas in (i), a hydrogen cost of 8.3 US$/GJ has been estimated and this will increase to 11.5 US$/GJ with carbon capture (updated from Ref. [17]). A minimum purchase price of 13.4 US$/GJ is anticipated for imported green hydrogen and this is currently believed to be too low for western European countries to compete.

For coal as a feedstock in (ii), the numbers become 11.8 US$/GJ and 15 US$/GJ respectively, but all these numbers are sensitive to feed cost. Disposal costs need to be added and deep disposal of carbon dioxide (e.g. in former oil and gas producing wells) is currently favoured. This can imply transport of carbon dioxide over some distance (some studies for this have been developed see e.g., [18]) which all adds cost. As electrolysers use electricity, renewables are available now to generate this, including nuclear for onshore applications and offshore if located within reasonable transmission cable distance (e.g. the Beatrice platform in the North Sea when it was a production platform). Electrolysers on offshore platforms using offshore renewables will be considered when sufficient electrolysers can be fitted into the space available. Some ideas using them are presented here (e.g. for those offshore locations where sea area is available) but costs offshore are high, being potentially some 12 times more expensive than equivalent tasks onshore. This factor reflects a combination of lower productivity and higher unit costs for offshore work.

Previous promising technologies such as plasma arc pyrolysis, solar reforming and anaerobic bacterial action have been studied and generally discounted but certain of these could be attractive in the smaller size applications.

Ammonia generated in world scale units from natural gas would be more easily distributed than hydrogen at high pressure as the vessels for ammonia storage would be designed for significantly lower pressures than those for hydrogen. The ammonia can be broken down locally [19] to produce hydrogen for fuel cells or consumed directly in IC engines. Ammonia has safety issues due to the reactions of people when exposed to it and its use is only advantageous in weight sensitive applications.

In this chapter, the following definitions are employed. Grey hydrogen is hydrogen produced from hydrocarbons where no attempt has been made to recover any carbon dioxide produced in the process. Sometimes it is subdivided further with grey hydrogen being reserved for natural gas feedstock, brown hydrogen used when it is produced from oils and black hydrogen when produced from coal. Blue hydrogen is hydrogen produced from natural gas in a process where any carbon dioxide formed is captured and stored in a suitable location. Green hydrogen is hydrogen produced from a source, e.g. water, where no carbon compound is involved in the process. Electricity to provide the energy for splitting the water molecule must come from a renewables' source.

1.3 Target hydrogen capacity for trains

Typical hydrogen unit will be replacing the local DMU and shunters [20]. There are approximately 1022 sets with individual power in the range 300–799 bhp. By taking average values we get a total requirement of 35.2 kg/hr./train which for 1022 sets gives 35.6 Te/hr. of hydrogen or 865 Te/day neglecting any quiet periods. Only one to two world scale grey hydrogen plants would be needed to produce this quantity of hydrogen: its distribution is the important factor.

The prototype trains from Porterbrook or from Alstrom have fuel cells with capacities of 100 kWe and 200 kWe respectively. They both have batteries to help smooth out the power demand. If these cells have an installed efficiency of 35%, the overall hydrogen demand will be 8.58 kg/h and 17.16 kg/h respectively. A hydrogen plant for the former would have a capacity of 0.21 Te/day/train – well within current technology for electrolysers.

If the full electrification programme for the UK is implemented, then only 3 to 4% of trains would use hydrogen as a fuel which in turn would generate a hydrogen demand of 14.6 Te/hr. or 350 Te/day. The quantity of hydrogen that needs to be produced depends on many factors outside the remit of train evaluation.

2. Some methods to generate hydrogen

2.1 Steam-hydrocarbon reformers

This process has been used for a long time: catalysts were developed to use what was once lower cost naphtha to make H_2 + CO synthesis gas. Subsequently it was used to make "Town Gas". In the UK, the Town Gas requirement continued until the completion of the natural gas grid to domestic households with one of the last reformers in operation being the Foster Wheeler design at Southall in west London. To-day the feedstock in the UK for hydrogen is usually natural gas.

There are many arrangements of steam-hydrocarbon reformers but the critical component, the furnace, falls into one of three basic patterns. There is the original ICI "down fired" design in which the catalyst tubes are suspended from the roof in lanes with the burners located between the lanes firing downwards. The second common design has the tubes in a single line with a multitude of small burners located in the side walls firing horizontally either side of the tubes to give uniform radiant heating. The third common design is the Foster Wheeler Terrace Wall design. This consists also of a single row of vertical tubes but the walls are displaced at an intermediate level to accommodate the burners which fire vertically upwards. There are usually two terraces of burners per side and their flames adhere to the wall giving a uniform radiating surface. All three furnace designs have approximately the same effectiveness. The marginal differences in performance of each is reflected in their application with client preferences frequently dictating the selection.

In the reforming process the purified feed hydrocarbon (the catalyst can suffer from sulphur poisoning) is heated from ambient temperature in external heat exchangers and/or the convection bank of the main furnace to approximately 350 °C and mixed with superheated steam. The preheat process continues with heating the mixed gases to approximately 600°C before entering the catalyst tubes in the radiant section where the reforming action occurs. The tubes have typically internal diameters of 3.5–4.0 inches (88.9–101.6 mm) and contain the catalyst pellets. The gases leave the tubes at 900–950°C and now contain a mixture of hydrogen, carbon monoxide, carbon dioxide, feed slippage and excess steam with their pressure falling from roughly 32 bar abs to 28 bar abs. The tube materials are high alloy, e.g. spun cast 25 Cr-35 Ni and are 13 to 15 metres long depending on the process needs.

The main reactions within the tubes are: $CH_4 + \mathrm{H_2O} + \mathrm{heat} = 3\,\mathrm{H_2} + CO$

And $CO + \mathrm{H_2O} = \mathrm{H_2} + CO_2 +$ a little evolved heat

The hot furnace flue gases leave the radiant section at a temperature above 1000°C and are cooled to approximately 150°C before entering the flue stack.

The reformer section of the furnace has a low thermal efficiency (~48% LHV depending on the fuel and temperature profiles needed) and its overall efficiency is raised to some 92% LHV by heating the process feed and raising high pressure steam in its convection bank. This steam is suitable for mechanical drives. These processes are well known and the technology rests with the mechanical design to handle these high temperatures.

Excess steam is needed in this operation to minimise carbon formation and its deposition on the catalyst. This steam is condensed out as water and recycled.

2.2 Gasification

In gasification, the feed supply is burned in air or oxygen under sub-stoichiometric conditions to produce a $H_2/CO/CO_2/N_2$ mix if air is used for combustion or a minimum nitrogen mix if an ASU (air separation unit) is employed to produce the oxygen-only supply.

Early applications included gas production for domestic use. These often started with coal which was heated in retorts to produce coal gases and tars and the resulting coke was then used to make gas. The tars at that time had a market value. The gas production was essentially a series of batch processes with coke being introduced and a sub-stoichiometric quantity of air passed over it which ignited the coke and raised its temperature evolving a CO/N_2 mix. Then steam was added producing an $H_2/CO/CO_2$ mix which in turn lowered the solid materials' temperature. The process was then repeated until the coke feed batch was exhausted, the ovens cleaned out and recharged with any ash recovered in the cleanout process. The resulting gas streams were then combined.

Modern processes use coal or similar feed and are continuous and employ oxygen supply instead of air. The feed progressed from a top hopper downwards going through the above separate stages but in a single unit. The ash exits from the bottom. Any tars evolving are also gasified in the process. The off-gas needs cleaning and any carbon dioxide removed to leave clean hydrogen. The basic problem with coal is that it produces a larger quantity of carbon dioxide compared with steam-hydrocarbon reforming with natural gas. For example, methane produces 55.0 gm CO_2/MJ (2.5 kg CO_2/kg) compared with 88.4 gm CO_2/MJ (2.75 kg CO_2/kg) for coal.

One positive side effect is that the gasification process produces a large amount of heat which can be used to produce steam and this in turn produces power to drive the plant and even export electricity. The overall plant is expensive and tends to be used where coal is readily available at low cost.

2.3 Electrolysers

Electrolysers are used to split water into hydrogen and oxygen using electricity. Currently they are only available in the smaller sizes (1 to 5 MWe) but they are being scaled up with an 100 MWe electrolyser being designed in Japan.

There are two fundamental designs used for most electrolysers, viz. Proton Exchange Membranes (PEM) and Alkaline Electrolysers. In the former a solid polymer membrane is used with an applied current so that the protons being small, pass through the membrane to capture electrons from the electrical circuit to form hydrogen. PEM technology gives a flexible device and the quantity of hydrogen being produced can be adjusted over the required full operating range. The system is compact and reliable.

In an Alkaline Electrolyser, an alkaline electrolyte is used (usually potassium hydroxide – KOH) with a porous separation between the anode and the cathode. Hydroxyl ions pass through the separator in the liquid solution to form oxygen and water. At the other electrode hydrogen is generated along with the hydroxide ion by the external electrical source. Alkaline electrolysers are efficient and reliable.

Catalysts are being developed to improve the efficiency of both processes. Both technologies are the subject of much research and development. The units are compact and can fit inside the envelope of a standard container and can be scaled up as multiple containerised units.

Electrolysers have efficiencies in the range 70 to 80% thus to produce 1 kg of hydrogen, 50 to 55 kW-h of electricity is needed. With the prototype trains needing 8.6 kg/h and 17.2 kg/hr. of green hydrogen, then 0.47 to 0.95 MW-h electricity from a renewable source is needed. For the 35.2 kg/hr./train of the typical train in the UK, approximately 1.9 MW-h of electricity is required therefore for 1022 trains 1980 MW-h of renewable electricity is needed. The trains do not operate for 24 hours by 7 days per week, so introducing a diversity factor of 0.65, 1286 MWe from a continuous source of electricity is required which is approximately the output from one large nuclear station. This assumes that adequate hydrogen buffer storage is available to smooth out the flow between peak demands.

2.4 Other methods

The energy density using various techniques is presented not to discourage research in any field but to highlight the difficulties faced when using "renewables".

2.4.1 Ammonia

Steam-hydrocarbon reformers are used to produce synthesis gas to make ammonia. It can be made also from feed gas from gasifiers. Ammonia can burn and produce large quantities of NO_x but there is a widow in which pollution emissions are minimal. It has been used successfully with internal combustion engines and its choice is based frequently on its ability to be moved under atmospheric pressure. It can be split also to release its hydrogen for use with IC engines and fuel cells as with any other method to produce hydrogen.

2.4.2 Algae

Certain algae can produce hydrogen from water. Early work in the 1970's demonstrated this method of hydrogen production using the sun's light but the energy density was very low [21]. With current technology the energy density is still low at approx. 2 W/m^2 but development work with energy cells is in progress and its production meets all renewables criteria.

2.4.3 Intermediate products such as alcohols

These can be made from natural gas in steam-hydrocarbon reformers or by using renewables (e.g. beverage production) [22]. The methanol or ethanol produced could be shipped to site using trucks, trains, etc. and at the specified location either fed directly to a suitable fuel cell or reduced to hydrogen first and then fed to the fuel cell.

2.4.4 Other sources

There are many other sources of renewables including solar, geothermal, PV, wave and tidal. In the UK, many are not useable. Wave and tidal stream electrical generation is being developed but most schemes are simply too expensive. This belief may be revisited when the final bill for the Hinckley C EPR nuclear complex is received. Tidal schemes, for example, may have variable outputs but their variation is predictable in advance, unlike wind.

3. Power drives

3.1 Fuel cells

Hydrogen benefits from limited hydrocarbon emissions but when hydrogen is used with IC engines its efficiency is still relatively low. Its use with fuel cells can be much better depending on their design. With stationery devices waste heat recovery can improve the picture overall but its use on trains is somewhat limited. Space heating is one application for this heat as may be air conditioning if space and weight limitations permit.

Fuel cells are ideal where low pollution emissions are essential, in applications when disconnected from the grid, where frequent and comparatively rapid start-up is necessary and when fuel supply is continuous. Options to hydrogen as a fuel, include fuel cells using hydrocarbons (including alcohols) but they produce carbon dioxide and unless the alcohols are naturally brewed, they are usually made from natural gas.

Fuel cells using hydrogen are ideal for trains and research is ongoing to recycle time expired fuel cells as occurs with batteries. Many fuel cell configurations have been examined and each has a niche application: some are detailed below. In most train drives the cells are used with batteries which help to smooth out the load on the cells (**Table 3**).

3.2 Internal combustion engines

Along with electric drives, internal combustion engines are the most common train drives following the demise of steam. Hydrogen fuelled IC engines are modified versions of diesel or gas engines. Though relatively high efficiencies can be attained (in the range 25–40% overall), they suffer from the normal limitations of internal combustion engines in that high temperature pollutants, e.g. NO_x, are still produced even though no carbon dioxide or other carbon based pollutants would be

Fuel cell typical examples				
	Generic type	**Op. Temp. °C**	**Fuel**	**Efficiency %**
1	Proton exchange membrane fuel cells (PEMFC)	60 to 100	Hydrogen	
2	Direct methanol fuel cell (DMFC)	90–120	Methanol	10–25
			Modified versions can reach 40%	
3	Alkaline fuel cell (AFC)	<80	Hydrogen	up to 62
			Used by NASA in early days	
4	Phosphoric acid fuel cell (PAFC)	~200	Hydrogen	37–42
			Can run on impure hydrogen	
5	Solid oxide fuel cell (SOFC)	600–1000	Hydrogen	55–60
			Can run on natural gas or propane	
6	Molten carbonate fuel cell (MCFC)	650–1000	Hydrogen	45–55
			Can run on natural gas, propane or even diesel	

Table 3.
Typical fuel cell examples.

Hydrogen for trains	Advantages	Disadvantages
CAPEX for new rail	Less expensive than electrification	
Design of drivers	Less weight than battery driver	More complex than battery or electric drivers
Distance limitations		Electric driver has no limit
CAPEX of engines		More expensive than electric drives
OPEX	Quicker hydrogen fill than battery recharge	
Operational safety		Hydrogen needs very careful handling
Reliability	No overhead cables	Electrified routes have overhead pantographs
Maintenance		Much more maintenance of fuel cell drivers
Emissions	None, if blue or green hydrogen	Electric or battery drivers need to run on renewables to equate
Hydrogen production		Competes directly for renewable energy sources
Hydrogen transport	New pipeline grid for 100% hydrogen gives robust supply system	Limited quantities by road bottle trailers

Table 4.
Benefits and problems associated with the use of hydrogen for trains.

emitted. IC engines are far less sensitive to hydrogen impurity and usually exhibit very rapid responses to load change. If the exhaust is hot and clean, it can be used for indirect space heating using an intermediate fluid (**Table 4**).

3.3 The use of hydrogen for trains

The benefits and problems associated with using hydrogen as a fuel for trains is presented in **Table 4**.

4. Location of the hydrogen generators and H_2 transmission to users

4.1 Locations

A distributed system of electrolysers will need the major utilities with an adequate supply of water and electricity. If there are not adequate waste-water facilities, then a holding pond will be required where water can be treated before its discharge as well as the usual personnel-related facilities needed for a manned plant.

As the hydrogen economy in the UK develops, these regional facilities will contribute to the initial injection of hydrogen into the gas grid. This is likely to be limited to 10–20% by volume. In the UK, 78.8 billion cubic meters of natural gas was consumed in 2019. By replacing 10% by volume of this natural gas with energy equivalent hydrogen, approximately 15.5 million tonnes of carbon dioxide emission will be avoided each year.

It will be the political decisions of individual countries to determine how or even if. they proceed with the replacement of all or part of their existing natural gas infrastructure with hydrogen. If the hydrogen requirements for trains increases more rapidly than the new supply facilities, small boutique hydrolysers may be located at principal loading locations. This would give a cost savings on road transport of hydrogen, mitigate the safety risk and increase reliability of supply. Regional hydrogen projects will continue to be attractive in locations that have the facilities to accommodate the necessary carbon capture and storage, have industries nearby that can utilise the hydrogen – including trains – and are in areas that are attractive for the necessary grants and financial support.

4.2 Offshore

As the hydrogen economy develops, there will be a natural decrease in the production and use of hydrocarbons. In the North Sea, the production companies and offshore asset owners will be examining how they may make best use and financially benefit from the existing platforms and pipelines. Studies are already underway to determine the suitability of these types of assets in supporting hydrogen production. The basic steel structures (jackets and platforms) will need assessment and if in good condition, re-used perhaps with minor modifications and upgrades. The necessary infrastructure of accommodation, life support, safety and communications will still exist but may need refurbishment. The difficulties start with the removal of unwanted existing equipment and its replacement with the new facilities. These difficulties include total weight and its topside distribution and access.

As green hydrogen for the replacement of natural gas is a goal for substantive emissions reduction, renewable energy is required to produce the hydrogen. Offshore wind energy is one source. Turbines in the vicinity of selected platforms could provide power directly and exclusively for this process, eliminating the costly cable to shore. The production of hydrogen based on wind energy alone would be part of an overall industry business plan to supply hydrogen only when wind energy was available.

New compressors will be needed to send the produced hydrogen to shore as the molecular weight of hydrogen is much lower than natural gas. Its physical properties are different from hydrocarbons and every rotating component will need unique attention due to hydrogen's ability to escape through tiny apertures. The compressor drive will be several megawatts for systems that would be financially attractive.

The transport of the hydrogen to shore and into the existing natural gas grid is more problematic. Modern carbon steel pipes are frequently not compatible with hydrogen gas. Initial investigations and ongoing studies show that the more recently introduced high grade steels (above grade X52), are unlikely to be acceptable as long-term infrastructure elements. Some possibility exists to re-use those of lesser grade steels e.g. X42 and X52 but these pipelines will need more rigorous analysis and testing. This is time consuming and costly and required for each line.

Societa Gasdotti Italia has engaged DNV GL to study its 18,000 km HP regional and national pipeline network to determine potential hydrogen transportation options. "The study will guide SGI in identifying suitable sections of its gas network to safely convey blended mixtures of natural gas and hydrogen. The gas network operator's aim is to understand if and how 100% hydrogen can be safely carried across its network." [23]. Given the fundamental requirement of a grid to distribute gas safely to the domestic, commercial and industrial markets, and now significantly reduce these sector's emissions, any re-use of existing gas pipeline systems for hydrogen must be thoroughly investigated, risk assessed, proven and accepted by the pipeline industry.

A 100% hydrogen filled onshore pipeline will be more costly than an equivalent natural gas pipeline. The increases in materials and construction costs will arise from:

i. NACE compliant line pipe, to specification "*MR0175/ISO 15156, Petroleum and Natural Gas*" has stringent steel chemistry requirements. It is lower in carbon, sulphur and phosphorus content than standard linepipe. The pipe manufacturing requires expensive quality control activities including inspection and this will increase its cost/tonne by some 6–8%;

ii. Line pipe for the same design pressure will be considerably thicker due to the lower yield strength of the required materials. Whereas X60 to X65 or higher grade is suitable for use with natural gas; Grade B, X35 to X52 is needed for hydrogen. For comparison, API pipe for 24 inch, 100 bar design pressure will show an increase in cost/metre of pipe ~ 11–77% for this change in grade;

iii. Line pipe logistics and handling costs will increase by up to 50%, due to the increased pipe weight.

iv. Construction costs will be impacted due to the increased time for welding and increase in welding spreads required for thicker wall pipe. The increase in construction cost will be ~ 13–25%

For an onshore pipeline, like-for-like costs would increase in the range of 12–27%. For offshore lines the increases could be doubled, due to the impact of escalated costs for installation and support vessels together with the various risk factors associated with construction and installation and weather states. For a given energy throughput and permissible pressure drop, a larger pipe ID is needed for hydrogen than for natural gas. This will be expensive if one is near a cusp which demands a step-up in specification of installation equipment.

4.3 Coastal locations

This general location is attractive during the emerging hydrogen economy period when the pipelines to shore are still carrying natural gas. An existing gas plant site can be partially or completely converted to use this feedstock to make grey or blue hydrogen. The pipeline may also be used for the transport of captured carbon dioxide when it is redundant and if the spent gas field is suitable for carbon dioxide storage.

4.4 Inland locations 1: large hydrogen production hubs

Hydrogen is made either from natural gas or from water using electrolysers in large production hubs located near the shore. Electricity from offshore windfarms is one possibility as are nuclear sources. The hydrogen produced will be distributed and if the existing grid cannot be used, additional costs must be added for any onshore pipeline distribution cost. If the hydrogen is derived from natural gas, any carbon dioxide produced must be collected and sent by pipeline to the disposal well.

4.5 Inland locations 2: hydrogen production hubs local to train line(s)

Hydrogen production is located near the train loading station hence the production facilities will be based on electrolysers: also there may be a local market to use these generated gases. The hubs will contain hydrogen storage facilities which will cover minor outages and give warning of impending trouble that can be resolved with truck supply. The site will have any necessary compression facilities to give maximum supply pressure to the trains to reach their required storage pressures.

4.6 Distribution by pipeline, ship, train and vehicle and their economic consideration

The use of ships to transport hydrogen for trains needs to be studied in detail for specific situations. If the hydrogen is to be liquefied for tanker transport, the source of the energy required to both convert to a liquid and then back into gas before compressing onto the train bottles needs to be considered carefully. If this energy is not renewable, there is an immediate argument that this hydrogen use is more environmentally damaging than the use of diesel as the train's fuel.

Work has already begun in the UK to replace ageing user pipeline connections from cast iron and other materials to plastics, in readiness for hydrogen. This also has the added benefit of immediately reducing harmful emissions from the old pipework [24].

The potential for hydrogen use, either in modified diesel engines or fuel cells, is likely to exceed the economic or safe limit for delivery by road transport and initially diesel power will be retained. The current volume of hydrogen being used to power trains in the UK is negligeable and their 420 kg/day is easily delivered from existing production facilities in bottles via trucks. A supply of 475 Te/day of hydrogen needed after the system upgrade though would require increased production capacity as well as a more robust delivery system. If the demand by rail services is slow in developing, the more general hydrogen economy may have developed to the point where a national hydrogen grid exists. Transportation and distribution pipelines will then be able to supply train terminals. This supply may be directly by pipe connections as is used by a typical commercial or industrial user or by shuttle trucks from a nearby hydrogen terminal.

Depending on hydrogen quantity needed, it is practicable to have a waggon carrying a standard size container which would carry hydrogen at pressure. Full containers would be located at the refuelling station to permit a rapid turn-around. The empty container would be taken by truck to the hydrogen production facilities for re-charging.

Prior to this national hydrogen grid, there will be the development of facilities for blue hydrogen production where there is access to both the natural gas feedstock and the conditions for CCS. An example of this is the low carbon hydrogen project by Hynet which is located on the existing refinery in Ellesmere Port, England. This novel development will include new hydrogen-from-natural-gas production facilities, carbon capture and storage in the Liverpool Bay gas fields as well as a new pipeline for local distribution to regional users for their hydrogen.

4.7 Current availability in the UK

Hydrogen is currently available in the UK via road using tube trailers with standard capacities of 300 kg at 228 bar g or high pressure trailers up to 900 kg at 300 bar g. These trailers will be designed to be used on site as storage so that additional decanting into static storage tanks is not necessary. Being of a similar size to a standard 38 tonne, 12 m long, container trailer, these will be located strategically to train loading sidings.

For a typical hydrogen train with an approx. 17 kg/h of average day demand, operating for 16 hours per day and a route that had two trains running at any time, the requirement for fuel would easily be met with a trailer delivered every 12 to 48 hours. The usual considerations – cost of additional pressurisation, availability of HP trailers and any differential cost of transport – would determine trailer selection. With higher delivered pressure, hydrogen would be beneficial in reducing the on-site compression required during loading operations and reduce loading duration.

5. Safety and codes

Hydrogen is a colourless, odourless, tasteless gas which is highly flammable. Its limits of flammability in air (25 °C/atmospheric pressure) are 4.0% (lower limit) and 75% (upper limit). The values in oxygen are 4.0% (lower limit) and 94% (upper limit). It has a high energy density on a mass basis (LHV = 119.9 MJ/kg) but a poor one on a volumetric basis (LHV = 10.8 MJ/m^3). It is a small molecule and will pass in quantity through small leaks and is difficult to contain and a fuel-air mixture is easy to ignite. Controlling this flame can present challenges but its combustion at source will prevent any flammable accumulation and thus prevent any explosions. Hydrogen disperses readily and both raw gas and flame tend to rise rapidly. It is widely used in the oil industry which has a suite of codes and standards covering its safe handling.

As the non-oil hydrogen industry is still in its infancy, the starting point for the preparation of suitable codes and standards could be to consult those companies that currently produce and handle hydrogen as part of their normal business activities. These companies, along with the rail operators, should work with the Safety Boards and National Standards authorities in the development of the necessary suite of documents for hydrogen use. International communication and cooperation with those countries and companies using hydrogen for trains will facilitate the development of the required regulations. Formal risk assessment procedures will be needed to reflect the hazards introduced by hydrogen and should form part of the new standards and guidance.

Training and safety courses for those personnel handling hydrogen in large quantities is a pre-requisite. The mandatory earthing during the transfer and loading process, personal protection equipment requirements, reclassification of hazardous areas, use of special hoses and equipment and operator safety must all be covered. These subjects can be presented in training courses as well as being stated in the new standards. The certification of these operators through a recognised formal process should be considered as should the training and certification of the technicians and engineers involved in the maintenance and inspection activities. Any Emergency Response Planning in place for current rail operations must be reviewed and updated to reflect the new hazards.

6. Hydrogen fuelled trains

6.1 Application

The most recent report by ORR [4] states that those lines in the UK that will likely not be electrified for economic reasons, total 3,700 STkm This assumes that the 11,700 STkm currently ear-marked for electrification are so converted. In addition, from the 3,700 STkm, a case for conversion to electricity of another 1,340 STkm can be made. The potential for hydrogen if these services were converted using new internal combustion engines is estimated (assuming 25% mechanical efficiency) as 1450 Te/day.

This future quantity of hydrogen will not likely be allowed on the roads to be transported from the few existing or planned new built production locations. If a broad national hydrogen economy infrastructure plan is not in place as the train numbers increase, smaller hydrolyser plants will be considered, located at or near major train fuelling locations. These essentially packaged units, including the required water treatment facilities and hydrogen storage at the unit or the rail siding, will be powered by renewable energy making this green hydrogen production.

In the design of the facilities, there will be a degree of redundancy. There will be an on-line spare compressor for example together with several days hydrogen storage capacity to cover outages together with diesel generators to provide black start capabilities.

6.2 Porterbrook: Hydroflex

Porterbrook own and lease railway vehicles in the UK. They have developed with Hydroflex a hybrid train based on the Class 319 local train. The class 319 was developed originally in 1987 and is well proven in UK service. It has a steel body roughly 19.9 m long by 2.82 m wide by 3.58 m high. This experimental vehicle can operate from a third rail (750 V DC) or from an overhead supply (25 kV AC). It has a 100 kWe fuel cell and stores 20 kg of hydrogen in four pressure vessels at high pressure, delivering the hydrogen to the fuel cell at 8.5 bar g. Its operating range will be from 345 bar g to approx. 12 bar g. The fuel cell delivers its output to a Li-ion battery pack from where all drive power is taken. Early development work and research was performed at the University of Birmingham, UK.

6.3 Alstom Coradia iLint train

Alstom manufacture a variety of trains including the Hydrogen powered Coradia iLint. This vehicle is based upon a diesel engine chassis and the latter has been sold worldwide including to Canada. The hydrogen train is configured with 150 seats, a range of 1000 km and has a maximum speed of 140 km/hr. The hydrogen is stored in the roof of the vehicle at 5,000 psia (35 MPa) and the hydrogen is distributed to the train fuel cell at 1 MPa (145 psia). Two prototype iLint trains have been operated in Germany carrying passengers: possible orders for trains for regular service are being considered for lines in Germany and Austria.

7. Examples of possible decarbonised trains

7.1 Melbourne, Australia

These passenger trains have been refurbished and now are nearing replacement. They are used on metropolitan lines out of Melbourne city and consist of 3 cars per set but are usually run with 6 cars. Though normally using electricity (an ideal situation) it is included to cover the situation if electricity is not available.

Power consumption = 800 kW typical fully laden including air conditioning.
Passenger load = 420 seated (1530 "crushed").
Speed = 40–60 km/hr. average.
Power supply (currently) = 1.5 kV DC collected using pantographs.
Carbon dioxide avoided = 615 Te/hr. for diesel @ 35% efficiency.
Hydrogen needed = 60 kg/hr. @ 40% efficiency.

7.2 Alstom hydrogen trains: Model for Oxford to Cambridge route

Distance = 170 km.
Power = 0.465 kW.
Fuel cell power = 200 kW.
Battery pack = 225 kW-hr.

Passenger load = 138 seats + 190 standing.
Average speed = 60 km/hr.
Hydrogen needed = 17 kg/hr. @ 35% efficiency.
Carbon dioxide avoided if using diesel (35% effic.) = 155 kg/hr.
NO_x avoided = 2.34 kg/hr.

7.3 BHP iron ore train : Western Australia

Test train on BHP private track for maximum achievable train length: Length = 7.32 km.
Track length = 275 km.
Eight (8) locomotives (with GE AC6000CW 6000 HP diesel electric engines) distributed as three (3) pair and two (2) single units along train length. AC traction.
Individual engine weight = 192–196 Te.
Fuel tank capacity per engine = 21,000 litres.
Number of waggons = 682.
Total gross weight = 99,724 Te.
Total ore weight = 82,000 Te wet ore.
Average speed = 46 km/hr. (excluding coupler breakdown time).
Maximum speed = 120 km/hr. individual engine.
Fuel consumption = 3,500 l/hr. diesel average (on test, engines idled for nearly five hours).[1]
Hydrogen needed @ 40% eff. = 21.5 Te/hr.

7.4 Fuel cell driven switcher: California USA

Experimental replacement of a diesel engine switcher with a zero emissions' fuel cell using hydrogen as a fuel and advanced battery technology. The overall aim is to improve local air quality.
Typical switcher fuel consumption = 50, 000 US gallons/year diesel.
This machine data is based on units used in marine ports which run at near continuous operation and power levels.
Fuel saved assuming 4,000 hours per year full load operation = 47.14 l/hr.
Carbon dioxide avoided = 520 Te/year.
Hydrogen needed @ 35% eff. = 58.3 Te/year.

7.5 Hydrogen fuelled trains in the Kingdom of Saudi Arabia

An example of a country that has an opportunity to showcase hydrogen fuelled trains is Saudi Arabia. The new city of Neom, a city of one million people located in the northwest of the kingdom, will maximise the use of renewable energy and hydrogen and that the hydrogen would be produced in sufficient quantities both to satisfy the city's needs and leave a sizeable surplus for export. The proposed export price of the hydrogen would be less than that envisaged for UK green hydrogen production. The new train lines would connect Neom to the rest of the country and would be able to show hydrogen fuelled trains with minimal emissions.

The takeover of the original railway operator, Saudi Railways Organisation (SRO) by Saudi Railways (SAR), announced in February 2021, should allow advancement of the national strategy for transport and logistics rail. The current Saudi Railway Master Plan (2010–2040) has several major projects which will connect major cities, ports and industrial areas. The new lines will total nearly 5000 km

[1] The total time was 10 hours 40 minutes but nearly 5 hours was spent repairing a broken coupler.

and will include rail links between all the GCC countries (Bahrain, Kuwait, Oman, Qatar, Saudi Arabia, and the United Arab Emirates). The potential rail links with Neom will increase this length considerably.

The use of hydrogen for trains on these new lines would both satisfy the requirement to go green with the reduction of emissions from diesel drivers as well as being a very impactful advertisement for their hydrogen production and export industry.

8. Costing of pollution

Pollution has an economic cost [25]. Pollution from hydrocarbon fuel's costs depends on many factors including locale and the numbers here are based on UK inner city parameters [26]. They are indicative of many western industrial societies. The numbers used in this analysis are given below and should be adjusted for each location (**Table 5**).

The following examples show the variety and extremes of railway locomotives, their loads, the power they produce, approximate quantity of hydrogen that they would use and the volume of their hydrogen tank. For the smaller and medium sized drive units a stored pressure of 205 bar g is assumed (design = 225 bar g @ 150°C) and for the larger machines, the proposed stored pressure is 300 Bar g (design = 330 bar g @ 150°C). In the USA for trucks, a stored pressure of 600 bar g has been considered though at these pressures, compression power needed would be high and detract from efficiency even though more hydrogen storage per unit volume would be achieved. The economic success depends on capital cost, fuel cost and the pollution avoided cost by using hydrogen.

Cost parameters	US$	Unit
NO_x	9,062	$/Te
CO_2	1.24	$/Te
SO_2	18.74	$/Te
PM2.5	104,180	$/Te
NH_3	7,923	$/Te
Cost of hydrogen	4.65	$/kg
Diesel	1.432	$/litre
Electricity	171.10	$/MWe-h^2
Pollution		
CO_2 produced from diesel	2.68	kg/l
LHV diesel fuel	36.9	MJ/l
	45.5	MJ/kg
NO_x	0.46	gm/kW-h (diesel)
Particulates	0.17	gm/kW-h (diesel)
S content of diesel fuel	Euro VI limits	—
CO_{2e} from passenger trains	35.1	gm/passenger-km
CO_{2e} freight trains	27.5	gm/Te-km

Table 5.
Cost allowance for individual polluting components.

Cost item/example	1	2	3
Cost CO_2	0.39	132	0.22
Cost NO_x	1.50	1864	300
Cost particulates	0	75	
Cost fuel (based on diesel)	144	42,169	68
Cost hydrogen	294	100,175	169

Table 6.
Cost comparisons: Emission and fuels – Costs in US$/hour operating.

8.1 Example 1 (7.1 above)

A 1500 Volt DC electric train supplied from overhead cables and using pantographs (description as above) is included as an example as an example of existing use of high voltage electrification. The electricity is most probably supplied from Yallorn power station which uses brown coal which would benefit from gasification.

8.2 Example 2 (7.2 above)

This was a test train used by BHP-Billiton in Western Australia to take iron ore from the mines to the coast. The distance the test train travelled was 275 km. The train used eight locomotives (GE AC6000CW) configured as three engine sets, each of two engines plus two independent engines under the control of a single driver operating the whole train. The individual engine weight was 192–196 Te, the train had 682 waggons stretching 7.32 km with the engines distributed along their length. The gross weight was 99,734 Te of which 82,000 Te was wet ore. The assumed total travel time was six hours. This feat has still the world record for load carried and train length.

8.3 Example 3 (7.3 above)

This is a retired shunter (switcher) engine used in Los Angeles – details as above. It was nearing retirement and is now proposed to be used as a basis of a study by replacing its diesel engine with a fuel cell running on stored hydrogen. The precise details are still the subject of further experimental study/analysis, but it is predicted to save 50,000 US gallons diesel each year. If the predictions are achieved and the results are applicable to all such engines in the port, potentially 12 million US gallons diesel each year will be saved. The prime aim is to eliminate undesirable emissions in the vicinity of the port. The cost numbers presented are based on UK metrics (**Table 6**).

Power station costs depend on other factors including the fuel itself and here it could be brown coal. Power stations concentrate their emissions making their disposal somewhat easier. If down hole location is selected, other geological problems must be addressed, including any bacterial actions.

There are other undesirable components produced by energy transformation and use but it is unlikely that they will justify the movement to hydrogen fuel on their own based on cost. Engine design is progressing with improvements in emissions taking place. The use of many of the renewables presents their own problems.

9. Conclusions

Hydrogen to power trains, replacing diesel fuel and reducing its related emissions, is a necessary consideration on the path to decarbonisation of any railway. As shown, a sizable use of IC engines with hydrogen or using fuel cells reduces these emissions. The route to make and supply the necessary hydrogen is dependent on many external factors. If there is a hydrogen gas grid in place, either a new build or refurbishment of an existing natural gas system then oversizing of hubs (giving economies of scale) is one attractive option. If new infrastructure is needed, and is not available to an acceptable timescale, then using many dispersed local electrolysers is also an option.

Another decision to be accepted is the degree of electrification to be used as any problems will be passed back to the source of the power required, which must be renewable. An electrified system using high voltage overhead supply with pantograph collection is expensive to instal but uses the minimum energy when compared with hydrogen power using fuel cells. The electricity supply can be from indigenous nuclear stations which also have high capital cost and low running cost. Hydrogen's cost, even if imported, will still be high. The route selected will be controlled by the political process and other factors such as the cost of money, the extent of electrification already in place and its age (sunk cost) and the ability and extent to use existing infrastructure to distribute hydrogen.

In the medium term, all governments considering a green hydrogen economy to reduce emissions, essentially from hydrocarbon fuels, must make those decisions on their chosen way forward. In the UK as well as those countries that have a natural gas infrastructure that supplies gas for home heating and industry, the choice to convert to hydrogen will help make transport decisions. As the hydrogen national grid will deliver to most of the country, it should carry the future volume requirements for rail especially if a large portion of the current diesel-powered trains are converted to electricity.

The bigger picture for hydrogen as a future fuel and significant emissions reducer can only be projected on the assumption that this is mostly green hydrogen. The related challenges will include the competition for renewable energy, the space – onshore or offshore – for the number of new wind turbines that will be needed in the new energy mix, the CAPEX, the disruption to the overall economy especially during the transition phase, and political capital needed to establish a true hydrogen economy.

Technology that is yet in its infancy, including industrial processes to supplant the old processes with high emission outputs such as steel making and cement manufacture, will need to be formalised, piloted, upscaled and implemented in a decreasing timeframe. Improvements in battery and fuel cell design will occur and help here.

For rail to widely use hydrogen, the first step should be the production of suitable codes and standards.

Abbreviations

BPD	Barrels per Day
CAPEX	Capital Expenditure
CCS	Carbon Capture and Storage
EJ	Exa Joules
STkm	Single Track kilometres
TE	Metric Tonne
TW-h	Tera Watt hours

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