Technological Characterisation of Hydrogen Storage and Distribution Technologies

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Executive Summary

Introduction

The suitability of each of the various hydrogen storage and distribution technologies is closely related to the nature and architecture of the kind of hydrogen future for which it is envisioned. The scale of production, centralised or distributed, and the major end use application, transport fuel or stationary power generation, are important factors in the design of infrastructure and thus the most appropriate forms of distribution and storage.

Hydrogen Storage

Liquefaction is an expensive and energy intensive process, with strong economies of scale. This implies that liquefaction would only be suitable for large centralised hydrogen production centres, and that liquefaction would only occur once per well-to-wheels cycle, making it a more favourable option where distribution and end use technologies also operate with liquefied hydrogen.

Compressed gas storage requires less energy than liquefaction, and is easily scaled down. However, it suffers from low volumetric energy density and requires relatively costly storage tanks. Increasing the pressure of the storage achieves large reductions in volume for modest increases in weight and cost, but may require more costly filling arrangements.

Bulk underground storage can be a favourable option depending on the available geology: if suitable caverns are available naturally, the capital cost is very low. Energy requirements are relatively low since hydrogen is held at lower pressures than above-ground compressed gas. It costs less than above ground compressed gas and liquid storage, it is much less sensitive to storage duration, more energy efficient, and can achieve much higher capacities. These factors confirm its suitability for large, long term storage.

Chemical hydrides have high volumetric (comparable to LH_2) and gravimetric energy densities, and have the advantage that hydrogen is readily liberated when they are exposed to water (hydrolysis).
The cost of storage is closely related to the cost of production: although producing metal hydrides will be more expensive than producing pure hydrogen, the subsequent storage and distribution will be cheaper.

Metal hydrides achieve high volumetric energy density (better than LH_2) at ambient temperatures and pressures. They are inherently safe with no danger of catastrophic leaks or runaway reactions. However, they are very heavy, and have no economies of scale in terms of weight or cost. Current filling times (~10mins) may be a problem for commercial vehicles, and their sensitivity to impurities can degrade storage performance over time.

The storage costs presented in this study range from about \$0.12 -\$4 /kg depending on the technology. Therefore storage costs range from being a minor component of hydrogen cost, if the cheapest storage technology and favorable conditions are assumed, to being several times the cost of production if cheap production is coupled with expensive storage.

Hydrogen Distribution

Hydrogen distribution by pipeline has a reasonably high energetic efficiency, although capital costs are high, and increase linearly with distance. The economics of pipelines are therefore improved with higher capacities.

Tube trailers are capable of transporting between 300-500 kg hydrogen at 20-60 MPa. Their economics are restricted by the low energy density of compressed hydrogen. Longer distances entail worse labour utilisation as more money is spent paying for trucks to return empty. However, for distances less than 200km, tube trailer delivery may be cheaper than pipeline delivery.

Liquid hydrogen tankers can carry 400 - 4,000 kg LH_2, allowing for a higher energy density than tube trailers. However the liquefaction process entails energy losses, and boil off and flash losses (rapid evaporation) can also cause efficiency problems. Costs are relatively insensitive to distance at shorter distances, but become increasingly sensitive at longer distances.

The likely costs of liquid hydrogen delivery by ship are difficult to estimate as no LH_2 tankers have yet been built. However, LNG tankers are being built with capacities of 145, 000 m3 of LNG (equivalent to about 10 million kg LH_2). Boil off could be a major problem due to the long journey times. Estimates have predicted that shipping could add $1.75-$2 to every kg of H2.

Other possibilities include transportation in metal hydrides (though bulk transport would be difficult due to heavy weight) and chemical hydrides, which could allow for transportation in liquid form.

Hydrogen distribution costs are very sensitive to distance and capacity, pipeline delivery tending to be most economical for higher throughputs, with tube trucks more viable for smaller throughputs and shorter distances, and LH2 delivery becoming more viable over long distances.

Pipelines have the advantage of offering storage and buffering capacity, however their high capital costs make investment less likely if the market for hydrogen is uncertain.
The cheapest distribution method is through high capacity pipelines which can add as little as $0.1/ kg to the price of hydrogen. Liquefaction and transportation by road on the other hand could double the price of hydrogen, depending on the production method.

Providing a Hydrogen Infrastructure

Cost figures for implementing a comprehensive hydrogen infrastructure are difficult to predict, however one recent study estimated that a coal to hydrogen infrastructure serving 10% of Ohio's vehicles would cost $1.3 billion. By comparison, upgrades to the UK's natural gas importing capacity have been assisted by private investment of more than $10 billion. It would seem that large private investments in infrastructure are not unfeasible, as long as a return can be expected on that investment. Until sufficient demand exists, infrastructure may be limited to demonstration projects typically utilising a single refuelling depot, rather than a network of refuelling stations.

1 Introduction

If hydrogen is to be adopted as a significant energy vector, it must be able to be effectively stored and transported. In particular, if hydrogen Fuel Cell Vehicles (FCVs) are to become widespread, then an infrastructure will be needed to allow vehicles to refuel. Different visions of a 'hydrogen economy' require different amounts and types of transport and storage depending on where hydrogen is produced e.g. centralised vs distributed; how it is transported e.g. pipeline vs tanker; and how it is consumed e.g. transport fuel vs stationary power generation.

Table 1.1 shows six hydrogen visions developed by PSI to accommodate the various hydrogen futures found in the literature, and to serve as a framework for further discussion and analysis (Eames and McDowall 2005). Some visions see hydrogen transported globally from countries with large renewable energy resources – requiring a large transport and storage capacity, while in other visions hydrogen is produced close to the point of demand, with the existing electricity grid or natural gas network providing the energy transport infrastructure

Central Pipeline	Hydrogen has become the dominant transport fuel, and is produced centrally from a 'mixture of clean coal and fossil fuels (with C-sequestration), nuclear power, and large-scale renewables. Hydrogen is distributed as a gas by dedicated pipeline.
Forecourt Reforming	Hydrogen produced locally from natural gas is the dominant road transport fuel. The 'existing natural gas network provides the delivery infrastructure, and hydrogen is 'generated on-site by steam methane reforming at the refuelling station.
Liquid Hydrogen	Liquid hydrogen produced by nuclear power and large scale renewable installations has become the dominant transport fuel. There is an international market in liquid hydrogen. This is largely a scenario of substitution, with current energy and transport paradigms remaining unchanged.
Synthetic Liquid Fuels	Renewably produced hydrogen again provides the dominant transport fuel. In this case, however, it is 'packaged' in the form of a synthetic liquid hydrocarbon, such as methanol, to overcome the difficulties of hydrogen storage and distribution. The carbon for fuel synthesis comes from biomass and from the flue gases of carbon-intensive industries.
Ubiquitous Hydrogen	Gaseous hydrogen is not only the dominant road transport fuel. Many buildings also use fuel cell CHP systems running on hydrogen. Distributed renewable generation predominates, reducing need for long distance transmission and distribution, and allowing hydrogen to compete directly with electricity as the main energy vector for the provision of domestic and commercial heat and power. Regional grids of hydrogen pipelines connect (predominantly local) hydrogen supplies with local needs.
Electricity Store	Hydrogen is not only the dominant road transport fuel, it also plays a vital role providing distributed energy storage to overcoming the intermittency problems of renewable electricity generation. Hydrogen is produced locally in small scale electrolysis units for forecourt refuelling and onsite storage for use in domestic and commercial CHP units at times of peak electricity demand/limited supply.

Table 1.1: Six alternative hydrogen visions (Eames and McDowall 2005)

The characteristics of the hydrogen transport and storage infrastructure are of key importance when assessing the merits of these various and competing visions of a hydrogen economy. Among the most important characteristic to consider are the safety, capacity, cost, and efficiency of the different options and for hydrogen storage, weight and volume are also important. This paper reviews the main technologies which can be used to store and transport hydrogen, focusing on costs, capacities, and energy efficiencies. It identifies key drivers of the data, such as storage time and transport distance, and also identifies key uncertainties. This can be used to inform quantitative modelling and analysis of the hydrogen visions, and inform opinions on whether or not a particular vision's infrastructure is feasible, achievable, or desirable.

1.1 Notes on methodology

Costs have been given per kg H_2, rather than per GJ[1], since this appears most often in the literature, and avoids any confusion over higher and lower heating values. Much of the data comes from Amos (1998) who used a 22-year straight line depreciation at a zero rate of return, to estimate the cost of the various technologies. Therefore this represents a storage or transport cost rather than a price which might be charged to a consumer. All numbers have been adjusted to year 2000 US dollars.

Storage costs can be expressed per unit of storage capacity ($/kg), or as a cost per unit of hydrogen stored ($/kg H_2). The latter is useful when estimating how much storage might contribute to the final hydrogen price seen by the consumer, and also for assessing how the cost of storage compares with the cost of production. However, it depends on the throughput of hydrogen over the course of the storage facility's economic lifetime: shorter storage times give higher throughput, and hence lower costs per unit of hydrogen stored.

Energy efficiencies are estimated for all technologies, as shown in Figure 1.1. For storage, it is likely that the energy needed will be provided externally i.e. as electricity. For transport, it might be the case that hydrogen is used directly e.g. taking hydrogen from a pipeline to power compressors. However, a common definition was used for consistency. The efficiency of electricity generation is not included in any estimates.

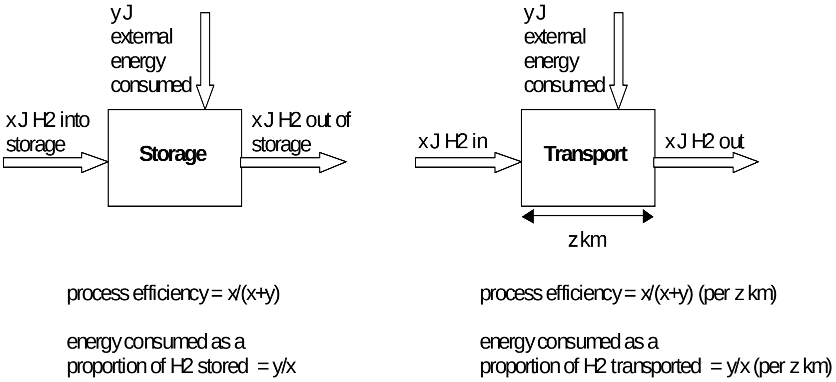

Figure 1.1: Energy requirements and efficiency of hydrogen storage and transport

Estimated or projected economies of scale can be expressed as scale factors (also called sizing exponents). For a base size s_{base}, at a base cost c_{base}, the cost of the scaled equipment, c_{scaled}, is given by:

$$c_{scaled} = c_{base} \times (s_{scaled} / s_{base})^{sf}$$

where *sf* is the scale factor. For many kinds of industrial equipment, scale factors of around 0.8 are typical (Amos 1998).

Occasionally, estimated progress ratios are given. A progress ratio describes by how much production costs decrease each time production volume is doubled. For example, a progress ratio of 0.9 implies that every time production doubles, the unit cost of production falls by 10%. For new energy technologies, progress ratios have been found to be anywhere from 0.75–0.95 (McDonald and Schrattenholzer 2001). Progress ratios should be used with caution since, if no minimum cost is specified, they will eventually predict unrealistically low costs.

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[1] 1kg H_2 = 142MJ (HHV) 1 kg H_2/hour =39.4kW

2 Hydrogen Storage

Storage may be needed at different scales: on-board vehicles, at filling stations, at production centers, and nationally as a strategic reserve. Hydrogen can be stored as a compressed gas, as a liquid, chemically combined as a compound, or physically held within structures such as metal hydrides or carbon nanofibres.

The major variable cost for most storage technologies is the energy required to get hydrogen into and out of storage. This is directly related to the quantity of hydrogen stored and is therefore easily expressed as an addition to the final hydrogen price.

2.1 Liquid Hydrogen Storage

2.1.1 General

Liquid hydrogen (LH_2) storage is currently used in industrial hydrogen demand centres such as refineries. It is produced in a central liquefaction plant and distributed to consumers by road tanker. Liquefaction plants typically have production rates between 110 - 2 300kg LH_2/h (Amos 1998 p10). Industrial consumer storage tanks typically have capacities between 110 – 5 300kg, while central liquefaction plants typically have over 100 000kg, and NASA have the largest LH_2 tank in the world which holds 228 000 kg (Amos 1998 p10).

Hydrogen's boiling point is very low: -253^{o}C (20.3K), in comparison to natural gas which is liquid at -160^{o}C (113K). This means the equipment for LH_2 storage and handling will be more expensive than for liquefied natural gas (LNG). Boil-off (evaporation) of LH_2 will always occur, no matter how well insulated the vessel is.. Boil-off rates depend on the size (surface area to volume ratio) of the storage vessel and range from 2%-3% per day for small portable containers down to 0.06% per day for large vessels, with a typical rate being 0.1% per day (Amos 1998 p23). Boil-off gas can be used immediately, vented, reliquefied, or allowed to build up pressure within the storage vessel's specified limits.

2.1.2 Efficiency

Amos (1998) gives the theoretical minimum energy for liquefaction as 11.62MJ/kg for cooling from 300K to 20K, whereas Bossel et al (2003) calculate it as 14.2MJ/kg for cooling from 298K to 20K. Bossel's figure is likely to be more accurate since it includes the energy of vapour condensation and the energy needed for a catalytic conversion stage which is essential to limit subsequent boil-off.

In practice, ideal liquefaction cannot be achieved. Amos reports existing liquefaction plants require 29-46 MJ/kg, Bossel et al (2003) reports 36-54 MJ/kg, and Drnevich (2003) reports 45-54 MJ/kg. The process efficiencies associated with these requirements are given in Table 2.1. Bossel et al (2003) report strong economies of scale, with larger liquefaction plants being more efficient.

Energy requirement (MJ/kg)	Process efficiency %
30	83%
40	78%
50	74%

Table 2.1: Energy requirements and process efficiencies for hydrogen liquefaction

Future energy requirements might be reduced to as low as 18MJ/kg with magnetocaloric cooling(Amos 1998), making the liquefaction process 89% efficient, but this technology appears to be at an early stage of research.

Any subsequent hydrogen boil-off represents a loss of liquefaction energy, and therefore detracts from the overall efficiency over time

2.1.3 Capital costs

Here the capital cost of liquefaction is regarded as a storage cost, although it could be regarded as a production cost. The major component is the liquefaction plant, which is very large relative to the cost of storage tanks. Table 2.2 shows some estimates of liquefaction plant capital costs. These are plotted in Figure 2.1, along with projected economies of scale: Amos (1998) use a scaling factor of 0.65, while E4Tech (2005) use 0.6.

Production rate kg/h	**Cost (million $)***	**Cost ($/kg/h)**	**Source**	**Quoted in**
170	21.72	128 122	Zittel and Wurster 1996	Amos (1998)
380	13.10	34 473	Taylor et al. 1986	Amos (1998)
1,500	42.13	27 796	Taylor et al. 1986	Amos (1998)
?	?	125 950	Cuoco et al. 1995	Amos (1998)
417	33.87	81 284**	B Valentin (2001)	E4tech (2005)
1042	55.91	53 674**	B Valentin (2001)	E4tech (2005)
2083	83.68	40 164**	B Valentin (2001)	E4tech (2005)
4167	126.98	30 474**	B Valentin (2001)	E4tech (2005)
6250	162.80	26 047**	B Valentin (2001)	E4tech (2005)
8333	194.49	23 339**	B Valentin (2001)	E4tech (2005)
10417	223.43	21 450**	B Valentin (2001)	E4tech (2005)

* adjusted to year 2000 dollars
** These have been estimated from the same equation, so are not independent data points
? data unavailable

Table 2.2: Hydrogen liquefaction costs

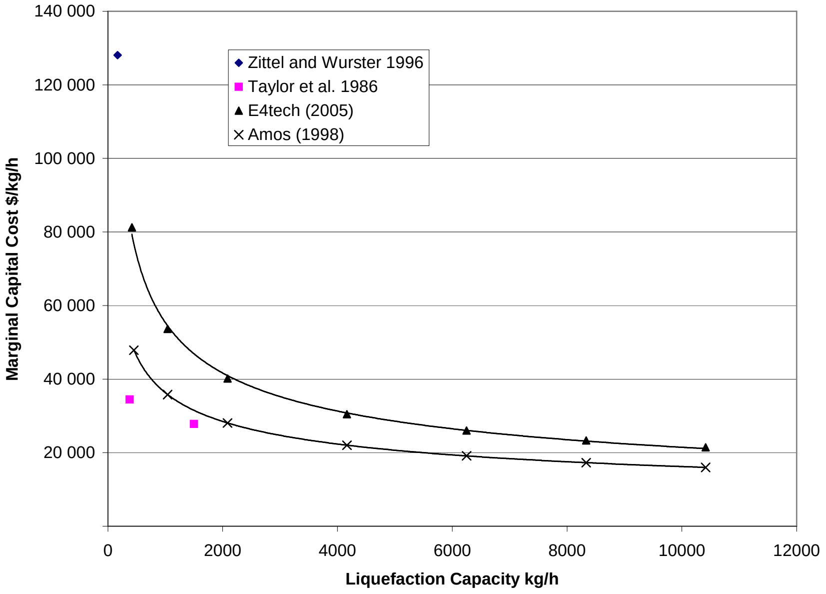

Figure 2.1: Liquefaction capital costs and projected economies of scale. The largest liquefaction plants currently in operation produce about 2 500 kg/h

Table 2.3 shows some estimated of capital costs for LH_2 storage vessels. These also exhibit economies of scale. Amos (1998) uses a base cost of $441/kg for a 45kg capacity vessel, and a scaling factor of 0.7

Size (kg)	Cost ($)*	Cost ($/kg)	Source	Quoted in
?		32 - 565	Carpetis 1994	Amos (1998)
8.9 - 890		23 - 39	Oy 1992	Amos (1998)
0.089 - 8.9		532 - 760	Oy 1992	Amos (1998)
270	130,293	489	Taylor et al. 1986	Amos (1998)
300,000	5,863,192	20	Taylor et al. 1986	Amos (1998)

* adjusted to year 2000 dollars

Table 2.3: Capital costs of LH_2 storage vessels.

Capital costs of LNG plants have declined 35-50% over the last ten years, from around $500 per tonne of liquefaction capacity to less than $200 per tonne at existing plants (EIA 2004). This is largely due to economies of scale, as well as improved plant design, and improved component technology. This suggests there may be significant potential for decreases in the cost of LH_2 plants, and supports the projected economies of scale.

2.1.4 Variable costs

The major variable cost for liquefaction is the energy cost. For different energy requirements, and electricity prices, energy costs are given in Table 2.4

Although energy costs are likely to be the major variable cost, little data exists on other components. Boil-off gas is often re-liquefied or simply vented. In both cases it represents an additional variable cost which would typically add at 0.1% to the storage cost per day of storage.

Liquefaction energy (MJ/kg)		Electricity price (p/kWh)*	Energy costs $/kg**	
low	high		low	high
30	50	3	0.45	0.76
		5	0.76	1.26
		8	1.21	2.02

*UK pence

** converted to $ using £1=1.818

Table 2.4: Energy costs under different energy requirements and electricity prices

2.1.5 Added cost to hydrogen

Figure 2.2 shows the cost liquid storage adds to the cost of hydrogen, depending on the size of the liquefaction plant.

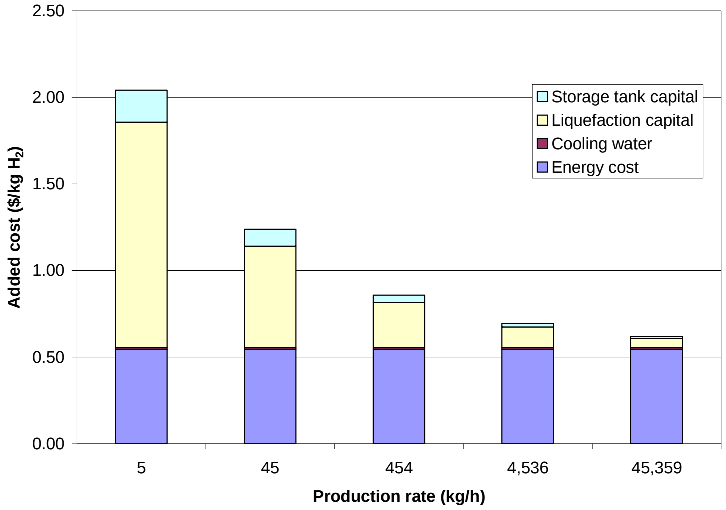

Figure 2.2: Added cost to hydrogen for liquefaction (Amos 1998). Uses electricity price of 5c/kWh, liquefaction energy 35MJ/kg.

Based on Figure 2.2, liquefaction might be expected to add $0.5 - $1.25 to the production cost of hydrogen. This would be higher if electricity were more expensive, or if the efficiency was less (Table 2.4). This is consistent with other analyses: Shwarz (quoted in Amos 1998) estimated that liquefaction added $1.2/kg to hydrogen cost, while Ogden (1999) puts the total cost of LH_2 storage between $0.7-1.4 /kg, and NRC (2004) quote a value of $0.6/kg for the added cost of liquefaction (NRC 2004),

Liquefaction is clearly an expensive and energy intensive process, with strong economies of scale. This implies that liquefaction would only be suitable for large centralised hydrogen production centres, and that liquefaction would only occur once per well-to-wheels cycle.

2.2 Above Ground Compressed gas

2.2.1 General

Compressed gas storage is widely used in the refining and chemical industry, as well as being deployed in many current fuel cell vehicle prototypes. It requires less energy than liquefaction, and is easily scaled down. However, it suffers from low volumetric energy density and requires relatively costly storage tanks. Tanks storing hydrogen at 70MPa have been designed and fabricated (DOE 2004). These high pressures achieve large reductions in volume for modest increases in weight and cost, but may require more costly filling arrangements (Cherryman et al. 2004 p49). Also, there some are safety concerns around using highly pressurised gas storage on-board domestic vehicles, and there is as yet no consensus about whether the level of safety is acceptable.

2.2.2 Efficiency

Compression requires energy, and with initial compression stages requiring the most. Bossel et al (2003) estimates that with typical multistage compressors, compression to 35MPa and 70MPa would require energy equivalent to about 8% and 11% of the HHV of the stored hydrogen. This does not consider the efficiency of the compressors themselves (Bossel, Eliasson et al. 2003), which may be as low as 40%-50% for very small compressors, between 65%-70% for typical compressors (Amos 1998) and up to 80% for state-of-the-art compressors (Drnevich 2003). Table 2.5 shows overall process efficiencies for compression (not including the efficiency of electricity generation).

Final Pressure (MPa)	Compression energy (% HHV)*	Compressor efficiency (%)		Overall efficiency (%)	
		low	high	low	high
35	7.5	60	80	89	91
70	11	60	80	85	88

* estimated from (Bossel, Eliasson et al. 2003)

Table 2.5: Compression energy required with typical compressor efficiencies. Does not account for the efficiency of electricity generation.

2.2.3 Capital costs

The two major components are the compressors and the storage tanks. Hydrogen compressors are relatively expensive due to the need to keep hydrogen free from contamination with oils and water, and the low manufacturing volumes of hydrogen compressors (Myers et al. 2002 p76). Figure 2.3 shows some reported estimates of hydrogen compressor costs, which exhibit positive economies of scale. Amos (1998) settles on a base case of $1000/kW for a 4000 kW compressor, with a scaling factor of 0.8, while Myers et al (2002 p94) predict a scaling factor of 0.75.

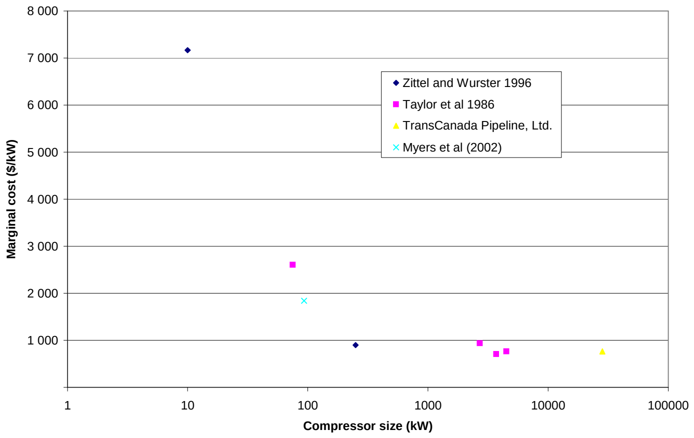

Figure 2.3: Reported estimates of compressor costs.

Costs are usually quoted per kW of compressor motor power. Relating this to a throughput of hydrogen is not straightforward, although for given inlet and outlet pressures it can be approximated by a linear relationship, Figure 2.4 (source http://www.rixindustries.com/finder_find.html). Data on higher pressures and throughputs was not available.

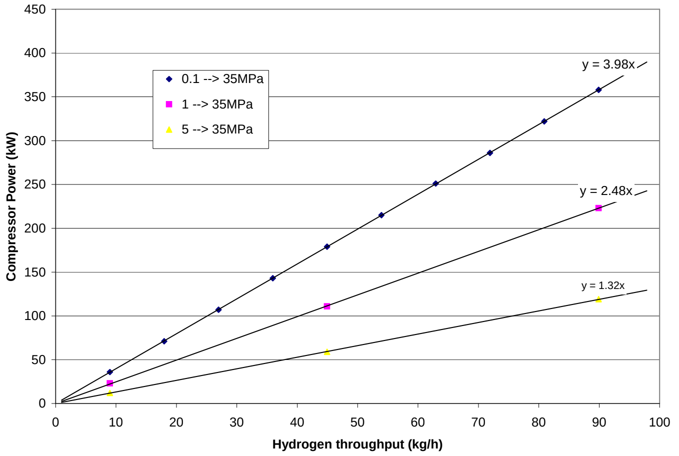

Figure 2.4: Compressor size and hydrogen throughput

Capital costs for steel hydrogen tanks are reported to be in the range \$500-\$650/ kg H_2 (Myers, Ariff et al. 2002). High-volume projections for carbon-fibre composite tanks are similar: Myers et al (2002) reports capital costs of \$300 - \$600 /kg H_2 stored, and Carlson et al (2004) estimate the cost of 35MPa and 70MPa carbon fibre tanks at \$350 and \$450 / kg, at high volume production, with 50% of this being the cost of carbon fibre. However, these are future projections and current carbon-fibre composite tanks are likely to be more expensive.

It is not clear whether compressed gas tanks have strong economies of scale: Myers at al (2002) estimate a scaling exponent of 0.95 whereas Amos (1998) use a scaling factor of 0.75.

2.2.4 Variable costs

The largest variable cost for compressed gas storage is the compression energy requirement. Using the assumptions in Table 2.5, compressing hydrogen to 70MPa would require 5.4 – 7.2 kWh/kg which, at 5p/kWh, equates to about \$0.14 - \$0.20/kg.

2.2.5 Added cost to hydrogen

Figure 2.5 shows an estimate of the total cost of compressed gas storage against storage time. Costs rise as storage time increases, since the overall throughput of hydrogen is lower. Figure 2.6 shows how the cost added to hydrogen decreases with storage capacity, since the overall throughput of hydrogen is higher.

Care must be taken when expressing storage cost as an addition to the price of hydrogen. A large component is compression energy, which may already have been counted as a production cost. Also, if the consumer purchases the storage technology - as in a vehicle - the capital cost is paid up-front, and is never amortized over a quantity of hydrogen. In other situations - for example where hydrogen is stored at a filling station or production plant - it is useful to know how much storage contributes to the end-price.

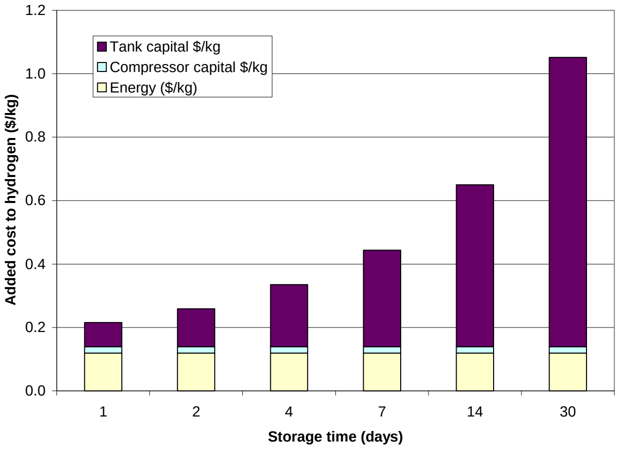

Figure 2.5: Cost of storage against storage time. Production rate fixed at 454kg/h Source (Amos 1998).

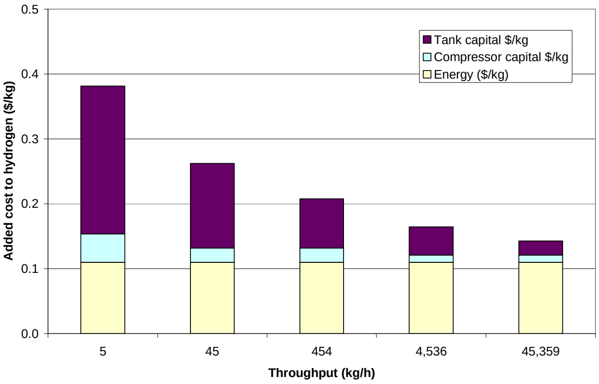

Figure 2.6: Cost of one day storage at different throughputs (total storage capacity is throughput x 24). Source (Amos 1998)

From Figure 2.5 & Figure 2.6, compressed gas storage for periods of up to one week, might be expected to add $0.15-$0.4/kg to the production cost of hydrogen. Other sources quoted in Amos (1998) gave higher costs: $0.65/kg, and $1.09-1.63/kg.

2.3 Bulk Underground storage

2.3.1 General

Bulk underground storage is widely used for crude oil and natural gas, and also for hydrogen in the chemical and refining industries. It relies on suitable geology, and requires a large cavern or porous chamber with impermeable cap rock above. Options include natural gas wells, aquifers, solution mined salt caverns, and other manmade caverns. Hydrogen is extracted by using another fluid e.g. brine in the case of salt caverns, to displace it. Extractions are generally planned in advance and happen in bulk. The UK has an active H_2 storage site at Teeside, where salt caverns have the capacity for nearly 1000 tonnes H_2 storage (Roddy 2005).

2.3.2 Efficiency

Bulk underground storage has relatively low energy requirements since it is held at lower pressures than above-ground compressed gas. Amos (1998) uses an energy requirement of around 8MJ/kg for compression to 20MPa. If no energy were needed to retrieve gas from storage, this would make the process 95% efficient. This is likely to be a conservative estimate, although no other estimates could be found for the energy penalties imposed by bulk storage.

2.3.3 Capital costs

Little data exists on the capital cost of bulk underground hydrogen storage, which strongly depend on whether a suitable cavern already exists.

Figures quoted in Amos (1998) are shown in Table 2.6. These are one or two orders of magnitude less than those for LH_2 or above-ground compressed gas storage. In their further analysis Amos settles on a capital cost of \$9.6/kg H_2 capacity. Mintz et al (2003a), apparently from 20 data points, report that capital costs roughly fit the line $y=2747x$ ($R^2 = 0.69$), where x is the working gas capacity in millions of cubic feet. At storage pressures between 0-20MPa, this equates to about \$0.9-\$1.1/kg H_2 capacity – about one tenth of the costs used by Amos (1998).

Capacity (kg)	Cost per kg capacity $*	Source	Quoted in
?	10.9	Carpetis 1994	Amos (1998)
8.9 - 890	2.7 - 7.6	Oy 1992	Amos (1998)
?	6.8 - 20.5	Taylor et al. 1986	Amos (1998)
2 000 000	31.1**	NYSEG 1996b	Amos (1998)

*adjusted to year 2000 dollars
** includes the cost of 89km of pipeline
? not available

Table 2.6: Capital costs of underground storage

If a cavern has to be mined, this raises capital costs considerably. Mining may cost around \$23/m^3 for solution mining, or \$34-\$84/m^3 for hard rock mining, depending on the depth (Taylor et al. 1986 quoted in Amos 1998 p21). This would imply capital costs one or two orders of magnitude higher than those for a pre-existing cavern.

2.3.4 Variable costs

A major component is the energy requirement for compressing the gas into underground storage and subsequently displacing and possibly boosting the pressure of gas coming back out. Amos (1998) uses a figure of 7.92MJ/kg, based on compression up to 20MPa. At 5p/kWh, this gives an energy cost of \$0.20/kg.

No estimates could be found for the other O&M costs associated with running an underground storage facility, so it is difficult to assess whether energy is the only significant component. Maintenance, monitoring and planning (when to inject or release reserves) may carry significant costs.

2.3.5 Added cost to hydrogen

Figure 2.7 & Figure 2.8 show the cost underground storage adds to hydrogen. It can be seen that energy costs dominate. Since these are directly linked to the amount of hydrogen stored, and since capital costs do not exhibit economies of scale, there is little variation with storage capacity or time. For storage times of 7 days or more, cavern capital starts to become more significant (Figure 2.8) as the hydrogen throughput over the facility’s lifetime decreases.

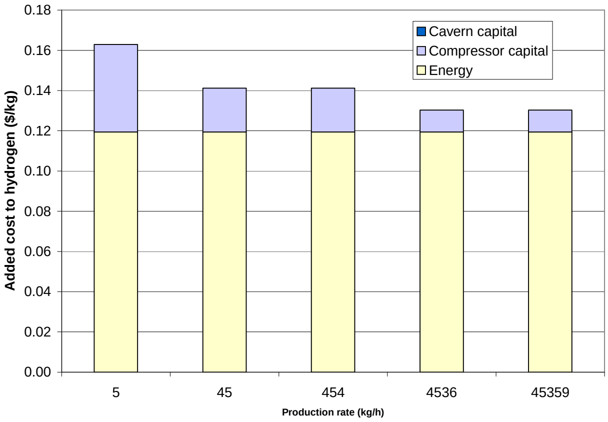

Figure 2.7: Underground storage costs against production rate

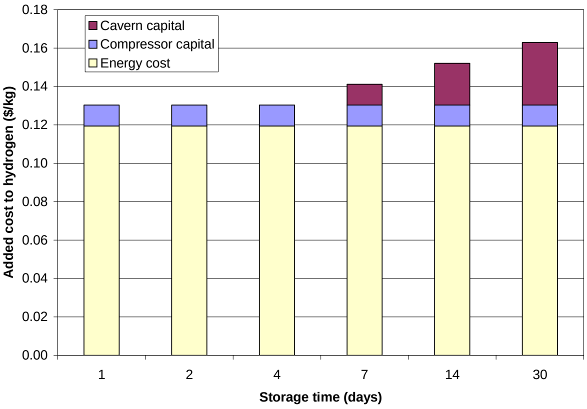

Figure 2.8: Underground storage costs against storage time

From Figure 2.7 and Figure 2.8, underground storage is likely cost $0.13 - $0.16 /kg H_2. It costs less than above ground compressed gas and liquid storage, it is much less sensitive to storage duration, more energy efficient, and can achieve much higher capacities. These factors confirm its suitability for large, long term storage.

2.4 Chemical Hydrides

2.4.1 General

Hydrogen can be stored chemically combined in a hydride such as CaH_2, LiH or $NaBH_4$ These have high volumetric (comparable to LH_2) and gravimetric energy densities, and have the advantage that hydrogen is readily liberated when they are exposed to water (hydrolysis). Some of the hydrogen is ‘stored’ in the hydride, and some is liberated from water in the reaction. Common reactions utilised are shown below:

$CaH_2 + 2\ H_2O \rightarrow Ca(OH)_2 + 2\ H_2$
$MgH_2 + 2\ H_2O \rightarrow Mg(OH)_2 + 2\ H_2$
$LiH + H_2O \rightarrow LiOH + H_2$
$LiBH_4 + 4\ H_2O \rightarrow LiOH + H_3BO_3 + 4\ H_2$
$NaBH_4 + 4\ H_2O \rightarrow NaOH + H_3BO_3 + 4\ H_2$

Hydrides are stored as slurry with a mineral oil, effectively making them a liquid fuel which can be stored in most conventional tanks. The hydrolysis reaction is highly exothermic and needs to be carefully controlled – capturing this waste heat might be possible in a CHP application, but would be difficult on-board a vehicle. Conversely, the regeneration process is highly endothermic, and is relatively inefficient and expensive. Used fuel (metal hydroxides) require high temperatures and large energy inputs for regeneration, and must be returned to a central plant for regeneration.

For chemical hydrides, it is hard to differentiate the cost of ‘storage’ from the cost of production.

Chemical hydride storage has been demonstrated at various scales from portable battery replacement to vehicle power, and is available commercially in some power-backup devices (Robson 2004). Most notable is Millenium Cell’s “hydrogen-on-demand” system, based on $NaBH_4$.

2.4.2 Efficiency

For chemical hydrides, the major energy requirement is regenerating the hydride from spent fuel (reversing the reactions shown above). Bossel et al (2003) reports that, at best, to store 1J of hydrogen as a hydride requires an additional 0.6J of high grade energy (e.g. electricity), making the process 63% efficient. This excludes the energy originally needed to manufacture the alkali metals (usually via electrolysis), and also excludes inefficiencies of electricity generation. However, the relative inefficiency of production may be balanced by greater efficiency of transport and storage, and preliminary well-to-wheels analysis suggests the overall efficiency, including 500km of transport, may be comparable with LH_2, and better than compressed gas (McClaine 2005).

2.4.3 Capital costs

The major capital costs are likely to be the regeneration plant. However, very little data exists on the likely cost of this, although it is the focus of research (DOE 2004)

2.4.4 Variable costs

The major variable cost is the energy needed for retrieving and regenerating the spent fuel. If the process were 60% efficient, then regenerating fuel which (effectively) stores 1kg of H_2 consumes 94.6MJ of high-grade energy. At prices of 3 and 5 p/kWh, this would cost \$1.4 - \$2.4 /kg. This does not include the cost of the alkali metal itself, which is also largely determined by primary energy prices.

2.4.5 Added cost to hydrogen

It is difficult to asses the 'added' cost to hydrogen, since the cost of storage is tied up with the cost of production. Although producing metal hydrides will be more expensive than producing pure hydrogen, the subsequent storage and distribution will be cheaper. One analysis estimates that chemical hydrides can be manufactured at cost between \$7/kg H_2 at annual production levels of 3.6 million kg, falling to \$3/kg H_2 at annual production levels of 9 billion kg (McClaine 2005), and it has been claimed that the cost of hydrogen from chemical hydrides can compete with gasoline (McClaine et al. 2000).

2.5 Metal Hydrides

2.5.1 General

Hydrogen can be stored within a metallic lattice such as $LaNi_5$, which forms $LaNi_5H_6$. In contrast to chemical hydrides, absorption of hydrogen (hydriding) is exothermic and requires cooling, and releasing hydrogen (dehydriding) is endothermic and requires heating. The temperature at which hydrogen is released is a property of the hydride.

Metal hydrides achieve high volumetric energy density (better than LH_2) at ambient temperatures and pressures. They are inherently safe with no danger of a catastrophic leaks or runaway reactions. However, they are very heavy, and have no economies of scale in terms of weight or cost. Current filling times (~10mins) may be a problem for commercial vehicles, and also their sensitivity to impurities can degrade storage performance over time.

Metal hydride storage has been demonstrated in applications where extra weight or limited range is not a problem. Hydrogen hydride storage canisters are commercially available for stationary power systems (see e.g. Ovonic Hydrogen) and systems have been demonstrated in mine vehicles (Jollie 2001), tractors (Motyka et al. 2003) , buses and scooters. Hydride storage was recently tested in a modified Toyota Prius hybrid (H_2 combustion engine), achieving a driving range of 200 miles (compared with 600 with gasoline), and requiring a filling time of 8 minutes (Hydrogen Forecast 2005).

Metal hydrides can be used for thermal compression, since the pressure at which hydrogen is released increases with temperature. Preliminary analysis at 35MPa indicates hydride compression could require 60% less energy than mechanical compression (DOE 2004). Metal hydrides can also be used for purification, since impurities tend to be held within the metal (they can be flushed out at a higher temperature later). This means hydrides could be used to perform combined storage, purification, and compression, which would improve their economics.

2.5.2 Efficiency

This varies considerably depending on the alloy – typical reaction energies vary between 9.3 MJ/kg to more than 23 MJ/kg H_2 (Amos 1998 p11). That is, releasing one kilogram of hydrogen from storage requires an input of 9.3 - 23MJ depending on the alloy. Conversely, this is the energy released when the alloy is hydrided, which will require cooling. However, the energy input to release hydrogen can often be provided from the exhaust of a fuel cell, and some the energy generated when storing hydrogen may be recoverable.

As a indication of efficiency, the reaction energy of MgH_2 is 14.6MJ/kg. If this is assumed to be the external energy consumed per storage cycle, the process is 91% efficient. However, this efficiency could be lower (down to 83%) if both heating and cooling are taken into consideration, or higher if it assumed that waste heat can be used. This does not account for energy needed in the manufacture of the alloy.

2.5.3 Capital costs

The major capital costs are the materials and manufacture of the alloy itself. Metal hydride storage is capitally intensive, and there are little or no economies of scale. Table 2.7 shows some estimates capital costs. These estimates span a large range of costs, reflecting the uncertainty in the cost of large-scale manufacture.

Cost/kg H_2 ($/kg)*	Source	Quoted in
1 916	Carpetis 1994	Amos (1998)
2 280 - 2 820	Carpetis 1994	Amos (1998)
65 147	Hydrogen Components inc (1997)	Amos (1998)
890 - 1 410	Oy 1992	Amos (1998)
1,520 – 1,950	Oy 1992	Amos (1998)
3,420 – 13,250	Zittel and Wurster 1996	Amos (1998)
6,520 – 23,890	Zittel and Wurster 1996	Amos (1998)
3,260 – 11,940	Zittel and Wurster 1996	Amos (1998)
2,390 – 8,900	Zittel and Wurster 1996	Amos (1998)

* adjusted to year 2000 dollars

Table 2.7: Capital cost of metal hydride storage

2.5.4 Variable cost

The major variable cost is the energy required to get hydrogen into and out of storage. However, this is difficult to cost since it depends on whether waste heat can be used for dehydriding, and on whether the heat released during hydration requires external cooling, and whether any can be recycled. As a first approximation, Table 2.8 shows how reaction energies translate into electricity costs.

Reaction energy (MJ/kg H_2)		electricity price (p/kWh)*	energy cost per half storage cycle ($/kg/)*	
low	high		low	high
10	20	3	0.15	0.30
		5	0.25	0.51
		8	0.40	0.81

*using £1=$1.818

Table 2.8: Energy costs for metal hydride storage

2.5.5 Added cost to hydrogen

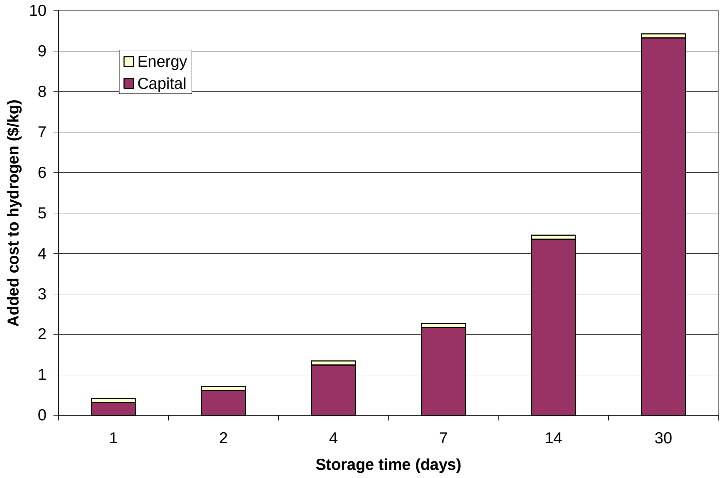

Figure 2.9: Metal hydride storage costs (Amos 1998)

Figure 2.9 shows how metal hydride storage is dominated by the capital cost of the alloy. This makes it very sensitive to hydrogen throughput, and hence storage time. Storage times above one week cost over \$2/kg H_2. For storage times of two weeks, the cost of storage is very likely to cost more than the hydrogen itself.

2.6 Other options

There are a number of other options for storing hydrogen, however most, apart from synthetic hydrocarbons, are at a relatively early stage of research.

The most important of these, and one which is not examined here, is ‘storing’ hydrogen in a synthetic hydrocarbon fuel such as methanol. Some see this as a solution to the costs and inefficiencies of hydrogen storage and distribution (Bossel, Eliasson et al. 2003). This ‘storage’ option was not examined here for due to time limitations, and because it raises enough issues to warrant an individual analysis. Methanol can be produced from a variety of primary energy sources and methods, many of which do not involve the prior production of hydrogen. Methanol can be burned, or used in Direct Methanol Fuel Cells (DMFCs), without prior reforming. For example, methanol could be produced from coal, transported via tanker, and used in DMFCs. This does not necessarily represent a “hydrogen economy”, rather a hydrocarbon economy with a different mix of primary energy sources.

Hydrogen can be adsorbed onto the surface of carbon nanofibres, and released through heating. Early results (Chambers et al. 1998) appear to have been overly optimistic, and there is a ‘mixture of excitement and skepticism’ (Davies et al. 2000) over the performance of carbon-based storage. Much research is being done, although experiments are so far confined to very small samples.

Hydrogen is liberated from ammonia when heated, making ammonia a possible hydrogen carrier. There are a number of ammonia-based hydrogen storage mechanisms. Recent interests has focused on ammonia storage in compact solid metal salts such as $Mg(NH_3)_6Cl_2$, which can provide compact solid, rechargeable “hydrogen tablets”. Recent results have reportedly exceeded US DoE goals (Strangholt 2005). However the process is proprietary, so these claims cannot be confirmed, and no data about its costs or efficiency is available. Another possibility is to store ammonia as ammonia borane (NH_3BH_3) or ammonia borohydride (NH_4BH_4), although these systems appear to be at an early stage of research.

Hollow glass microspheres have also been postured as a hydrogen storage mechanism. When heated they become porous to hydrogen, and so, if immersed in an atmosphere of pressurized hydrogen and then cooled, pressurized hydrogen is trapped inside. Again, this technology is at a relatively early stage of research, and efforts are underway to improve the uptake and release rates of hydrogen.

2.7 Summary and Discussion

Table 2.10 summarises the advantages and disadvantages of different hydrogen storage technologies.

The key drivers are storage time, storage capacity, and energy requirements. Storage time determines hydrogen throughput – shorter storage times mean higher throughput and hence lower costs per unit of hydrogen stored. Larger capacity storage can benefit from economies of scale, provided there are economies of scale in the underlying technology. Energy requirements are directly related to the amount of hydrogen stored, and therefore do not vary with storage time or capacity. Reducing the energy costs would rely on increasing the efficiency of storage, or utilizing cheap energy.

The most suitable storage option will depend on situation specific factors including the final application, the amount of storage required, the amount and type of energy available, the geology of the area, and the amount of capital available (Amos 1998 p24).. Although all those factors contribute, some generalisations can be made for current technology (Amos 1998 p27).

Underground Storage	For large quantities of gas or long-term storage.
Liquid Hydrogen	For large quantities of gas, long-term storage, low electricity costs or applications requiring liquid hydrogen.
Compressed Gas	For small quantities of gas, high cycle times or short storage times.
Metal Hydrides	For small quantities of gas.
Chemical Hydrides	For small quantities of gas, or where a premium can be paid for high energy density

Table 2.9: Most suitable hydrogen storage option. Adapted from Amos (1998)

It is difficult to compare the cost of storage with the cost of hydrogen production, since both vary depending on the situation. However, storage costs presented here range from about \$0.12 -\$4 /kg depending on the technology. Hydrogen production costs from large scale SMR or coal gasification, which are the cheapest routes to hydrogen, might be around \$1/kg. Therefore storage costs range from being a minor component if the cheapest technology and favorable conditions are assumed, to being several times the cost of production if cheap production is coupled with expensive storage. However, hydrogen produced from electrolysis, it might cost between \$4 and \$10, and storage is likely to be a minor (though significant) component of hydrogen cost.

	Bulk Underground storage	**Liquid**	**Compressed gas**	**Metal Hydrides**	**Chemical Hydrides**
Advantages	Large capacities (millions kg) Long times (months, years) Lowest capital cost if suitable cavern exists Low O&M cost	Better energy density than compressed gas Low storage vessel costs Strong economies of scale	Simple capital equipment (compressors) Modular Easily scaled down	Good volumetric energy density at ambient temperature and pressure. Safe - no risk of catastrophic leaks Can also be used to purify and pressurise	High energy density Stable if kept away from water Easy to store and transport
Disadvantages	Requires pre-existing caverns, otherwise more costly Not suitable for small amounts of short-term storage	Very low temperature (20K) High capital cost of liquification plant Large energy requirement for liquification Boil off	Low energy density Higher capital cost of tanks than liquid storage Safety concerns for on-board storage	Heavy High capital costs No economies of scale	Spent fuel requires recyling Energy intensive manufacture Controlling some reactions is difficult High cost of manufacture
Suitable for	Large quantities of gas, or long-term storage	Large quantities of gas, long-term storage, or applications requiring liquid H2	Small amounts of gas, short cycle times	Small quantities of gas	Applications where high energy density is valued and primary energy available
Capacity (kg)	10,000 - 1,000,000	100 – 200, 000	0 – 1,000	Weight, volume and expense limited 0 – 100	
Efficiency	85 – 95	70 – 80	85 – 90	85 – 90 (uncertain)	60 – 65 **
Added cost to hydrogen* $/kg	\$0.12 - \$0.30	\$1.00 - \$1.50	\$0.15 - \$0.60	\$0.40 - \$4.0	\$1.5 - \$2.5 **
Major cost components	Energy (90%)	Energy (50%), Capital (50%)	Energy (25 - 50%), Tanks (25 - 75%)	Metal (95%)	Energy
Scaling Factor	1	0.6 - 0.65	0.80 - 0.95	1	1

* these figures depend on capacity and storage time, and it is difficult to give a single range
** includes some energy and costs which would be regarded as production

Table 2.10: Characteristics of different hydrogen storage technologies

3 Hydrogen Distribution

This section examines the characteristics of the technologies which can be used to build a hydrogen distribution infrastructure, focusing on pipelines, ‘tube trailers’ carrying compressed gas, and road tankers carrying liquid H_2. Data on the costs and efficiencies is presented, and major driving factors such as capacity and delivery distance are examined.

3.1 Pipeline

3.1.1 General

Hydrogen is delivered by pipeline in several areas of Europe, the US and Canada. The longest European pipeline is 400km long, from northern France to Belgium, while the UK has about 30km of hydrogen pipeline in the Tees Valley (Roddy 2005).

It is possible that the existing natural gas infrastructure could be used to carry hydrogen, either pure or in a mixture with natural gas (Hythane™). The original gas infrastructure in the UK was developed to carry town gas, a mixture of hydrogen and carbon monoxide, derived from coal. However, in certain circumstances hydrogen can induce cracking in steel pipelines, it may react with lubricants and seals, may require different compressors, and may permeate plastic pipelines (IEA 2002). Due to these reasons, it is not clear how much investment would be needed to allow the existing infrastructure to hydrogen or various grades of Hythane™. Investigating this is a major aim of the European NATURALHY project (http://www.naturalhy.net/).

As well as transport, pipelines can provides some storage capacity since the pressure of gas in the pipeline can be increased above what is needed to meet the immediate demand (known as line-pack). It has been estimated that in the UK, line pack provides about 26 million m^3 of natural gas storage, slightly more than the amount held in low-pressure gas holders, and adequate to meet about 45% of the UK’s diurnal storage requirement. (National Grid 1998).

3.1.2 Efficiency

Pipelines are the most energy efficient way to transport large amounts of hydrogen. Energy is supplied by compressors spaced along the pipeline – for natural gas these are usually powered by gas engines supplied from the pipeline itself, or by electricity.

The energy requirements depend on the desired hydrogen throughput, which is mainly determined by the inlet and outlet pressures and the pipeline diameter. Due to its lower energy density, it is estimated that to transmit 1J of hydrogen requires between 3 to 4 times the energy needed to transmit 1J of natural gas (Ogden 1999; Bossel, Eliasson et al. 2003), and Bossel et al (2003) estimate that pipeline transmission consumes 0.77% of the H_2 (HHV) per 100km traveled, an efficiency of 99.3% per 100km. However, they do not consider that dedicated hydrogen pipelines would be designed with larger diameters than equivalent natural gas pipelines, nor do they consider the possibility of using efficient fuel cells to power the pipeline compressors (although no studies have been done to assess whether this would be cost effective).

By comparison, High Voltage DC (HVDC) electricity transmission loss is estimated at 0.4 - 0.6% per 100km (Mazza and Hammerschlag 2004 p13). However, further losses occur in transformer substations and in the low-voltage distribution system. In the UK, total losses are estimated to amount to about 1.5% of overall demand (DTI 2003). It seems that hydrogen distribution by pipeline and electricity distribution may have broadly similar energy requirements.

3.1.3 Capital costs

Estimates for hydrogen pipelines are based on reported costs of natural gas pipelines. These depend on the pipeline diameter, the terrain, and the degree of urbanisation (not often reported with the estimate). Total length does not appear to be important for unit length costs (Mintz et al. 2003b). Table 3.1 shows some capital cost estimates found in the literature for natural gas pipelines, and Figure 3.1 shows cost against diameter for pipelines whose diameters are known.

Diameter Inches	**Cost /km ($/km)***	**Source**	**Quoted in**
?	257 329	TransCanada Pipeline, Ltd. 1996	Amos (1998)
?	840 391	TransCanada Pipeline, Ltd. 1996	Amos (1998)
?	1 085 776	TransCanada Pipeline, Ltd. 1996	Amos (1998)
?	1 357 220	TransCanada Pipeline, Ltd.1993	Amos (1998)
?	743 757	TransCanada Pipeline, Ltd. 1997	Amos (1998)
?	143 322	NYSEG 1996	Amos (1998)
?	337 351		Ford (1997)
3	180 000		Mintz et al (2002)
9	420 000		Mintz et al (2002)
12	540 000		Mintz et al (2002)
24	690 000		Mintz et al (2002)
3	99 339**	Oil and Gas Journal	Mintz et al (2003)
6	198 679**	Oil and Gas Journal	Mintz et al (2003)
9	298 018**	Oil and Gas Journal	Mintz et al (2003)
12	397 358**	Oil and Gas Journal	Mintz et al (2003)
24	794 715**	Oil and Gas Journal	Mintz et al (2003)
36	1 192 073**	Oil and Gas Journal	Mintz et al (2003)
3	422 879***	Oil and Gas Journal	Parker (2004)
6	456 105***	Oil and Gas Journal	Parker (2004)
9	496 871***	Oil and Gas Journal	Parker (2004)
12	545 177***	Oil and Gas Journal	Parker (2004)
24	813 800***	Oil and Gas Journal	Parker (2004)
36	1 203 066***	Oil and Gas Journal	Parker (2004)

? data not known
* adjusted to year 2000 dollars
** based on regression equation presented in Mintz et al (2003)
*** based on regression equation presented in Parker (2004)

Table 3.1: Capital cost estimates of natural gas pipelines

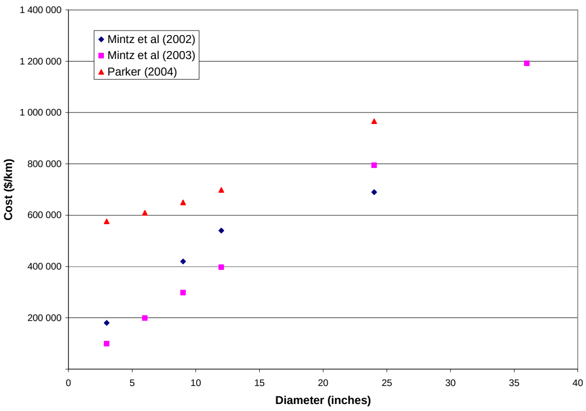

Figure 3.1: Construction cost against diameter for natural gas pipelines.

Pipeline costs are composed of labour (~45%), followed by materials (~26%), right-of-way costs (~22%) and other miscellaneous costs such as planning and management (~7%) (Parker 2004).

Multipliers are often used to estimate hydrogen pipeline costs from natural gas pipeline costs. For example, Parker (2004), estimates labour will be 25% more expensive due to the need for special welding, while material costs will be 50% more expensive. Ogden (1999) suggests that overall capital costs of hydrogen pipeline will be 40-50% higher than natural gas pipelines. However, these numbers are provisional.

3.1.4 O&M costs

Few estimates exists for the O&M costs a hydrogen pipeline, although the major component will be the energy consumed moving hydrogen through the pipeline. As noted, this could be 3-4 times higher than for natural gas, although Amos (1998) found that O&M costs were very small compared to the capital costs of pipelines.

If Bossel's estimate of 0.77% H_2 HHV consumed per 100km is reasonable, and hydrogen were used to power the pipeline compressors, then energy costs would amount to about 0.77% of the value of the hydrogen for every 100km of pipeline. Alternatively, if grid electricity were used to power pipeline compressors, energy costs would be around $0.03/kg/100km (assuming 5p/kWh and 80% compressor efficiency). This is similar to other estimates which put the O&M cost of piping hydrogen between $0.03 - $0.06 /kg/100km (Amos 1998; Ogden 1999).

3.1.5 Added cost to hydrogen

Capital and O&M costs are aggregated over a pipeline's lifetime throughput to calculate the final costs which pipeline transmission adds to hydrogen i.e. the price a pipeline operator would have to charge to break even over the investment period. This depends strongly on the length (which determines capital costs) and capacity (which determines capital costs and throughput) of the pipeline. Although wider diameter pipelines are more expensive, this is more than compensated for by their extra capacity.

Figure 3.2 shows how the added cost to hydrogen decreases with increasing pipeline capacity (note that both scales are logarithmic – ie its not a linear relationship). By comparison, a major natural gas transmission pipeline might carry more than 1 million kg per hour (National Grid 2005b)

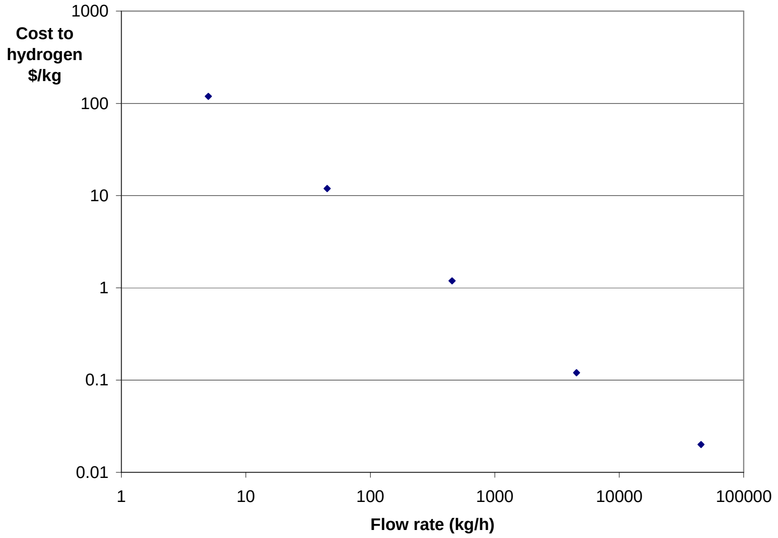

Figure 3.2: Cost of pipeline transmission at different flow rates (Amos 1998). In this case delivery distance is fixed at 161 km (100 miles). 100kg H_2/h = 3.9 MW (HHV)

Figure 3.3 shows how costs increase linearly with distance. The implication of this is that longer pipelines are only feasible for high capacities. In practice high capacity lines would connect major demand and population centres, with smaller pipeline radiating out to end users

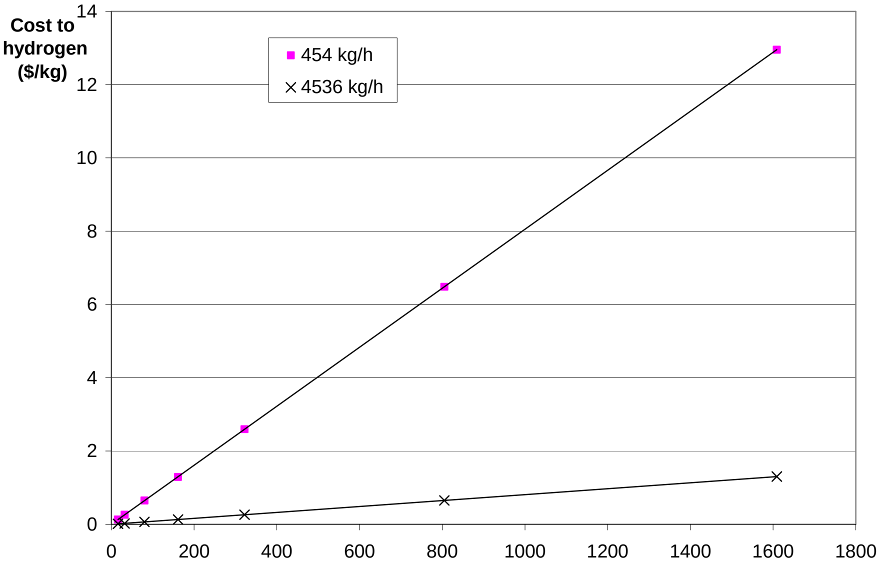

Figure 3.3: Cost of pipeline delivery with distance at different pipeline capacities. (Amos 1998)

3.2 Tube trailer

Tube trailer deliveries are currently used to transport hydrogen to smaller industrial customers, where LH2 is not available or feasible. They consist of several steel cylinders mounted to a protective framework, and can carry between 60-460 kg at 20-60 MPa (Amos 1998). A typical trailer might carry 300kg of hydrogen (Drnevich 2003; Castello et al. 2005), which represents about 1% of the total mass of the truck (Cherryman, Maddy et al. 2004 p127).

3.2.1 Efficiency

In their analysis, Bossel et al (2003) assume full trucks carry 500 kg H_2 (to allow for future improvements in truck design) and deliver 400 kg to consumer's vessels, returning the residual gas to the depot. For a delivery distance of 100km, 57GJ of hydrogen is delivered and 3.56GJ of diesel is consumed. This gives an efficiency of 94% over 100km, compare to 99.3% for a pipeline, and is estimated to be 33 times the energy required to deliver gasoline over the same distance (Bossel, Eliasson et al. 2003). After accounting for the extra efficiency of fuel cell vehicles, it is still estimated that 15 times the number of trucks would be needed to service the same number of vehicles.

3.2.2 Capital costs

Tube trailer capital costs depend on the operating pressure of the truck, and the storage capacity of each trailer. Few estimates are available: Amos (1998) found an estimate of a $450 000 for cab and trailer capable of carrying 460 kg of hydrogen. Recent analysis by the US DoE uses a total cost of $300 000 for a cab and trailer (DOE 2005).

3.2.3 O&M costs

The major component is driver labour, which depends on delivery distance. Longer journeys have worse utilization of labour since more money is spent paying for trucks returning empty

3.2.4 Added cost to hydrogen

Figure 3.4 shows one analysis of the cost of tube trailer delivery. As delivery distance increases, the return journey time of each truck increases, and both capital and labour are under utilised. Also, there are no economies of scale, since delivering more hydrogen requires more trucks, and the capacity of a single truck is limited by physical constraints.

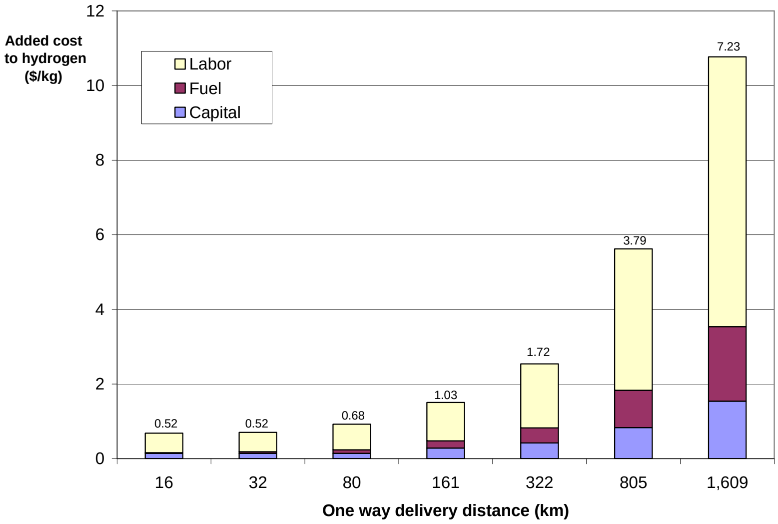

Figure 3.4: Cost of tube trailer delivery with distance (Amos 1998). Overall throughput constant at 45kg/h

From Figure 3.4, it can be seen that for distances less than 200km, tube trailer delivery may be cheaper than pipeline delivery, depending also on throughput.

Higher estimates were made by Ogden et al (2005), who put the levelised cost of tube trailer delivery at $2.5 /kg for a 100km plant-to-pump journey.

3.3 LH_2 Road Delivery

3.3.1 General

Liquid hydrogen delivery by road is widely used in the chemical and refining industries, since more hydrogen can be delivered per vehicle than with tube trailers. Tank trucks can carry between 400 – 4,000 kg LH_2 (Amos 1998 p23), a factor of ten more than tube trailers. LH_2 can also be carried by rail, in cylindrical tanks with capacities of around 9000kg (Amos 1998). Boil-off can be a problem, which typically runs at 0.3 - 0.6%/day (Amos 1998 p33; Castello, Tzimas et al. 2005), although road deliveries taking more than one day would be very rare in the UK. Flash losses (rapid evaporation) when transferring from a high pressure vessel to a lower pressure one can be high: between 10-20%, and possibly up to 50% (Amos 1998), although this can be reduced if LH_2 is transported at atmospheric pressure (Sherif et al. 1997), although with presumably some loss in carrying capacity.

The most significant costs for LH_2 transport is the cost of liquefaction. This is studied in the storage section, but must be considered if a fair comparison is to be made between distribution options.

3.3.2 Efficiency

Bossel et al (2003) assume a 30 tonne road tanker delivers 2,100 kg of LH_2 to customers, and consumes 40kg of diesel per 100km when full, and returns empty to the depot. On a 100km (200 km round trip) delivery, 298GJ of hydrogen is delivered and 2.59 GJ of diesel is consumed, an efficiency of 99% per 100km. This compares to 94% for tube trailer, and 99.3% for pipeline. This is estimated to require about 4.5 more energy than gasoline delivery and, after accounting for the extra efficiency of fuel cell vehicles, require about 3 times the number of delivery trucks are required to service the same number of vehicles (Bossel, Eliasson et al. 2003)

However, this does not include the efficiency of the liquefaction process which is about 75-80%.

3.3.3 Capital costs

Few estimates are available for the capital costs of an insulated LH_2 truck. Berry (1996) finds an estimate of $400 000, or $122/kg LH_2 capacity. The H2A model (DOE 2005) uses a cost of $800,000 or $200/kg LH_2 capacity, and Castelolo et al (2005) quote a figure of $530 000 for an unspecified size.

These do not include the liquefaction capital costs, which might amount to $0.1- $1.0/kg LH_2 (Figure 2.2)

3.3.4 Variable costs

For road delivery, variable costs include fuel, driver/crew, and any boil off and transfer losses. Few estimates could be found, and Amos (1998)estimated that variable costs were generally small compared with capital costs (Figure 3.5).

3.3.5 Added cost to hydrogen

Figure 3.5 shows the cost of road delivery of LH_2. This does not vary with overall throughput, since each tanker carries a fixed amount. Costs are relatively insensitive to distance at shorter distances, but increase once the distance becomes large enough (i.e. long enough journey time) that extra trucks are required to maintain the same throughput.

The numbers in Figure 3.5 are consistent with an estimate by Ford, of $0.55/kg to deliver LH_2 800km by tanker truck, including the capital recovery and driver labour (Ford 1997 p11).

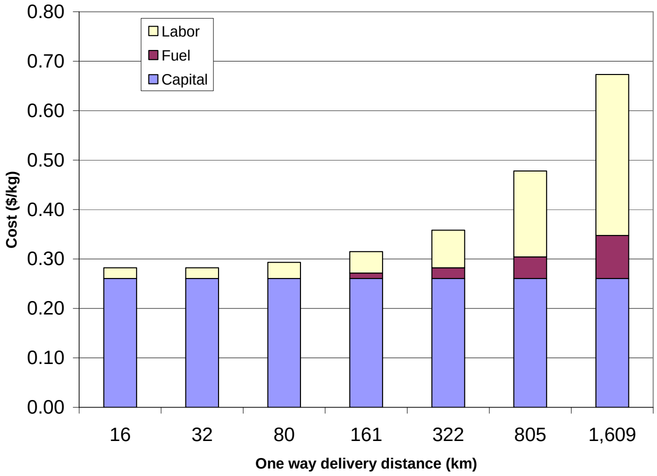

Figure 3.5: Cost of liquid delivery by road tanker. Source: (Amos 1998). Throughput is fixed at 45kg/h

However, this does not include the cost of liquefaction (§2.2.3), which outweighs any of the transport components. A the (low) throughout of 45kg/h, liquefaction would add $1.23 to the hydrogen delivery cost, or $0.7/kg at a higher throughput of 4,500kg/. This is reasonably consistent with Ogden et al (2005) who put the levelised cost of LH_2 delivery, including the costs of liquefaction, as $1.2 – 1.6 /kg over 200 km.

3.4 LH_2 Delivery by Ship

3.4.1 General

LH_2 could potentially be transported internationally by or ship, as is done increasingly for Liquefied Natural Gas (LNG). No LH_2 tankers exist, but LNG tankers are being built with capacities of 145,000 m^3 of LNG (equivalent to about 10 million kg H_2), and ships with capacities up to 240,000 m^3 are under study (EIA 2004). Canada is reported to have some designs for LH_2 ships carrying up to 14 million kg LH_2, (Amos 1998 p33). Boil off can be a problem since journey times are longer. For large vessels, boil-off rates might be 0.2 - 0.4% per day (Amos 1998 p33). Re-liquefaction on board ship is currently not feasible due to the large refrigeration plant needed, and boil off in LNG ships is usually used to supplement fuel for the carriers.

3.4.2 Efficiency

No estimates were found for the efficiency of LH_2 delivery by ship.

3.4.3 Capital costs

Predicted costs for hydrogen barges might be estimated from LNG ships, although Amos (1998) expects a hydrogen ship to cost 3.5 – 4 times as much as an LNG ship, probably due to the lower temperature of operation and the lack of experience in building them. If LH_2 ships were to become widespread this gap might reduces due to economies of scale and learning effects.

Costs of LNG ships are difficult to estimate, since most are owned and run by the gas producing companies themselves. The Gas Technology Institute estimates that the average price of a 138,000m^3 ship (equivalent to about 9.8 million kg LH_2) in November 2003 was US$155 million, down from a peak of US$280 million in the mid-1980s (EIA 2004), mainly due to economies of scale, learning effects, and increased competition between producers.

3.4.4 Variable costs

Likely O&M costs for LH_2 ships are unclear. Charter rates for LNG tankers (which will include capital recovery) vary widely from as low as $27,000 per day to as high as $150,000 with the average long-term rate between $55,000 and $65,000 per day (EIA 2004).

3.4.5 Added cost to hydrogen

Amos predicts shipping hydrogen adds between $1.75 – $2.00 per kg H2 to its cost, 80% of which is freight charges and the rest is capital of the container. Another source quoted in Amos (1998) estimates long-distance transportation of liquid hydrogen from Africa to Europe costs $1.80- $2.10/kg, while another is quoted as stating that shipping LH_2 across the Atlantic would triple its price (Oy 1992). (Amos 1998 p35). However, these estimates are uncertain since no hydrogen ships have been built.

3.5 Other Options

Hydrogen could be transported in metal hydrides. The major capital costs would be the metal hydride, which once filled, could be shipped or trucked like conventional freight (Amos 1998 p36). However, given very high weight and currently very high capital cost of metal hydrides, this is unlikely to be adopted for the bulk transport of hydrogen.

Chemical hydrides could be used to transport hydrogen. If the hydride is held as a slurry with oil, it can be pumped and trucked or even piped like a liquid fuel. Spent fuel would also have to be transported back for regeneration. This has not been analysed here due a lack of data on costs or feasibility, although it is a possibility.

3.6 Summary and Discussion

The characteristics of hydrogen transmission technologies are summarised in Table 3.2. The main point to note is that costs are very sensitive to distance and capacity. Previous research has shown that the least cost option depends on distance and capacity, as shown in

Figure 3.6. A similar result was reported by (Shayagan et al. 2005).

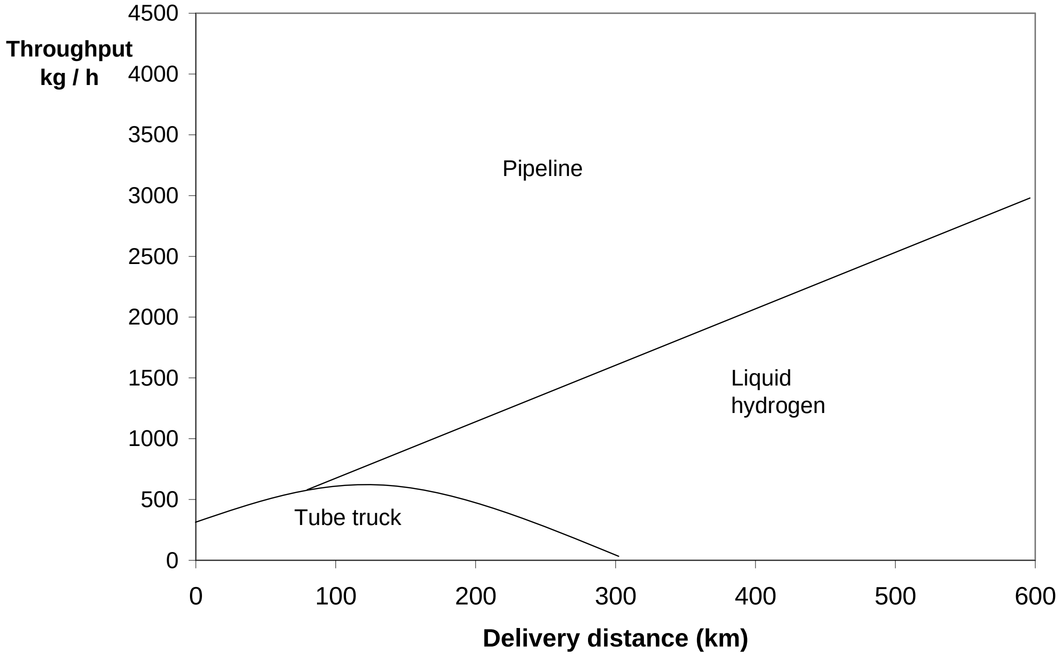

Figure 3.6: Least cost options with distance and capacity. Data from (Yang and Ogden 2004)

However, Figure 3.6 is based only cost, not practical considerations. For example, delivering 500 kg/h by tube trailer would require more than one truck delivery per hour. Simbeck and Chang (2002) suggest tube trailer delivery is suitable up to capacities of up to about 13 kg/h, and LH_2 trucks are suitable up to 1000kg/h, while pipelines can deliver up to 100 000kg/h.

Also pipelines offer a storage and buffering capacity, and their useful lifetime is likely to be longer than their investment lifetime, so companies might see investments in pipelines as strategic. However, the high capital costs of pipelines makes investment less likely if the market for hydrogen is uncertain. Decisions on the mode of transport are linked to the mode of storage, for example if both the producer and consumer are using liquid storage, then it makes sense to transport hydrogen as a liquid.

Comparing distribution costs with the cost of production is difficult since both vary depending on the pathway and technology. The cheapest options for producing hydrogen (large scale fossil fuel routes) might cost around \$1/kg. The cheapest option of transporting hydrogen is by high capacity pipeline, which can cost less the \$0.1/kg over 100km. However, if hydrogen is liquefied and transported by road, the cost is likely to be over \$1/kg – possibly more than the cost of production. Hence the costs of hydrogen transport are a significant factor when analysing the cost of hydrogen.

	Pipeline	**Liquid (road)**	**Liquid (ship)**	**Tube trailer**
Advantages	Large volumes	Higher volumes than compressed gas	Could allow international transport	Can be deployed at small scales
	High efficiency	High efficiency	Very high volumes	
	Also provides storage and buffering			
	Low variable cost			
Disadvantages	Capital intensive	Expense and inefficiency of the liquefaction process	No experience of LH2 shipment	Small deliveries per truck
	Needs large volumes of hydrogen to justify pipeline costs	Boil off losses	Not feasible until large supply and demand exists	Energy inefficient
	Required volume increases with distance	Increases road traffic	Boil off losses are more significant than road	Can't handle large capacities
				Increases traffic
Suitable for	Large and very large quantities of gas	Large quantities of gas	Very large quantities of gas	Small quantities of gas
	Where pipeline storage is used	Where liquid storage is used	International transport	Small distances
Capacity	Up to 100 000 kg/h (3.9GW)	Up to 4000kg per truck	Potentially 10 million kg per shipment	Up to 400kg (delivered) per truck
Capital costs	$200,000 - $1,000,000 /km	$300,000 - $400,000 per truck	$155 million for LNG barge	~$300,000 per truck
O&M costs	$0.1 - $2.0 per kg H2 or more depending on distance and capacity	$0.3 / kg H2 (excluding liquefaction plant)	could be 3-4 times higher for LH_2 barge	$0.10 - $0.40/ kg
	Energy costs of pipeline compressors	Driver labour @ ~ $18 /h	Crew labour and fuel	Driver labour
	~$0.03 /kg	$0.02 - $0.20 /kg	Uncertain	$0.5 - $2.0 / kg
Total cost $/kg/100km	$0.10 - $1.00	$0.3 – $0.5	$1.8 - $2.0	$0.5 - $2.0 / kg
Energy required	Pipeline compressors	Transport fuel	Transport fuel	Transport fuel
Efficiency	99.2% per 100km	99% per 100km for transport	fuel use unknown	94% per 100km
		75% efficiency of liquefaction.	boil-off 0.3% per day	

Table 3.2: Characteristics of major hydrogen distribution options

4 Providing a Hydrogen Infrastructure

It has been shown here that hydrogen storage and transport costs vary significantly depending on the technology used, and factors such as throughput and delivery distance. However, looking at costs, capacities and efficiencies does not address the question of whether, or how, an infrastructure might develop in the face of uncertain future hydrogen demand. High capacity options such as large pipelines may be the cheapest options, but are unlikely candidates until significant and certain hydrogen demand exists. If hydrogen could be injected into existing natural gas pipelines, this would dramatically reduce the distribution costs by pipeline, and make them suitable over a much wider range of hydrogen capacities.

There is much speculation on the overall investment needed to build a hydrogen infrastructure serving a country or region. For example Mintz et al (2002) reports that infrastructure to serve 40% of the US light duty vehicle fleet could cost '$500bn or more', while IPTS speculate that enabling 20% of European fuelling stations to dispense hydrogen might cost about €20bn (IPTS 2004). While these estimates are useful to get an idea of the magnitude of overall investment needed, they amplify many uncertainties and are misleading by suggesting that the building and investment will be made in one stage. It is more realistic that any investment would be made in stages, dictated by the success or failure of previous investments and the current and projected demands for hydrogen. Therefore smaller scoped estimates may be more useful at this stage, for example Ogden et al (2005) estimate a coal-to-hydrogen infrastructure serving 10% of Ohio's vehicles (380 000 vehicles) would cost $1.3 billion.

Also, when faced with these seemingly large figures, it is useful to consider investments made in existing infrastructures, such as the UK's gas infrastructure. The current program of replacing iron pipes with polyethylene is expected to cost $3.4bn per year over the next eight years (National Grid 2005a). Upgrades to the UK's gas importing capacity have seen private investments of up to $10bn for pipelines from continental Europe. This demonstrates that if both supply and demand exist, then large private investments in infrastructure can and will be made. The critical factors are not the absolute size of the investment, but whether a return can be made on that investment, and the degree of associated risk.

Until large and certain hydrogen demand exists or can be predicted, any hydrogen infrastructure will only develop around particular niches and publicly funded research/demonstration projects. An example of this is the fuel cell buses being deployed in European cities as part of the Clean Urban Transport for Europe (CUTE) project. The project is a collaboration between governments, academics and industry, and has the added benefit of reducing urban air pollution. Whether such programs become widespread enough to kick-start the development of a 'hydrogen infrastructure' will depend on a complex mix of economic, technological and policy related developments.

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