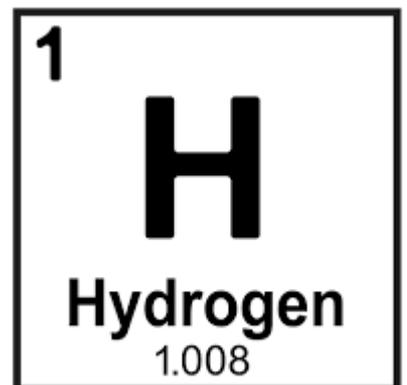




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Hydrogen in New Zealand Report 3 – Research

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1 Introduction

This report is one of three prepared as part of a study considering the cost effectiveness and outlook for hydrogen in the context of efforts to decarbonise the New Zealand economy. Its purpose is to collate background research and analysis developed during the study.

The other reports complementing this report are:

- Summary Report – background and overview of key findings
- Analysis Report – detailed analysis of cost effectiveness and outlook.

Material collated in this report is summarised below.

Topic	Summary
Production	Background information on methods of producing hydrogen
Storage	Background information on methods of storing hydrogen
Distribution	Information on methods and costs of transporting hydrogen
Use	Background information on uses for hydrogen
CNG and LNG	Comparative information on the costs of storing compressed and liquified natured gas
Networks	Information on technical feasibility of transporting hydrogen in existing gas networks
Carbon Capture and Storage	Brief survey of CCS methods, economics, international developments and prospects in New Zealand
Ammonia	Information and analysis on use of ammonia as a carrier. Background information on toluene as an alternative carrier.
Leeds City Gate	Summary of a study examining the feasibility of converting the Leeds (UK) gas network to hydrogen
Worldwide Interest	Survey of investment in hydrogen research and development
Fleet Recharging	High-level analysis of away-from-base charging needs for the New Zealand heavy vehicle fleet

2 Hydrogen production

Although hydrogen is the most abundant element in the universe, it is very rare on earth in its 'pure' molecular form. Hydrogen must be produced by extracting it from compounds – typically water or hydrocarbons – hence hydrogen is an energy vector, not an energy source. There are two main methods of doing this: electrolysis, and steam methane reforming (SMR).

2.1 Electrolysis

All electrolysis techniques work using the same fundamental mechanism: a voltage is applied across an anode and a cathode immersed in an electrolyte but separated by an electrically insulating membrane. This creates a stable electric field without short-circuiting the electrolysis cell. Water is injected into the cell and is split into its component hydrogen and oxygen ions by the electric field. These ions then travel to the cathode and anode, respectively. Here electrons are transferred allowing the ions to combine into hydrogen and oxygen gases which can be collected. The three most common types of electrolysis are:

- Alkaline water electrolysis, which uses dissolved salts to increase the current-carrying capacity of water to aid electrolysis
- Proton exchange membrane (PEM) electrolysis, where a catalytic polymer membrane is used to separate electrons and hydrogen atoms (protons) from water at the anode and transport them to the anode where they recombine into hydrogen gas.
- High pressure and high temperature electrolysis, which reduce the electricity requirements by substituting thermal energy.

The electrolysis process can be catalysed, often by precious metals such as platinum or iridium. Since these metals are extremely expensive much research has been devoted to discovering new, cheaper catalysts. The latest alkaline electrolyzers can use nickel and iron catalysts which are significantly cheaper, however electrodes are prone to corrosion so are typically still made from or coated with platinum as it is highly corrosion resistant and increases the life of the electrodes.

Worldwide, approximately 5% of synthetic hydrogen gas is produced by electrolysis. Most of this is produced as a by-product of generating chlorine and sodium hydroxide in the chlor-alkali process, which is effectively alkaline electrolysis.

Alkaline electrolysis is less flexible than PEM electrolysis making it more suitable for baseload hydrogen production. PEM electrolysis can increase or decrease rates of production very quickly, taking around 10 seconds to increase production from 0 to 100%¹, making it more suitable for use as variable load or for taking advantage of cheap excess renewable electricity.

The two main inputs for electrolysis are electricity and water. As set out in the analysis report, if electrolyzers can stop production at times of peak electricity demand, it is likely that they can achieve lower wholesale electricity and network costs. However, as also set out in the analysis report, there are trade-offs involved in seeking to vary production with varying electricity prices:

- While lower electricity prices can be achieved, the lower utilisation of the electrolyser and higher storage requirements increase the cost of these components for delivered hydrogen. There is a typical 'bath-tub' shape to delivered hydrogen costs with varying production capacity factors;
- Only some types of electrolyser (PEM) are sufficiently flexible to vary production in this way. In addition, if the hydrogen is to be stored in liquid form or converted to ammonia or toluene for

¹ Based on information from Siemens regarding state-of-the-art PEM electrolyzers

storage, these processes are very inflexible, further reducing the ability to vary production with varying electricity prices.

Electrolysers require replacement of electrodes, catalysts and membranes after a certain amount of time. This is generally accepted to be an expense of 25-33% of the initial capital costs every 15-20 years (although this depends heavily on capacity factor), based on estimates made by the NREL in the USA².

There are potentially savings to be made in future as hydrogen production becomes less of a niche field. A French power-to-hydrogen programme is anticipating electrolyser prices falling from around 800€/kW currently to 400€/kW in 2028 to make hydrogen competitive with fossil vehicle fuel – based on the assumption of large-scale uptake of hydrogen and the associated improvements in the technology.

2.2 Steam methane reforming

Steam methane reforming is a very mature technology and is nearly ubiquitous in hydrogen production, accounting for over 95% of the hydrogen produced worldwide. The processes are fundamentally similar to those used for upgrading crude oil: hydrocarbons are broken down into their component parts and re-formed into more useful products which are then collected – in this case, the product is hydrogen.

There are several sub-types of steam reforming, but all follow a very similar process: methane (or other light hydrocarbons) from natural gas, waste, or coal, reacts with high temperature steam in the presence of a metal catalyst. The required temperatures are over 700°C and nickel is commonly used as a catalyst.

This process produces hydrogen and carbon monoxide as a waste product. This carbon monoxide can be reacted with steam again, in the presence of a copper or iron catalyst, to produce more hydrogen and carbon dioxide as a waste product.

The hydrogen for the 'H21' Leeds City Gate project will be supplied by four SMRs with a total production capacity of 1,025 MW, construction costs have been estimated at NZ\$767 million. This equates to a cost of just under \$750,000 per MW of production capacity.

The operating costs of SMR are mainly dependant on the price of natural gas and cost of emitted carbon. Natural gas is used as a raw material and can also be burned to generate the heat needed to raise steam for the SMR process³.

Leeds City Gate is budgeting NZ\$60 million per year for infrastructure management, but this figure includes costs for CCS, pipeline and all other hardware and infrastructure maintenance and upkeep.

Since SMRs produce carbon dioxide it is usually suggested that future SMR facilities could be built to include carbon capture and storage (CCS) technology. This process extracts carbon dioxide from the output gases, allowing it to be moved to long term storage or used as a raw material itself. Most carbon storage is expected to take the form of underground sequestration in depleted oil or gas wells in the same way that carbon dioxide is currently used for enhanced oil and gas recovery.

CCS processes and example projects are explored in more detail in Section 8.

Coal and biomass gasification

Hydrogen can also be produced by gasification of coal and biomass (or bio-waste or waste plastics) in a process which is very similar to standard SMR. The solid feedstock is heated to release light

² <https://www.nrel.gov/docs/fy10osti/46719.pdf> p13

³ Although, since the SMR reaction is exothermic, once it reaches a certain temperature it can be self-sustaining

hydrocarbons (methane, ethane, propane etc.) which are reacted with pressurised, high-temperature steam and oxygen to break them down. This produces carbon dioxide and hydrogen, along with other waste chemicals (exactly what, depends on the chemical composition of the feedstock).

Due to the relative abundance of natural gas these techniques are not widely used at present but are being developed for hydrogen production in Victoria, Australia. Gasification is viable there because Victoria's Latrobe Valley has an abundant brown coal resource to use as a feedstock, and several underground CO₂ sequestration options are being evaluated as potential carbon storage sites.

2.3 Production models

2.3.1 Centralised production

Centralised production is based on a single large hydrogen production facility (or a few facilities) which then distributes hydrogen by road, rail or pipeline to its point of use. Examples of this kind of production can be found in Europe and North America where large steam methane reformers (SMRs) are concentrated at industrial sites with good access to natural gas and then deliver hydrogen to the end user by pipeline (often the SMRs are built near to the end users to minimise transportation costs).

This kind of production does not ideally suit electrolysis, since economies of scale for electrolyzers are very limited. Each electrolyser cell can only work efficiently with a relatively small exchange membrane working with a small volume of water, so large electrolyzers are typically made up of "stacks" of multiple cells.

SMR does benefit from significant economies of scale, since a larger reaction vessel can hold more gas and more catalytic material, thus producing more hydrogen per hour. Additionally, a single large SMR requires only one natural gas pipeline and steam source, while several smaller, geographically dispersed SMRs would require several sets of infrastructure to supply them.

2.3.2 Local (distributed) production

Local, or distributed, hydrogen production is based on hydrogen being produced by a small facility at the point of use. This model for hydrogen production makes more sense for electrolysis than for SMR, since SMR benefits greatly from economies of scale whereas electrolysis does not.

Local hydrogen production eliminates hydrogen transport costs but requires multiples of infrastructure such as water pipes and pumps, and also requires suitable electricity connections (larger electrolyzers can draw a lot of power).

However, since water is much easier and cheaper to move around than hydrogen, the savings from eliminating the need to transport hydrogen usually outweigh the additional balance of plant costs. Further, making use of an existing electricity network is generally cheaper than developing and using dedicated hydrogen transport infrastructure.

Local electrolyser stacks can be bespoke for each application: low users can have a small stack and high users will have a larger stack. This is especially useful for small users who are not connected to the existing gas network, where the cost of building an entire pipeline just to meet a small demand would be difficult to justify.

3 Hydrogen storage

Hydrogen is the smallest molecule in the universe and has a very low viscosity; this can make it challenging to store as it is capable of escaping through pores or joints in a storage container and is small enough to fit through gaps in the microscopic structure of many materials.

Once it has permeated into a material, hydrogen can affect the material's crystal structure. Over time this leads to embrittlement and makes the material more susceptible to failure, a process which is well documented in high-strength steels in particular. Polymers are often more suitable for storing hydrogen as they are not prone to embrittlement.

There are several methods used to store hydrogen including compression, liquefaction and chemical bonding.

3.1 Compressed gas

Large volumes of hydrogen gas can be stored in underground formations or depleted reservoirs in the same way as natural gas; the storage requirements are very similar to those for natural gas storage (aside from hydrogen's greater ability to leak through porous rock) and are well understood. This is a proven technique and has been used on an industrial scale for many years.

Compression is one of the more energy efficient ways to store hydrogen, using around 0.19 GJ to compress 1 GJ of hydrogen to 70 MPa from atmospheric pressure. I.e., approximately 19% of the energy is 'lost' through having to expend energy running compressors. This energy penalty can be mitigated by using high-pressure electrolysis systems, where water is injected into an electrolysis cell under pressure (it is generally easier to compress a liquid than a gas) and the hydrogen is likewise produced under pressure (up to approximately 20 MPa).

Smaller volumes of hydrogen are normally stored in gas cylinders or storage tanks, although these can be expensive if they are intended for storing large hydrogen volumes and make use of exotic high-strength materials – this is more of a concern when designing mobile storage for transport where low tank weight is a priority.

Storage for transport

Storage tanks used on current fuel cell vehicles and modern transport trucks are made from an aluminium or polymer liner with a carbon fibre outer shell for reinforcement. These tanks are, in the case of the Toyota Mirai HV, rated to safely store 5 kg of hydrogen at a pressure of 70 MPa. To cope with this high pressure and meet crash test safety requirements these tanks must be built robustly; even though they are made from lightweight materials (the Mirai's fuel tanks weigh 87.5 kg when empty⁴), the weight of the fuel is a fraction of the weight of the storage tank.

In vehicle fuelling stations hydrogen is typically stored in large tanks at high pressures, albeit below the 70 MPa used in car fuel tanks. When the gas is pumped into a vehicle the pressure is stepped up to 70 MPa using a high-power pump. The fuel station storage pressures are a trade-off between maximising the amount of hydrogen that can be safely stored in a given volume while minimising the cost of storage vessels; by avoiding the complexities that come with ultra-high storage pressures.

Underground storage

Hydrogen can be stored underground just like other industrial gases, provided that there is a suitable underground formation. Reports suggest that depleted natural gas reservoirs are not always

⁴ <https://pressroom.toyota.com/releases/2016+toyota+mirai+fuel+cell+product.download>

suitable for storing hydrogen and surveying will be required before they are be used. It is generally accepted that hydrogen can most easily be stored in salt caverns⁵, there are several reasons for this:

- Depleted gas reservoirs may be porous to hydrogen (although still impermeable to larger methane molecules), allowing it to escape – this is not the case for salt caverns which are impermeable to hydrogen
- Depleted gas reservoirs may be colonised by sulphate-reducing bacteria which turn hydrogen into hydrogen sulphide and must be treated with biocide before they can be used. Salt caverns are free from these bacteria
- Formations suitable for building salt caverns are abundant in Europe and North America (and Australia)

There are no suitable salt formations in New Zealand, so if hydrogen is to be stored in an underground formation it must be in a depleted fossil fuel field (Ahuroa, for example), a hard rock cavern or an aquifer.

Surveys would be required to determine whether the chosen formation supports sulphate-reducing bacteria, this is considered a serious issue (a GERG paper has called it a “show-stopper”) as it can lead to loss of hydrogen and even damage to equipment⁶. If these bacteria were present it represents an additional cost (if not a complete barrier to hydrogen storage) – although oil wells are often treated with biocide to remove sulphate reducing bacteria, and they are not common in New Zealand.

Surveying would also be needed to determine how porous the reservoir is, to find out whether it could be used without first needing to be lined or capped. This would also need to be done on a case-by-case basis as some reservoirs (e.g. Ahuroa) are too deep for a cap to have any effect on the reservoir’s ability to store hydrogen.

Existing gas storage and extraction equipment (pipes, compressors, etc.) would be compatible with a limited mix of hydrogen and natural gas without any modifications. As the proportion of hydrogen increased over time incremental upgrades may be necessary, but these would likely follow paths established by underground hydrogen storage facilities elsewhere in the world.

3.2 Cryogenic liquid

When cooled to -253°C (only 20°C above absolute zero) hydrogen gas can be condensed into its liquid phase. Stored as a liquid, the hydrogen is much denser than as a compressed gas but requires special treatment to maintain cryogenic temperatures and stop it boiling.

Liquid hydrogen tanks are usually vacuum insulated and can also be jacketed with a layer of liquid nitrogen to maintain the extremely cold temperature. Despite this, some boil-off losses are inevitable and essential to maintaining cryogenic temperatures. Boil-off is caused by ‘warm’ hydrogen molecules escaping from the surface of the liquid to become a gas, which increases the pressure inside the storage vessel (but lowers the average temperature of the remaining liquid). To avoid building up a dangerous overpressure the tanks are fitted with pressure relief valves to allow the gaseous hydrogen to escape; this gas is either captured and re-condensed or lost to the atmosphere.

Cooling a gas is an energy-intensive process, requiring nearly twice as much energy as compression alone: inputs of up to 0.36 GJ are needed to liquify 1 GJ of hydrogen, i.e. up to 36% of the energy is

⁵ <https://www.sciencedirect.com/science/article/pii/S0360319914021223>

⁶ http://www.gerg.eu/public/uploads/files/publications/GERGpapers/SD_gfe_03_13_Report_Altfeld-Pinchbeck.pdf

'lost' through the cooling and compression process. If boil-off losses are being re-condensed this also requires further energy inputs for the duration of the storage time.

3.3 Chemical bonding

Hydrogen can be stored within other molecules by hydrogenation, which is any reaction where hydrogen is added to another chemical. These molecules are referred to as hydrogen carriers. Using carefully chosen hydrogen carriers this technique allows hydrogen to be stored as a chemical which is liquid at manageable temperatures and pressures; this can reduce the complexity and cost of storage and transport at the expense of energy-intensive production and greater weight than pure hydrogen.

When the hydrogen is needed, the hydrogenation reaction can be reversed. Both hydrogenation and de-hydrogenation usually require catalysts, pressure and heat to proceed at a reasonable rate.

Ammonia or liquid organics such as toluene are often considered to be good hydrogen carriers because each molecule can accommodate large numbers of hydrogen atoms and can be easily stored and transported with relatively simple chemical containers or pressure vessels. The hydrogenation and de-hydrogenation processes of each are well understood and are performed on industrial scales, particularly the hydrogenation of nitrogen (the Haber-Bosch process) to produce ammonia for use as a base for fertilisers.

An additional benefit to storing hydrogen within other compounds is that the hydrogen carrier itself can potentially be useful. Ammonia, for example, can be burned in special turbines to produce energy without emitting any greenhouse gases, mixed with other fuels to reduce emissions or used to produce nitrogen fertilisers. Many organic chemicals have uses as solvents or as raw materials for the chemical industry.

3.4 Metal hydride storage

A relatively new technology involves injecting pressurised hydrogen into a metal hydride matrix, where it bonds with the hydride and is trapped at higher densities than can be achieved with pure compressed hydrogen. The hydrogen can be recovered later by heating the metal.

Metal hydride storage is not yet ready to be used commercially, however, and therefore is not considered in this report.

3.5 Storage costs

Where only a small amount of hydrogen storage is required it is practical to use compressed gas cylinders or tanks. Storage as a compressed gas requires less energy input than liquid hydrogen storage, but the amount of hydrogen that can be stored in a given volume is smaller.

For larger applications (without access to underground facilities) liquid hydrogen storage becomes preferable, as the benefit of having access to large amounts of hydrogen in a smaller volume outweighs the energy losses and extra costs of liquifying it.

The costs of hydrogen gas storage vessels are high: fuel tanks for hydrogen vehicles cost on the order of \$7,000 per GJ of storage capacity.

As discussed in Section 6.2, there is no direct analogue for liquid hydrogen storage so it has not been possible to produce a precise estimate of the costs.

4 Hydrogen distribution

Hydrogen can be transported:

- **As a gas in a pipeline**, such as a ‘re-purposed’ natural gas pipeline. Pure hydrogen requires specially-selected pipes and a system which has been designed to minimise the number of joints and valves through which the hydrogen might escape. Since most of New Zealand’s gas network is made up of either polymer or low-strength steel⁷ pipes it is likely that the existing gas network could be used to transport a low concentration hydrogen and natural gas mix as has been proposed in other countries. It is also possible that a future transition to pure hydrogen could be made with limited upgrades to the infrastructure.

As detailed further in section 10, the Leeds City Gate project in the UK aims to use the existing natural gas infrastructure to transport hydrogen mixed with natural gas, with the possibility of incrementally increasing the hydrogen concentration up to 100% in future.

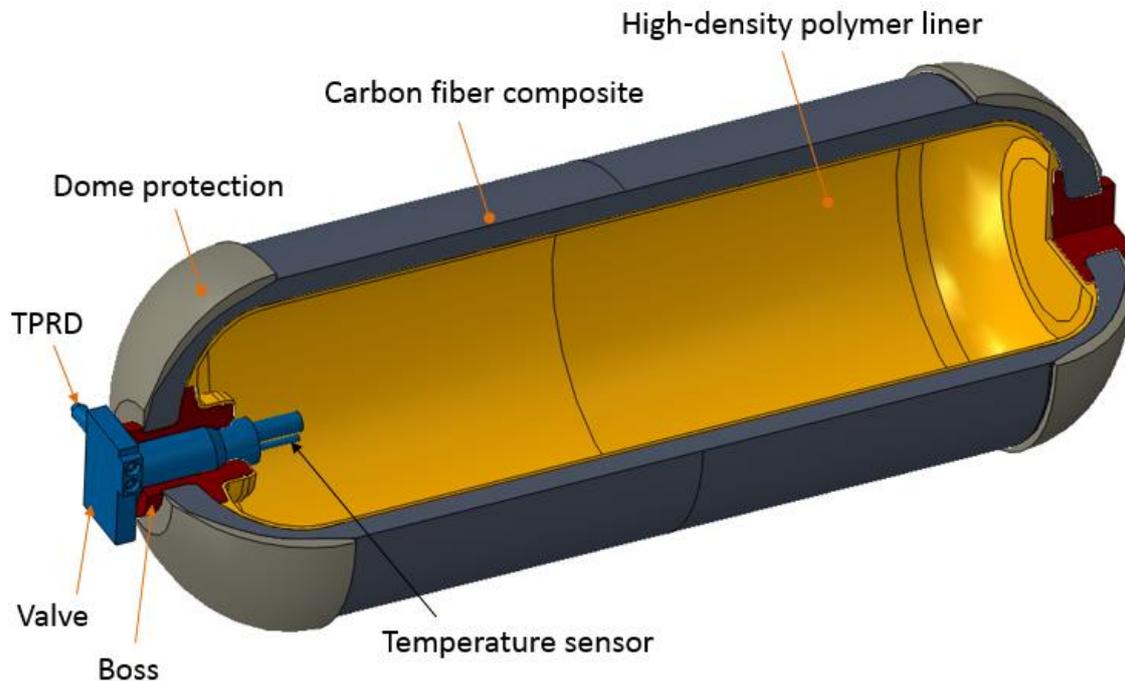
- **As a compressed gas in cylinders or tanks**. State-of-the-art (class IV) tanks are typically made from polymer and carbon fibre to ensure high strength and low weight, although this makes them expensive. Due to the low energy density of compressed hydrogen the capacity of each tank is lower than a comparable LPG tank (or tank of other conventional fuel). For example, a conventional 45 kg cylinder filled to normal operating pressure with hydrogen instead of LPG would contain 8.9 MJ of energy (or 62 g of H₂) rather than the usual 2,200 MJ.
- **As a cryogenic liquid in pressure-regulated insulated tanks**. These tanks are specialist pieces of equipment and are not usually used for fuels today, the closest common equivalent would be liquid nitrogen tanks. Liquid hydrogen has a higher density than compressed gaseous hydrogen so liquid transport is useful where large quantities of hydrogen are needed.
- **Bonded to another chemical, as a liquid, in a chemical tank**. This is identical to the methods currently used to transport ammonia or other bulk chemicals and depends on the chosen hydrogen carrier. Chemical tanks are typically steel, as the hydrogen carrier can be selected to ensure it is unreactive. This transport method allows the highest possible energy densities, even higher than pure liquid hydrogen.

As with most bulk products, transporting hydrogen can contribute significantly to its final cost. Currently, it is common for green hydrogen produced by electrolyzers to be made and consumed on-site – effectively using the electricity network to transport the fuel to where it is required.

For applications where a smaller supply of hydrogen is required there are companies which offer small electrolysis plants, capable of fitting in an ISO container or outbuilding. These kinds of plants are typically capable of producing of the order of one tonne of hydrogen per day and are intended for use in laboratories or technology testing situations.

⁷ Hydrogen embrittlement is more of a problem for high strength steels. New Zealand’s pipelines are mainly X42 and X56 low-strength steel which is more resistant to hydrogen embrittlement.

Figure 1: A class IV hydrogen tank



TPRD = Thermally Activated Pressure Relief Device

Credit: Process Modeling Group, Nuclear Engineering Division, Argonne National Laboratory (ANL)

Source: Process Modelling Group, Nuclear Engineering Division, Argonne National Laboratory. Via the US Department of Energy⁸

This cutaway diagram shows how modern class IV gas cylinders, as used for gaseous hydrogen transport, are constructed. The relative thickness of the expensive carbon fibre composite is clearly visible. Carbon fibre is used because of its high strength to weight ratio.

4.1 Distribution costs

Pipeline

As with other industrial gases, a pipeline offers very low marginal costs for hydrogen transport and makes most sense when there are large volumes to be moved.

Based on current figures, we estimate that a large hydrogen pipeline would cost in the region of \$1M to \$2M per km to construct⁹, excluding the cost of intermediary compressors if they were required.

Road

There are three mechanisms for transporting hydrogen by road on a truck-trailer unit: as a compressed gas, as a cryogenic liquid or bonded within a chemical carrier.

- Hydrogen “tube trailer” trucks used for bulk road deliveries (in California for example) use either steel or carbon fibre cylinders to transport gaseous hydrogen at pressures of up to 18 MPa¹⁰.

⁸ <https://www.energy.gov/eere/fuelcells/physical-hydrogen-storage>

⁹ http://www.mbie.govt.nz/info-services/sectors-industries/energy/energy-data-modelling/technical-papers/pdf-library/hydrogen_fuel.pdf

¹⁰ <https://www.energy.gov/eere/fuelcells/gaseous-hydrogen-delivery>

Using steel cylinders, the maximum capacity of a full-size articulated truck is approximately 280 kg (just under 40 GJ) of hydrogen. Polymer composite (i.e. carbon fibre or similar) class IV tubes allow each truck to transport up to 800 kg (114 GJ) of hydrogen at a time but come at an increased cost¹¹ (see Figure 1).

- The cost of compressed gas tube trailers is currently around \$7,500 per GJ of capacity, and this is expected to fall to \$6,200 per GJ before 2030¹². The high price is partly due to the cost of the exotic materials which are used to construct large parts of the storage tanks (carbon fibre currently costs around \$170/kg wholesale), and partly due to the careful construction and rigorous testing these pressure vessels require¹³
- Liquid hydrogen deliveries are typically used for long-distance and high-volume hydrogen deliveries, as the energy lost in liquefaction is offset by the ability to transport more hydrogen per truck. Existing liquid hydrogen tank trailers can transport up to 4 tonnes (568 GJ) of hydrogen at a time.
- Chemical bonding (e.g. ammonia, toluene): the hydrogen carriers are selected for their ease of transport and very high hydrogen density (see Section 9). This allows a lot of hydrogen to be transported in a relatively cheap and simple tank which can be built from steel or aluminium, to match the properties of the chosen hydrogen carrier.

We have estimated the cost of delivering hydrogen by truck, as a compressed gas. For a truck delivering 20 TJ of hydrogen per year to a site 100 km from the H₂ production facility, the cost of delivering hydrogen works out at \$7.51 per GJ. Delivering the same amount of energy in the form of ammonia costs \$1.41 per GJ (see Section 9 for more detail on ammonia).

This large cost disparity is due to two key factors:

- the small capacity of hydrogen tube trailers. What takes a hydrogen truck nearly 200 deliveries an ammonia truck can complete in less than 30 trips
- the high capital costs. A hydrogen trailer costs (even based on conservative estimates) over fifteen times as much as a comparable ammonia trailer¹⁴.

The chart below illustrates this difference in costs.

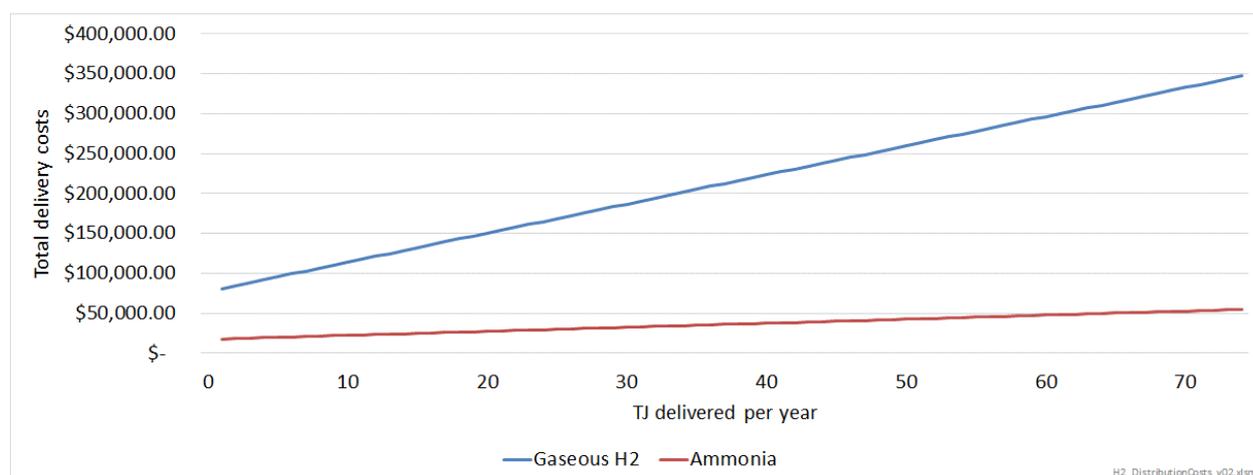
¹¹ <https://www.energy.gov/eere/fuelcells/hydrogen-tube-trailers>

¹² https://www.hydrogen.energy.gov/pdfs/review16/tv028_aliquo_2016_p.pdf

¹³ 70 MPa is an extreme pressure; greater than the pressure 6,500 m under the sea and more than 30 times greater than the overpressure caused by an exploding firework

¹⁴ Our estimate for the cost of an ammonia trailer is \$180,000 dollars, which is based on the cost of an ammonia rail transport tank. In reality it is very likely that a road-going ammonia tanker would be somewhat cheaper than this

Figure 2: Total annual energy delivery costs over a 200 km round-trip



This chart shows the difference in costs for delivering energy in the form of compressed hydrogen gas and ammonia. The higher costs for gaseous hydrogen are due to the expensive tube trailer and the fact that it has to make many more trips to deliver the same amount of energy when compared to the ammonia trailer. Delivering large amounts of energy as gaseous hydrogen quickly becomes uneconomical.

This analysis assumes that a truck is capable of making up to two complete round trips (for a total distance travelled of 400 km) per day – necessary for the gaseous H₂ truck to keep up with demand as energy requirements increase.

The cost of delivering large quantities of hydrogen as a cryogenic liquid has been estimated as being up to four times cheaper than delivery as a compressed gas, on a per GJ basis¹⁵. These savings are the result of the liquid hydrogen carrier being able to transport more hydrogen per trip, which can offset the efficiency losses of liquid H₂ relative to gaseous H₂.

¹⁵ https://iea-etsap.org/E-TechDS/PDF/P12_H2_Feb2014_FINAL%203_CRES-2a-GS%20Mz%20GSOK.pdf

5 Hydrogen use

5.1 Electricity generation

Fuel cells

Fuel cells can use hydrogen as a raw material to produce energy, in the form of electricity and heat. High-purity hydrogen is passed over a catalyst, often platinum-based, in the presence of oxygen. The hydrogen reacts with the oxygen to produce water, heat and electricity in a “reverse-electrolysis” reaction. No greenhouse gases are produced in this process, which is why hydrogen is considered a ‘clean’ and ‘green’ energy vector.

The hydrogen fuel is required to be 99.999% pure, as fuel cells are extremely sensitive to impurities which can poison (i.e. deactivate) the catalysts. Since the voltage produced by an individual fuel cell is quite small, around 0.7 V, it is standard practise to combine multiple fuel cells into a ‘stack’ capable of producing a useful voltage.

Fuel cells have been used for decades in specialist applications where hydrogen’s light weight and the zero-emissions nature of fuel cells are desirable. The lunar landing craft of the Apollo missions famously had fuel cells on board to generate electricity and fuel cells continue to be used in space applications today.

There are very few utility-scale fuel cell systems operating, most of these are in South Korea which has almost 300 MW of installed fuel cells generating electricity.

There are major challenges in using fuel cells for utility-scale electricity generation, namely:

- procuring enough extremely high-purity hydrogen to operate the cells
 - fuel cells require hydrogen of 99.999% purity; to overcome this, most large static fuel cells have integrated natural gas reformers
- fuel cells are expensive
 - the US DoE estimates that the minimum cost to produce a mass-market fuel cell would be around NZ\$1,865/kW¹⁶ (this includes power output as heat and assumes building 50,000 units per year), significantly more expensive than most other electricity generation on a \$/kW basis¹⁷.
 - This is less of an issue in places such as South Korea, where the fact that fuel cells produce a lot of energy on a per-m² basis minimises exposure to extremely high land costs (see Section 11.6)
- fuel cell lifetimes are short
 - a (stationary) fuel cell stack lifetime of eight years, assuming baseload operation, has only been achieved within the last three years¹⁸. This is a very short lifetime for an expensive electricity generating asset

Hydrogen turbines

Hydrogen can also be mixed with natural gas and burned in turbines, to produce electricity in the same way as a conventional natural gas turbine (although not actually in a conventional turbine). These turbines must be designed to resist hydrogen embrittlement and also to cope with hydrogen’s

¹⁶ https://www.energy.gov/sites/prod/files/2016/07/f33/fcto_battelle_mfg_cost_analysis_pp_chp_fc_systems.pdf

¹⁷ <https://www.eia.gov/todayinenergy/detail.php?id=31912>

¹⁸ <https://academic.oup.com/ce/advance-article/doi/10.1093/ce/zky012/5055431#118892186>

burning characteristics – not a trivial task: this requires specialist designs and carefully selected materials.

Burning hydrogen in turbines produces no CO₂, only water and some oxides of nitrogen (due to high-temperature reactions between atmospheric oxygen and nitrogen). It is relatively simple to remove nitrogen oxides from an exhaust stream – this allows a hydrogen turbine to theoretically operate with only water vapour emitted.

Siemens has reportedly built a gas turbine which can burn a hydrogen/natural gas mixture of up to 80% hydrogen¹⁹, and has commercially available turbines which can accommodate fuels including up to 15% hydrogen (by volume)²⁰.

In January 2018, Mitsubishi-Hitachi completed tests on a hydrogen/natural gas mix fuel for a specially designed full-scale turbine, reporting that testing was successful with a hydrogen mix of up to 30%. They also reported a drop in CO₂ emissions of up to 10% compared to burning pure natural gas²¹. Assuming research and development continues (Mitsubishi is planning to accelerate the development of its hydrogen turbines), we expect that 100% hydrogen compatible turbines are likely to be commercially available within approximately the next ten years.

5.2 Raising heat

Like natural gas, hydrogen can be burned directly to generate heat. The resulting flame can reach very high temperatures: over 2,200°C under ideal conditions. This makes hydrogen potentially suitable for a wide range of heating applications, from relatively low-grade domestic heating to high-grade industrial process heating situations.

Hydrogen has a high burning velocity and a different calorific value to natural gas, which makes pure hydrogen incompatible with existing natural gas burning apparatus (due to the increased risk of flashback, among other things). It is possible, however, to convert existing burners from natural gas to hydrogen fuel and as hydrogen in natural gas grids becomes more common it is likely that hydrogen-compatible appliances will start being manufactured.

As part of the UK's Leeds City Gate project, all mains-connected gas appliances in Leeds will in future be converted to burn hydrogen or switched to 'hydrogen safe'²² appliances; a significant task as around 90% of people in Leeds use natural gas for domestic heating and cooking (see Section 10 for more information).

It has also been suggested that piped hydrogen could power domestic fuel cells but there seem to be very few advantages to this in New Zealand, except in cases where a consumer has access to the gas network but is cut off from the electricity grid, assuming a future where fuel cells are cheaper than domestic solar and a battery.

Existing home fuel cells (also called 'Ene-Farms') strip hydrogen from a piped natural gas supply to heat water and also produce some electricity, emitting CO₂ in the process. They are effectively methane reformers used for water heating which produce electricity as a by-product. They are being backed by the Japanese and German governments with generous subsidies of up to €11,000, or

¹⁹ As discussed at a Wellington "hydrogen energy" event hosted by Siemens and Thinkstep. We assume this is purely a research turbine and not available to buy

²⁰ http://m.energy.siemens.com/US/pool/hq/energy-topics/technical-papers/gas%20turbines/pge_2017_paper_hydrogen-cofiring_igt_larfeldt_siemens.pdf

²¹ <https://www.power-eng.com/articles/2018/01/mitsubishi-hitachi-tests-turbine-that-burns-natural-gas-hydrogen-mix.html>

²² 'Hydrogen safe' appliances are (currently theoretical) devices which are designed to be compatible with hydrogen whilst still being able to burn conventional natural gas, likely to be developed during a natural gas to hydrogen switchover

\$18,000, in Germany. However, as they use natural gas to indirectly power a fuel cell, their CO₂ emissions are higher than using the natural gas for direct heating.

Europe and Leeds: H21

The Leeds City Gate hydrogen project will only burn hydrogen, it will not (in the near- to medium-term at least) use hydrogen to power fuel cells. There are four main reasons for this:

- 1) The fact that residential fuel cells are very uncommon, even in countries like Japan where there has been a government-backed push to grow the technology.
- 2) Hydrogen from pipelines, even if it were not mixed with natural gas, needs to be purified before it can be used in a fuel cell.
- 3) Most homes in the UK (and many in Europe) already rely on burning gas for space and water heating, so switching to electric heating would introduce an additional cost (in the short term).
- 4) Since most UK homes are already able to burn gas, converting hydrogen back into electricity before it can be used increases the total life-cycle efficiency losses for no additional benefit.

Hydrogen has been injected into several gas grids in Europe (albeit in very low concentrations and/or very small areas) where it is used for space and water heating exactly like conventional natural gas.

5.2.1 Industrial process heat

Hydrogen can be burned to raise steam or other industrial heat in the same way as natural gas, or blended into the existing natural gas infrastructure and used as a hydrogen/natural gas mix. Up to around 20% hydrogen the mixtures can be used by most existing heating equipment with no modifications needed.

Hydrogen can burn at higher temperatures than natural gas making it especially useful for high-grade heating.

5.3 Raw material

Most of the hydrogen produced today is used as a raw material in the chemical industries, particularly in the production of:

- food, where hydrogen is used to convert unsaturated fats, such as plant oils, into saturated fats like margarine;
- petrochemicals, where hydrogen is part of the cracking and reforming process to turn heavy oils into more valuable fuels;
- synthetic fuels, as a crucial part of reforming carbon chains extracted from biomass or other sources to produce useful fuel;
- industrial acids, since hydrogen forms the active component in all acids;
- ammonia, an important base for nitrogen fertilisers and the second most commonly synthesised chemical in the world, which is produced from hydrogen and atmospheric nitrogen in the Haber-Bosch process.

Hydrogen also has uses in some industrial processes, for example the manufacture of steel and glass.

5.4 Transportation

5.4.1 How Hydrogen Fuel Cell Vehicles (HVs) work

All hydrogen fuel cell vehicles work in fundamentally the same way: a fuel cell is used to continuously recharge a battery which drives electric motors. This continuous recharge extends the

driving range of the vehicle and means that only a relatively small battery is required, saving weight. This also eliminates long recharge times as the battery never has to be plugged in to recharge.

The fuel cell itself works by catalysing a reaction between oxygen and hydrogen to produce water and energy (it is effectively an electrolyser run in reverse).

A fuel cell vehicle is essentially identical to a battery electric vehicle, with two major exceptions:

- 1) It includes “hydrogen infrastructure” and the support equipment needed to operate fuel cells
 - a. Hydrogen (fuel) tanks
 - b. Hydrogen transport and compression system (i.e. fuel pipes from the tanks to the fuel cell)
 - c. Air intakes and compressors
 - d. Purification systems (for both hydrogen and air)
 - e. Fuel cell stacks
 - f. Exhaust system (a water outlet)
 - g. Other ancillaries (e.g. heating and cooling for the fuel cells, air and hydrogen monitoring systems, electrical control systems etc.)
 - h. Hydrogen leak detectors and hydrogen safety equipment (fuel cut-offs etc.)
- 2) The battery is much smaller, c. one kWh vs. tens of kWh²³.

The hydrogen infrastructure provides fuel, oxygen and ‘life support’ to the fuel cell, just like the ancillaries needed to run an internal combustion engine (ICE). One of its most important functions is filtering the hydrogen and air before they enter the fuel cell. Any pollutants or impurities can severely damage the cell, so the filtration process is rigorous²⁴.

Heating and cooling systems are required for fuel cells to keep their temperature in the ideal operating range. The latest fuel cells can “cold-start” at temperatures as low as -30°C, but vehicles operating in cold climates need heating coils to pre-warm the cell. Cooling is provided by a radiator filled with deionised water (this is a separate system to any liquid cooling of the electric motors) – deionised water is used because any current carriers would short-circuit and damage the fuel cell. HVs supply their own deionised water by including a deioniser in the cooling water circuit.

The battery in a fuel cell vehicle does not need to be as big as in a battery EV because the fuel cell can provide a continuous recharge, meaning that the battery will never be fully depleted as long as there is hydrogen in the tank. This is very similar to how the batteries in conventional cars are recharged by the alternator.

Fuel cell vehicles must have batteries to provide energy to the electric motors because the response time and peak power output of fuel cells is not suitable for driving – vehicle fuel cells aren’t able to provide enough power quickly enough for sudden, hard acceleration. The battery is also used to power things like the car’s climate control, lights and radio.

The battery in a Toyota Mirai is a nickel-metal hydride-type (NiMH) which generally have a lower performance than lithium-based batteries and would be impractical for a battery vehicle, but can

²³ The battery in a Toyota Mirai is a 1.6 kWh NiMH, the latest generation Nissan Leaf uses a 40 kWh Li-based battery.

²⁴ The Hyundai Nexu is capable of filtering PM2.5 pollution from its air intake – particulate matter with a diameter of 2.5 micrometres or less, only 3% the diameter of a hair.

meet the lower energy capacity per unit weight demands of a hydrogen vehicle. NiMH batteries have the advantage of being somewhat cheaper than lithium batteries.

Hydrogen leak detectors are a necessary safety feature and are connected to fuel tank interlocks which shut down hydrogen flow in the event of a leak or collision, just like fuel pump cut-off switches in conventional cars. In addition to these 'active' safety measures, the Toyota Mirai (and presumably other HVs) is designed such that the passenger compartment is completely separated from the hydrogen infrastructure. This is similar to, but a step up from, the design principles used in conventional cars to isolate passengers from fire hazards such as fuel systems.

Refuelling

Fuel cells vehicles are refuelled with hydrogen at a hydrogen fuel station, in much the same way as conventional vehicles. The hydrogen is delivered as a compressed gas through an interlocked fuel nozzle which attaches to a refuelling port on the car. Filling a hydrogen vehicle takes less than ten minutes.

Existing hydrogen pumps deliver gas at two different pressures: 35 MPa used for buses and similar heavy vehicles (currently, heavy HVs may be able to use high-pressure pumps in future) and 70 MPa used to refuel hydrogen cars. A vehicle designed for 35 MPa hydrogen cannot be filled to 70 MPa, and a 70 MPa vehicle can only ever be filled to 50% capacity by a 35 MPa pump.

Vehicles leased on hire purchase schemes typically have hydrogen fuel costs included up to a certain date, distance travelled or cost.

Driving

Fuel cell vehicles are identical to battery vehicles in terms of driving: their electric motors produce maximum torque from standstill, they have no gears and can use regenerative braking systems to increase their driving range. The only 'engine noise' is from the electric motors and the air compressors providing hydrogen and oxygen to the fuel cells.

Vehicle lifetime

A vehicle's fuel cells and hydrogen fuel tanks are both limited-life components. State-of-the-art vehicle fuel cells are designed to last for 10 years of normal driving (or 161,000 km, whichever comes first)²⁵ and the fuel tanks (in the case of the Mirai) have a lifespan of 15 years from the date of manufacture²⁶, although there is a chance these could be re-certified following an inspection. These lifetimes are long enough that they are of no consequence to most people buying a brand new car, but could have a significant impact on people buying a used hydrogen vehicle. This is not dissimilar to issues with battery degradation in battery EVs.

5.4.2 Light vehicles

There are three hydrogen fuel cell vehicles available to buy or lease today: the Toyota Mirai, Honda Clarity, and Hyundai Nexo (on sale in late 2018), although these are only available in selected markets (e.g. Japan and California). As of 2018 there are just over 6,500 fuel cell cars on the road worldwide²⁷, half of these are in California. Most of these cars are owned on lease or hire-purchase agreements which include not only servicing but also a (time- and distance-) limited amount of hydrogen fuel.

²⁵ <https://www.hyundai.news/uk/press-kits/all-new-hyundai-nexo-the-future-utility-vehicle-made-by-hyundai/>

²⁶ <https://insideevs.com/2016-toyota-mirai-refuel-2029/>

²⁷ <https://insideevs.com/there-is-only-6500-hydrogen-fuel-cell-cars-in-the-world-half-in-california-report/>

5.4.3 Buses

Hydrogen for use as a fuel in urban buses is well established. Trials and pilots of hydrogen powered buses have been carried out in many cities across the world, particularly in Europe (the CUTE trials), where there are small fleets of hydrogen buses still operating in urban centres²⁸. The fact that some of these buses have been kept on after the end of the experiment indicates that in some cities hydrogen buses may be viable.

However, a hydrogen bus trial in Perth (which ran from 2004 to 2007) reported that although the hydrogen buses had an availability of just over 90%, the bus refuelling system failed on 54% of attempted refuelling operations. The CUTE study reported hydrogen bus availability rates which varied from 60% to nearly 100%²⁹.

The reported fuel efficiency of these buses was 5.7 km per kg of hydrogen (2.5 GJ/100km), which is lower than would usually be expected since these buses were designed for maximum reliability while being as cheap as possible, not for maximum efficiency.

5.5 Safety

Hydrogen is non-toxic, non-corrosive and harmless to humans (except in very high concentrations, when it can act as an asphyxiant). Gaseous hydrogen is undetectable to human senses: it is colourless; odourless; burns with near-invisible flame and without smoke.

Since it is undetectable, gas and heat detectors are required in any situation where there is a risk of people being exposed to hydrogen, or where high concentrations of hydrogen could build up in an enclosed space (this includes anywhere hydrogen is stored or transported through, due to its tendency to leak). This is reflected in Japanese hydrogen fuel cell vehicle regulations, which mandate that vehicles are fitted with hydrogen detectors in case of a leak.

A similar system of regulations would need to be introduced in New Zealand because hydrogen sensors and all the storage and piping systems are safety-critical for any hydrogen application. It is unlikely that this would be particularly difficult or costly in New Zealand: since most vehicles and appliances are imported it would be straightforward to “import” regulations, techniques and equipment to align with those in hardware-exporting nations.

Although hydrogen has very wide explosive limits it rises and disperses quickly in air, so any hydrogen leaks in well-ventilated spaces quickly dissipate. The overall fire hazard is usually considered to be comparable to the fire hazard posed by conventional fuels, such as petrol or diesel, which are more difficult to ignite but do not quickly dissipate after leaking. Tests conducted in France as part of the Dunkirk hydrogen injection into the natural gas grid have found that a hydrogen leak in the home can disperse quickly enough that the risk is roughly equal to a natural gas leak. (This is not the case in poorly-ventilated spaces where hydrogen can build up).

Before hydrogen could be used in residential applications it must be odourised, just like natural gas. This presents a problem for pure hydrogen, for which there are no known odorants – these larger molecules simply “drop out” of the hydrogen stream and are not carried throughout the pipe network. This is not an issue for hydrogen/natural gas blends as the methane stream is capable of carrying odorants. An alternative would be to install detectors in any areas where hydrogen may possibly leak, and especially any areas where hydrogen might leak and then build up rather than disperse into the wider atmosphere³⁰.

²⁸ London and Aberdeen, for example

²⁹ http://www.eltis.org/sites/default/files/case-studies/documents/dpi_perth_fuel_cell_trial_summary_of_achievements_2004-2007_200806_4.pdf

³⁰ It is assumed that, by the time hydrogen is used in homes, the purchase and installation costs of detectors would be trivial

6 Hydrogen in comparison to other fuels

This section is included to provide some context and to allow informed comparisons to be drawn between existing fuels and hydrogen.

6.1 Gaseous H₂ fuel comparisons

6.1.1 Compressed natural gas

Of all the common fuels, CNG is the most similar in terms of infrastructure and handling requirements to compressed hydrogen.

Key differences between hydrogen and CNG include hydrogen's lower volumetric energy density (fewer MJ/m³) and tendency to damage or escape from storage vessels. CNG is a conventional fuel and is therefore underpinned by very mature, mass-produced technologies and a large amount of knowledge and expertise in production, storage, transport and use – which hydrogen does not currently benefit from to the same extent.

The difference in MJ/m³ is critical, and is the reason compressed hydrogen gas is an unsuitable fuel for space-constrained applications. At atmospheric pressure hydrogen contains 12.8 MJ/m³, natural gas contains 40.3 MJ/m³; an energy storage ratio of over 3:1 in favour of natural gas. As pressures increase this ratio gets wider due to the differences in the compressibility³¹ of each gas – at 30 MPa it is over 4:1. The result of this is that a vessel (gas cylinder, underground reservoir, fuel tank etc.) filled to normal operating pressure with hydrogen rather than natural gas will contain, as best, three times less energy than it normally would.

6.2 Liquid H₂ fuel comparisons

Unlike gaseous hydrogen and CNG, there is no fuel which can be usefully compared with liquid hydrogen (LH₂), although liquified natural gas (LNG) probably comes closest. The extremely low temperatures needed to form LH₂ set it apart from most other substances.

The critical temperature of hydrogen is -240°C (33 K), at temperatures higher than this hydrogen will always be a gas under any circumstances. In practise LH₂ is typically kept at a temperature of 20 K, or -253°C. For comparison, the critical temperature of natural gas is -83°C (190 K), although it is usually cooled to -160°C (113 K) to form LNG.

The fact that LNG is kept at temperatures over three times hotter than LH₂ is significant: the more cooling is required the more energy is required and the more complex the cooling process becomes. Liquifying hydrogen involves several steps, needs specialist cryo-cooling apparatus and requires a deliberate alteration of the molecule's quantum state.

Although it is not used as a fuel, the closest industrial analogue for liquid hydrogen is liquid helium. Liquid helium has a similar condensation process and is stored at around -270°C.

6.2.1 Storage and handling

Bulk liquid hydrogen storage would almost certainly be based on existing helium storage technology, as this is one of the few liquids which is stored at cryogenic temperatures. Helium tanks are usually constructed from steel with three insulating layers: a layer of 'superinsulation' (many insulating

³¹ The compressibility, Z , of hydrogen is greater than 1 and increases with pressure, meaning that hydrogen stores less well than an ideal gas. Conversely, Z for natural gas is less than 1 (except at very high pressures in excess of 40MPa) which means that more natural gas than predicted by ideal gas assumptions can be stored in a given volume at a given pressure.

layers bonded together), a vacuum insulation layer (like a Thermos flask) and a liquid nitrogen-filled 'jacket' layer.

Due to its storage temperature LH₂ requires careful handling. Unlike fuels which are liquid at room temperature it cannot be quickly moved using a high-power pump, as this would cause the hydrogen to overheat and boil – hence hydrogen fuel cell vehicles use gaseous hydrogen.

LH₂ storage is of interest because it allows large amounts of hydrogen to be stored in a relatively small volume: 1 m³ (just under 71 kg) of liquid hydrogen would take up 851 m³ as a gas at atmospheric pressure. As a pressurised gas, the same 1 m³ of liquid hydrogen would take up approximately 3 m³ at 35 MPa and 1.85 m³ at 70 MPa³².

LH₂ storage costs

Our analysis indicates that the absolute minimum possible capital cost for liquid hydrogen storage in a large insulated tank with boil-off re-liquefaction is currently \$408 per GJ of installed storage capacity. It should be noted that this analysis is based on the costs of full-containment bulk LNG storage which is simpler, less temperature-critical and on a much larger scale than liquid hydrogen storage.

NASA uses a 125,000 L tank (1,257 GJ of hydrogen when the tank is full) to research liquid hydrogen storage. This tank was previously used for mass storage of liquid hydrogen rocket fuel³³. LNG, by contrast, is stored in volumes of millions or billions of litres³⁴.

³² These figures account for the compressibility of hydrogen at high pressures, where ideal gas assumptions (PV = nRT) do not hold

³³ <http://iopscience.iop.org/article/10.1088/1757-899X/278/1/012012/pdf>

³⁴ <http://www.glmri.org/downloads/focusAreas/presentations/emmer2-2012.pdf>

7 Hydrogen in gas networks

As with natural gas, pipelines are the cheapest and often most convenient way to transport large quantities of hydrogen.

Hydrogen has different properties to natural gas which affect how it can be used in existing gas infrastructure. When mixed with natural gas, hydrogen can be safely used in the existing gas network up to a certain concentration without any hardware modifications. This critical concentration depends on the mains gas infrastructure and also on the appliances at the point of use, e.g. boilers and gas cookers. The key differences between hydrogen and natural gas are:

- Hydrogen burns faster and at higher temperatures than natural gas
- It requires a different gas to air ratio to burn under ideal conditions
- Hydrogen has a greater tendency to leak through and embrittle pipeline materials (especially iron and steel but also some plastics)
- Hydrogen has a different calorific value to natural gas

Mixed in low concentrations with natural gas and at low pressures these effects are not noticeable but, at a certain point, it becomes necessary to use dedicated hydrogen-burning hardware and legacy pipelines and other distribution infrastructure will need to be replaced. Generally, high-strength steel pipes are considered unsuitable for transporting hydrogen (due to embrittlement issues) and polymer pipes (as used in most modern gas networks) are favoured.

Hydrogen gas network projects in the UK and France plan to initially mix hydrogen up to concentrations of 5% and 6% respectively, without having to make any changes to their existing networks or appliances. The French project in Dunkirk aims to eventually increase this mix to 20% hydrogen without making any changes to gas-using equipment. In the UK, gas appliance change-over is expected to be necessary well before reaching a 50% hydrogen concentration.

Similar projects have also been started or proposed in other countries including Germany and Australia. See Section 11 for more information on these projects.

7.1 Hydrogen in New Zealand's gas network

7.1.1 Technical feasibility

Since much of New Zealand's gas network is modern polymer pipe, hydrogen could be injected in low concentrations without making any changes to the pipework. It is also possible that pure hydrogen could be used in some of the existing pipework, although this would have to be assessed more rigorously before transitioning to a pure hydrogen gas grid (the Maui and 'Vector' transmission pipelines, for example, are known to be steel^{35, 36} and therefore further investigation may be required before they are used to transport pure or high-pressure hydrogen).

Hydrogen injection pressures would have to be managed to avoid disturbances in pipeline pressure and gas velocities, however this process is both routine and well understood for natural gas and is expected to be similar for hydrogen. Of greater concern is that hydrogen injection would decrease the Wobbe index³⁷ of the pipeline gas and may cause it to fall below acceptable levels³⁸. If this were the case then the effect would have to be mitigated by removing nitrogen, CO₂ and other 'inerts'

³⁵ http://firstgas.co.nz/wp-content/uploads/FGL_transmission_2016_asset_management_plan.pdf

³⁶ <http://firstgas.co.nz/media-release/acquisition-maui-pipeline/>

³⁷ The Wobbe index is effectively a measure of the energy delivered by each cubic metre of gas; a lower Wobbe means that a gas provides less energy to an appliance at a given pipeline pressure

³⁸ Acceptable Wobbe limits are set out in New Zealand's gas specifications: NZS 5442

from the gas stream – potentially not a straightforward or cheap process. (This is not expected to be a problem for hydrogen concentrations below approximately 12%, and this limit will vary depending on the exact composition of the piped natural gas).

Gradually increasing the concentration of hydrogen in the natural gas network and observing the results of European hydrogen gas injection will allow potential problems to be picked up before they can become big issues.

Hydrogen injection rates

Rates of hydrogen injection into the grid would have to be carefully monitored to make sure that the gas blend (i.e. the hydrogen to natural gas ratio) was always consistent. A fluctuating hydrogen injection rate would need active oversight by gas producers and would be, at best, an inconvenience to customers who use natural gas as a feedstock.

If the hydrogen were being produced intermittently (by making use of occasional very low electricity prices, for example) then storage would be essential – this would allow excess hydrogen to be stored and injected into the grid during times of low production to maintain the blend ratio.

7.2 Effect on gas consumers

Home appliance conversion

Converting the natural gas network to carry increasing concentrations of hydrogen will eventually require converting or replacing the appliances connected to the network (this is safety-critical).

Conversion programmes typically shield the end user from the full one-off up-front cost.

There are two examples of a gas change-over that we can draw from:

- 1) On the Isle of Man, where an LPG/air to natural gas conversion has been completed relatively recently, the total cost of the conversion was approximately £3,500 (\$6,760) per household. Of this, £1,200 (\$2,300) worth of work was required inside the household, which includes the cost of converting appliances to run on the new fuel.
- 2) The H21 project in Leeds expects the labour cost of converting boilers, cookers, heaters, meters and making any required pipework adjustments to be £842.09 (\$1,625) per household. The cost of hardware is predicted to be £1,723 (\$3,325) per household for a total conversion cost, including a 20% overhead, of £3,078 (\$5,950) per property³⁹.

(See Section 10 for more information)

H21 suggests that socialising that cost across the whole population by increasing gas bills is the best way to pay for the conversion. This would lead to a modest increase in the UK's gas bills spread over many years.

These conversion costs are why many hydrogen gas fuel projects do not plan to reach a high hydrogen/natural gas ratio for decades, if at all. This allows time for 'hydrogen ready' or 'flexible-fuel' appliances to be developed and begin to saturate the market as old equipment wears out. Some proposals have suggested that the process is comparable to the analogue to digital TV switchover (although over a longer timeframe as cookers and boilers tend to have longer service lives than TVs).

³⁹ <https://www.northerngasnetworks.co.uk/wp-content/uploads/2017/04/H21-Report-Interactive-PDF-July-2016.compressed.pdf> Ch. 5

Other gas users

Gas turbines are known to be extremely sensitive to hydrogen content, in most cases it is considered a contaminant to be minimised or eliminated before it can enter the turbine. Existing turbines (especially those with modern lean pre-mix combustion systems) can only tolerate small amounts of hydrogen before suffering from undesirable combustion effects or hydrogen-induced damage.⁴⁰

This is important because New Zealand uses natural gas turbines to generate electricity. If hydrogen were to be injected into the natural gas grid there would need to be a mechanism in place whereby it could be removed before getting into the turbines. An alternative would be to replace the existing turbines with hydrogen-compatible models (if these were available), although this is likely to be a very capital-intensive exercise.

⁴⁰ <https://www.energy.siemens.com/hq/pool/hq/energy-topics/pdfs/en/technical%20paper/Siemens-Technical%20Paper-Gas-Turbine-Fuel-Quality-Requirements.pdf>

8 Carbon Capture and Storage

Carbon capture and storage is seen as a way of allowing polluting industries to achieve net-zero carbon emissions. Exhaust gases from polluting facilities have the carbon dioxide extracted and it is then transported by pipeline to a storage site. Storage sites are typically depleted oil or gas wells into which the CO₂ is pumped to be stored as a supercritical fluid⁴¹.

This technology is most applicable to facilities which exhaust large volumes of relatively pure CO₂, such as industrial materials processing, e.g., manufacturing steel and cement, and fossil fuel electricity generation.

The theory of underground carbon sequestration is well understood as it is very similar to the techniques routinely used in enhanced fossil fuel recovery, where CO₂ is pumped into oil or gas fields nearing the end of production to displace the remaining fossil fuels. CCS has been demonstrated at several sites around the world and is generally accepted as a necessary part of the global efforts to mitigate climate change.

CCS is not a passive process: the CO₂ must be chemically filtered from exhaust gases; the filtration chemicals are then heated to release the CO₂; this is then transported to a storage site by pipeline and compressed for storage. The energy input required for these stages effectively lowers the efficiency of whichever facility the technology is applied to, hence the greater benefits for concentrated, high-volume polluters: capturing large amounts of CO₂ means the environmental benefits can more easily outweigh the energy costs.

Carbon capture and mineral storage

Carbon dioxide can also be stored as mineral carbonates rather than a supercritical liquid. In “ordinary” CCS the carbon dioxide is injected into suitable underground formations where it slowly reacts with the surrounding rock to form carbonates such as limestone. This is a natural process which will occur in most carbon storage sites.

In “mineral carbon storage”, the CO₂ is heated and passed over carbonate-forming elements to mimics the natural process but over a much shorter timeframe.

This technology is not as well developed as supercritical fluid storage and requires significant energy input, as well as the use of catalysts. The IPCC estimates that a power plant equipped with CCS using mineral storage would require 60% to 180% more energy to operate than a similar plant without any CCS technology⁴².

This technology can also be used to produce useful carbonate raw materials, although currently only on small scales. Captured CO₂ can similarly be used as a base to produce synthetic fuels (e.g. by the Fischer-Tropsch process), but this is energy-intensive.

8.1 CCS in hydrogen production

Due to the energy conversion losses associated with making hydrogen from hydrocarbons, the CO₂ emissions associated with this ‘brown’ hydrogen are approximately 25% worse than burning the gas or coal directly.

⁴¹ “Supercritical” means that the CO₂ will behave like a liquid – a supercritical fluid is a gas under such high pressure that it shows liquid-like behaviour even at temperatures above the fluid’s normal boiling point

⁴² IPCC special report on Carbon Dioxide Capture and Storage. Prepared by working group III of the Intergovernmental Panel on Climate Change. Metz, B. et al. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA

However, if these CO₂ emissions can be captured and permanently sequestered, there is the potential for SMR+CCS hydrogen to be a low-carbon fuel.

To-date, most CCS facilities have managed to extract and store between 30-50% of the CO₂, but some project plans are suggesting that CO₂ removal rates of up to 90% be achieved.

GNS surveys have concluded that NZ has some small (by international standards) sites suitable for carbon storage, particularly in and off the coast of the Taranaki region⁴³. There may be other suitable sites in the Waikato coal fields, but further surveying would be required to confirm this. It is generally accepted that CCS makes much better economic sense when applied to high-volume CO₂ producers while they are being built, retrofitting CCS technology is much more expensive.

8.2 Economics of CCS

There is little information on the costs of CCS, and several papers indicate that estimates made as few as ten years ago bear no resemblance to current costs. What is clear is that costs vary widely by situation, depending on the specifics of the carbon capture technology, the availability of existing infrastructure and the location of the CO₂ source and storage sites.

The costs associated with CCS can be divided into three parts:

- CO₂ capture at the source of pollution,
- transporting the CO₂ to the storage location, and
- storing the captured CO₂, by compression and injection underground.

In terms of the costs associated with CO₂ capture, the additional construction costs for deploying CCS technology on an SMR are likely to be lower than for a fossil fuel power plant. This is because CCS requires gas separation technology: an additional and unnecessary cost for power generation, but absolutely necessary for an SMR (even without CCS) in order to purify the hydrogen. The additional costs of CCS for an SMR will be only in compressing, transporting and storing the CO₂.

This is significant, since according to the IPCC, “in most CCS systems, the cost of capture (including compression) is the largest cost component.”⁴⁴ This assumes that most CCS systems use a pipeline to transport CO₂ to a storage site as this is the most economical way to move large volumes of gas on a per-tonne basis.

In a recent paper examining the costs of SMR in Europe, the cost of CO₂ transport and storage was estimated at NZ\$18 to \$36 per tonne stored (this does not include the cost of capturing the CO₂ in the first place). The higher cost estimates account for longer CO₂ transport distances and offshore rather than onshore storage⁴⁵. These estimates assume existing infrastructure can be used to transport the CO₂ to its storage site and pump it underground (for example, into a depleted field where enhanced fossil-fuel recovery was previously used).

Monitoring techniques are expected to be adapted from existing techniques used in the oil and gas industry, with a very minimal learning curve. Using depleted oil or gas fields means that there is existing geological knowledge of the storage site and its recent history is known in detail. (Additionally, CO₂ injection into near-depleted oil and gas reservoirs is an established practise used for enhanced oil and gas recovery).

⁴³King, P. *et al*, GNS Science Report 2009/58

⁴⁴ https://www.ipcc.ch/pdf/special-reports/srccs/srccs_wholereport.pdf p41

⁴⁵ Techno-Economic Evaluation of Deploying CCS in SMR Based Merchant H₂ Production with NG as Feedstock and Fuel, Collodi *et al*, Energy Procedia 114 (2017)

Carbon capture and use

Much of today's industrial CO₂ is produced as a by-product of SMR, particularly by reformers used to fuel ammonia production. In the UK, in 2018, there was even a CO₂ shortage when global ammonia demand was low and many of Europe's large ammonia synthesis plants simultaneously shut down for maintenance.

There is a possibility that CO₂ created as a waste product of hydrogen production in New Zealand could be sold for use in fertiliser, food or paper production. Although this would not have a significant effect, if any, in terms of mitigating greenhouse gas emissions (due to the relatively short sequestration times) it may be more economically viable than geological carbon capture and storage as the "waste product" CO₂ would become a saleable by-product.

8.3 Carbon emissions

It is interesting to note the difference in how effective CCS is expected to be: the UK's H21 programme expects CCS fitted to a methane reformer to capture 90% of the CO₂ produced; the Quest CCS project in Canada also fitted CCS to SMRs but is only capturing 35% of the emitted CO₂ (it is not clear what the reason for this is). In our SMR modelling we have used an aggregate figure of 75% which was influenced by multiple estimates from the IPCC and H21 and the real-world performance of CCS facilities such as Quest. With a carbon capture effectiveness of 75% each GJ of hydrogen produced emits 17 kg of CO₂ to atmosphere (approximately 1.2 kg of CO₂ per 1 kg of H₂)⁴⁶.

It cannot be assumed that fitting an SMR plant with CCS automatically makes it zero emissions. Hydrogen produced by SMR will have to offset some amount of CO₂ emissions in other ways if the hydrogen is to be net-zero carbon.

CCS technology, including the Quest and Leeds City Gate examples, are explored further in the following section.

8.4 Worldwide efforts in CCS

8.4.1 Example CCS projects

According to the Global CCS Institute, there are currently 15 large scale CCS projects in operation around the world, with a further 7 under construction. Most of these are enhanced oil and gas recovery schemes rather than purpose-built carbon storage because enhanced fossil fuel recovery is a more lucrative process than carbon storage. Some examples of large-scale dedicated CCS projects are presented below.

- Norway has spent considerable time and money investigating the feasibility of and developing large scale CCS using depleted Equinor (Statoil) fields, for example, the first-of-its-kind Sleipner CO₂ storage facility based in a depleted offshore gas field. Sleipner was commissioned in 1996 and stores 0.85 Mt of CO₂ annually; over 17 Mt has been stored since it was opened.
- In 2015 in the oil-producing region of Alberta, Canada, oil upgrading SMRs were retrofitted with CCS technology in the Quest CCS programme. This project aims to capture around 1 Mt of CO₂ annually and 2 million tonnes had been captured and stored as of July 2017. The project cost CA\$1.35bn (approximately NZ\$1.52bn), is capable of capturing 35% of the emissions from the SMRs and is based in a well-developed oil producing region where there is an abundance of potential storage sites and existing infrastructure.

⁴⁶ Assuming that the reformer is operating at optimal efficiency and that steam is raised from water used to cool the reaction vessel.

- In Western Australia, carbon storage wells are being included as part of the Gorgon offshore gas fields development. The Gorgon carbon storage will make use of existing nearby geological formations rather than depleted gas fields. The facility is expected to come online in 2018 or 2019 and store up to 4 Mt of CO₂ per year, making it the largest carbon storage site in the world. The CCS project alone is expected to cost US\$2bn⁴⁷ (approximately NZ\$2.85bn) and will be able to make some use of infrastructure installed as part of developing the gas fields.

8.4.2 CCS prospects in New Zealand

GNS undertook a study into the feasibility of underground carbon storage in New Zealand and published their report in 2009.

The report examined the Waikato region and the Taranaki basin for potential storage sites and found that in the Waikato:

- There were no obvious large-scale carbon storage sites in the Waikato. The underground formations are either unsuitable or not enough is known about them
- Potential storage sites in un-mineable Northern Waikato coalfields are estimated to have a combined capacity of 14 to 17 Mt, which is relatively small. Additionally, accessing this storage capacity would require significant investment in drilling
- The existing seismic data (in 2009, when the report was published) is not of sufficient quality to define suitable off-shore storage sites around the Waikato region.

The Taranaki region was found to have the most favourable conditions for CO₂ storage, as:

- There are several currently producing oil and gas fields which could be converted at the end of their lives to store CO₂; e.g. Kapuni and Maui, which have storage capacities of approximately 100 and 300 Mt respectively
- Thanks to the oil and gas industry there is considerable subsurface data and knowledge about the region
- There are significant greenhouse gas sources in the region which would be suitable for CCS
- Additionally, there is some existing gas infrastructure in the region which could be re-used.

The GNS report concludes that, in global terms, the carbon storage potential in New Zealand is relatively small – but notes that so are expected levels of greenhouse gas emissions. Overall, New Zealand’s carbon storage potential is deemed to be adequate⁴⁸.

Rather than availability of storage sites, GNS’s report suggests that social issues including uncooperative landowners, public opposition and the need to respect the beliefs of local Iwi might be the biggest obstacle to implementing CCS in New Zealand. MIBE’s report into CCS notes that current legislation would not easily support CCS developments and would most likely need to be overhauled, with underground carbon storage explicitly accounted for, to make CCS in New Zealand a reality.

⁴⁷ The Gorgon project cost US\$54 billion in total

⁴⁸ <http://www.mbie.govt.nz/info-services/sectors-industries/energy/energy-efficiency-environment/documents-library/ccs-docs/2009-53-CCS-Waikato-Taranaki-overview%20-PDF%201.4%20MB.pdf>

9 Ammonia technology

Ammonia (NH₃) is one of the most commonly produced industrial chemicals in the world, with production using 2% of the world's entire energy supply according to some estimates.

Ammonia is usually produced by the Haber-Bosch process, where hydrogen and nitrogen are heated, pressurised and passed over catalysts to react and form ammonia. The ammonia is then used as a raw material in the production of chemical fertilisers. This same basic process has been used for over 100 years.

Due to the world's huge fertiliser demand the Haber process usually uses hydrogen produced by SMR (as there is no other hydrogen producing technique that can compete with SMR in terms of cost and production rate), consuming up to 5% of the world's natural gas production. The requisite nitrogen is sourced from the air.

Although the Haber-Bosch process itself produces very few greenhouse gas emissions (trace amounts of NO_x), the SMR used to produce hydrogen for the process and the use of fossil fuels for pressurisation and heating is responsible for approximately 1% of global CO₂ emissions.^{49, 50}

Owing to its long history and global importance the Haber-Bosch process is very well understood and underpinned by mature technology and techniques. It has been intensively researched and refined, meaning that (barring any miraculous scientific breakthroughs) it will remain the most effective way to produce ammonia for the foreseeable future.

9.1 As a hydrogen carrier

Interest in ammonia has recently piqued, owing to its possible use as a hydrogen carrier. There are many advantages to using ammonia as a carrier rather than other organic carriers, or using hydrogen directly as a compressed gas or liquid:

- Ammonia has a high hydrogen density, higher even than compressed or liquid hydrogen - ammonia is 17.8% hydrogen by mass
- Ammonia is widely produced, and the ammonia industry is already a large producer and consumer of hydrogen
- Ammonia is easy to store in large quantities and for extended periods of time
- Comprehensive storage and transport infrastructure already exists
- Specialist knowledge and expertise is already widespread in the ammonia industry, and ammonia handling is not significantly different from dealing with LPG
- If used as an energy storage medium, ammonia quickly becomes more economical than liquid H₂ storage
- Ammonia can be burned directly without producing CO₂, unlike other organic hydrogen carriers (e.g. toluene)

Ammonia is easily liquified, a moderate pressure or temperature just below -33°C is sufficient, and liquid ammonia can then be stored in minimally-insulated sealed containers. In its liquid phase, ammonia has a volumetric hydrogen density 50% greater than that of pure liquid hydrogen: 10.7 kg/100L (0.022 GJe per kg).

⁴⁹ <https://ammoniaindustry.com/ammonia-production-causes-1-percent-of-total-global-ghg-emissions/>

⁵⁰ <http://www.sciencemag.org/news/2018/07/ammonia-renewable-fuel-made-sun-air-and-water-could-power-globe-without-carbon>

Ammonia can be decomposed back into hydrogen and nitrogen using heat and catalysts. These gases can then be separated, and the hydrogen used to power fuel cells or burned to produce heat. The nitrogen can safely be released back into the atmosphere.

9.2 Ammonia production costs

Ammonia prices are variable and currently dependant on natural gas prices, as the hydrogen used in the Haber-Bosch process is made by SMR. A study commissioned by the NH₃ Fuel Association found that the price of hydrogen is the main component of the cost of ammonia.

Most existing ammonia production plants are very large scale, to match the world's huge demand for ammonia. A conventional ammonia plant (1,400 tonne/day capacity, or 35,000 GJ/day worth of H₂) with some storage capacity costs approximately NZ\$490M (based on 2012 costs from the USA)⁵¹; more recent projects have seen cost estimates for "world scale" ammonia plants far in excess of NZ\$1bn⁵².

Recently though some small-scale ammonia production plants have been built in the USA as demonstration projects or to meet only local requirements. A small plant built recently in Wyoming, for example, cost US\$350 million (NZ\$515 million) and is capable of producing 200,000 tonnes of ammonia per year.

In the Netherlands, a consortium including heavy industry majors has proposed a small-scale ammonia plant for a power-to-ammonia demonstrator. This project will use tidal power to run a 20 MW electrolyser to produce hydrogen which will then be turned into ammonia, at a rate of 45 tonnes of NH₃ per day. This project is expected to cost around €30 million (NZ\$51 million).

Siemens has stated that the overall energy efficiency of turning hydrogen into ammonia, then back into hydrogen which is then used to generate electricity in a fuel cell is of the order of 25%. This is very similar to the figure predicted by our models and has been used throughout this analysis.

Producing one tonne of ammonia requires approximately 10 MWh of electricity and stores around 175 kg of hydrogen, equivalent to 25 GJ. A demonstration scale electrolysis and ammonia production plant is being built in Australia, this will have 30MW of electrolysers and be able to produce up to 50 tonnes of ammonia per day. This project is expected to cost \$145 million.⁵³

9.2.1 Production from excess renewables

A 2017 report by the Institute for Sustainable Process Technology (ISPT) into the feasibility of power-to-ammonia states that because renewable electricity is intermittent by nature it is a poor match for ammonia production. Existing fertiliser production plants operate continuously, they do not shut down under normal circumstances. This is partly because of the time and energy cost of getting the reaction vessel and catalysts back up to the requisite temperature and pressure (the ammonia production plant in Kapuni, Taranaki, takes a week to shut down and a week to re-start⁵⁴), partly because cooling and heating the catalyst materials damages them and also because leftover, unreacted hydrogen can embrittle the reaction vessel.⁵⁵

However, a demonstration project is currently underway in the UK designed to investigate how ammonia production copes with an intermittent power and hydrogen supply. If these projects indicate that running an ammonia synthesiser intermittently is not realistically possible it presents a

⁵¹ <https://nh3fuel.files.wordpress.com/2012/05/chemicalmarketingservices.pdf>

⁵² <http://www.ammoniaindustry.com>

⁵³ <https://ammoniaindustry.com/thyssenkrupps-green-hydrogen-and-renewable-ammonia-value-chain/>

⁵⁴ <https://www.stuff.co.nz/business/77127262/Production-goes-on-hold-for-Ballances-Kapuni-turnaround>

⁵⁵ <http://www.ispt.eu/media/ISPT-P2A-Final-Report.pdf>

problem for 'renewable' ammonia production. Operating an ammonia plant based on renewable electricity would require a dedicated energy storage system such as batteries and an over-built electrolyser with hydrogen storage to maintain a constant hydrogen supply⁵⁶ (as is recommended by the ISPT report).

9.3 Distribution

Extensive ammonia transport infrastructure, including trucks, pipelines and ships, already exists. Transporting hydrogen in the form of ammonia rather than a cryogenic liquid or a compressed gas and "piggy-backing" on this existing infrastructure could offer significant up-front capital savings.

Our models predict that the cost of delivering hydrogen as a compressed gas is over six times higher than the cost of delivering the same amount of hydrogen as ammonia, based on the same journey. This is a consequence of both the greater hydrogen density of ammonia and the much cheaper ammonia transport vessels.

A report by the NH₃ Fuel Association estimates that pipeline transport of ammonia could be up to ten times cheaper than transporting hydrogen by pipeline⁵⁷. This is principally due to their low estimated costs for an ammonia pipeline: a large ammonia pipeline is expected to cost in the region of NZ\$500,000/km, significantly cheaper than most estimates of the cost of a hydrogen pipeline (see Section 4).

Ammonia is commonly transported both by road and rail, an ammonia tank-equipped rail car costs in the region of NZ\$180,000 and we have used this figure as a basis for our estimate of the cost of an ammonia transporting truck trailer.

9.4 Storage

Ammonia is commonly stored in large quantities prior to being distributed. Bulk ammonia containers are typically double-walled and vacuum-insulated to maintain a temperature close to -33°C, this keeps the ammonia liquid with zero or minimal boil-off. These kinds of tanks are a common feature of ports, industrial estates and agricultural areas.

Although this analysis has focussed on low-temperature storage it is also possible to store ammonia as a pressurised liquid at room temperature. This can be achieved at relatively mild pressures: less than 1 MPa is sufficient.

This flexibility in storage would allow the ammonia transporter or storage facility to choose the method which best suited and was most economical for their purposes.

⁵⁶ <https://www.thechemicalengineer.com/news/green-ammonia-project-set-for-launch-in-uk-today/>

⁵⁷ <https://nh3fuelassociation.org/wp-content/uploads/2013/07/bartels-dec2008-implementinganammoniaeconomy.pdf>

Table 1: Ammonia storage properties

Technology	Storage pressure (MPa)	Storage temperature (°C)	Storage loss (% per 6 months)	Power to power efficiency (approx. %)
Liquid H ₂	Ambient	-253	5.5	34
Gaseous H ₂	70	Ambient	0	38
CH ₄ (syngas)	Ambient	-163	3	28
NH ₃	Ambient	-33	0.6	25-31

This table has been adapted from the 2017 ISPT report “Power to Ammonia”

This table lists some key storage characteristics of different energy vectors and fuels. It shows that ammonia has a lower power-to-power efficiency than pure hydrogen technologies; however, this low efficiency is counterbalanced by the ease of transporting and storing ammonia relative to LH₂ or GH₂⁵⁸.

Storage costs

A report published by the NH₃ Fuel Association⁵⁹ lists some indicative costs for ammonia storage:

- Assuming that hydrogen will need to be stored for 182 days, the costs of storage are NZ\$5.87/GJ of H₂ stored as ammonia (versus NZ\$170.50/GJ for liquid hydrogen storage).
- A 30 kt capacity refrigerated storage terminal costs in the region of NZ\$30M to build (NZ\$45.45/GJ H₂ capacity).
- Constructing bulk pressurised ammonia storage costs around NZ\$2.00 per litre (\$117.64/GJ H₂ capacity).

9.5 Using ammonia

9.5.1 Hydrogen recovery

The hydrogen contained within ammonia can be recovered with some energy input. The round-trip efficiency of producing renewable hydrogen, converting it into ammonia, recovering the hydrogen and then generating electricity in a fuel cell varies between 25 to 31%, based on the specific technology used at each stage⁶⁰.

9.5.2 Direct combustion or direct fuel cell use

Ammonia itself can be burned directly to produce heat, although its HHV is lower than that of pure hydrogen while its octane rating is higher, i.e. it is more difficult to ignite and yields less energy per kg (although more energy per m³). Ammonia also has a relatively low flame speed which affects how it can be used in turbines or other applications.

There has been research into electricity generating turbines which can burn ammonia as a fuel, but these are still very new technologies – a partially ammonia-fuelled electricity generating turbine was only demonstrated on a large scale for the first time in 2014. Despite this, ammonia compatible turbines are being investigated by global industrial majors, particularly in Japan and Germany.

The 2017 ISPT report concludes that ammonia-burning gas turbines are a technology for the medium-to-long term at the earliest, and that current research would be more productively

⁵⁸ <http://www.ispt.eu/media/ISPT-P2A-Final-Report.pdf>

⁵⁹ <https://nh3fuelassociation.org/wp-content/uploads/2013/07/bartels-dec2008-implementinganammoniaeconomy.pdf>

⁶⁰ Siemens estimate their round-trip efficiency is 25%, the ISPT state that 31% is achievable

focused on cracking ammonia to release the stored hydrogen which can then be burned as part of a natural gas/H₂ mix.

Due to the relatively narrow explosive limits of ammonia and its slow flame speed it is not considered suitable as a mainstream replacement for liquid fossil fuels in vehicle engines. It can however be used to power specially designed ammonia burning engines or engines designed to have a high degree of fuel flexibility, although these are very niche technologies.

Fuel cells capable of using ammonia directly are still in their early stages: as of 2018 the first “real world” demonstrations of this technology are just concluding. We consider it unlikely that this technology will become widespread without extensive and varied use of hydrogen and an accompanying “ammonia economy” (where ammonia is used to facilitate easy transport and storage of hydrogen), as it is of little use otherwise.

9.5.3 Raw material

Industrially produced ammonia is used as a working fluid or raw material in many processes and products, including refrigeration, fertiliser manufacture and household cleaning products.

Due to the high costs of electrolyser hydrogen in comparison to SMR-sourced hydrogen it is unlikely that ammonia produced based on electrolysis would ever be used to produce fertilisers or other industrial products. Some estimates of the cost of electrolyser-sourced ammonia are over NZ\$1,700/tonne (\$68/GJ e H₂)⁶¹, which is close to this century’s peak price for ammonia.

It has been estimated that for electrolysis-based ammonia to be cost-competitive with SMR-based ammonia in Europe, electrolyser costs would have to fall to €300 (NZ\$510) per kW while natural gas and carbon prices rose. Even the most optimistic reports don’t anticipate that electrolyser costs could fall to €400 (NZ\$680) per kW until 2028, so this is probably still some way off⁶².

9.6 Toluene as a hydrogen carrier

This report has focussed on ammonia as a hydrogen carrier because facts and figures about the ammonia industry are far more readily available than information about toluene and its hydrogenated form methylcyclohexane (MCH) (see Equation (1)). Since toluene has been proposed as a potential hydrogen carrier for the near future, we have included this overview of the properties of toluene and MCH and highlight any important differences and similarities to ammonia.



Using the basic chemical properties of MCH and ammonia it is possible to calculate the hydrogen density for each substance. In the case of MCH, we consider ‘useful hydrogen’, as not all the hydrogen in MCH will be extracted during dehydrogenation (the MCH is turned back into toluene, which includes eight hydrogen atoms). The useful hydrogen density of MCH is 51 g H₂ per kg of MCH, or 7.2 MJ/kg. For ammonia, this figure is 176 g H₂ per kg of ammonia, or 25 MJ/kg. Ammonia has a useful hydrogen density per kg over three times higher than MCH.

Extracting hydrogen from methylcyclohexane is over twice as energy intensive per mole as extracting hydrogen from ammonia, assuming no catalysts are used⁶³. The theoretical ratio of GJ of energy input to GJ of hydrogen energy recovered is 0.29:1 for MCH and 0.22:1 for ammonia.

Since methylcyclohexane is a liquid at room temperature and pressure it is easier to store than ammonia, requiring no insulation or pressure-relief apparatus on storage vessels. MCH’s boiling

⁶¹ www.ammoniaindustry.org

⁶² <http://www.ispt.eu/media/ISPT-P2A-Final-Report.pdf>

⁶³ This is unlikely in the real world, but catalysts are assumed to reduce the energy required for each reaction by a similar proportion, so the ratios will approximately hold

point is just over 100°C and it is very unreactive with most container materials including plastics, steel and glass; in physical terms storing MCH is not significantly different to storing water.

In terms of health risks, ammonia is more dangerous than both MCH and toluene: a short exposure is sufficient to cause serious short- or long-term health issues (although neither toluene nor MCH are particularly pleasant either). However, ammonia has a very strong smell and most people are able to detect it in minute quantities, before it reaches dangerous concentrations. By contrast, MCH and toluene are much more flammable than ammonia (similar to petrol, whereas ammonia is more similar to cooking oil).

Although toluene/MCH and ammonia have different chemical and physical properties, we estimate that the economics and practicalities of using each chemical as a hydrogen carrier are similar. Generally, it can be assumed that the costs and energy efficiencies of ammonia production are applicable to toluene hydrogenation – with the exception that MCH cannot be used as a fuel directly.

10 Leeds City Gate: H21 hydrogen conversion study

Here we present the key fact and figures from the H21 study into the City of Leeds's hydrogen gas network conversion project. Leeds is a city in the north of England with good access to the UK's national gas grid.

10.1 Introduction

Leeds City Gate is a UK initiative to incrementally convert the natural gas network in the city of Leeds to run on a mixture of natural gas and hydrogen. This mix will, over time, have the hydrogen content increased until it reaches a 50% hydrogen 50% natural gas mix called town gas. The project will act as a demonstrator and, if successful, will provide a 'blueprint' for a nationwide town gas conversion. A potential long-term aim is to transition from town gas to a pure hydrogen national gas supply.

H21 is a study which has investigated the feasibility and costs of the project and recommended a progression plan and roadmap. This study was undertaken by Northern Gas Networks, Wales and West Utilities, Kiwa and Amec Foster Wheeler.

Leeds City Gate is intended to help the UK meet its Paris Agreement CO₂ reduction targets and reduce dependency on foreign gas imports. It may also have the additional benefit of providing a starting point for a UK hydrogen economy.

The UK's gas network is extensive, over 80% of people use mains (i.e. supplied through the main national distribution network) natural gas. This figure rises in cities to over 90% of the population. Mains natural gas is mostly used for space heating, hot water and for cooking.

Leeds was selected as the starting point for a potential hydrogen conversion for a number of reasons:

- It is home to approximately 660,000 people (1% of the UK's population) consuming 9.9 TWh of gas annually, a manageable but statistically significant population
- It is close to the industrial areas of Teesside and Hull which between them have existing hydrogen infrastructure and access to both CO₂ and hydrogen storage sites
- Recent government initiatives have been set up to encourage development in the North of England and there is the potential for this project to tie in with those.

The UK gas network originally used town gas synthesised from coal and oil and was converted to run on 100% natural gas between 1966 and 1977. Since then other local isolated gas grids have also been switched over, for example on the Isle of Man, which was converted to use natural gas within the last decade.

The proposed natural gas to town gas conversion therefore has recent precedent and the UK gas industry still has some gas conversion expertise and experience. The H21 study determined that an incremental conversion to a natural gas and hydrogen mix in Leeds is possible and there is the potential to later transition to a 100% hydrogen national gas grid.

Figure 3: Breakdown of natural gas use in the UK (793 TWh total per year)

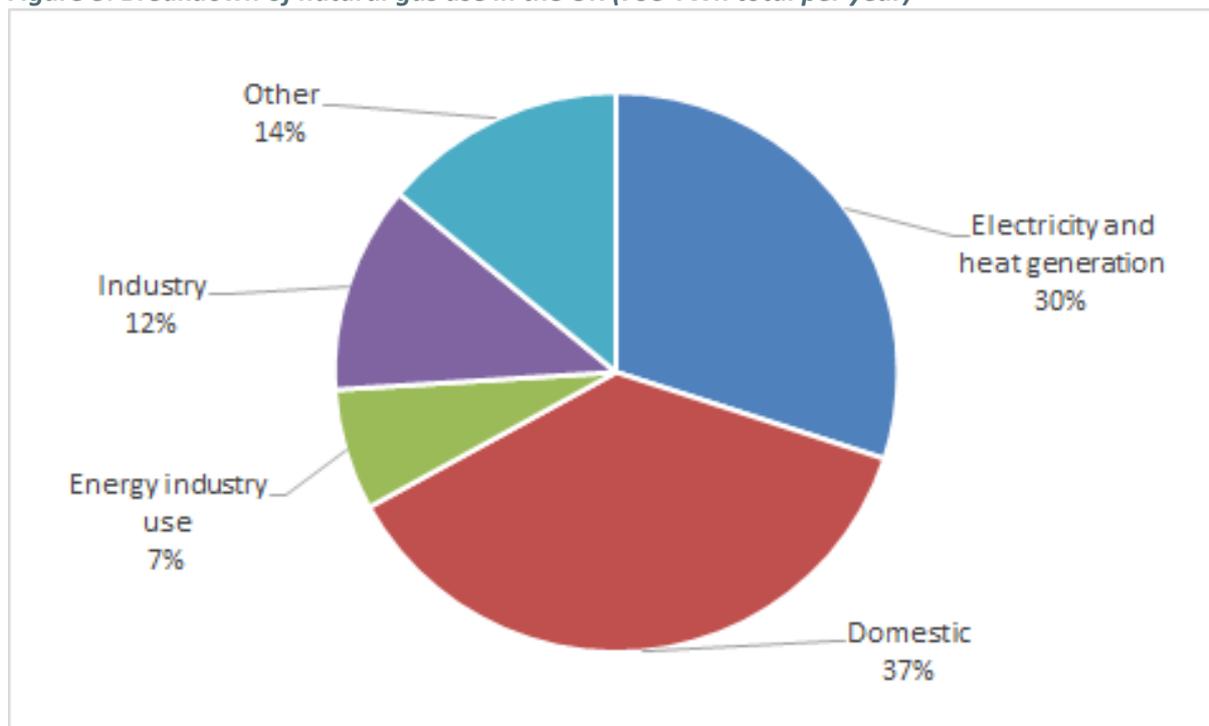


Figure 3 shows that residential (domestic) natural gas use makes up a large portion of gas use and is therefore a good candidate for national decarbonisation⁶⁴.

10.2 Hydrogen production and storage

The study examined various methods of hydrogen production including electrolysis, chlor-alkali plants and steam methane reforming. It was found that electrolysis and chlor-alkali plants were both uneconomical and unsuitable for environmental reasons, since the UK's electricity which would power electrolysis largely comes from fossil sources. Therefore, the hydrogen will be produced by four steam methane reformers with a total production capacity of 1,025 MW_{HHV}, located in the nearby borough of Teesside.

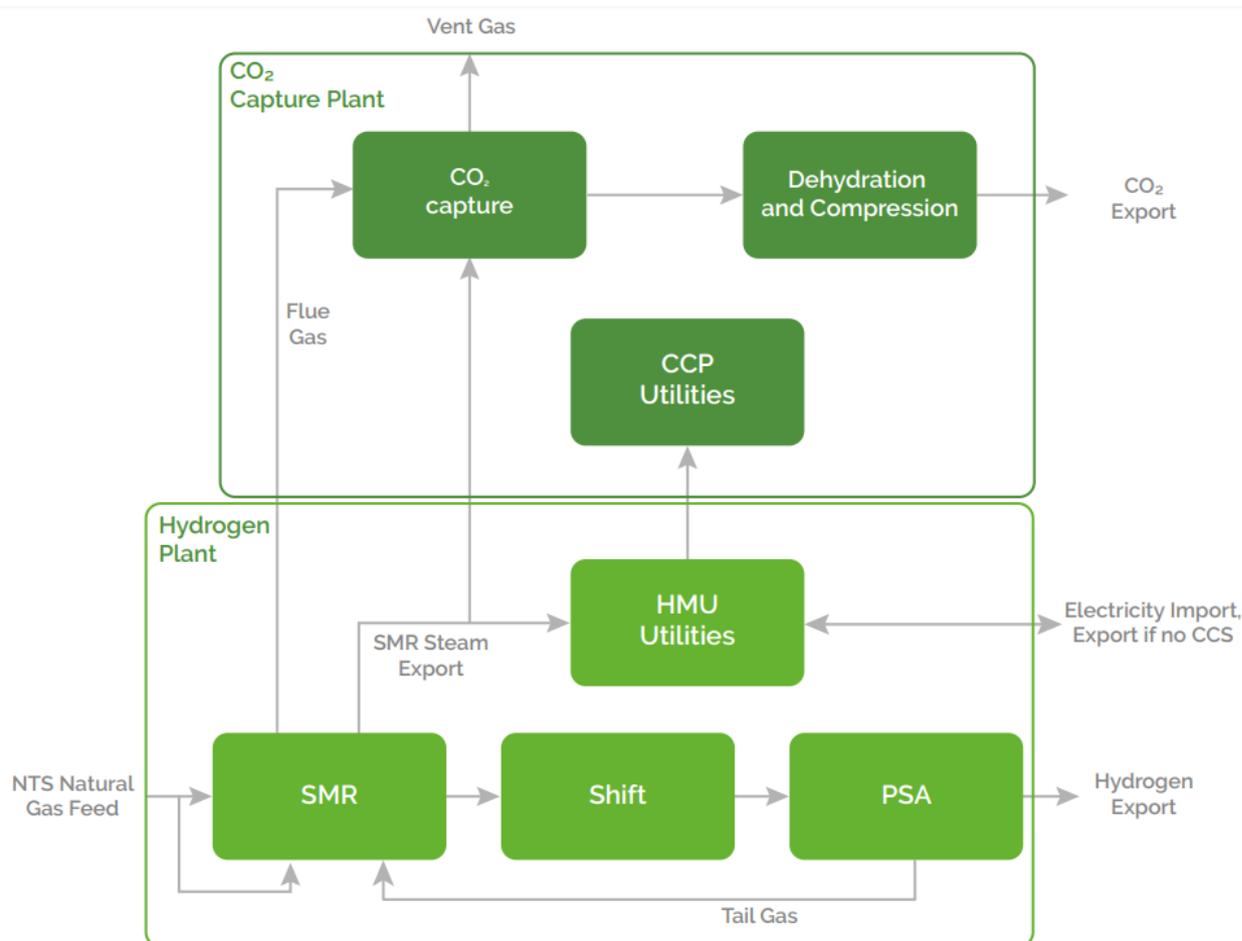
These SMRs will be fitted with CCS technology which would allow 90% of the emitted CO₂ to be captured and then transported by pipeline to storage sites in depleted oil and gas fields beneath the North Sea. The block diagram below gives a simplified view of how the SMR and CCS processes will work. Previous studies have concluded that the UK has abundant CO₂ storage space, and the H21 report assumes that storage space will be available locally as and when required.

The hydrogen will be stored in salt caverns, located in Teesside or in nearby Hull, for intraday and inter-seasonal use. It is predicted that the total hydrogen energy input into the local gas network will be approximately 6 TWh per year.

There is already one SMR with accompanying hydrogen infrastructure at Teesside, producing hydrogen for industrial purposes. This will benefit the Leeds City Gate initiative since the new SMRs could, to some extent, take advantage of the existing infrastructure.

⁶⁴https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/729395/Ch4.pdf

Figure 4: A diagram of the SMR and CCS process



Source: Leeds City Gate H21 report, 2016

This is a simplified block diagram of the SMR and CCS processes. The diagram shows how hot steam from the SMR systems is used to drive the carbon capture. CCP stands for carbon capture process.

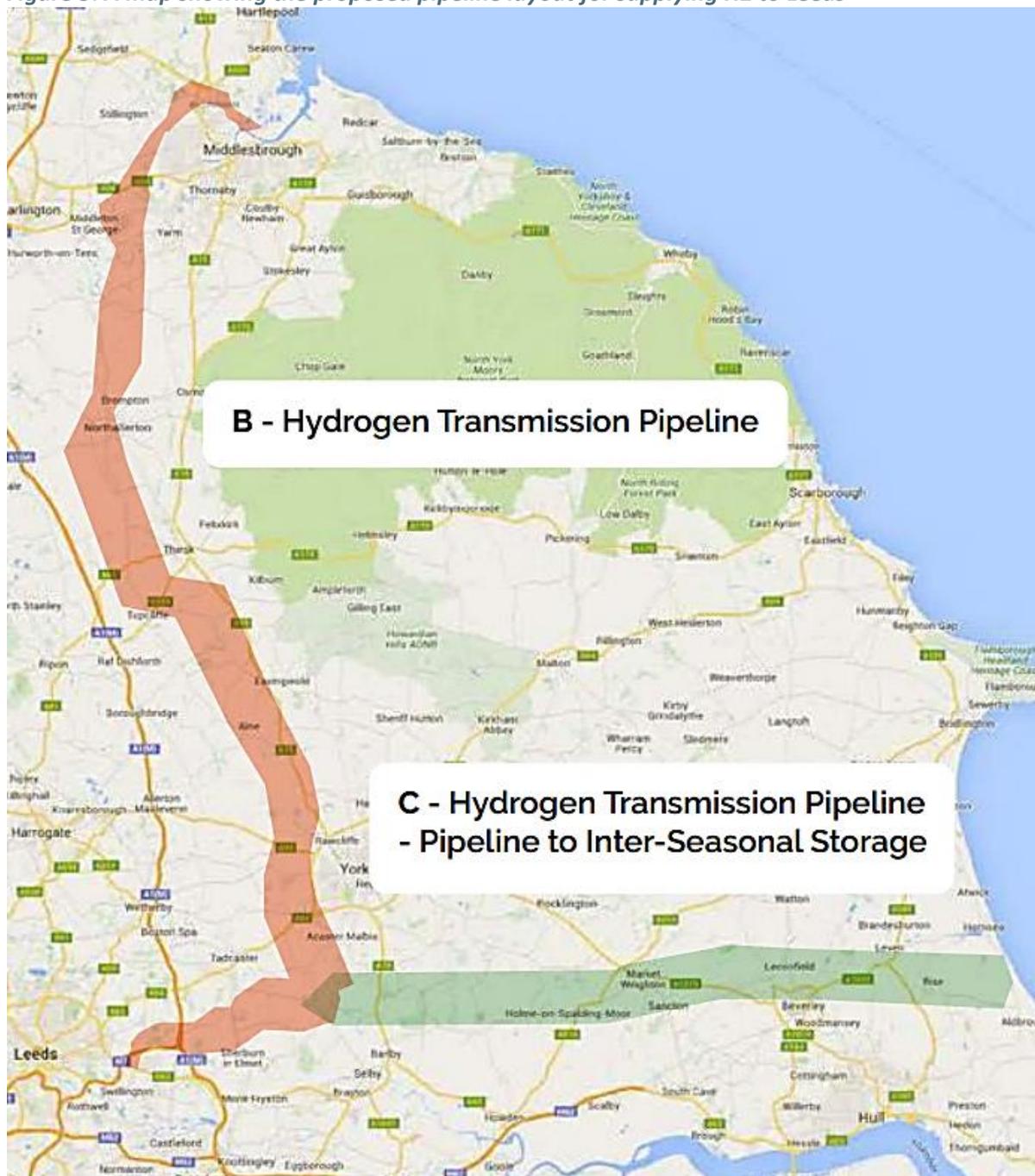
10.3 Distribution

Hydrogen will be transported from the production facility at Teesside to local storage caverns or caverns near Hull and then on to Leeds using the existing natural gas network, which the study finds could be upgraded to carry 100% hydrogen relatively easily. This is largely facilitated by the ongoing Iron Mains Replacement Programme which aims to replace a significant proportion of the UK's ageing iron and steel gas pipes with polyethylene by the year 2032. Hydrogen, especially in high concentrations and at high pressures, permeates and embrittles iron and high strength steels; this can lead to leakage and eventually to failure of the gas pipe. Polyethylene, however, is considered suitable for transporting pure hydrogen.

With polyethylene pipework in place most of the remaining work to convert the gas grid to supply town gas would be in upgrading and modernising pressure conversion facilities and other valves and joints in the pipes. The conversion will be carried out over three years and the work would take place only during the summer months when gas demand is relatively low, to minimise disruption to consumers.

Indicative pipeline routes are shown in figure 42, which also gives an idea of the locations of Leeds, Teesside (Middlesbrough) and Hull.

Figure 5: A map showing the proposed pipeline layout for supplying H2 to Leeds



Source: Leeds City Gate H21 report, 2016

Indicative hydrogen pipeline route corridors for supplying Leeds. The area covered by the map is approximately 110km (W-E) by 130km (N-S).

10.4 Consumption

The town gas mixture will be burned at the point of use to provide heat, the same way conventional natural gas is currently used. This will require conversion of existing gas appliances to use town gas; either by swapping to new burners and combustion equipment within the appliance or the installation of entirely new appliances. The cost of any conversions and new equipment will be covered in the hydrogen conversion budget and provided to the consumer at no apparent up-front cost.

10.5 Costs

The study predicts the total CapEx for converting Leeds to run on town gas will be £2.05bn (\$4.02bn) over the 2017 to 2029 timeframe, with ongoing OpEx costs of £139m (\$272m) per year. An estimated cost breakdown is reproduced here in table 2. The report suggests that the gas conversion work would be paid for by increases to the transmission component of the UK's gas bills. The report estimates that a nationwide increase of 1% to 3% over 45 years would be sufficient to pay for the work.

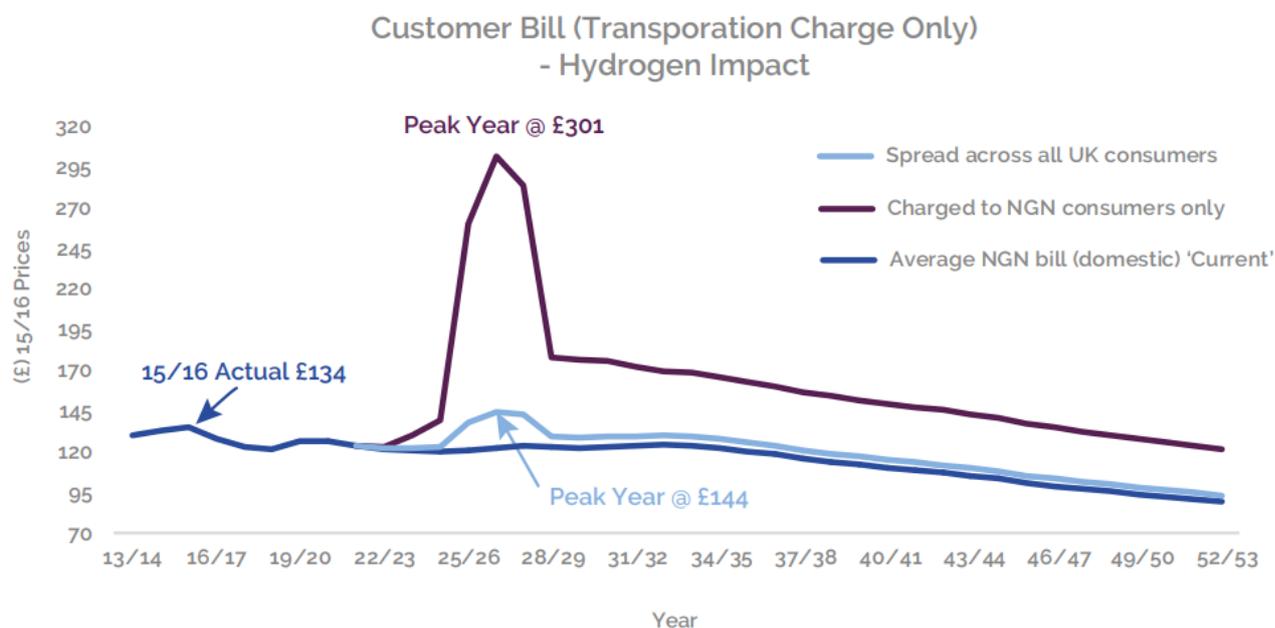
Table 2: Estimated cost breakdown for conversion from natural gas to a hydrogen/natural gas blend

Cost summary	Cost incurred £m (\$m)	Ongoing yearly costs £m (\$m)
Network conversion preparatory work	10 (19)	
Hydrogen infrastructure and conversion costs		
Methane reformers	395 (767)	
Intraday salt caverns	77 (150)	
Inter-seasonal salt caverns	289 (561)	
Domestic, commercial and industrial appliance conversion	1,053 (2,000)	
Hydrogen transmission system	230 (447)	
Ongoing OpEx costs		
Carbon capture and storage		60 (117)
Infrastructure management		31 (60)
SMR efficiency loss		48 (93)
Total	2,054 (3,990)	139 (270)

Source: Leeds City Gate H21 report, 2016

NZ\$ costs have been converted from GBP and may not sum exactly due to rounding.

Figure 6: Impact of hydrogen switchover on the customer's gas bills



Source: Leeds City Gate H21 report, 2016

This chart shows how customer bills would be affected by the cost of implementing the Leeds hydrogen project. The chart only covers the transportation charge (i.e. the network costs) component of the annual bill, fuel costs would be additional. This chart illustrates the effect of socialising the cost of the transition, resulting in a brief, moderate increase to consumer's bills.

The report estimates that the sale price of hydrogen to a residential consumer (including UK value added tax at 20%) will be \$47.08/GJ; the UK consumer currently pays approximately \$18.31/GJ for natural gas.

The hydrogen costs break down into:

- Production costs of \$7.63/GJ, which covers the capital costs of the SMR equipment, hydrogen storage and ongoing O&M costs
- Variable costs of \$19.89/GJ, which includes natural gas (purchased at \$9.81/GJ), CCS running costs, an SMR+CCS efficiency factor of 68.4% and penalties for CO₂ emissions
- Other costs which make up the remaining \$11.72/GJ including transmission and distribution costs, billing costs and profit margins
- +20% value added tax

10.6 The future of hydrogen in UK gas pipelines

The study predicts that a UK-wide hydrogen conversion is feasible but would require many decades and significant investment to complete. If all hydrogen were produced by SMR with CCS, it would be possible to reduce the UK's greenhouse gas emissions from heating by up to 73%.

The low concentrations of hydrogen in the initial town gas mix would make extracting hydrogen of sufficient purity to power a fuel cell impractical at best. However, H21 predicts that in the long term a pure hydrogen gas grid could be used to supply fuel cells. The pipeline quality hydrogen would be extracted from the gas network, purified and then fed into fuel cells to generate electricity and some potentially useful heat.

Since access to the electricity grid is almost universal in the UK, this is most likely to be useful to specialist industrial or commercial consumers for whom the mains electricity supply is unsuitable.

With the addition of a purifier and a sufficiently powerful compressor the mains gas supply could, at least in theory, be used to refuel a hydrogen fuel cell vehicle without the need to visit a fuel station.

11 Worldwide interest in hydrogen

Interest in hydrogen as an energy vector has fluctuated over the past 20 years, often influenced by government funding programmes. In the early 2000s the USA, under the Bush administration, set aside US\$1.2bn to spur the development of hydrogen infrastructure and encourage the uptake of hydrogen vehicles. This led many companies, notably car manufacturers, to begin researching hydrogen-fuelled combustion engines and fuel cell technology. Under the Obama administration this funding was reduced by 60% and the focus shifted to basic research into hydrogen production, particularly by SMR.

The Hydrogen Council announced its formation at the 2017 World Economic Forum in Davos. This is a group of (as of September 2018) 52 companies whose stated ambition is to accelerate the development and commercialisation of hydrogen and fuel cell technologies. The original members of the hydrogen Council are Alstom, Air Liquide, BMW Group, Daimler, ENGIE, Honda, Hyundai Motor, Kawasaki, Royal Dutch Shell, The Linde Group, Total and Toyota. The Council has announced investments of US\$10.7bn for the promotion of hydrogen and hydrogen technology between 2017 and 2022 and has published reports which anticipate further funding in future.

11.1 Vehicle manufacturers

Transport is often put forward as potentially being a major consumer in a hydrogen economy. With the transfer away from fossil fuelled vehicles inevitable it is useful to have an idea of where vehicle manufacturers are focussing their “future vehicles” research and development. Manufacturers of light vehicles can broadly be split into two camps in terms of future fuels: those focussing primarily on battery electric vehicles (including hybrids) and those focussing mainly on hydrogen fuel cell vehicles. The positions of the major manufacturing groups are outlined here.

Those focussing on hydrogen technology are:

- Honda, which has stated that their main focus for future fuels is on hydrogen vehicles but are maintaining the ability to quickly pivot to battery electric if this emerges as the dominant future vehicle technology. Honda currently produces one HV, the Clarity.
- Hyundai, which currently has a fuel cell car on sale and a further two fuel-cell cars and a fuel cell bus which have yet to go on sale. However, the executive vice-president announced in 2017 that the company would be changing its future vehicle focus from hydrogen fuel cells to battery electric vehicles.
- Fiat-Chrysler Automobiles has previously focussed on battery and hybrid technology but is currently in talks with Hyundai to partner with them on fuel cell technology.

The major companies focussing on battery technology are:

- Daimler/Mercedes-Benz, which has over 50 electric or hybrid vehicles planned for release by 2022, of which one is a fuel cell vehicle. The head of Daimler AG has stated that fuel cell vehicles are no longer a major part of the company’s plans for the future and that the company will accelerate its development of battery electric vehicles⁶⁵. Daimler is also the world’s largest truck builder and has delivered battery trucks to customers for on-road testing. Daimler-MB is planning to invest over US\$11bn in battery technology⁶⁶.

⁶⁵ Note that this statement came several months after Daimler announced its involvement in the hydrogen council at Davos. <http://fortune.com/2017/04/02/daimler-fuel-cell-car-development/>

⁶⁶ <https://electrek.co/2016/11/27/daimler-investment-electric-vehicles/>

- The Volkswagen-Audi Group (VWAG), which is planning to have 80 electric vehicles on sale by 2025. By 2022 the group plans to have invested US\$40bn in zero-emission vehicles⁶⁷ (as part of an \$85bn spending plan⁶⁸), there will be over 300 models on sale and every vehicle in the group will have an electric or hybrid model. This includes US\$1.7bn for developing electric powertrains for heavy vehicles. Audi had a fuel cell vehicle programme but according to the VWAG CEO there is little interest in this field and the president of Audi America has indicated that hydrogen powered prototypes are not expected to be in testing until 2022 at the earliest, and then in extremely limited numbers.
- Ford, which had a hydrogen vehicle programme in the early 2000s, but that has since been abandoned in favour of battery electric vehicles. Ford plans to invest US\$11bn in electric vehicles by 2022⁶⁹.
- Nissan, which sold 163,000 battery vehicles in 2017 and is aiming to sell one million in 2022. Eight new battery-electric models are currently being developed. Renault-Nissan-Mitsubishi is generally accepted as being the world leader in battery electric vehicles.
- DHL, the world's largest logistics company, is building battery-powered vans for its own local deliveries and selling the vans to other companies. DHL aims to eventually electrify its entire light commercial fleet.

Toyota and BMW are exploring both battery electric and fuel cell vehicles. Toyota currently sells the Mirai HV, is testing a fuel cell truck at a US port and have announced a megawatt-scale hydrogen power station which will produce 2.35 MW of electricity and 1.2 tons of hydrogen a day, by reforming bio-waste. Outside of hydrogen technology, Toyota are planning to invest US\$13.3bn in battery vehicle technology by 2030⁷⁰. They are working in partnership with Panasonic to develop next-generation battery technology and have stated that by 2025 every model in their range will be available as a battery, hybrid or fuel cell vehicle.

BMW is planning to produce a limited number of fuel cell cars in 2021. They have stated that fuel cells may make sense in models above the 5 Series, for models below that BMW are focussing on batteries.

It is also worth noting that there are some similarities between hydrogen and battery electric vehicles (i.e. batteries and electric motors). This means that although manufacturers may currently be focussing on one technology, there is some potential crossover if their focus changed in future.

11.2 Hydrogen in France

In May of 2018 the French government announced it would be making 100 million Euros available for hydrogen subsidies up to 2023. This money will go towards:

- Transitioning hydrogen production from SMR to local electrolysis, sufficient to meet 10% of France's hydrogen demand by 2023;
- Helping private companies purchase hydrogen powered vehicles. This will consist of 5,000 vans and 200 trucks, buses, boats and trains

⁶⁷ <https://www.bloomberg.com/news/articles/2017-11-17/vw-is-said-to-budget-85-billion-for-five-year-investment-plan>

⁶⁸ <https://www.reuters.com/article/us-volkswagen-investment-electric/volkswagen-accelerates-push-into-electric-cars-with-40-billion-spending-plan-idUSKBN1DH1M8>

⁶⁹ <https://www.reuters.com/article/us-autoshow-detroit-ford-motor/ford-plans-11-billion-investment-40-electrified-vehicles-by-2022-idUSKBN1F30YZ>

⁷⁰ <https://www.reuters.com/article/us-toyota-electric-cars-idUSKBN13204D>

- Building additional hydrogen filling stations, the target is 100 by 2023, up from around 20 currently;
- Beyond 2023 hydrogen may be injected into the national gas grid in small quantities or used to produce methane in a power-to-gas initiative (there are no targets for these though).

Also, in 2018 French utility company EdF bought a 20% stake in McPhy, another French company specialising in hydrogen technology and generally regarded as the European leader in hydrogen fuel station installations. EdF cited a desire to expand into a “hydrogen-based mobility market” and stated that it believes hydrogen is an essential part of decarbonising industry and transport.

In June of 2018 the first power-to-gas demonstrator in France (sited in Dunkirk) came online. The facility will produce hydrogen by electrolysis to be injected into the local natural gas grid, supplying 100 houses with a mix of 94% natural gas and 6% hydrogen. The project aims to eventually supply the community with a mix of 80% natural gas and 20% hydrogen, without making any changes to the existing gas distribution network or home appliances. The French Environment and Energy Management Agency (ADEME) believes there is nationwide potential to deliver 30 TWh of hydrogen per year by 2035.

By 2028, France aims to be producing hydrogen at a cost of 2-3€ per kilo (\$3.30 to \$5/kg; \$28 to \$42/GJ), target prices for 2018 are around double that. This reduction in cost relies on the price of electrolyzers (on a \$/kW basis) falling from €800/kW to €400/kW by 2028.

11.3 Hydrogen in Australia

In early 2018 South Australia announced plans for a hydrogen-producing power-to-gas plant, to be built in Adelaide. This will be based on a 1.25 MW PEM electrolyser powered by excess renewable electricity and the hydrogen produced will be injected into the local natural gas network, initially at concentrations up to 15%.

A separate project based in Port Lincoln, Adelaide, will also use excess renewable electricity, to power a 15MW electrolyser. The hydrogen produced by the electrolyser will be stored for periods of low generation, when it will be burned to power a 10 MW gas turbine to produce electricity. Hydrogen not used for electricity generation will be used for fertiliser production.

A commercial-scale SMR facility has been announced for the Latrobe Valley in Victoria, where local brown coal will be gasified and reformed into hydrogen which will then be exported to Japan. The hydrogen will be mixed with natural gas and burned in specially built gas turbines to produce electricity. CCS technology will be used to minimise the carbon footprint of this process once it moves beyond the pilot phase.

A power-to-hydrogen scheme has been announced in Western Australia, where excess electricity from solar PV will be used to create hydrogen by electrolysis. This will then be injected into the gas network (details are sparse at this early stage).

11.4 Hydrogen in Germany

As of 2013 a power-to-gas scheme had been operating in Frankfurt, Germany. This is a pilot-scale operation based on a 315 kW PEM electrolyser, it operates on-demand and is powered by excess electricity when renewable generation peaks. The plant injects hydrogen directly into the local gas distribution network up to a concentration of 2%.

A network of hydrogen filling stations is currently being built in Germany, there are plans to have 100 in operation by 2019.

11.5 Hydrogen in Japan

In 2013 Japan announced that the 2020 Tokyo Olympics would be the “hydrogen Olympics”, earmarking almost NZ\$530 million for hydrogen vehicle and filling station subsidies and aiming to have the Olympic village powered entirely by hydrogen (either by grid electricity from hydrogen burning turbines or by local electricity produced by ‘Ene-Farm’ natural gas reformers and fuel cells). The intention is to leave Tokyo with a “hydrogen society” as a legacy of the 2020 games. To enable this, Tokyo aims to power the Olympic village exclusively using hydrogen-based electricity or fuel cells and to provide transport to the athletes using only hydrogen powered vehicles.

By 2020, Tokyo hopes to have 6,000 fuel cell cars and 100 fuel cell buses on the road (to give a sense of scale, the population of the Greater Tokyo area is almost 40 million), along with enough fuel cell taxis to transport the Olympic athletes between the Olympic village and venues. The vehicles will be supported by 35 hydrogen filling stations. The cost of this will be subsidised by the city of Tokyo. As of March 2018, there are 2,000 fuel cell cars on the road in Japan.

There are two key drivers for Japan’s desire to move towards a hydrogen-based power supply:

- 1) the Fukushima nuclear disaster
 - there is now a strong desire in much of Japanese society to move away from nuclear power
 - in the wake of the Fukushima event many of Japan’s nuclear reactors were decommissioned, leading to multiple power shortages and concerns about blackouts
- 2) Japan’s shortage of domestic renewable energy potential coupled with its remote island status
 - densely populated, mountainous and with a complex electricity grid, Japan’s opportunities to build renewable generation are limited
 - in order to meet its Paris agreement obligations Japan must somehow import renewable energy
 - its remote island status means that importing renewable electricity via electricity transmission lines from other countries is costly.

Japan-Australia hydrogen partnership

Kawasaki Heavy Industries (KHI) is working in Australia to set up a brown coal gasification and reformation plant to produce hydrogen, which will then be liquefied and sent by ship to Japan. In Japan, the hydrogen will be burned in special turbines to produce electricity or used in fuel cells. Kawasaki is the major participant at every stage of the process after the coal has been mined, providing hydrogen infrastructure, port facilities, transport ships and electricity generation turbines. Construction of the plant is expected to be completed by 2021⁷¹.

KHI anticipates Japan becoming a major hydrogen importer, operating a fleet of 80 hydrogen transport ships by the year 2050. These tanker ships are similar in design to LNG tankers, but with much heavier tank insulation and diesel powertrains, unlike LNG tankers which run on LNG and boil-off gases⁷². KHI anticipate that they will eventually be able to import hydrogen for a ‘landed’ price of around \$35/GJ, and at this price point the project will be commercially viable.

Initially this project was intended to have CCS systems on the hydrogen production plant, but this was deemed impractical for the demonstration phase of the project. Bringing the CCS online has

⁷¹ <http://www.abc.net.au/news/2018-04-12/coal-to-hydrogen-trial-for-latrobe-valley/9643570>

⁷² <http://www.motorship.com/news101/ships-and-shipyards/first-liquid-hydrogen-carrier>

been pushed back until the project has moved from its demonstration to its commercial phase (expected around 2030)^{73, 74}.

Japan-Brunei hydrogen partnership

A separate consortium of Japanese heavy industry majors, led by Mitsubishi, have reached an agreement with Brunei to supply Japan with hydrogen (Brunei is currently a major supplier of LNG for Japan). The hydrogen will be steam reformed from natural gas and shipped to Japan as methylcyclohexane. This project will begin its demonstration phase in 2020 and aims to supply 210 tonnes of hydrogen that year. There is no CCS associated with this supply of hydrogen.

11.6 Hydrogen in South Korea

South Korea is in a very similar situation to Japan: heavily reliant on nuclear power which it wants to move away from and with limited scope to build renewable electricity generation; it too must import renewable energy to meet its Paris commitments. South Korea is investigating the prospect of producing or importing hydrogen both for use in electricity generation and as a vehicle fuel. It is estimated that hydrogen vehicles could make up 3% of new car purchases in Korea by 2030⁷⁵. The South Korean government has announced US\$2.3bn to be invested in hydrogen technology by 2022⁷⁶, mostly in hydrogen vehicles (including buses) and refuelling stations.

Utility scale fuel cells

Currently, South Korea is one of the very few places with installed utility-scale fuel cell generation, around 300 MW as of 2018⁷⁷. These fuel cells reform natural gas then use the hydrogen to generate electricity which is supplied to urban areas around Seoul. The fuel cells are installed over several floors to maximise the MW per square metre or footprint, something which is not practical with conventional fossil fuel generation.

Minimising a facility's footprint, even at the expense of building expensive fuel cells rather than cheap fossil fuel generation, makes sense in South Korea due to the extremely high price of land. For example: property in the restricted area near the DMZ, which includes live 1950s minefields and where only residents and soldiers have access, costs upwards of NZ\$35,000 a hectare⁷⁸; in 2014 the median price for lifestyle plots in New Zealand was \$26,000/ha⁷⁹.

South Korea's 8th Electricity Supply Demand Plan calls for an expansion of utility-scale fuel cell installations, from 300 MW to 800 MW by 2022.

⁷³ <https://www.smh.com.au/business/the-economy/reality-check-on-a-half-billion-dollar-brown-coal-hydrogen-project-20180412-p4z98n.html>

⁷⁴ <https://thehub.agl.com.au/articles/2018/04/piloting-new-opportunities-with-a-hydrogen-energy-supply-chain>

⁷⁵ <https://www.hyvolution-event.com/en/south-korea-accelerating-hydrogen>

⁷⁶ <http://www.businesskorea.co.kr/news/articleView.html?idxno=23248>

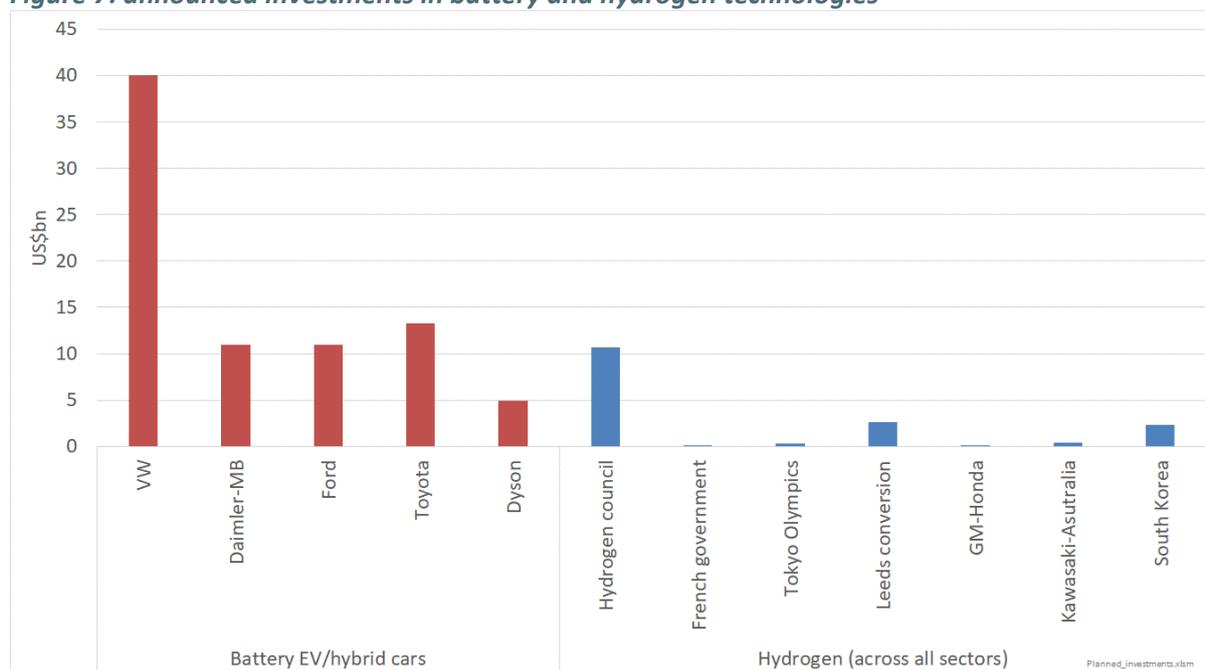
⁷⁷ <https://www.elp.com/articles/2018/08/feature-south-korea-flies-flag-for-fuel-cells.html>

⁷⁸ <https://www.nytimes.com/2007/10/05/world/asia/05dmz.html>

⁷⁹ <https://www.justlanded.com/english/New-Zealand/New-Zealand-Guide/Property/Property-Prices>

11.7 Announced investments

Figure 7: announced investments in battery and hydrogen technologies



VW is the Volkswagen group, MB is Mercedes-Benz and GM is General Motors.

This figure shows the magnitude of a selection of announced investments in battery and hybrid cars and hydrogen technology across all sectors (power generation, vehicles, gas blending etc.). All investments are within the to-2025 or to-2030 timeframe.

Figure 7 gives an illustration of where major technology investments are being made. The largest announced investment in hydrogen, by the 52-company group of the Hydrogen Council (US\$10.7bn), is smaller than the smallest announced investment in electric and hybrid cars by a single established vehicle manufacturer (Ford, US\$11bn).⁸⁰

The Hydrogen Council has estimated that to make hydrogen vehicles truly commercial by 2030 would require investments totalling US\$280bn.

⁸⁰ Dyson's electric cars are a completely new venture and a departure from their main product lines (which are vacuum cleaners and hand dryers) – as such they are not considered an established car manufacturer

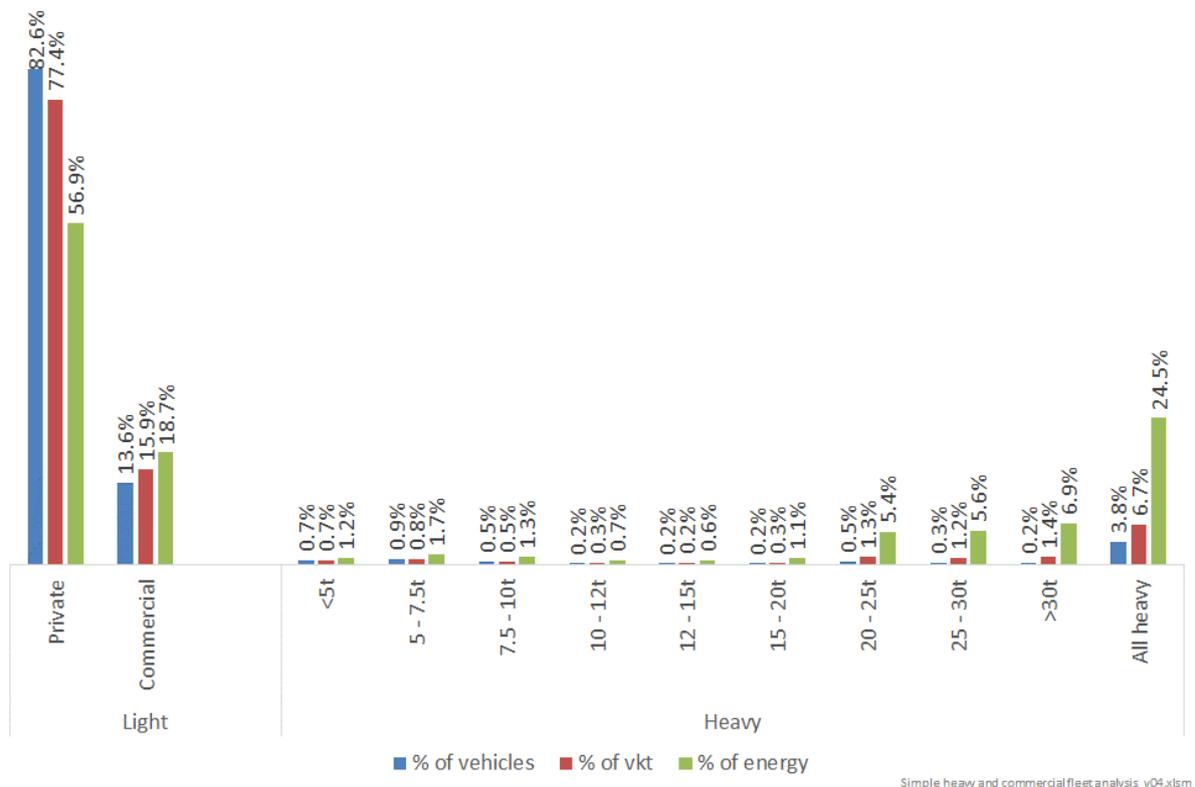
12 Analysis on heavy fleet away-from-base re-charging

Figure 8 shows a proportional breakdown of New Zealand’s land transport fleet by three key metrics:

- Number of vehicles
- Distance travelled (vkt⁸¹)
- Energy consumed

This split is between light private vehicles, light commercial vehicles, and heavy goods vehicles. This latter category is split between the different heavy goods weight classes.

Figure 8: Breakdown of New Zealand's land transport fleet⁸²

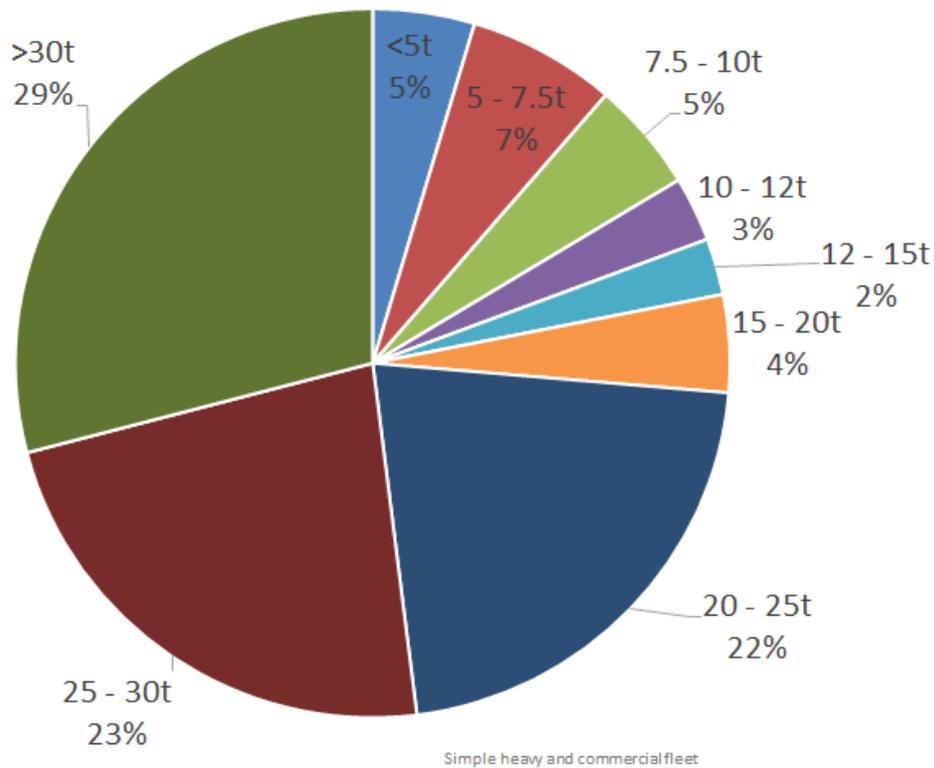


The proportion of energy just for the heavy fleet is shown in Figure 9.

⁸¹ vkt stands for ‘vehicle kilometres travelled’

⁸² This data was from a mix of different sources, of varying degrees of quality. This has required estimation to ‘fill in the gaps’ in a number of cases. Where we have done this we have tried to sanity-check through comparison with a variety of other data points to ensure the estimations are reasonable. As such, despite the data gaps, we believe the analysis provides reasonable first order approximations of the nature and scale of commercial and heavy fleet energy requirements.

Figure 9: Estimated proportion of energy consumed by weight categories within the heavy fleet

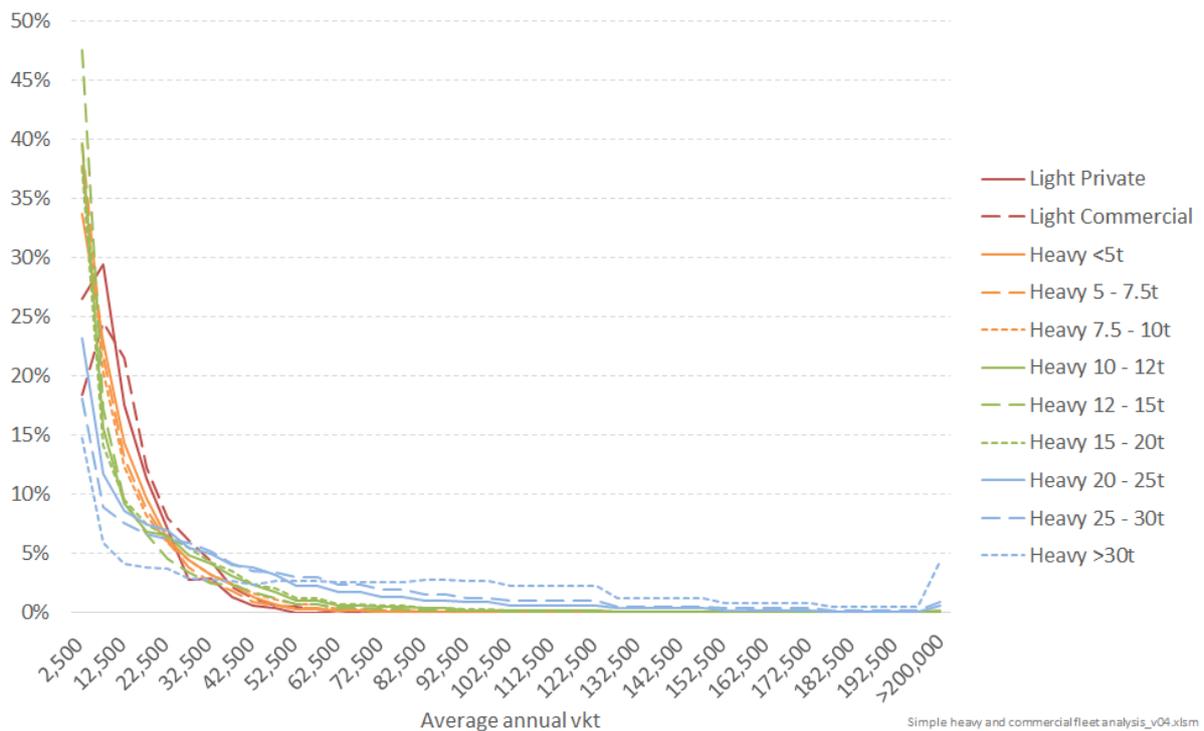


The key take-away from Figure 8 is that heavy freight vehicles – particularly the heaviest vehicles – tend to be driven a lot further per vehicle than light vehicles, and consume significantly more energy per km than light vehicles.

Figure 10 shows the distribution of travel by the different vehicle classes. Understanding such travel patterns is important as it will give insights as to

- the proportion of energy which can be supplied to vehicles by charging overnight at their ‘base’ (people’s homes for light private vehicles; office buildings, depots, factories and the like for commercial and heavy vehicles), and
- the proportion which will need to be supplied during the day, including from away-from-base charging facilities.

Figure 10: Distribution of annual distance travelled by vehicle class

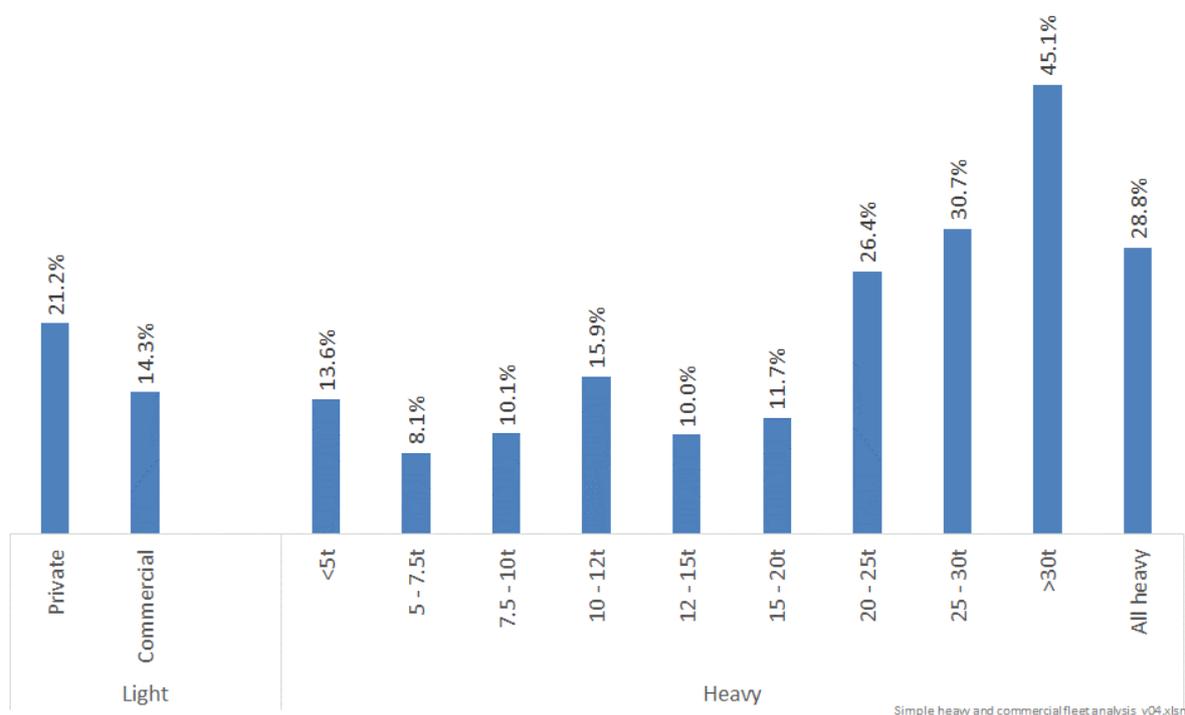


The key take-away from Figure 10 is that the heaviest vehicles tend to travel the longest distances, with some of the very heaviest vehicles travelling extremely long distances each year.

The data in Figure 8 and Figure 10 was combined in a simple model to provide a first-order approximation of what proportion of energy could be supplied overnight for each class of vehicle, and what proportion would need to be supplied 'away-from-base' during the day. This model was based on an assessment of the current ranges of EVs given current battery technology.

The results are shown in Figure 11 below.

Figure 11: Estimated proportion of energy required from day-time charging



Due to data limitations this analysis is necessarily high-level, and thus subject to some margin of error.

However, directionally it is considered that the key take-away from this analysis is sound: namely that heavy vehicles are likely to require a significant proportion of their energy from charging during the day.

As battery technologies improve, the longer range of EVs will result in significant falls in the proportion of energy required from 'away-from-base' recharging. Thus, we estimate that this 45% of away-from-base re-charging will fall to 5% in 20 years' time.

This apparently radical improvement in battery performance is in fact an estimated 75% increase in the range of heavy EVs. (i.e. 95%/55% minus 1, with 95% and 55% being the proportion of journeys undertaken on a base charge in the future and now, respectively)

Further, there are other technology initiatives which may reduce the down-time associated with EV away-from-base recharging.

- Catenary wires and pantographs are commonly used to power electric suburban trains and Siemens is developing this technology for use with trucks in Europe and North America. Intermittent wires above roads are used to recharge a small battery in electric and hybrid trucks, each charge provides enough power to make it to the next set of overhead charging wires where the battery is recharged again, and so on.
- Opportunity charging is the name given to intermittent on-the-job recharging of an electric vehicle. This takes the form of, for example, rapid charging stations at the end of bus routes where a bus can recharge for several minutes while it waits to start the return route. Each charging station provides enough power to reach the next one, so the vehicle does not need a battery capable of holding an all-day charge. Such opportunity charging stations may also be installed at sites where a truck regularly visits to unload / load.