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IEA HYDROGEN ANNEX 13
TRANSPORTATION APPLICATIONS ANALYSIS

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Abstract

Vehicles and power plants fueled by hydrogen produce virtually no pollutant emissions and are projected to become a serious alternative to hydrocarbon-fueled systems in the future. The transportation sector is already adopting hydrogen in a limited way. Current hydrogen vehicle designs produce power by consuming hydrogen in either a fuel cell or an internal combustion engine (ICE). Hydrogen can be stored on-board as either a compressed gas or a cryogenic liquid. Hydrogen-fueled vehicles need a ready source of fuel for routine use. The infrastructure to provide convenient refueling for passenger vehicles must be put in place in the near future, both in the US and internationally. Options for providing hydrogen fuel include electrolysis of water, reforming of hydrocarbon fuels at the fueling station, and transport of bulk hydrogen. This paper presents results of comparative analysis for passenger vehicle refueling options using either liquid or gaseous hydrogen.

Introduction

The transportation applications project is one of three integrated system activities currently underway as part of IEA Hydrogen Annex 13, “Design and Optimization of Integrated Systems.” Two other projects are addressing remote power generation (on a Norwegian island) and residential power and heating (in a Netherlands suburban community).

The goal of these projects is to address specific hydrogen demonstration opportunities, with respect to energy independence, improved domestic economies and reduced emissions. These development activities are selected to provide both specific findings to the immediate region and also generic conclusions to the hydrogen energy community. Rigorous analysis aids both the specific project and can be extended to additional opportunities in participating countries.

The transportation analysis is not as geographically specific as the other two projects. It is, however, based on current U.S. experience with hydrogen fueling infrastructure. It is meant to contribute to the ongoing discussion, both in the U.S. and internationally, on the preferred choice for fueling options and hydrogen distribution alternatives.

Project Scope

The overall scope of the transportation analysis includes a comparison of hydrogen passenger vehicle fueling options, including:

- Refueling alternatives, primarily various sources of gaseous or liquid hydrogen.
- Vehicle configuration alternatives, primarily various hydrogen storage and power plant selections.
- Driving cycle implications.
- Cost variations for electricity, natural gas and hydrogen with conditions and over international boundaries.

Figures of merit for the overall project include:

- Costs, both capital and operating
- Efficiency, both in terms of vehicle fuel economy, and also in terms of overall energy conversion efficiency
- Footprints for refueling station alternatives
- Emissions, for each alternative system

This paper addresses refueling station alternatives, where the primary considerations are:

- Liquid or gas storage on-site
- On-site or off-site hydrogen production
- The utilization factor of the refueling station

The goal is to aid a user's decision with respect to station type and components.

Case Studies

The specific cases analyzed are:

1. Bulk liquid hydrogen from an existing central reformer transported to the refueling station by truck, stored as a cryogenic liquid and dispensed to the vehicle as a liquid.
2. Bulk liquid hydrogen from an existing central reformer transported to the refueling station by truck, stored as a cryogenic liquid and dispensed to the vehicle as a gas.

3. Bulk gaseous hydrogen transported to the refueling station by existing pipeline, stored as a compressed gas at 5000 psi and dispensed to the vehicle as a gas. This case is valid only where there is a nearby pipeline. (Pipeline construction costs were not considered.)
4. Gaseous hydrogen generated at the refueling station from natural gas by steam methane reforming, stored as a compressed gas at 5000 psi and dispensed to the vehicle as a gas.
5. Gaseous hydrogen generated at the refueling station from natural gas by a partial oxidation process, stored as a compressed gas and dispensed to the vehicle as a gas.
6. Gaseous hydrogen generated at the refueling station by electrolysis, stored as a compressed gas at 5000 psi and dispensed to the vehicle as a gas. (For the present analysis, grid electricity is assumed to power the electrolyzer. Renewable electricity may be considered later.)

System diagrams for these 6 alternatives are shown in Figure 1.

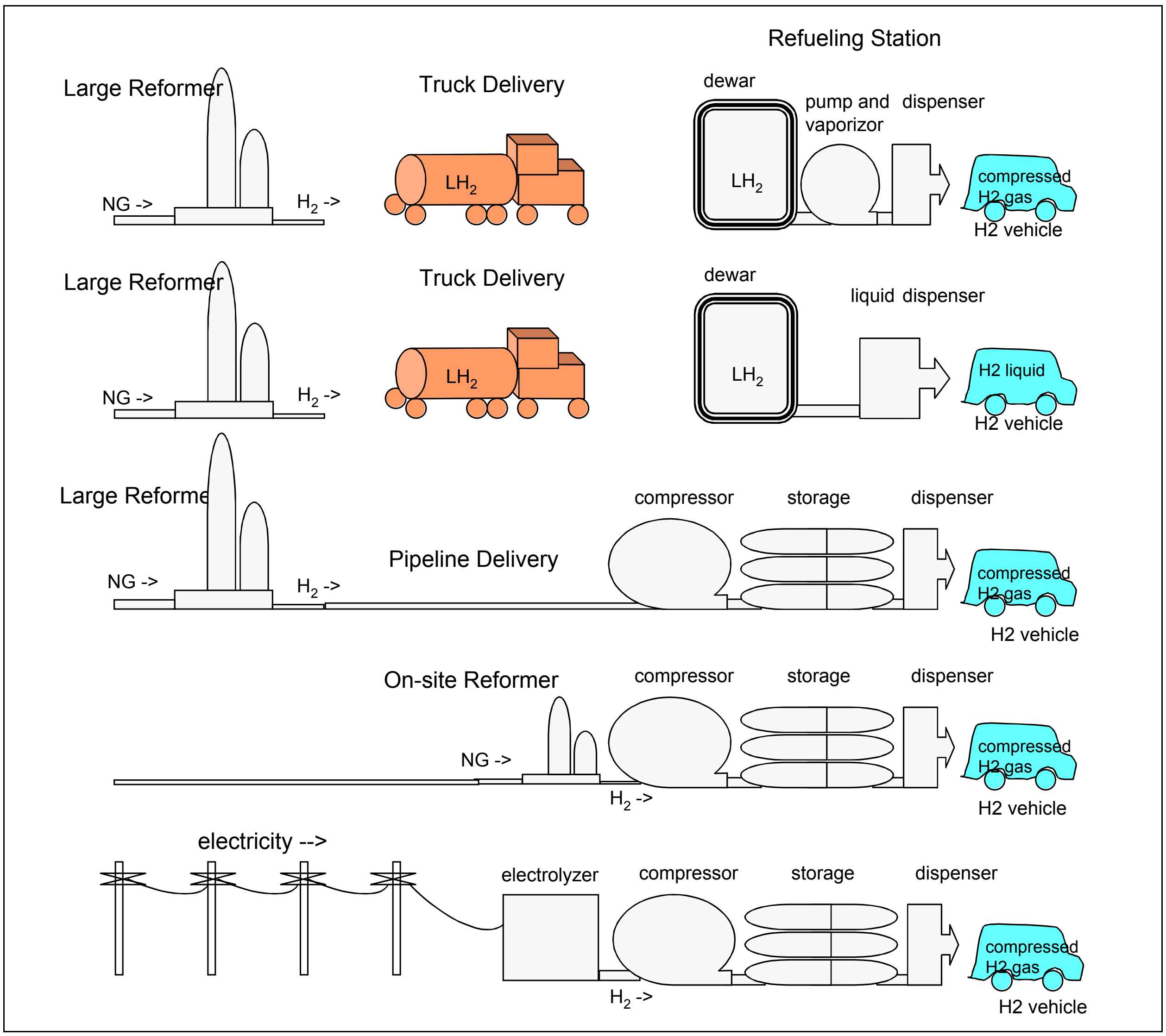

Figure 1. Refueling Station Alternatives

Refueling Station Operation

All refueling station alternatives assume the station is open for business 24 hours per day. Hydrogen is supplied to vehicles from the storage system. The storage is filled intermittently (once per week) in the case of truck delivery. Storage can be refilled continuously in the cases of pipeline gas and on-site production, or scheduled for optimum times, based on the cost of electricity, or other consumables.

The liquid-to-liquid system is assumed to operate similarly to that in the Munich airport, by interconnect to the vehicle and simple pumping of cryogenic liquid into the on-board storage tank. The liquid-to-gas system is also straightforward. It requires a pump and vaporizer, which are available technologies. In the liquid storage case, the dewar maintains a minimum of 30% storage. The gas-to-gas system requires that pressure to the vehicles be maintained at 5000 psi, even though pressure in the storage tank will drop as it is emptied. A boost compressor can provide suitable pressure, as long as the tank pressure remains above about 2000 psi. Thus, the gaseous storage tank must be oversized by about 40%. Figure 2 shows schematically the system diagram for the refueling system.

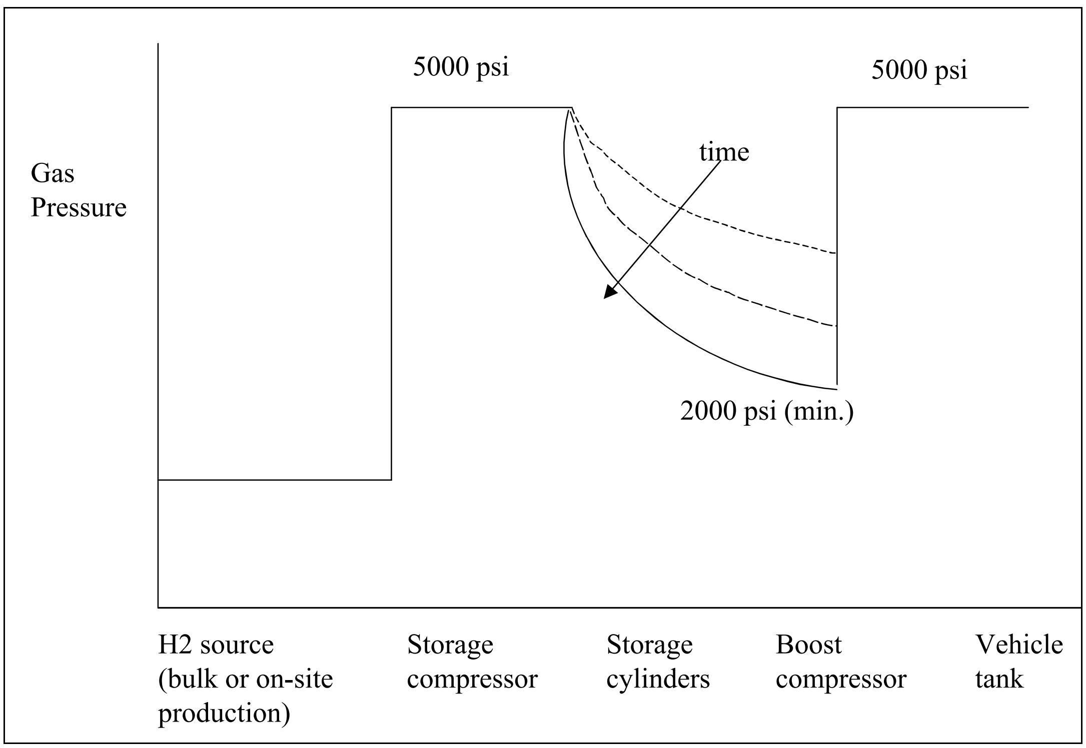

Figure 2. System Diagram for Refueling Analysis for Gaseous Systems

Technology Descriptions

Hydrogen production technologies are current, commercial types. The large reformer is assumed to be existing mature technology, centrally located with existing distribution networks of trucking routes or pipelines. The smaller, on-site generator could be a scaled-down steam methane reformer (SMR), or an autothermal reformer (ATR), or a partial oxidation reformer (also called an under-oxidized burner, or UOB). For this analysis, both a small SMR and an existing commercial UOB were considered. Although the commercial trend seems to be toward the ATR, no performance, cost or footprint data were available for analysis. Small electrolyzers are commercial products, although improvements in performance and cost are projected with a growing market.

Storage technologies are also assumed to be current, commercial types: a cryogenic liquid dewar for liquid hydrogen, and pressurized tanks for gaseous hydrogen. Other storage types, such as metal hydrides were not considered for bulk on-site storage. Storage compressors are commercial types with suitable flowrate to 5000 psi. A boost compressor is required to dispense at 5000 psi to the vehicle, once gas pressure in the storage tank drops as hydrogen is dispensed. Higher pressure storage would be more compact and require less boost compressor work. Higher pressure tanks are more expensive, however, as are higher pressure storage compressors. The dispensers are still developmental, with limited commercial practice both for gaseous and liquid hydrogen.

Approach

Assumptions

For the transportation infrastructure analysis to proceed, a number of initial assumptions were made regarding operation of the transportation system. These include:

- Only passenger vehicles are currently under consideration.
- The vehicles are assumed to be fueled with hydrogen (either liquid or gas), i.e., fuel processing is NOT done on board. (Later analysis will look at on-board processing.)
- The base case calls for capacity to refuel 100 vehicles per day.
- Each vehicle refueling event requires 4 kg of hydrogen. This is a “consensus” value of multiple other studies and matches the current value for PNGV targets and for the Ford hydrogen ICE vehicle. (Later analysis will look at variations in this requirement based on variations in vehicle weight / configuration, due to storage type and power plant, and to driving cycle assumptions.) As a result, at 100% utilization, 400 kg hydrogen is served per day. Storage is sized to serve the entire anticipated volume of customers, plus a buffer, as described below.
- A refueling station consists of the hydrogen production unit or receiving area, storage and its associated facilities, and the dispensing area with two dispensing units. These are the capital cost components considered in this study.
- Available dispensing hours are 24 hours per day, 365 days per year.
- On-site hydrogen production capacity is sized to fill the required storage once per day. (A trade-off between production capacity or rating and operating hours was considered for the electrolyzer and UOB cases to minimize the combined capital cost and electricity cost.)
- Liquid delivery is scheduled once per week. An average round trip delivery distance of 1500 miles was assumed. The dewar is sized for one week’s service plus 30%, to maintain proper conditions and reduce boil-off in the tank (Richards 2001.)
- Compressed gas storage capacity is oversized by 40% to maintain adequate pressure for dispensing via boost compressor, as indicated previously in Figure 2.
- The pipeline gas case is valid only for locations with existing infrastructure.

Cost Analysis

The cost analysis consists of computing both capital cost and the delivered cost of hydrogen for each alternative station case. The capital cost components include:

- Hydrogen generator (for on-site cases)
- Storage system and auxiliaries
- Storage compressor (for gaseous cases)
- Boost compressor (for gaseous cases)
- Dispensers and auxiliaries

(The central SMR and pipeline are not costed, as they are not part of the station. The cost of delivered hydrogen – liquid or gas – is included in the operation costs.)

For the assumed number of vehicles and mass of hydrogen required for refueling, along with the assumed 5000 psi fill pressure and the requirement to refill the gas storage tank each day, the minimum rating of the storage compressor is determined to be approximately 185 scfm. From the work of Ogden (Ogden 1995), we choose a commercial compressor rated at 254 scfm, for which performance and cost are known. Although this cost could be scaled, it wasn't because an existing product was preferred for the analysis. Likewise, we choose a known boost compressor (100 hp) and a known pump and vaporizer system (20 l/min) that provide 400 scfm to the vehicle tank. The fill time per vehicle is just over 4 minutes.

Table 1 lists the capital cost assumptions for the base cases.

Table 1. Capital Cost Assumptions (Base Case)

Item	Units	Cost	Reference
Pipeline terminus	$ per each	10,000	(Ogden 1995)
Small SMR	$/scfd	10	(Ogden 1995), (Keller 2001)
UOB	$/scfd	4.6	(Hummel 2001)
Electrolyzer	$/kW H2	600	(Fairlie 2000)
Liquid dewar	$/gal	10	(Richards 2001)
Compressed gas cylinders	$/scf	2.2	(James 1997), (Amos 1998)
Storage compressors (254 scfm at 5000 psi)	$ per each	170,000	(Ogden 1995), (Thomas 1998)
Boost compressors (100 psi)	$ per each	80,000	(Ogden 1995)
Gas dispenser	$ per each	25,000	(Ogden 1995)
Liquid dispenser	$ per each	100,000	(BMW/ARAL 2000)
Storage regulator valve	$ per each	10,000	(Ogden 1995)
Pump and vaporizer	$ per each	36,000	(Ogden 1995)

Capital costs for the 400 kg/day station are additive:

Total Capital Cost =
Cost of generator + Cost of storage system + Cost of compressors + Cost of dispensers

The operating cost components include:
- Capital charge (cost of money)
- Natural gas (if purchased)
- Hydrogen (if purchased)
- Catalysts or other consumables
- Electricity
- Operations and Maintenance charges (O&M)
- Labor

Table 2 lists the operating cost assumptions for the base cases. The cost of bulk liquid hydrogen is highly dependent on the delivery distance, and almost independent of the amount above a certain value. We assumed an average 1500 mile delivery distance (round trip) and a minimum delivery of 10,000 gal LH2. On-site generation cases assume labor for three full-time persons (one for each of 3 shifts), while delivery cases, which require less on-site attention, assume an equivalent of two full-time persons over a 24-hr operating day.

Table 2. Operating Cost Assumptions (Base Case)

Item	Units	Value	Comments / Reference
Capital charge rate	% of capital cost/yr	15	(Ogden 1995), (Thomas 1998)
Natural gas	$/MMBTU	6	Base case assumption
Liquid Hydrogen (bulk)	$/GJ	12	(Richards 2001)
Gaseous Hydrogen (bulk)	$/GJ	10	(Amos 1998), (Ogden 1999)
Electricity – on peak	¢/kWh	7	(Iannucci 2000)
Electricity – off peak	¢/kWh	2.5	(Iannucci 2000)
O&M	% of capital cost	4	(Ogden 1995)
Labor	$/yr/person	50,000	(Ogden 1995)
Catalysts	$/1000 scf H2	.65	(Ogden 1995), (Thomas 1998)

Operating costs are additive for each applicable item in each case, and for the number of vehicles served.

Annual Operating Cost =
Capital charge + Cost of consumables + Cost of electricity + O&M + Labor

The capital charge, O&M and labor are independent of the number of cars served, whereas the cost of consumables and cost of electricity are proportional to the number of cars served. These assumptions were used in determining the impact of utilization factor on the cost of delivered hydrogen. The cost of served or delivered hydrogen is calculated based on the annual operating costs divided by the amount of hydrogen delivered, in GJ. (The cost per driving cycle will be converted into an equivalent $/gal gasoline in the next phase of this study).

Delivered cost of hydrogen ($/GJ) = Annual operating cost / GJ hydrogen dispensed per year

Each of the station components has an associated efficiency and/or power requirement for operation. Efficiency is applied to the conversion to hydrogen, on a HHV basis. Electricity costs are calculated on the basis of power required during the time of operation. Whether the operation occurs on-peak (6 hours per day) or off-peak (18 hours per day) is also taken into consideration. The values assumed in this analysis are tabulated in Table 3.

Table 3. Operating Performance of Refueling Station Components

Item	Efficiency, %	Power requirement (while operating)	Reference
Small SMR	67	0.6 kWh/1000 scf H_2	(Ogden 1995), (Edlund 2000)
UOB	69	17.38 kWh/1000 scf H_2	(Hummel 2001)
Electrolyzer	80		(Fairlie 2000)
Storage compressor (254 scfm at 5000 psi)		82 kW	(Ogden 1995)
Boost compressor (100 hp)		75 kW	(Ogden 1995)
Liquid pump (20 l/min)		1 kW	(Ogden 1995)
Pump and vaporizer (20 l/min)		22.4 kW	(Ogden 1995)

Footprint Analysis

The footprint of the refueling station is of interest for comparing land area requirements for the various alternatives. The footprint was calculated for the following components:

- Hydrogen generator (if applicable)
- Delivery area (if applicable)
- Hydrogen storage and safety keep-out zone
- Compressors and other auxiliary components
- Dispensing area, including driving lane.

Safety codes and standards require a safety keep-out zone or perimeter fencing around hydrogen storage facilities (NFPA 1999, Weinmann 2001). Distances depend on the volume and state of hydrogen (gas or liquid), what other facilities are present and what type of fireproofing is provided. A typical perimeter for gas storage is 15 ft (4.6 m). The requirement for liquid storage can be as great as 50 to 75 ft, according to U.S. codes. Actual practice in the U.S. and Europe is much less as it is determined by local fire officials on the basis of "equivalent" protection (Weinmann 2001, Roby 2001). A base case perimeter value of 15 ft was used for the present analysis.

A representative layout of the site is shown in Figure 3. Footprint assumptions for the various cases are listed in Table 4.

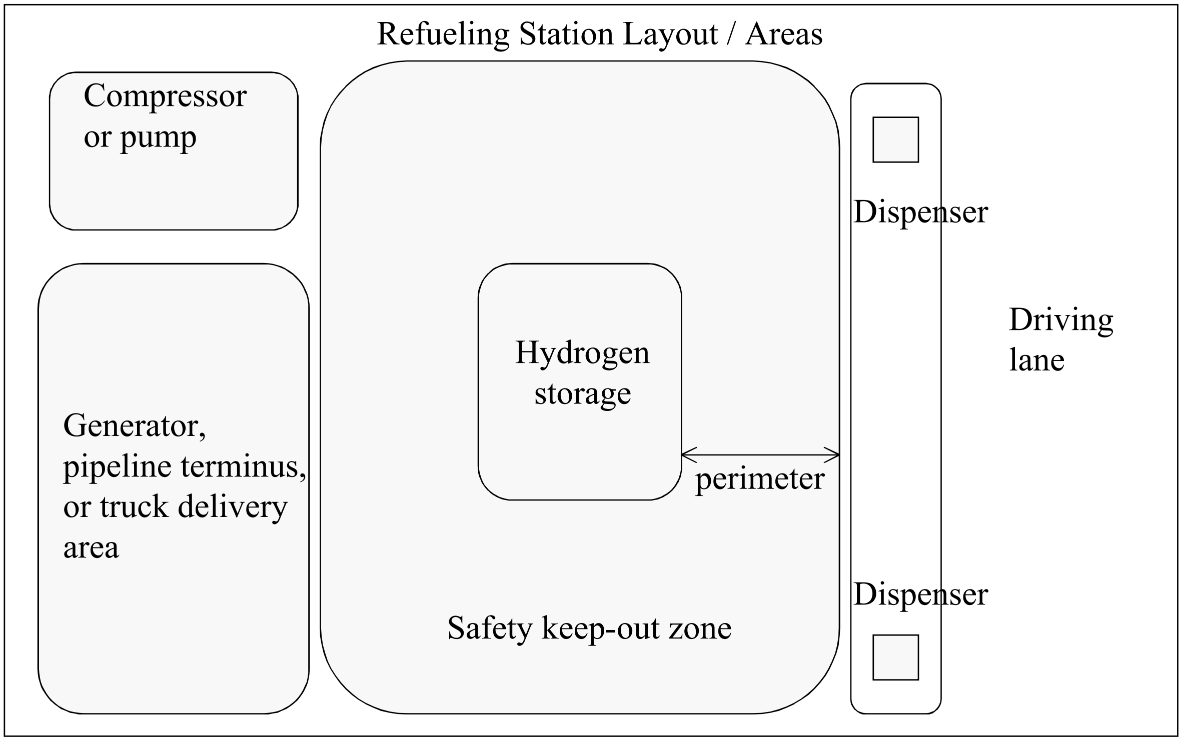

Figure 3. Refueling Station Layout for Footprint Analysis

Table 4. Footprint Areas of Refueling Station Components

Item	Units	Value	Comments / Reference
Truck delivery area	m^2 per each	39	Based on a typical service station
Pipeline terminus	m^2 per each	20	(Richards 2001)
Liquid dewar	m^2 / kg stored	2.75×10^{-3}	(Richards 2001), assumes a standing cylindrical dewar
Pressurized cylinder (5000 psi)	m^2 / kg stored	.132	(Abele 2001), based on stacks of horizontal cylinders
Safety zone perimeter	m from storage	5	(Bracha 2001), (Weinmann 2001)
Liquid dispenser area	m^2 per each	9	(Thomas 1998)
Liquid pump	m^2 per each	negligible	(Richards 2001)
Evaporator and pump	m^2 per each	4	(Richards 2001)
Storage compressor	m^2 / scfm	.0236	(Hummel 2001)
Boost compressor	m^2 / scfm	4	(Ogden 1995)
Small SMR	m^2 / scfd	6.4×10^{-4}	(Ogden 1995), (Edlund 2000)
UOB Hydrogen generator	m^2 / scfd	3.13×10^{-4}	(Hummel 2001)
Electrolyzer	m^2 / scfd	4.91×10^{-4}	(Fairlie 2000)
Gas dispenser area	m^2 per each	9	Based on a typical service station
Driving lane	m^2 per each	24	Based on a typical service station

Footprints of the individual components for each case are additive.

Refueling station footprint area =
Area for hydrogen source + Storage system area (including safety zone) + Delivery area + Dispensing area

Data Sources

An attempt has been made in this analysis to use current or near-term values for costs and equipment sizes. Some vendors and manufacturers were fairly cooperative in providing data; others less so, for competitive reasons. Some information was available from commercial web sites. When necessary, estimates from other studies have been used. The most significant are those of Ogden, Thomas, and various other DOE/national laboratory studies. Broader sources were also sought, and are listed as references within this report.

Results

This section contains results of the study to date, including capital costs, delivered hydrogen costs, sensitivity analyses, and refueling station footprints.

Refueling Station Capital Costs

Figure 4 presents Total Capital Costs for the 6 base cases. The components of those capital costs are shown in Figure 5.

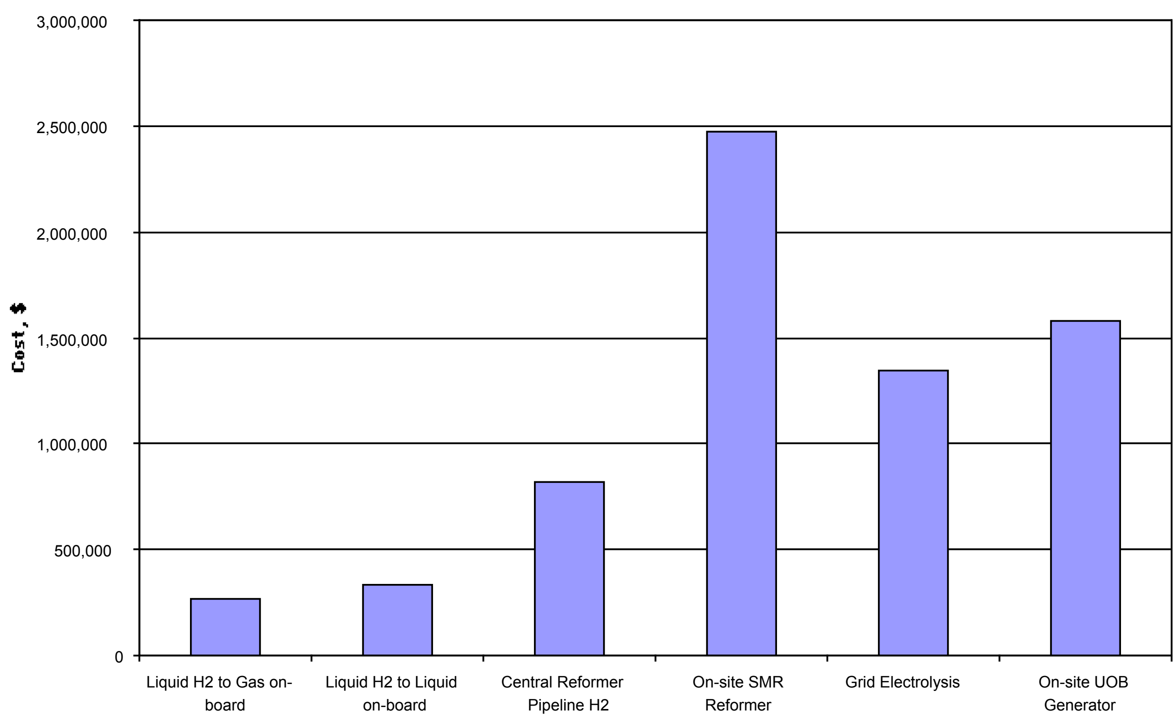

Figure 4. Total Capital Costs for Base Cases: Hydrogen Refueling Station

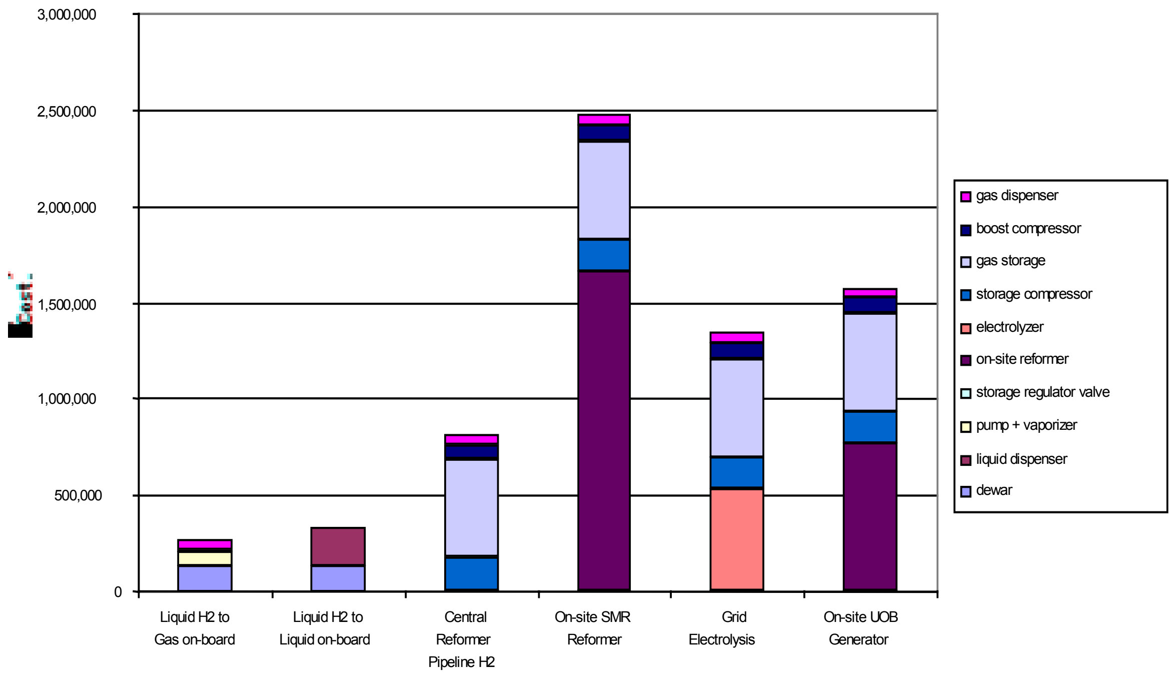

Figure 5. Capital Costs Components for Base Cases: Hydrogen Refueling Station

Cost of Delivered Hydrogen

The cost of hydrogen served or delivered is determined from the annual operating costs divided by the total GJ of hydrogen delivered per year. Figure 6 presents a comparison of delivered cost of hydrogen for the 6 base cases assuming 100% utilization factor for the refueling station, i.e., 100 cars are filled every day. Figure 7 presents the components of the fuel cost for each case.

For the base case, the electrolyzer was sized to produce a full day's supply of hydrogen during off-peak hours, to avoid on-peak electricity prices. This approach was also considered for the UOB because it also draws a large amount of electricity while operating. For the UOB, however, the increased capital cost for a larger unit was NOT offset by reduced electricity costs, unlike the electrolyzer. Figure 8 presents components of the delivered hydrogen cost for these two generators sized to run either 18 hours or 24 hours per day, thus either using or avoiding on-peak electricity costs. The SMR uses relatively less electricity and the system is optimized to operate 24 hours per day.

Sensitivity Studies

Two sensitivity studies have been completed to this point. First is a look at the impact of under-utilization of the refueling station, as may be the case in the early years of operation. Figure 9 shows a comparison of the cost of delivered hydrogen for 100% and 50% utilization (i.e., 50 cars served per day) for the 6 base cases. Capital charges, O&M and labor are independent of utilization, whereas consumables (i.e. natural gas or bulk hydrogen) and electricity use depend on the number of vehicles served.

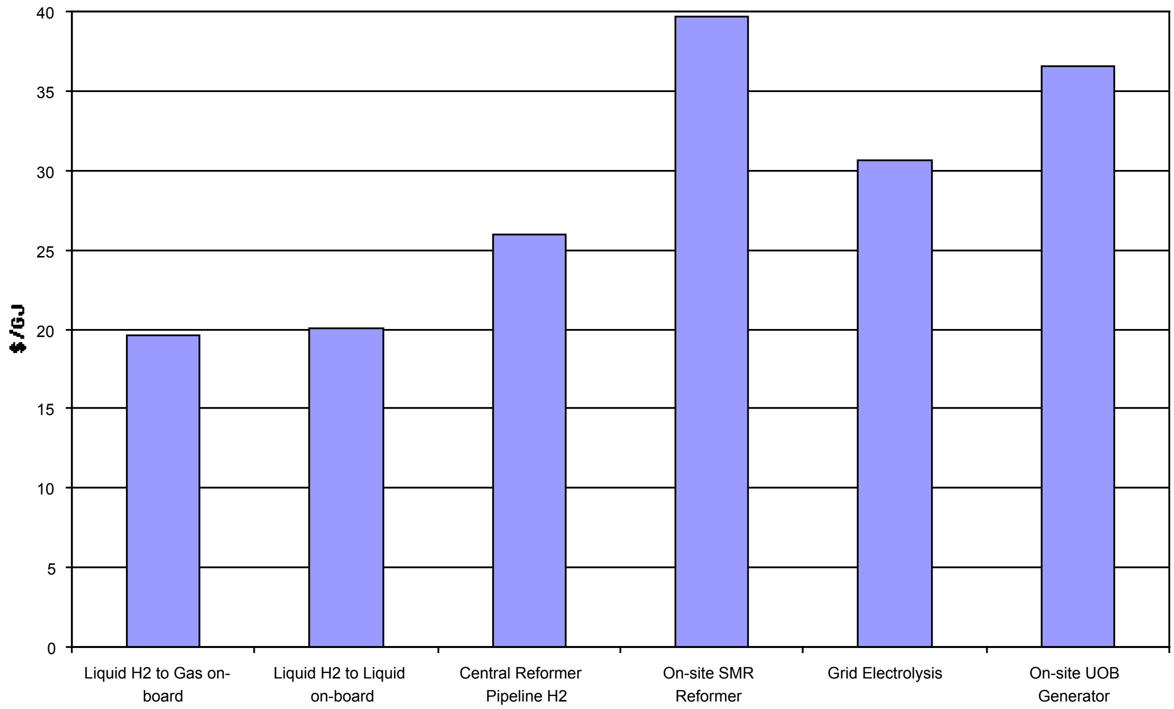

Figure 6. Delivered Cost of Hydrogen ($/GJ) for Base Cases, 100% Utilization Factor

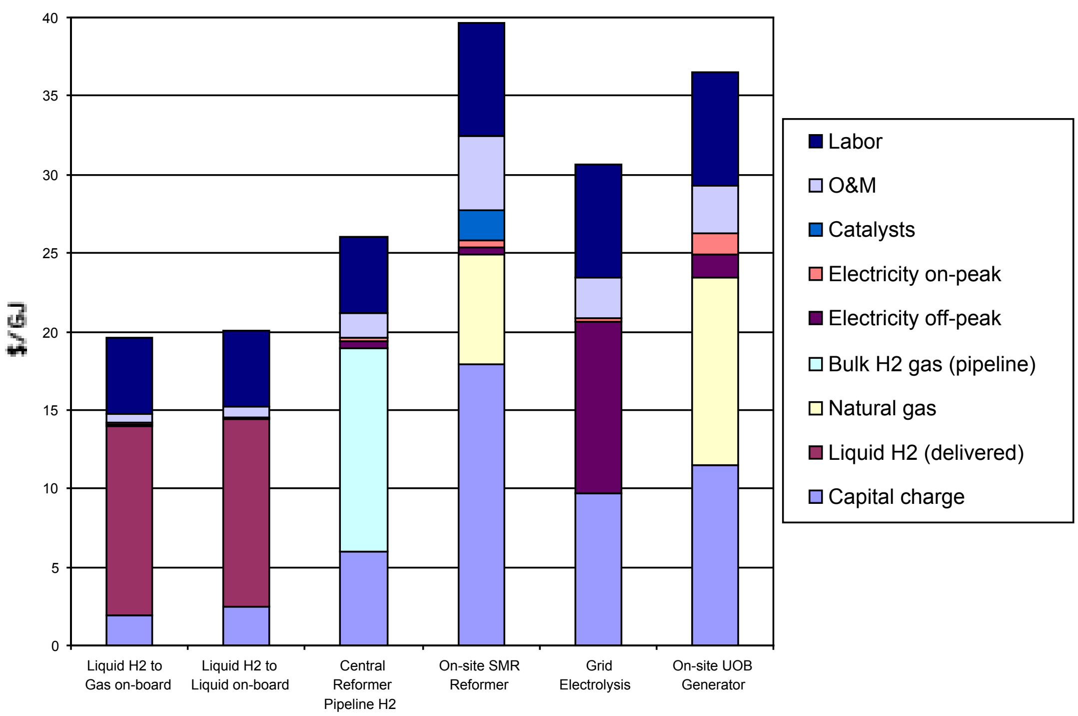

Figure 7. Components of Hydrogen Cost for Base Cases, 100% Utilization Factor

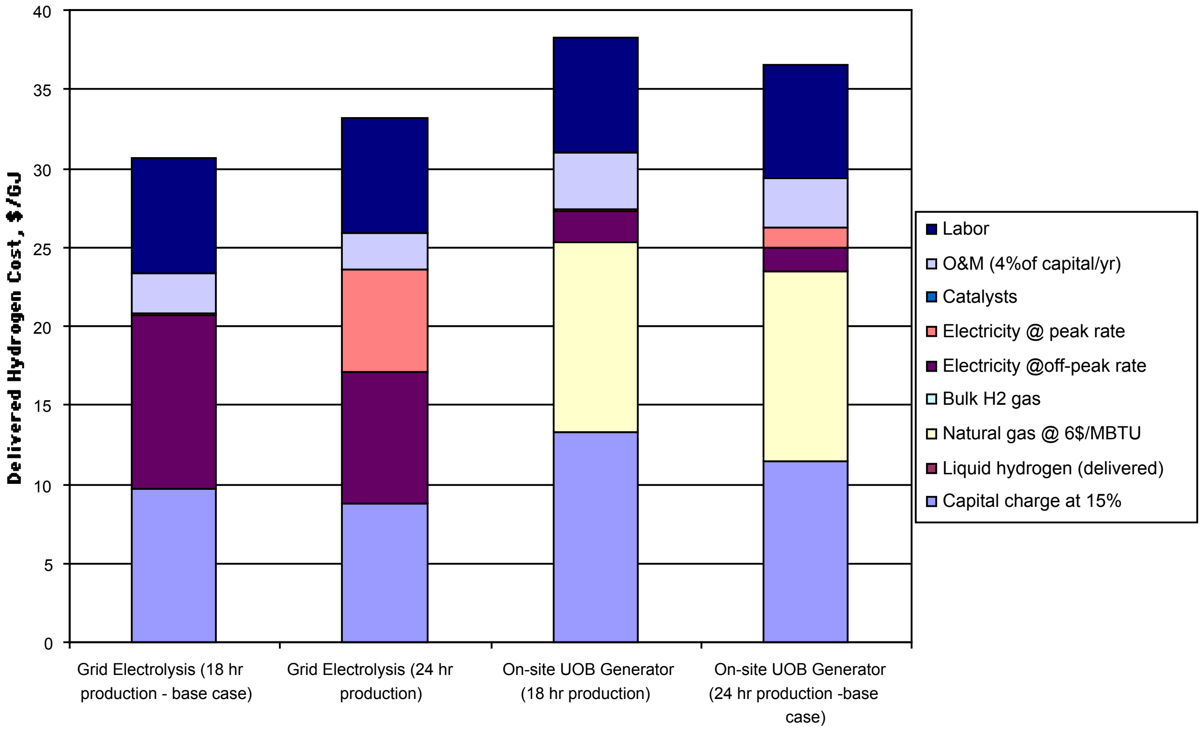

Figure 8. Comparison of Electrolyzer and UOB Generators Sized to Avoid (18-Hr Production) or Use (24-Hr Production) On-Peak Electricity

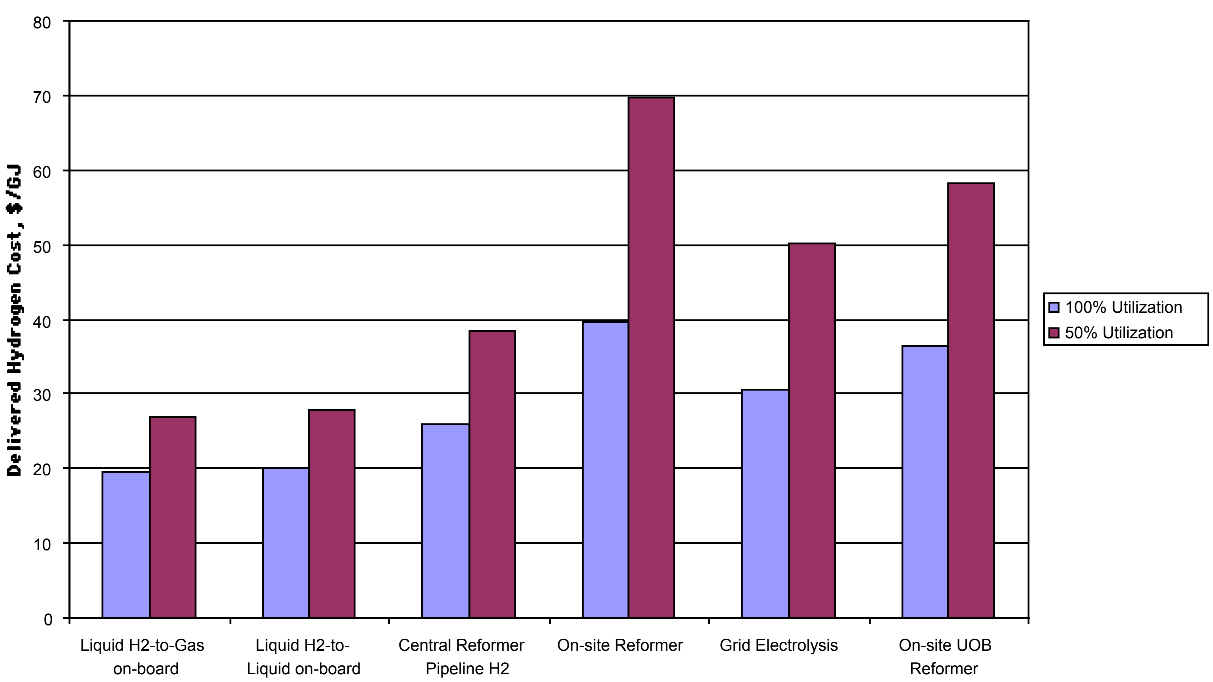

Figure 9. Cost of Delivered Hydrogen for 100% and 50% Utilization Factors

Another sensitivity analysis involves the cost of on-site hydrogen production units, as these make up the largest individual capital cost for those cases. With maturity, costs of these systems are projected to drop from current or near-term costs. Table 4 indicates the two sets of capital costs used in this sensitivity study. Figure 10 presents the capital cost results for these projected cases, in comparison to the other base cases. Figure 11 shows the delivered cost of hydrogen for projected cases; improvements in efficiency have not been projected, however.

Table 5. Capital Costs of On-Site Generators (Base Case and Projected)

System	Base cost	Projected cost	Reference
SMR	10 $/scfd	5 $/scdf	(James 1997), (Edlund 2001)
UOB	4.6 $/scfd	3 $/scfd	(Hummel 2001)
Electrolyzer	600 $/kW	300 $/kW	(Fairlie 2000)

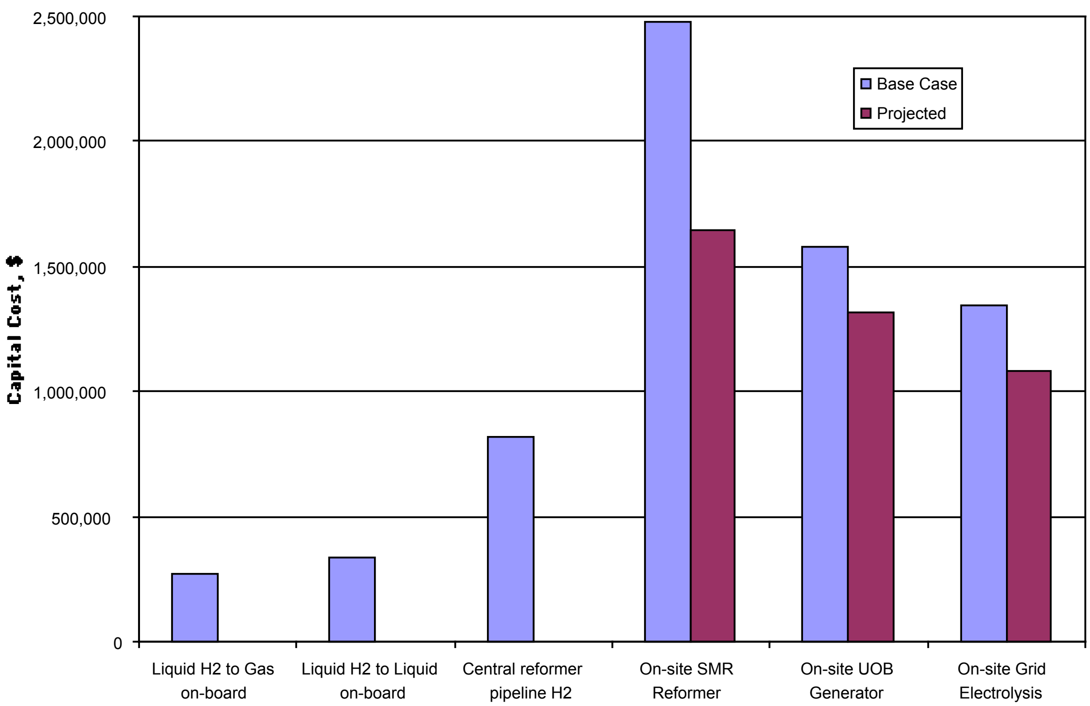

Figure 10. Capital Cost of Alternatives With Projected, Future Costs of On-Site Generators

Footprints

The footprint area results for each of the six base cases are presented in Figure 12. The components of the footprints are presented in Figure 13. Note that the liquid storage results are based on storing one week's mass of liquid hydrogen on-site, whereas only a day's worth of gaseous hydrogen is stored on-site. The footprints are dominated by the safety keep-out zone to a perimeter of 15 ft (5 m).

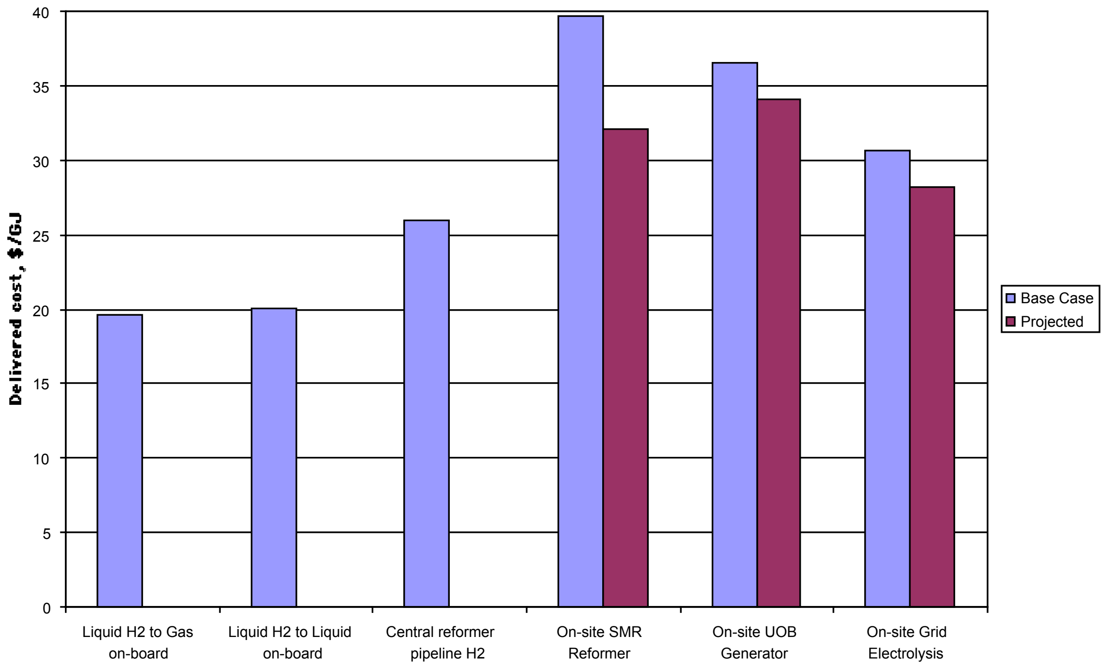

Figure 11. Delivered Hydrogen Cost of Alternatives With Projected, Future Capital Costs for On-Site Generators

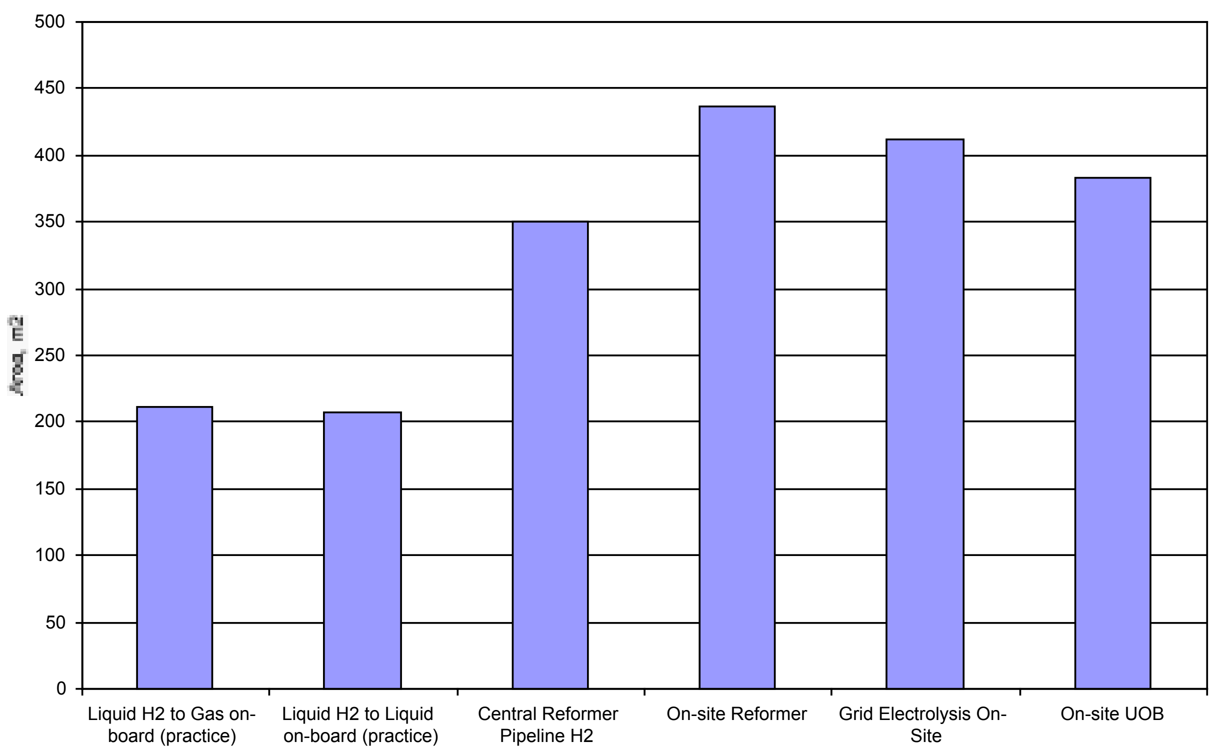

Figure 12. Footprint Areas Required for the 6 Base Cases, 100 Passenger Vehicles Per Day

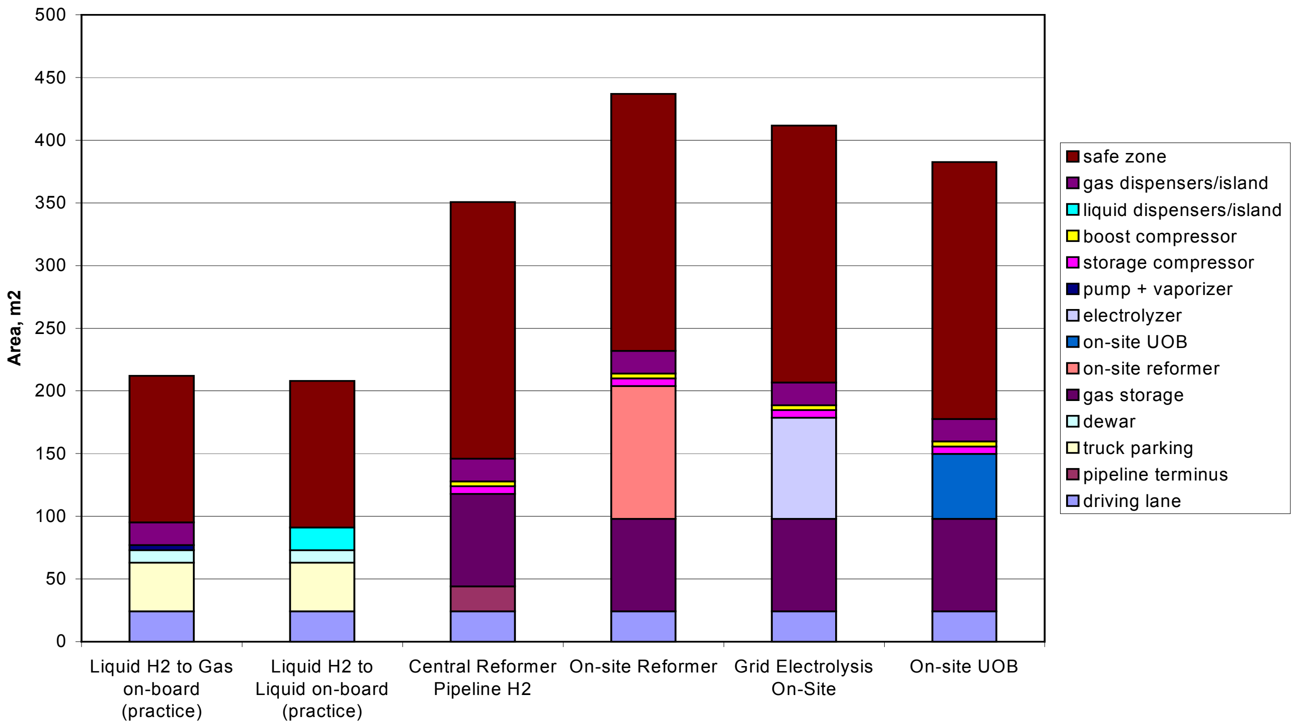

Figure 13. Footprint Components for the 6 Base Cases

Figure 14 shows the same components but includes liquid storage cases with a keep-out zone perimeter of 50 ft (15 m) around the liquid dewar. Although this is the value specified by U.S. fire codes, it is not observed in practice. However, if this perimeter were maintained for neighborhood refueling stations, then liquid storage would be at a severe disadvantage.

From the analysis done to date, the major conclusions are:

- The capital cost of the on-site generation options is greater than bulk delivery of hydrogen to the fueling station. This assumes existing delivery infrastructure. The cost trend for the on-site generation technologies is downward.
- The small steam methane reformer is the most costly option; however there is growing commercial development of this technology.
- The delivered cost of hydrogen is also generally greater for on-site production of hydrogen.
- When the station is underutilized, the delivered cost of hydrogen from all sources is always greater because the capital, O&M, and labor charges are independent of the utilization factor.
- For on-site generation alternatives, where the capital investment is higher, the delivered cost of hydrogen is even higher when the utilization factor is less than 100%.
- Footprint areas for on-site hydrogen generation alternative are somewhat greater than for bulk hydrogen delivered by pipeline.
- Footprint areas for liquid storage options are highly dependent on the safety keep-out zone requirements, and could be prohibitively large if conservative perimeters are maintained.

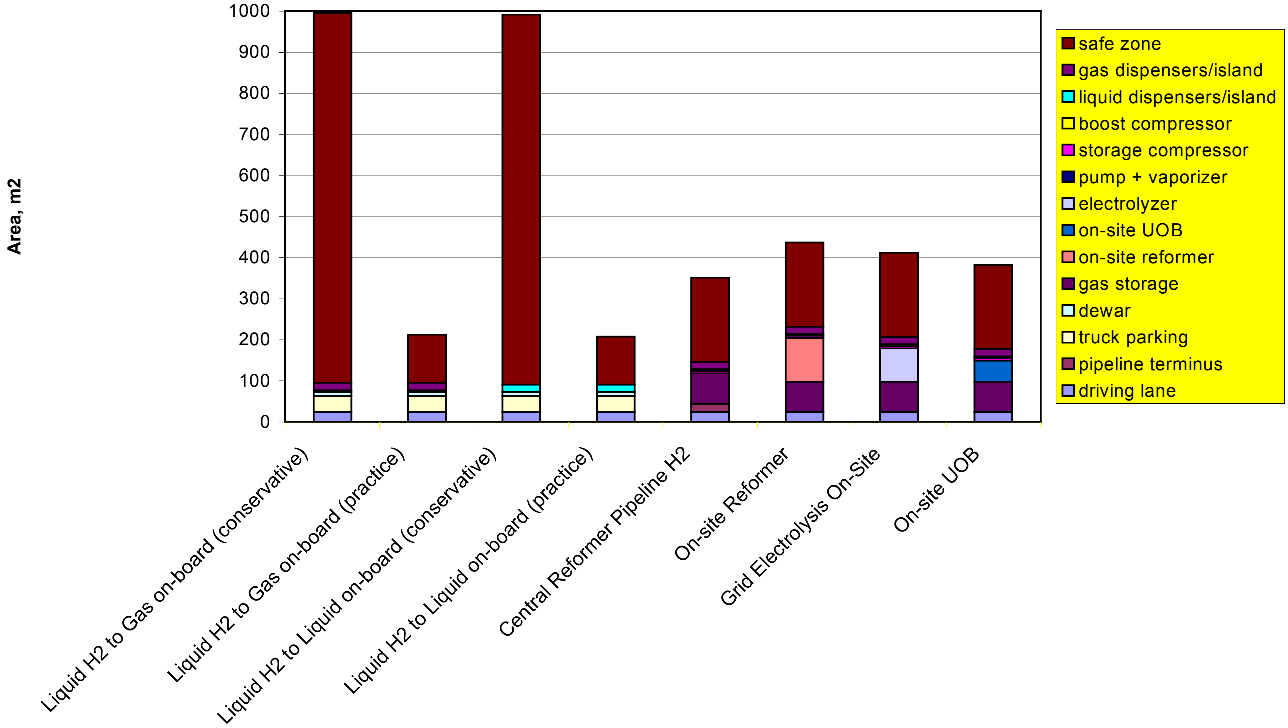

Figure 14. Footprint Components Including Expanded (Conservative) Safety Zone for Liquid Hydrogen

Discussion and Conclusions

This analysis suggests that early stations may be based on the use of delivered hydrogen, with on-site generation coming in as costs of these technologies decrease.

Future Analysis

This project is ongoing; the following analyses are in progress:

- Calculations of fuel economy and system efficiency
- Implications of alternative on-board storage alternatives, especially with regard to weight
- Implications of alternative power plant selections, i.e., fuel cell compared with an internal combustion engine
- Implications of on-board processing, with regard to both weight and cost per driving cycle
- Investigation of global driving cycle variations
- A comparison of overall emissions
- Sensitivity analysis to natural gas and electricity prices
- Consideration of renewable sources of grid electricity
- Analysis and impact of upstream technology developments, especially hydrogen pipelines and large-scale SMR production

All of these analyses are being coordinated with other efforts of the IEA Hydrogen Programme, so that cost and performance assumptions are consistent. The emissions analysis is being undertaken in conjunction with the efforts of the European Union Joint Research Center in Ispra, Italy.

Acknowledgments

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