Proceedings of the 2002 U.S. DOE Hydrogen Program Review
NREL/CP-610-32405

HYDROGEN TECHNICAL ANALYSIS ON MATTERS BEING CONSIDERED BY THE INTERNATIONAL ENERGY AGENCY - TRANSPORTATION INFRASTRUCTURE

Susan M. Schoenung
Longitude 122 West, Inc.
1010 Doyle Street, Suite 10
Menlo Park, CA 94025
Telephone: (650)329-0845
E-mail: schoenung@aol.com

Abstract

The comparison of options for hydrogen production, storage and utilization in the transportation sector is of great interest in the U.S. and in many other countries around the world, as a move to cleaner transportation fuels proceeds. The International Energy Agency (IEA) under its Hydrogen Implementing Agreement is sponsoring comparative analysis of hydrogen vehicle configuration and refueling alternatives. This paper presents results of a comparative analysis of refueling infrastructure options and passenger vehicle alternatives. The assessment includes sensitivity analysis including a new look at upstream infrastructure costs. Tailpipe and local / station emissions are also evaluated.

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 [1]) and residential power and heating (in a Netherlands suburban community [2]). The goal of these projects is to address specific hydrogen demonstration opportunities, with respect to energy independence, improved domestic economies and reduced emissions. These projects were 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 based on current U.S. experience with hydrogen fueling infrastructure, with comparative input from U.S. experience. 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.

Scope of Study

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 and fuel alternatives, primarily various hydrogen storage and power plant selections, compared to other fuels, including methanol and gasoline
- Cost variations for electricity, natural gas and hydrogen with economic conditions and over international boundaries
- Future costs of upstream infrastructure

Figures of merit for the overall project include:

- Costs, both capital and operating, leading to the cost of hydrogen dispensed to a vehicle

- Efficiency, primarily in terms of vehicle fuel economy
- Footprints, primarily for refueling station alternatives
- Emissions, for each alternative system

The base case refueling station analysis, including all cost and footprint assumptions, has been reported previously [3-6]. This paper addresses the sensitivity of dispensed hydrogen costs to a number of assumptions regarding future supply and demand assumptions and end-use aspects of various vehicle configurations and alternative fuels. The sensitivity analysis addressed the following parameters:

- Projected future costs of on-site generation technologies
- The utilization factor of the refueling station
- Number of vehicles served per day (or capacity of station)
- Natural gas and electricity prices
- Upstream costs of central reformers when demand exceeds existing supply
- Upstream costs of new hydrogen pipelines
- Delivery distance of bulk hydrogen by truck or pipeline

The end-use analysis addressed tailpipe emissions of various vehicle configurations and local station emissions for various station and vehicle combinations.

The objective throughout the study has been to aid decision-making with respect to station type, thus guiding infrastructure development. The overall goal is to answer the question: Where are we headed? Some have suggested a trend from bulk hydrogen delivery, to on-site hydrogen production, and possibly to on-board reforming. But does analysis of the costs and emissions, particularly for hydrogen dispensed to hydrogen vehicles, justify this scenario? This study attempts to shed some light on this question.

Refueling Station Infrastructure Alternatives

Originally, 6 refueling station cases were selected for analysis. These give an estimate of the cost of hydrogen dispensed to the vehicle. These cases were:

- Bulk liquid hydrogen from an existing central reformer is transported to the refueling station by truck, stored as a cryogenic liquid and dispensed to the vehicle as a liquid.
- 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.
- 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 considered later.)
- Gaseous hydrogen generated at the refueling station from natural gas by steam methane reforming (SMR), stored as a compressed gas at 5000 psi and dispensed to the vehicle as a gas.
- Gaseous hydrogen generated at the refueling station from natural gas by a partial oxidation (POX) process, stored as a compressed gas and dispensed to the vehicle as gas.
- 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 early analysis, grid electricity was assumed to power the electrolyzer. Renewable electricity was considered later.)

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

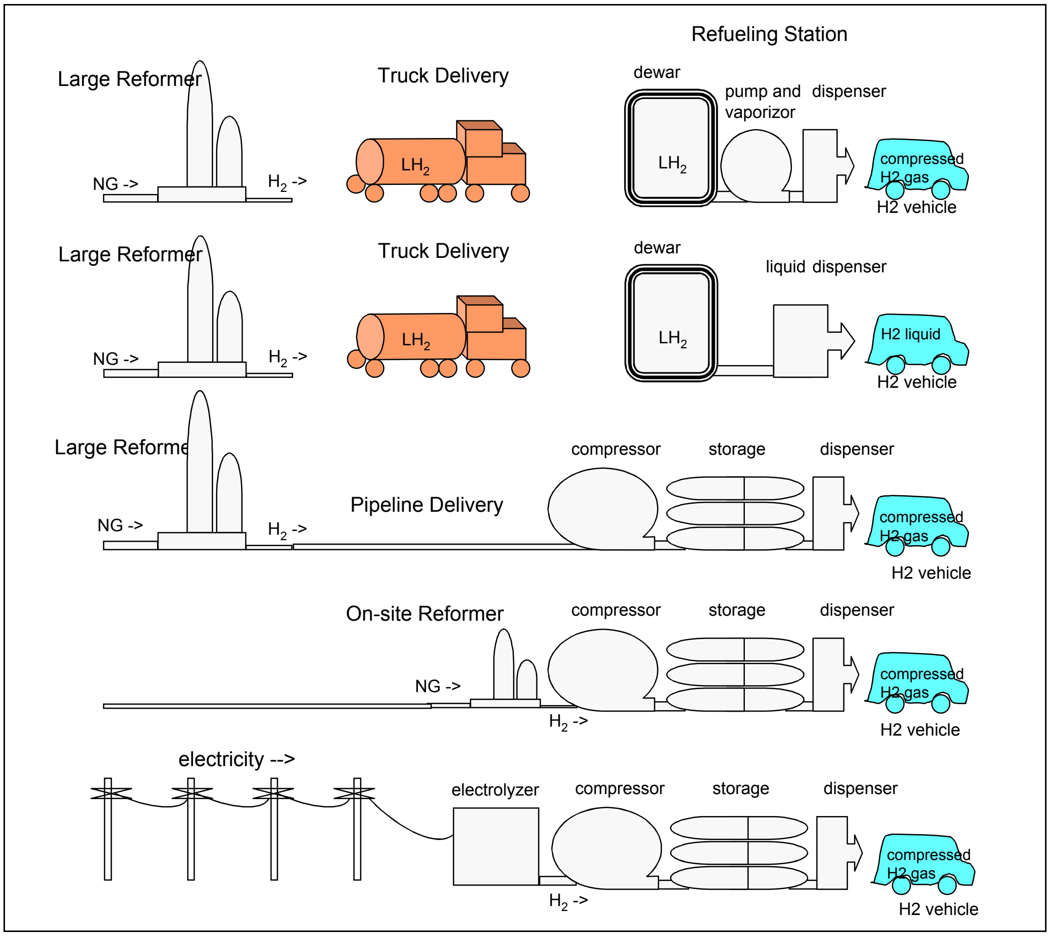

Figure 1. Refueling Station Alternatives (The on-site reformer is either SMR or POX.)

A number of initial assumptions were made regarding operation of the transportation and refueling system [3]. The most important ones are repeated here.

- The base case calls for capacity to refuel 100 vehicles per day.
- Each vehicle refueling event requires approximately 4 kg of hydrogen. 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.
- 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.
- Liquid delivery is scheduled once per week. An average round trip delivery distance of 1000 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.

The costing and sizing approach are described elsewhere [3]. 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 were not costed for the base cases, as they were not part of the station. The cost of delivered hydrogen – liquid or gas – is included in the operation costs. The upstream systems were costed for the sensitivity analysis presented here.

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

The cost of delivered or dispensed hydrogen is calculated based on the annual operating costs divided by the amount of hydrogen delivered, in GJ.

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

Figure 2 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 3 presents the components of the fuel cost for each case. These charts are all presented in $/GJ. An equivalent value to consider would be $/gallon of gasoline equivalent. $30/GJ is approximately $3/gallon. A 300 mile fill-up for a hydrogen fuel cell vehicle would be about $16 on average.

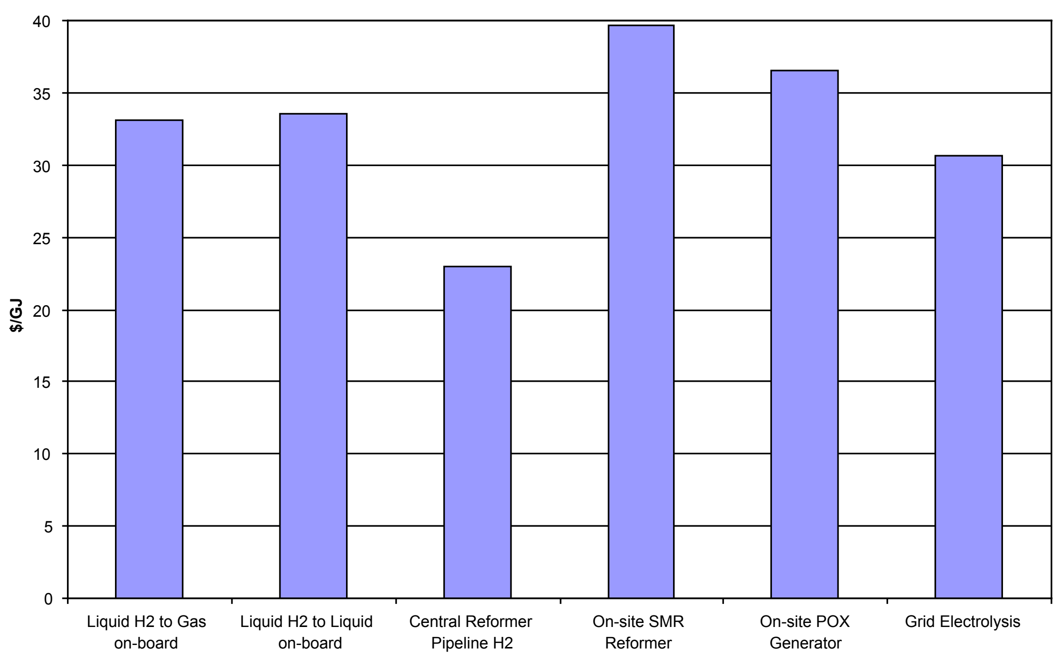

Figure 2. Delivered Cost of Hydrogen ($/GJ) for Base Cases, 100% Utilization Factor

Sensitivity Studies

The basic station model was used to study the effects of changing various parameters. These included the following parameters: number of vehicles, capital costs, and prices for gas and electricity. Upstream infrastructure costs were added later.

Sensitivity to Utilization Factor

The first sensitivity study was a look at the impact of under-utilization of the refueling station, as may be the case in the early years of operation. Figure 4 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. Thus, the cases with greater up-front capital cost, i.e., the on-site generation cases, are more dramatically impacted by the utilization factor.

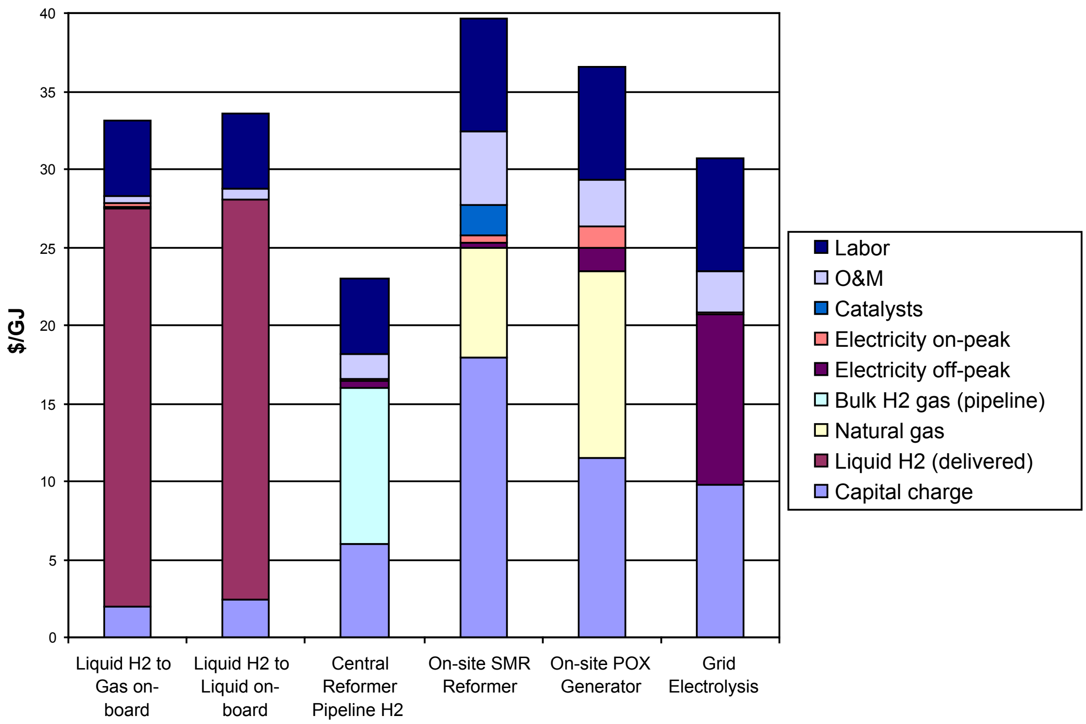

Figure 3. Components of Hydrogen Cost for Base Cases, 100% Utilization Factor

Sensitivity to Projected Future Costs of On-site Production Technologies

Small-scale hydrogen production is a technology in its infancy. Developers have projected significant cost reductions in small steam methane reformers, POX reformers and electrolyzers. Reductions in the capital costs of these components also reduces the cost of hydrogen dispensed at the pump. Figure 5 shows a comparison of the cost of delivered hydrogen for the base cases (near-term costs) and for projected reduced system costs for the on-site options. The cost assumptions have been described previously in Ref. 3. With projected costs, all systems give similar pump prices, except the pipeline case which is still the most attractive.

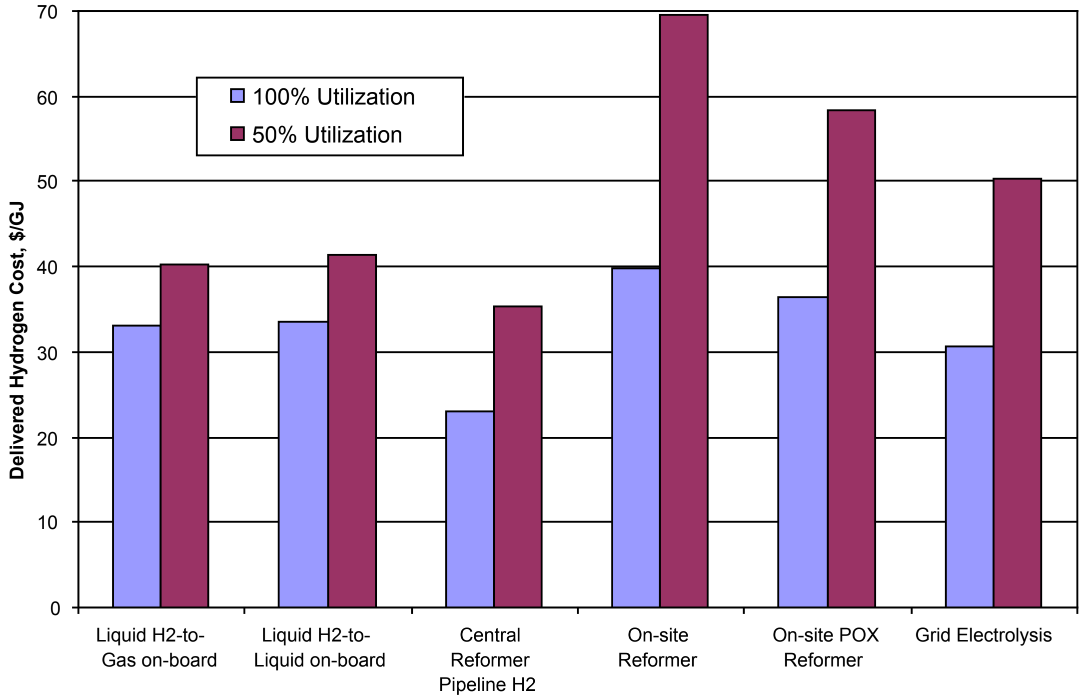

Figure 4. Cost of Delivered Hydrogen for 100% and 50% Utilization Factors

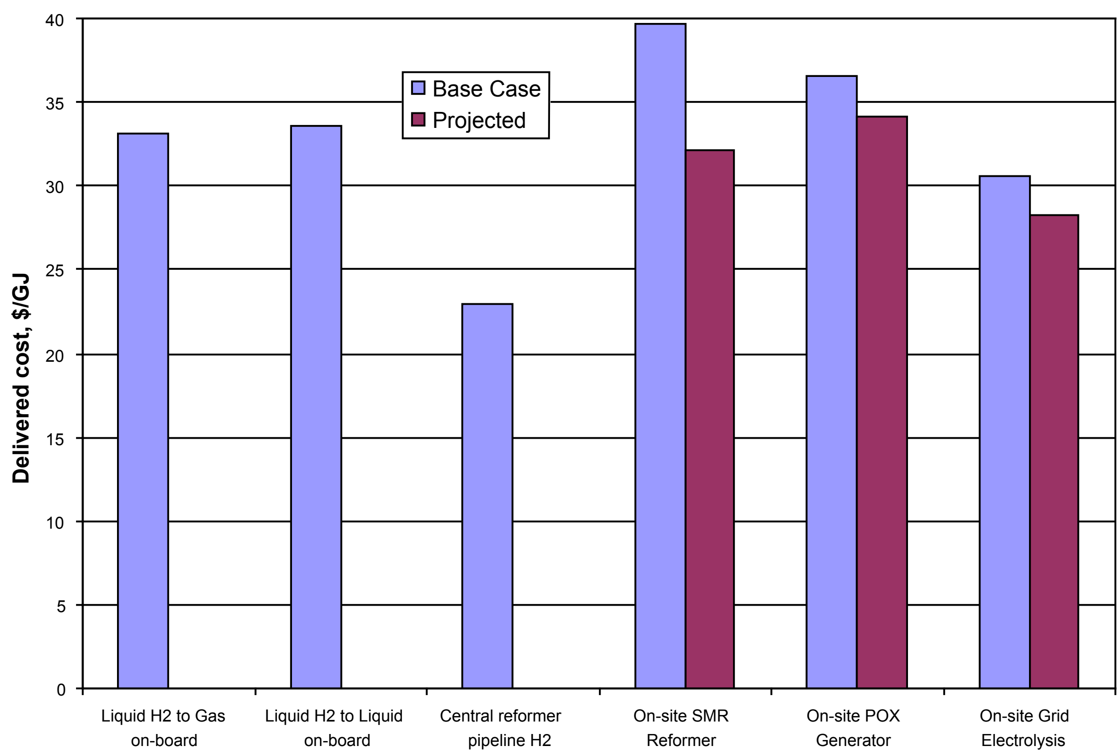

Figure 5. Cost of Delivered Hydrogen for Near-Term and Projected Costs

Sensitivity to Station Size

The original analysis was based on 100 passenger vehicles per day, or 400 kg of dispensed hydrogen. This corresponds to just over 165,000 scf/day. Some have questioned whether the conclusions would change if a larger station size were analyzed. The calculations for the 6 cases have been repeated assuming a larger number of vehicles: 200 per day and 500 per day. These correspond to 800 kg (330,000 scf/day) and 2000 kg (825,000 scf/day). The results, in Figure 6, show each station configuration for the 3 sizes. The overall cost of dispensed hydrogen decreases for a larger station, but the relative comparison between station types does not change significantly, although distinctions become less at larger sizes.

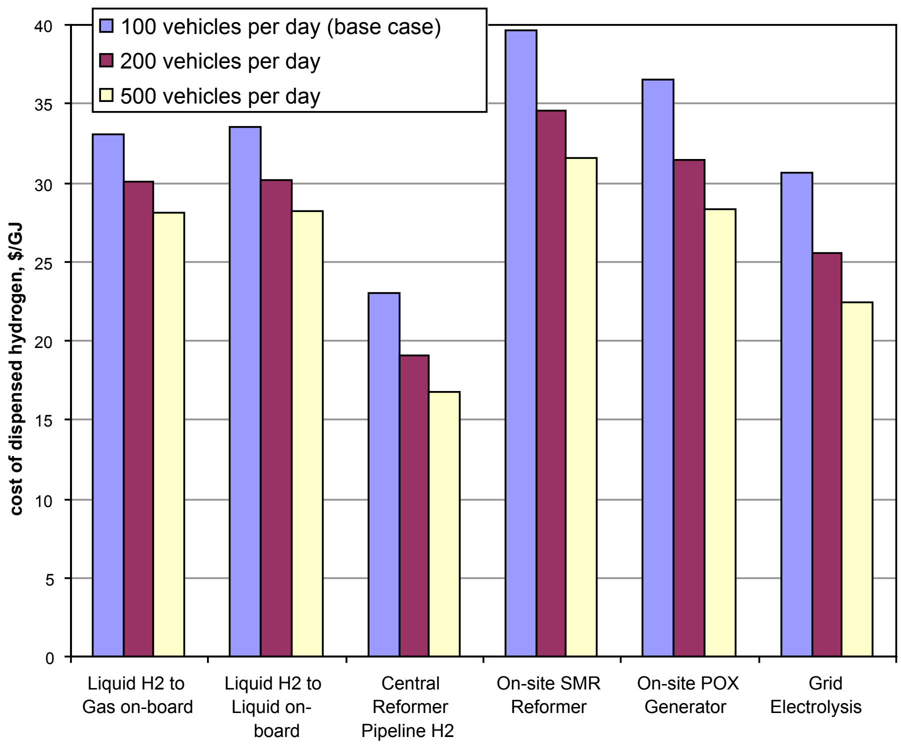

Figure 6. Sensitivity of Dispensed Hydrogen Cost to Station Size

Sensitivity to Changes in the Cost of Natural Gas and Electricity

The base case analysis assumed costs for natural gas and electricity that were representative of recent historical values. The costs are highly volatile, however, and also vary internationally. The study team expressed an interest in seeing how sensitive the infrastructure results were to variations in the costs of these consumables. Tables 1 and 2 list the original and parametric assumptions for the sensitivity analysis, for natural gas and electricity, respectively. Natural gas costs were halved and doubled to show general sensitivity. These changes in natural gas cost flowed through to bulk hydrogen costs in the following way. Dividing the natural gas cost by 2 reduced the bulk liquid hydrogen cost by about 15%, whereas multiplying the natural gas cost by 2 increased the bulk liquid hydrogen cost by a factor of 30%. This relationship was based on Ref. 8. Pipeline hydrogen from a central reformer is more directly impacted by changes in the cost of natural gas. As seen in Table 1, the resulting cost variations are greater.

Table 1. Natural Gas Prices and Resulting Bulk Hydrogen Prices for Sensitivity Study

	Natural gas, $/MMBTU	Bulk liquid hydrogen*, $/GJ	Pipeline hydrogen, $/GJ
Base case	6	25.6	10
Lower (× 1/2)	3	21.5	6
Higher (× 2)	12	33.5	18

*Assumes 500 mile one-way delivery distance

Electricity costs were also halved and doubled. These variations also impact the cost of hydrogen from a central reformer, as shown in Table 2. Renewable electricity from wind is approximately represented by the higher, doubled costs. Renewable electricity from solar photovoltaics would be nearly ten times higher. [9]

Table 2. Electricity Prices and Resulting Bulk Hydrogen Prices for Sensitivity Study

	Electricity, off-peak cents/kWh	Electricity, on-peak, cents/kWh	Bulk liquid hydrogen, $/GJ
Base case	3	7	25.6
Lower (× 1/2)	1.5	3.5	23.6
Higher (× 2)	6	14	29.4

The effect of changing the cost of consumables is to change the resulting cost of hydrogen dispensed at the pump. Figure 7a shows the sensitivity to natural gas prices. Only the on-site electrolyzer case is insensitive to the cost of natural gas. The POX system is seen to become relatively expensive as gas prices rise. Figure 7b shows the sensitivity to electricity prices. Not surprisingly, the results for the on-site electrolyzer are most affected by these changes. In fact, if the higher, doubled price represents wind power, then renewable electrolysis is not as attractive as it initially appeared, compared to other options.

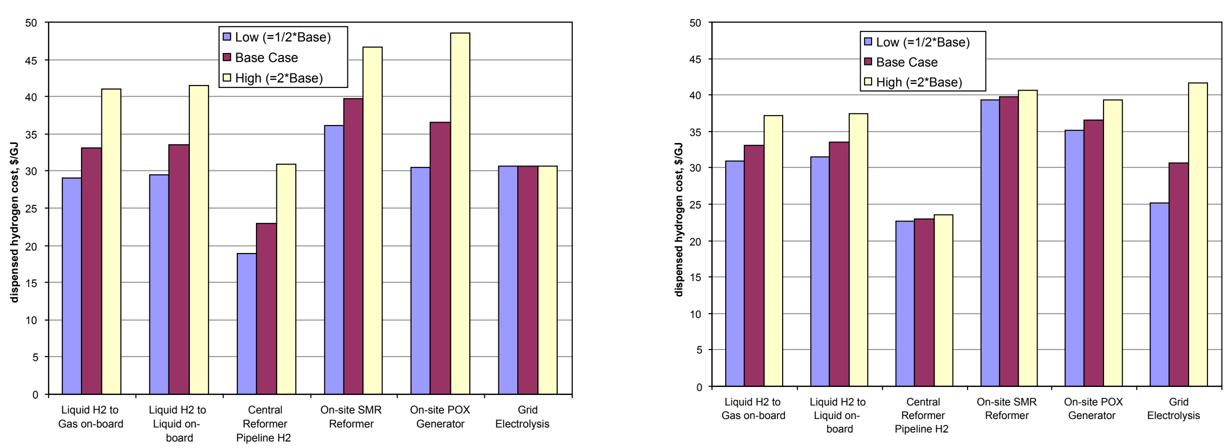

Figure 7a&b. Sensitivity of Dispensed H_2 Cost ($/GJ) to a) Natural Gas and b) Electricity Prices

Sensitivity to the Costs of Upstream Infrastructure

The original base case analyses were built around an assumption that refueling stations would be served from hydrogen resources already in place. Therefore, the cost of dispensed hydrogen did not reflect the need for new, central hydrogen production facilities elsewhere. The study team considered this situation unrealistic for the long-term and wondered what the cost of building upstream infrastructure would mean to the conclusions regarding preferred station selection. As this was seen as in important policy issue, new cases were added to the study. These include the cost of building new large central reformers (when current capacity is exceeded) and the cost of building new hydrogen pipelines where none currently exist.

<u>Central Reformer Development</u> The cost of a central reformer has been estimated as $340 million for a 153 MSCF/day plant, which is representative of a very large scale plant [10]. If the proportional capital cost is included along with the capital cost of the station (i.e., the fraction corresponding to 100 vehicles per day, or 0.165 MSCF/day), this adds $368,000 to the capital cost for those systems using bulk hydrogen. When computing this addition, plus corresponding O&M, the additional cost of dispensed hydrogen is 3.4$/GJ. This represents about a 10% increase in the cost of dispensed hydrogen for the two scenarios using bulk liquid hydrogen.

<u>Pipeline Development</u> Hydrogen pipelines exist is several places in the U.S., mostly in the vicinity of large refinery capacity [11]. Here, pipelines are used to ship by-product hydrogen short distances for industrial uses. Where pipelines do not exist, they could be built. Conversion of natural gas pipelines to hydrogen has also been proposed, but that option has not been evaluated in this study. It has been stated that construction of new hydrogen pipelines would be extremely expensive and such investment would not be made [12]. However, several studies and this estimate of pipeline installation costs seem to indicate that, within the larger picture of developing hydrogen fueling infrastructure, the construction of pipelines should not be categorically eliminated.

In this sensitivity study, the estimates of Ogden [13], Richards [14], and Amos [11] have been used to show the impact of including the construction of new hydrogen pipelines in the station infrastructure cost. Both Ogden and Richards has estimated a hydrogen pipeline cost for an urban area of $1M per mile. Amos' estimates range from $200,000 to $2 million / mile, for a range of conditions. Ogden further estimates the marginal, addition to the cost of new pipeline using a formula based on distance and mass flow [10]:

*$/GJ = 1.2 * distance in km / flow rate in million scf / day.*

Ogden limited her estimate to the mass flow range of 1 to 20 MSCF/day. For the current modeling, a value of $1M / mile for the flowrate range 10 to 20 MSCF/day was adopted. The proportional share of the pipeline capital cost was then added to the station capital cost for the pipeline case.

Figure 8 shows the impact of including upstream infrastructure costs into the calculation for dispensed hydrogen cost for the 100-vehicle station. The calculation assumes there are enough stations to share the full cost of the new infrastructure. A central reformer producing 153 MSCF/day would supply over 900 stations. A pipeline carrying 10 MSCF/day would serve 15 stations.

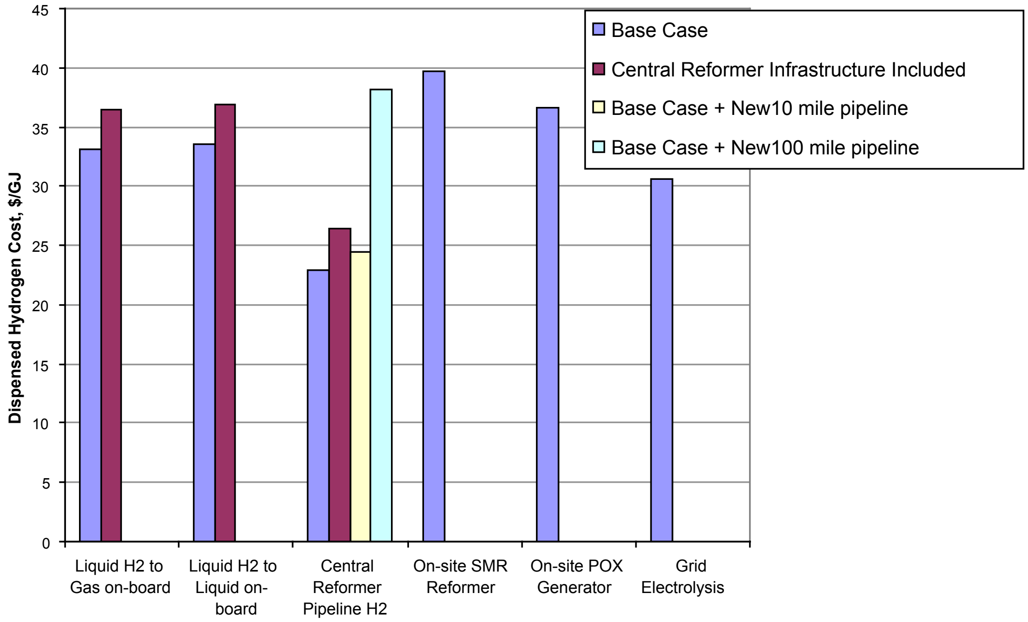

Figure 8. Cost Impact of Including Upstream Infrastructure Costs for Delivered Hydrogen

The two cases using bulk delivered liquid hydrogen show an increased cost of 3.375 $/GJ or about 10%. This assumes the same delivery distance (500 miles, or 1000 miles round trip) as the base cases. The pipeline case has 3 new results:

- the case of including new reformer capacity into the system capital cost,
- the case of including a new 10-mile pipeline (but not the central reformer) into the system capital cost, and
- the case of including a new 100-mile pipeline.

The 10-mile pipeline adds approximately 2$/GJ or about 8%. The 100 mile pipeline adds 12$/GJ, or about 50%. Thus, the overall general conclusion is that adding this upstream infrastructure does not necessarily price bulk hydrogen options out of the market for future refueling stations. The pipeline case is probably limited to a regional or urban area, however, because of the strong cost sensitivity to distance.

Emissions Analysis

Although an analysis of hydrogen refueling infrastructure was the major emphasis of this study, the IEA Annex was also interested in looking at alternative end-use scenarios to hydrogen fuel cell vehicles. Other fuels and vehicle configurations have been proposed for a clean future. The primary figures of merit for this part of the study were fuel economy and emissions. Tailpipe and local or station emission results are reported here. (Complete life cycle assessments have been prepared by other members of the Annex.)

Alternative vehicle configurations fall into the following categories

- Alternative hydrogen power plants: fuel cell or internal combustion engine (ICE)
- Alternative hydrogen storage types: compressed gas, cryogenic liquid, or metal hydride
- Alternative fuels for on-board storage (and reforming): hydrogen, methanol, or gasoline

- Alternative vehicle types: battery hybrid and advanced ICE, such as PNGV vehicles (The battery hybrid is considered the most likely competition for near-term clean vehicles.)

Fuel economy estimates were required in the analysis of tailpipe emissions. The fuel economy analysis was based primarily on other estimates, i.e., estimates from other sources were summarized and compared. Major sources were recent DTI studies [15,16] and more recent PSI results [17]. Some parameters that were considered in an attempt to find consistency among the studies were: vehicle weight, vehicle driving range, and driving cycle. Vehicle weight is impacted by the type of power plant, type of storage system, and the fuel type. As an example, for a base case vehicle weight of 900 kg, each additional kg of storage weight contributes 1.5 kg of vehicle weight [15].

Emissions results are also based primarily on other studies. These were also surveyed and compared. To help illustrate the local environmental impact, tailpipe and station emissions were estimated independently, although it was difficult in some studies to separate fueling operations emissions from the total. For the methanol and gasoline fueled vehicles, results are based on previous work by Ogden [13] and The American Methanol Foundation [18]. Methanol and gasoline stations are assumed to be similar to the hydrogen station, i.e., they have the same vehicle refueling capacity and same typical urban location. The methanol and gasoline storage tanks are assumed to be filled by weekly truck delivery, as in the hydrogen case. The diesel delivery trucks and the delivery process contribute to the local pollution; U.S. Environmental Protection Agency (EPA) data were used to estimate this impact.

Other specific assumptions for the emissions analysis included:
- Where available, actual vehicle data were used.
- Modeled vehicles were based on 900 kg PNGV Glider for DTI [16] and 650 kg Renault Twingo for PSI studies [17].
- The station was sized to serve 100 cars per day with 300-mile range per fill-up. Thus, the on-site storage capacity is a function of the assumed fuel economy of the vehicles.
- Fuel delivery trucks spend 3 hours per delivery (once per week) in the local, urban area, traveling an average of 20 mph, except for battery hybrid vehicle stations, which are serviced once every two weeks.
- Fuel delivery trucks are assumed to be powered by a heavy-duty diesel engines and have a fuel economy of 6.7 miles per gallon, based on Ref. [19].
- On-site POX generators produce emissions similar to the SMR, multiplied by 1.73, per Ref. [20].

Composite tailpipe emission results are shown in Figure 9. Details can be found in Ref. [7]. These give a graphical representation of the dramatic reduction in tailpipe emissions from hydrogen vehicles compared to all other alternatives.

Emissions from station operations or delivery of fuel to the station have been estimated for the various station configurations. These are primarily engine pollutants from diesel delivery trucks, fuel volatiles (so called "marketing emissions") for gasoline and methanol delivery, and green house gases for the cases with on-site hydrogen production from natural gas. The two cases with virtually no local emissions are the pipeline delivery of hydrogen and hydrogen production by electrolysis. For these two cases the major emissions occur elsewhere - at the central reformer and/or electric power station. Only renewable production of hydrogen avoids real-time air emissions throughout the system. Local emission results (in kg of pollutant per year) are shown in Figures 10a for green house gases and volatile organic compounds, and in 10b for CO, NO_x, SO_x, and particulates. Note the different scales for the two figures.

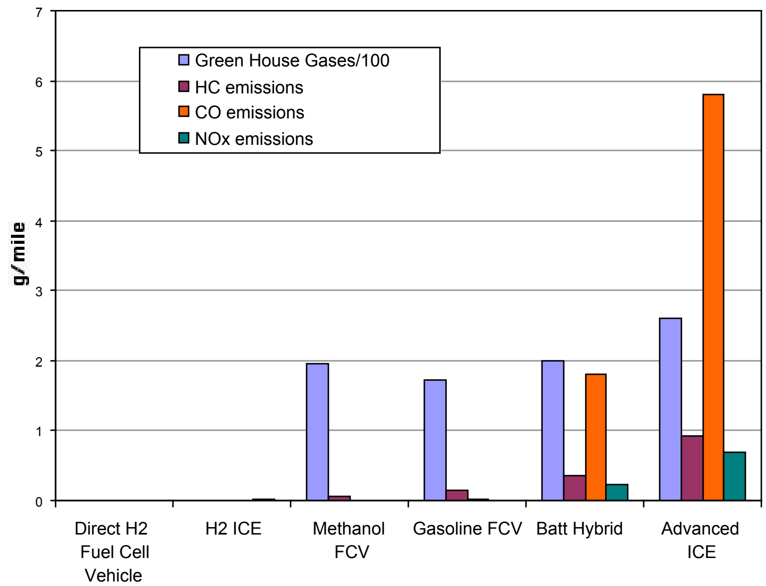

Figure 9. Composite Presentation of Tailpipe Emissions for Alternative Vehicles

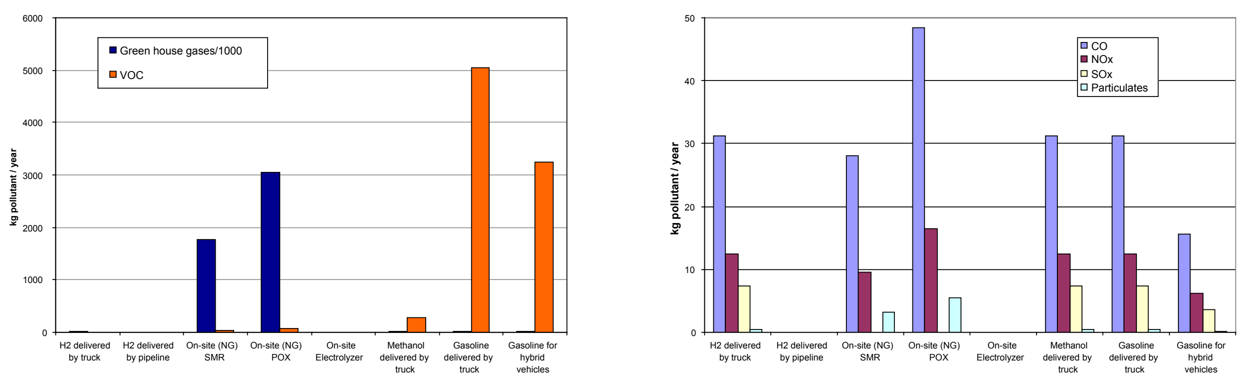

Figure 10a&b. Local Air Pollutants from Alternative Refueling Stations, kg/year

Summary

- The cost of dispensed hydrogen is generally greater for on-site production of hydrogen.
- When the station is underutilized, the cost of dispensed 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 cost of dispensed hydrogen is even higher when the utilization factor is less than 100%.
- A larger station would serve less expensive hydrogen fuel if fully utilized, but the comparison of options does not change significantly, i.e., pipeline hydrogen is least expensive, where available.

- Increasing costs of natural gas increase the cost of dispensed hydrogen for all cases, except on-site electrolysis.
- On-site electrolysis is most significantly affected by changes in the cost of electricity. Doubling electricity costs, which might be representative of current wind power costs, makes on-site electrolysis unattractive compared to other cases.
- Including the cost of upstream infrastructure in the system cost does not necessarily make bulk delivered hydrogen noncompetitive. Building a very large central reformer adds only about 10% to the cost of bulk hydrogen options.
- Pipeline costs depend on distance and flowrate. Modest volumes of hydrogen can be delivered regionally (within about 100 miles) at an infrastructure cost that still keeps the dispensed cost of hydrogen competitive with other options.
- Tailpipe emissions for hydrogen vehicles are zero or negligible, making hydrogen vehicles the best choice for urban driving. Station emissions for hydrogen stations are lowest for pipeline hydrogen and on-site production by electrolysis.

Conclusions

This analysis has shown that various options for hydrogen infrastructure are possible, and that the least costly option may vary with location, local pricing of gas or electricity, and technology maturity. Near-term options using hydrogen delivered from existing sources are quite feasible. The longer-term options include building new central production and distribution facilities. On-site generation requires development of commercial subsystems. The urgency of reduced local emissions can be met with hydrogen-fueled vehicles and clean hydrogen brought in by pipeline or produced by electrolysis.

Acknowledgements

This work has been sponsored by the United States Department of Energy, Hydrogen Program.

References

1. R. Glöckner, et al, "Integrating Renewables for Remote Fuel Systems," Proc. 18th World Energy Congress, Buenos Aires, Argentina, World Energy Council: London, 2001; www.worldenergy.org
2. A. de Groot, et al, "Hydrogen Systems for Residential Developments," Proc. 18th World Energy Congress, Buenos Aires, Argentina, World Energy Council: London, 2001; www.worldenergy.org
3. S. Schoenung, "IEA Hydrogen Annex 13, Transportation Applications Analysis," Proc. DOE Hydrogen Peer Review, 2001
4. S. Schoenung, "Hydrogen Vehicle Refueling Infrastructure Alternatives: An Analysis Developed for the International Energy Agency," Proc. 11th Canadian Hydrogen Conference, Victoria, Canada, June 2001
5. S. Schoenung, "Hydrogen Vehicle Refueling Station Alternatives: An Analysis Developed for the International Energy Agency," Proc. 35th Intersociety Energy Conversion Engineering Conference, Savannah, GA, July 2001
6. S. Schoenung, "Hydrogen Vehicle Fueling Alternatives: An Analysis Developed for the International Energy Agency," in SAE Publication SP-1635: Fuel Cells and Alternative Fuels/Energy Systems, 2001.
7. S. Schoenung, "IEA Hydrogen Annex 13, Transportation Applications Analysis" final report to DOE, cooperative agreement no. DE-FC36-00GO10607, 2002

8. C. E.,Thomas, Directed Technologies, Inc., personal communication based on report to Ford Motor Company, May 2001
9. Susan Horgan, "Implementing Distributed Energy Resources," report to the Federal Energy Management Program, November 2001
10. Joan M. Ogden, Adam B. Cox, and Jason W. White, "Case Study of Developing a Hydrogen Vehicle Refueling Infrastructure in Southern California," DOE report, December, 1996
11. W. A. Amos, "Costs of Storing and Transporting Hydrogen," NREL Report No. NREL/TP-570-25106, 1998
12. Larry Watkins, South Coast Air Quality Management District, personal communication, October 2001
13. Joan M. Ogden, Margaret M. Steinbugler, and Thomas G. Kreutz, 'A Comparison of Hydrogen, Methanol, and Gasoline as Fuels for Fuel Cell Vehicles: Implications for Vehicle Design and Infrastructure Development," Journal of Power Sources, December 1998
14. Jeff Richards, Praxair, personal communication, May 2001
15. C. E. Thomas, et al. "Integrated Analysis of Hydrogen Passenger Vehicle Transportation Pathways," March 1998, NREL subcontract report no. AXE-6-16685-01
16. C. E. Thomas, "PNGV-Class Vehicle Analysis," Task 3 Final Report, June 1999, NREL subcontract report no. ACG-8-18012-01
17. A. Röder, "Life-Cycle Inventory of Different Car Powertrains – Final Report," Oct. 30, 2000, Paul Scherrer Institute, Villigen, Switzerland
18. EA Engineering, Science and Technology, Inc., "Methanol Refueling Station Costs," February 1, 1999, The American Methanol Foundation
19. "Update Heavy-Duty Engine Emission Conversion Factors for MOBILE6: Analysis of Fuel Economy, Non-Engine Fuel Economy Improvements, and Fuel Densities," U.S. Environmental Protection Agency report, EPA 420-P-98-014, May 1998
20. Methanex Corporation, "Greenhouse Gas Emissions," June 27, 2000. Methanex web site: www.methanex.com