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The Hydrogen Futures Simulation Model (H_2Sim) Technical Description

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ABSTRACT

Hydrogen has the potential to become an integral part of our energy transportation and heat and power sectors in the coming decades and offers a possible solution to many of the problems associated with a heavy reliance on oil and other fossil fuels. The Hydrogen Futures Simulation Model (H_2Sim) was developed to provide a high level, internally consistent, strategic tool for evaluating the economic and environmental trade offs of alternative hydrogen production, storage, transport and end use options in the year 2020. Based on the model's default assumptions, estimated hydrogen production costs range from 0.68 $/kg for coal gasification to as high as 5.64 $/kg for centralized electrolysis using solar PV. This basic result does not change if carbon capture and sequestration costs are added ($0.16/kg). This result is fairly insensitive. For example, coal prices would have to more than triple or the assumed capital cost would have to increase by more than 2.5 times for natural gas reformation to become the cheaper option. Alternatively, natural gas prices would have to fall below $2/MBtu to compete with coal gasification. The electrolysis results are highly sensitive to electricity costs, but electrolysis only becomes cost competitive with other options when electricity drops below 1 cent/kWhr.

Delivered hydrogen costs are likely to be double the estimated production costs due to the inherent difficulties associated with storing, transporting, and dispensing hydrogen due to its low volumetric density. H2Sim estimates distribution costs ranging from 1.37 $/kg (low distance, low production) to 3.23 $/kg (long distance, high production volumes, carbon sequestration). Distributed hydrogen production options, such as on site natural gas, would avoid some of these costs.

H2Sim compares the per mile driving costs (fuel, capital, maintenance, license, and registration) of existing internal combustion engine (ICE) vehicles (0.55$/mile), hybrids (0.56 $/mile), and electric vehicles (0.82-0.84 $/mile) with 2020 fuel cell vehicles (FCVs) (0.64-0.66 $/mile), fuel cell vehicles with onboard gasoline reformation (FCVOB) (0.70 $/mile), and direct combustion hydrogen hybrid vehicles (H_2Hybrid) (0.55-0.59 $/mile). The results suggests that while the H2Hybrid vehicle may be competitive with ICE vehicles, it will be difficult for the FCV to compete without significant increases in gasoline prices, reduced predicted vehicle costs, stringent carbon policies, or unless they can offer the consumer something existing vehicles can't, such as on demand power, lower emissions, or better performance.

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Introduction

Hydrogen has the potential to become an integral part of our energy transportation and heat and power sectors in the coming decades. A hydrogen future offers a possible solution to many of the problems associated with a heavy reliance on oil and other fossil fuels. There are also many competing visions for a future hydrogen economy. Some suggest a decentralized approach, where hydrogen is produced at the fueling station or even at the household level by reforming natural gas or utilizing electrolysis. Others suggest a more centralized approach, producing the hydrogen at large, centrally located plants and distributing the hydrogen by pipeline, truck, rail, or ship. How the hydrogen economy will evolve is dependant on several factors, ranging from economics to government policies. The Hydrogen Futures Simulation Model (H_2Sim) was developed to provide a high level, internally consistent, strategic tool for evaluating the economic and environmental trade offs of alternative hydrogen production, storage, transport and end use options.

H_2Sim was developed as a two year, internally funded, Sandia research project. This report provides a technical overview of the model, including key technologic and economic assumptions. The report summarizes key results and provides a detailed sensitivity analysis.

Figure 1 illustrates potential pathways for hydrogen production and distribution. Several production technologies exist that can separate hydrogen from various feedstocks, including natural gas, coal, crude oil, and water. Transportation options include trucks, rail, ships, or pipelines. Depending on the system configuration, hydrogen may need to be stored at the production facility prior to transportation to the fueling station. Hydrogen can be stored as a gas, a liquid, or trapped in a solid medium (metal hydrides). Finally, several options for using hydrogen (end use) exist. In the transportation sector, hydrogen can be converted to electricity in fuel cells that power an electric motor or directly combusted in internal combustion engines. Similarly, hydrogen can be used in stationary systems to provide both electricity and heat for residential, commercial or industrial applications.

A hydrogen future could provide many environmental benefits. The lack of tailpipe emissions would significantly improve urban air quality. Hydrogen also offers the potential of reducing future emissions of carbon dioxide, a key greenhouse gas. However, if the hydrogen is derived from hydrocarbons, the carbon must be sequestered to gain this environmental benefit. Several methods for carbon sequestration are in use today or have been demonstrated at the pilot scale, and other hypothetical methods have been developed.

H_2Sim allows the user to vary production processes, as well as storage and transportation options for delivering hydrogen for use in the transportation sector or for stationary cells. H_2Sim also includes options for carbon sequestration. While Figure 1 illustrates several potential sequestration options, H_2Sim currently limits the options to include sequestration in underground wells, such as depleted reservoirs. H_2Sim does not provide a detailed end use analysis for stationary applications. This may be an option in future versions.

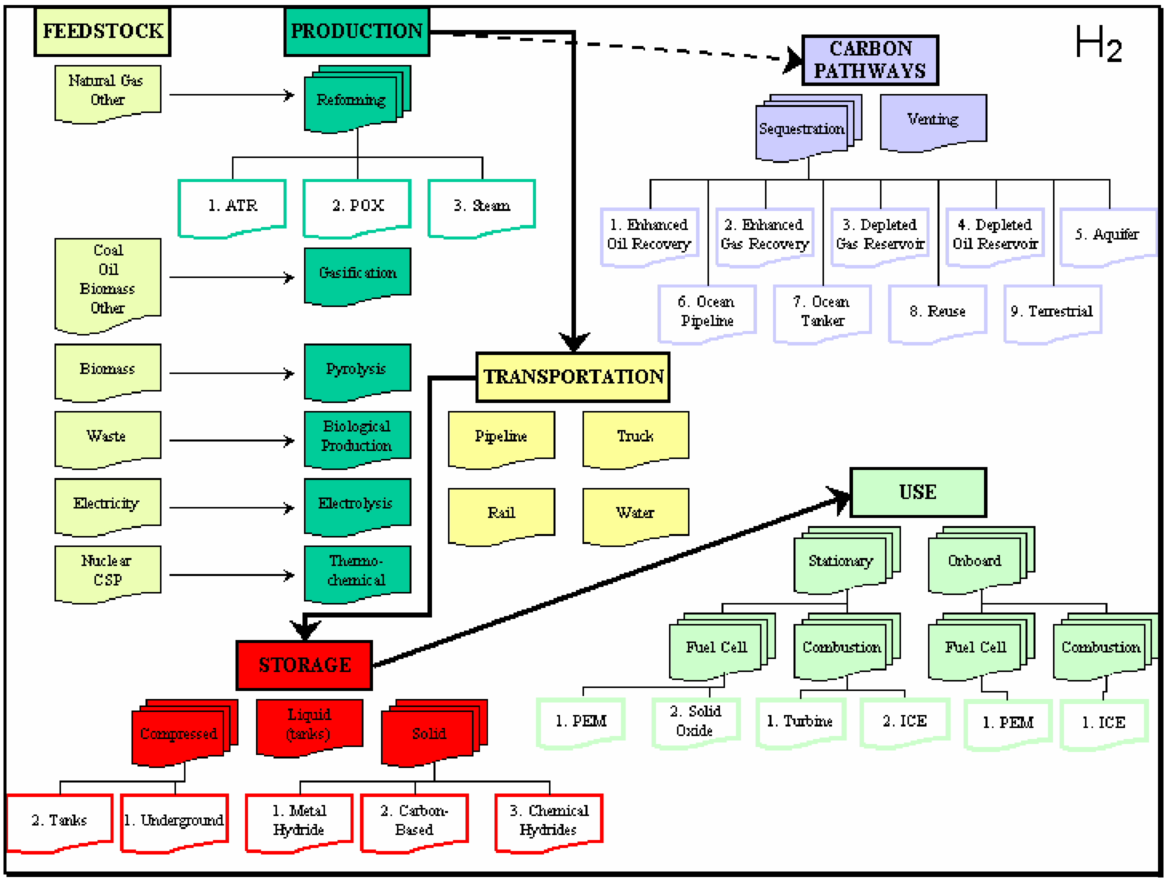


Figure 1. Hydrogen Pathways

Several other groups have conducted detailed economic analyses of various hydrogen technologies. Padró and Putsche (1999) provided an excellent overview of the costs for different technologies, and an extensive list of references. Several works from the National Renewable Energy Laboratory (NREL) examined hydrogen costs, including Amos (1998), Mann (1995), Spath and Mann (2001), and Simbeck and Chang (2002). Thomas and co-workers (1995, 1999) have completed a series of economic studies of hydrogen applied to various production paths and distribution schemes. Ogden *et al.* (1998, 1999) have performed economic analysis of a variety of hydrogen infrastructure schemes, including regional case studies. Williams (1996, 2001) and Blok *et al.* (1995) included carbon sequestration in the economic analyses. Mintz et al. (2002) analyzed different pathways to supply hydrogen for vehicles. In addition to the existing studies, a significant effort to standardize the economic analysis is being supported by the Department of Energy (DOE). With the lead of researchers at National Renewable

Energy Laboratory (NREL), the “H2A” project is an attempt to pull together those working for DOE on hydrogen economic models to standardize the methodology.

What sets the Sandia effort apart from other efforts to construct economic models for hydrogen is the integration of the hydrogen system components into a software-learning tool that easily can be used for parametric studies. The baseline values used in the model were gleaned from the literature or from Sandia experts, but the user can vary the parameters and examine their effect on the cost of hydrogen. While the model is generic, in that it does not apply to a specific region, it provides a high-level picture of the cost trade-offs that would have to be more carefully examined for specific applications.

The paper begins with a review of the model assumptions and methodology. This is followed with results and a detailed sensitivity analysis. The final section discusses insights from the model, specifically what it implies about the future for hydrogen.

Production

Although hydrogen is an abundant resource, it is not found in its elemental form. Hydrogen production involves stripping the hydrogen out of hydrocarbons or water. Several production options exist, including: steam reformation of hydrocarbons, usually natural gas; coal gasification; electrolysis; or thermo-chemical processes, utilizing high temperature heat from nuclear or concentrated solar power technologies.

Some of these production technologies are commercially available already (reformation, gasification, NPO, and electrolysis), whereas others are potential future options (thermochemical processes). Certain technologies only make sense for large-scale, centralized hydrogen production (coal gasification and thermochemical nuclear), whereas others offer a decentralized, small scale solution to hydrogen production (steam reforming and electrolysis).

Global annual production of hydrogen is currently about 15.9 trillion cubic feet (NAS, 2004). Most of this hydrogen, used for a variety of chemical and manufacturing processes, is produced using fossil fuels. The 2004 NAS study estimates that of this global total, 48% comes from natural gas, 30% from oil, 18% from coal, and 4% from electrolysis.

This section explains each production option and the assumptions used in H_2Sim. For each process, there are separate capital, feedstock, and operating and maintenance (O&M) costs. As many of these technologies are not yet commercially available, it is difficult to give precise or consistent estimates for these various costs. With this in mind, H_2Sim was designed to quickly show projected production costs for a wide range of capital costs.

The methodology for calculating the capital cost component is consistent across technologies. Financing costs assume that capital expenditures are uniformly distributed over the time of construction, and assume a default real interest rate of 5%. Once operational, annual capital costs are determined by multiplying the total capital cost, including finance costs, by a capital recovery factor (CRF)[1]:

$$CRF = \frac{r\,(1+r)^n}{(1+r)^n - 1} \qquad (1)$$

where: r = real discount rate for investment (default 10%)
n = plant life (default 20 years).

[1] The CRF calculates the annual revenue required to pay off the capital expenditure, including all financing costs. H_2Sim does not include consideration of taxes.

The base case, or default assumptions of H_2Sim are summarized in Table 1. For each option, the base case assumptions use projected cost and performance estimates for 2020, as reported in the literature, or as estimated by experts at Sandia National Laboratories.[2] As some of these technologies are not yet commercially available, such as the thermochemical processes, significant uncertainty exists. H_2Sim is designed to illustrate hydrogen production costs for a wide range of capital costs, allowing the user to understand the sensitivity of the estimated target costs. All numbers in this paper are reported in terms of the hydrogen content. For example, production facilities are reported in units of "MW-H_2." A MW of installed hydrogen capacity is equal to 720 kg/day[3] on a lower heating value[4] basis.[5]

Table 1. Production Facility Assumptions

Production Method	Capital Cost	O&M Cost	Thermal Efficiency	Capacity Factor	Construction Time	Facility Size
	\$/kW-H_2	\$/kWhr- H_2	%		years	MW- H_2
Reformation	500.9	0.00452	70.0	100	3	138
Coal Gasification	592.4	0.00337	70.3	80	4	1000
Electrolysis	300.0	0.00109	70 [1]	100	1	500
Therm. Ch. CSP	593.6	0.01200	45 [1]	69	3	497
Therm. Ch. Nuclear	669.0	0.00135	43 [1]	90	3	600
NPO	500.5	0.00254	36.8	90	3	100

[1]Efficiencies are for production process, not fuel converison.

Each production option is discussed in additional detail below.

Steam Methane Reformation

Steam reforming of hydrocarbons is the most widely used method for producing hydrogen today. The most common feedstock for this process is methane. The basic process involves steam heating of the hydrocarbon in a catalytic reactor, resulting in hydrogen and carbon dioxide:

$CH_4 + 2H_2O \rightarrow CO_2 + 4H_2$

[2] The estimates for NPO are estimates for currently operating processes; we do not assume considerable improvement in these costs over the forecast period.
[3] 1 MW*J/s/W*3600s/hr*24hr/day*kg/120MJ = 720 kg/day.
[4] H_2Sim uses the lower heating value of hydrogen, 120 MJ/kg, for all calculations. Others, including Williams, utilize the higher heating value of 142 MJ/kg. The lower heating value refers to the energy available in converting hydrogen to steam, whereas the higher heating value assumes the output is liquid.
[5] Similarly, a capital cost estimate of 100 \$/kW-H_2 translates into a capital cost of 138 \$-day/kg (100\$sec/kJ*120,000kJ/kg*hr/3600s*day/24 hr = 138 \$ day/kg.) The use of \$/kW-H_2 makes it much easier to compare to costs of installed electrical capacity.

Doctor (2003) notes that about 96% of the hydrogen produced for commercial use (merchant) is produced using this process.

Steam reforming is an option for either large scale centralized facilities or small scale decentralized facilities, such as at the fueling station or even the home. There are some economies of scale; Nemanich (2003) estimates costs are minimized for a plant size of 138 MW-H_2, or 100,000 kg H_2/day.[6] However, decentralized facilities eliminate or greatly reduce transportation and storage costs.

Based on a review of the literature, an estimate for the relationship between reforming facility size and capital cost is:

$$P_{Capital} = P_o \left(M_{H_2}\right)^A \qquad (2)$$

where: P_o = 22,000 \$/yr
M_{H2} = the production rate (kg/day)
A = a scaling factor (default = 0.7)

This functional form was estimated statistically for values found in the literature, as shown in Figure 2. The references identified by the symbols were used as data sources. An estimated relationship from Blok *et al.* (1997) is shown for comparison; this line is well below our estimate and includes a different slope, indicating that is remaining uncertainty regarding these estimates. Equation 2 is not actually used by H_2Sim, as H_2Sim calculates hydrogen production costs for all assumed capital costs. Rather, this equation is useful for considering questions of scale, including the projected capital costs associated with smaller, distributed reformers.

Using equation (2), the capital cost for a 100,000 kg/day facility would be \$69.5 million, or approximately 500 \$/kW- H_2; the capital costs for a smaller 1,000 kg/day facility (possibly located at a fueling station) would be \$2.8 million, or about 2000 \$/kW- H_2. However, this higher capital cost may be more than offset by reduced storage and transportation costs. For comparison, Thomas et al. (1997) suggest lower costs may be possible for mass produced units: 1120 \$/kW for a 450 kg/day unit and 2029 \$/kW for a 100 kg/day unit.

Feedstock costs consider the cost of the input, natural gas ($P_{feedstock}$), and the overall efficiency, η, of converting that feedstock to hydrogen. The basic relationship is:

$$P_{Fuel} = \frac{P_{feedstock}}{\eta} \qquad (3)$$

H_2Sim uses a default thermal efficiency of 70%.

[6] Nemanich estimates that a 100,000 kg/day facility could fuel 150,000 cars.

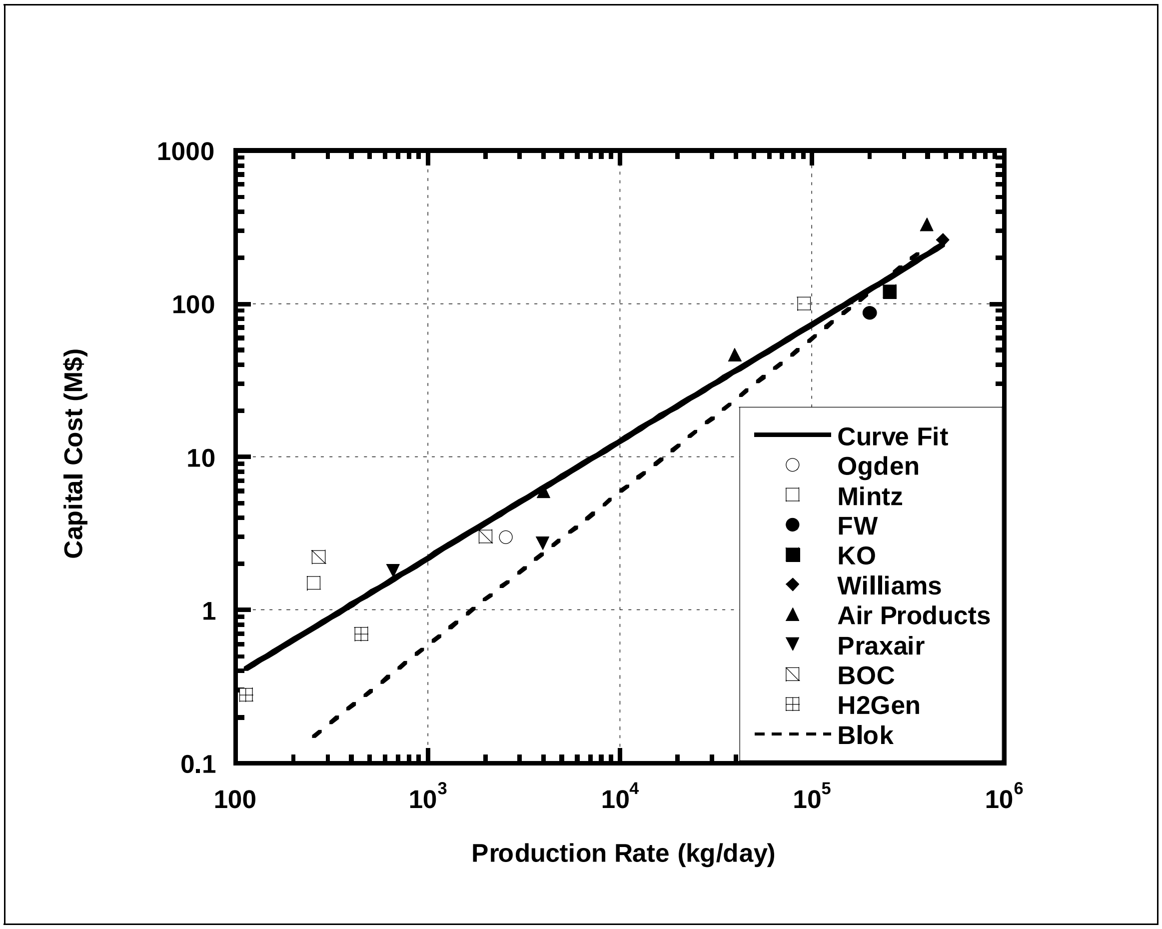


Figure 2. Derived Relationship between Capital Cost and Production Capacity (Rate)

SMR production costs are very sensitive to the price of the feedstock. One of the disadvantages to the widespread use of SMR is the potential for volatility of natural gas prices, although such risks can be managed through financial contracts and hedging mechanisms. Nemenich (2003) estimates that SMR is competitive with hydrogen from coal gasification if natural gas prices are less than 3.00 $/MBtu. The delivered costs of natural gas to electric utility plants averaged 5.46 $/MBtu, 3.61 $/MBtu, and 4.52 $/MBtu in 2003, 2002, and 2001, respectively. Natural gas prices peaked at a high of 9.36 $/MBtu in January 2001. For the same years (2003-2001), coal prices averaged: 1.27 $/MBtu, 1.26 $/MBtu, and 1.23 $/MBtu (DOE, 2004). The DOE long term projections assume natural gas prices will average 4.78 $/MBtu[7] by 2025.

The literature review suggests that O&M costs for a 100,000 kg/day SMR facility range from 3 to 8 million $/year. Williams (2001) assumes that O&M costs are a fixed fraction

[7] AEO 2003. Supplemental Table 20 (2003$).

of overnight capital costs (4% per year). For the 100,000 kg/day facility mentioned above, this would imply O&M costs of $2.8 million/year, at the low end of the literature range.

Coal Gasification

Hydrogen can also be produced by gasifying coal. Unlike steam reforming technologies, coal gasification only makes sense as a centralized production option due to economies of scale. Several proponents of this option, including Williams (2001), argue that for countries with large reserves, such as the U.S., India, and China, coal gasification, along with sequestration of the carbon, may be the least expensive and most attractive option for the large scale supply of hydrogen.

The basic process involves gasifying coal using oxygen and steam to produce synthesis gas (CO and H_2), and then separating out the H_2 for delivery at 60 bar.[8] The process also produces electricity.[9]

Williams estimates capital costs, without sequestration, of $592.4 million for a 1000 MW- H_2 facility operating in 2020 (2001$). Annual capital costs are a function of financed capital costs, construction time, and the capital recovery factor, as given by equation (1).

As with reformation, feedstock costs are determined using equation (3). The default thermal efficiency is 70.3%, as estimated by Williams (2001). H_2Sim assumes O&M costs equal to 4% of overnight capital costs, as suggested by Williams (2001).

Electrolysis

Electrolysis is a commercially viable technology for producing hydrogen and is used today for production of pure oxygen for uses in places such as hospitals and submarines. The basic process is well known: by placing positive and negative electrodes in water, the water is disassociated into hydrogen and oxygen. Evidence is mixed whether there are real economies of scale associated with this option, possibly making it an ideal source for decentralized production of hydrogen, thus avoiding the transportation and possibly all of the storage costs. However, electricity or the associated fuel must still be transported. The main cost associated with this option is the electricity.

[8] Williams (2001) provides details of the process.
[9] H2Sim does not currently consider electricity credits in the economic analysis; including these credits may further reduce projected costs, depending on the specific assumptions. Likewise, this analysis does not consider possible O_2 credits associated with the electrolysis option.

Proponents of this option suggest the use of cheap, off peak electricity to produce hydrogen. However, this only works for small scale production, as peak electricity prices would begin increasing as demand increased. The under use of the electrolysis equipment itself would also increase projected costs (producing less hydrogen with same capital costs). In a full scale hydrogen economy, wide scale use of electrolysis would require the construction of significant additional generation capability. Several energy industry groups including both renewable and nuclear energy groups, suggest their technology could power distributed electrolysis systems, providing hydrogen at either the fueling station or even at the household level. For example, the Nuclear Energy Institute (NEI) quotes an estimate by Walters, Wade, and Lewis that 240 new nuclear plants in the U.S. could power the entire transportation sector of the U.S.[10]

There is a wide range of estimates for capital costs for electrolyzers, Figure 3, depending on type and size. While proton exchange membrane (PEM) electrolyzers are currently around 1000 $/kW, several sources suggest that these costs could fall to around $300/kW by 2020 if these units are mass produced (NAS, 2004; Williams, 2001; and Schroeder, 2003). Others, including Thomas (2003), suggest the 300 $/kW target is highly optimistic, noting that current electrolyzers often exceed 2000 $/kW, Figure 3.

The efficiency of the electrolysis process is estimated to be between 70 and 85 percent. The default efficiency in H_2Sim is 70%. Williams (2001) estimates low operation and maintenance costs at approximately one tenth of a cent per kWhr used. However, as previously mentioned, the primary cost of electrolysis is the electricity required to perform the process.

Electricity costs are projected by H_2Sim for advanced coal, combined cycle natural gas, natural gas combustion turbines, nuclear, wind, solar thermal, and solar photovoltaic (PV).[11] Projected prices are for the production costs from plants built in 2020 and equipped with the best available pollution control technologies (BACT). Assumptions about capital and feedstock costs for the new generating facilities are taken from the EIA (2002). The key assumptions are summarized in Table 2. All dollar figures are in 2003 dollars. While H_2Sim defaults to these assumptions, the user can vary the assumptions and view the implications for electricity, and hence electrolysis produced hydrogen, costs. For example, the user can explore the affect of extended electricity plant construction time or test the economic competitiveness of combined cycle plants at higher projected natural gas prices (Drennen et al., 2003b).

[10] Estimate assumes US cars travel 2600 billion miles per year and need 0.013 kg H2/mile driven (Walters et al, 2002).
[11] The costs given in this paper are for newest available technologies for each option.

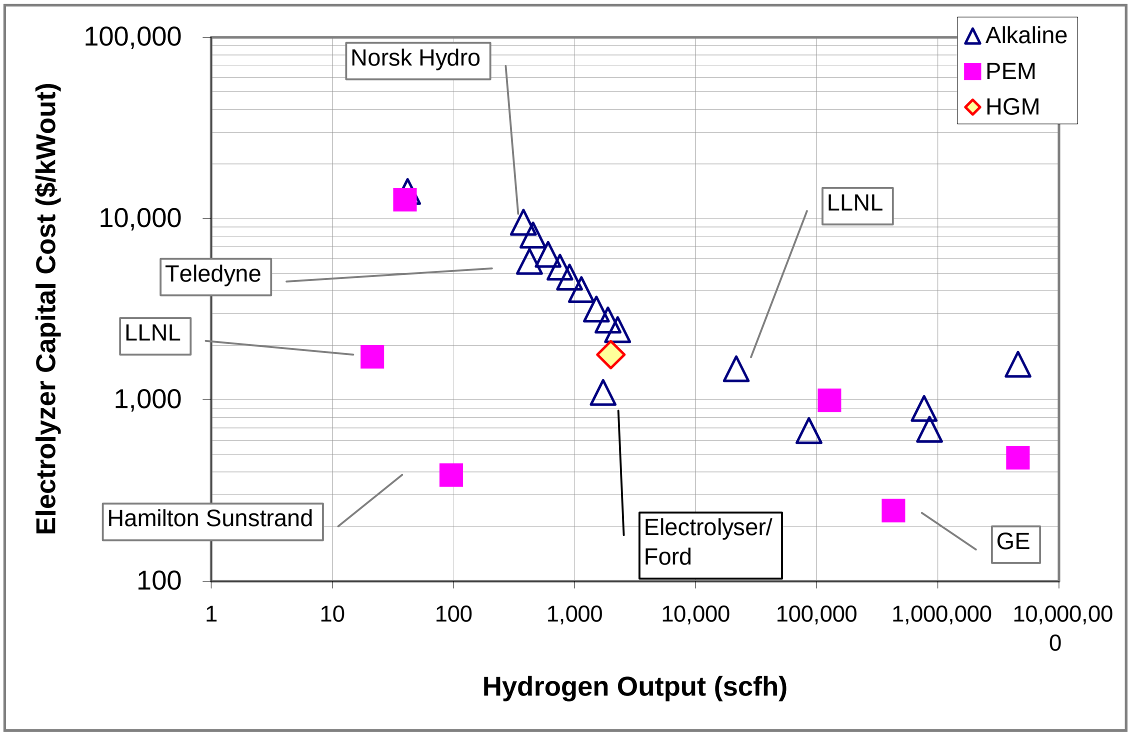


Figure 3. Estimated Electrolyzer Costs (Thomas, 2003)

Table 2. Cost and Performance Characteristics for New Generating Plants (2003 $)

	Capital ($/kW)	Fixed O&M ($/kW)	Variable O&M ($/kWhr)	Fuel ($/MBtu)	Years to Construct	Plant Size (MW)	Average Capacity Factor (%)	Heat Rate (MBtu/ kWhr)
Nuclear	1846	60.84	0.00045	0.43	5	600	90	10400
Coal	1225	25.51	0.00319	1.17	4	400	85	7200
Gas CC	485	10.63	0.00212	4.47	3	400	85	6350
Gas CT	348	8.50	0.00319	4.47	2	120	30	8550
Solar PV	2301	10.47	0	0	2	5	30	10280
Solar Thermal	2159	50.88	0	0	3	100	42	10280
Wind	985	27.15	0	0	3	50	42	0

The electricity production costs estimated in H_2Sim are the levelized costs of electricity (LCOE) over the life of the plant. LCOE are often used as an economic measure of electricity costs as it allows for comparison of technologies with different capital and operating costs over time, as well as different construction times, capacity factors and plant lives. H_2Sim calculates the LCOE before taxes, as taxes vary across regions and tax status of the producer (public vs. private producer).[12] The LCOE calculation is given by:

$$LCOE = \frac{((I * CRF) + O\,\&\,M + E + F)}{Q} \qquad (4)$$

where: I = capital investment, including financing charges (interest rate initially set at 5%)

CRF = capital recovery factor

Q = annual plant output (kWhr)

O&M = fixed and variable O&M

E = externality costs

F = fuel costs.

The electricity prices estimated by H_2Sim are at the plant gate; if hydrogen production is not done onsite, one must also include transmission and distribution costs, typically in the 2 cent/kWhr range. H_2Sim allows the user to evaluate the impact of these prices on hydrogen, as well as consider the impact of off peak electricity. Table 3 summarizes the default assumptions about electricity costs in 2020.

Table 3. Projected 2020 Electricity Costs from GenSim (Drennen et al., 2003)

	Electricity Cost (cents/kWhr)
Nuclear	4.55
Coal	3.69
Gas CC	4.04
Gas CT	6.12
Solar PV	11.47
Solar Thermal	8.99
Wind	4.21

[12] Alternative methods of calculating LCOE include detailed tax and depreciation considerations. Alternative methods may be incorporated into GenSim (Drennen et al., 2003) in future versions.

Thermochemical Processes

Thermochemical processes can produce hydrogen from water using high temperature heat from either nuclear or concentrated solar power (CSP). There are over a hundred thermochemical cycles for hydrogen production in the operating temperature range of 600 °C to 2500 °C, where direct dissociation of water occurs. In general, as temperatures decrease, the cycles have more intermediate chemical steps and lower efficiency.

Of all the thermochemical cycles, Shultz (2003) suggests the most promising cycle is the sulfur – iodine (S-I).[13] The chemical reactions in the cycle are:

$2H_2O + SO_2 + I_2 \rightarrow 2HI + H_2SO_4$ (120° C)

$2HI \rightarrow I_2 + H_2$ (450° C)

$H_2SO_4 \rightarrow \frac{1}{2} O_2 + SO_2 + H_2O$ (800° C)

The basic process involves combining water with sulfur dioxide and iodine at temperatures of approximately 120 degrees C to form H_2SO_4 and HI. The HI can then be disassociated at 450 degrees C to produce iodine and hydrogen. The H_2SO_4 is then recycled by heating at 800 degrees C to produce oxygen, sulfur dioxide, and water.

A key advantage of the S-I cycle is that the chemicals are all recycled; there are no effluents. The key challenge is that the process requires high temperatures (800° C) and is still in the experimental stages.

Schultz (2003) has estimated the costs of a nuclear thermochemical process. We use Schultz's estimates for the S-I process to forecast comparable costs for a CSP thermochemical facility. These costs are summarized below.

Thermochemical Nuclear

Schultz (2003) estimates the costs for a nuclear thermochemical facility utilizing the S-I cycle. The estimated capital cost for the hydrogen production facility is 669 \$/kW- H_2. Schultz estimates O&M costs, including fuel and waste, are approximately 7% of the overnight capital costs, or 0.0068 \$/kWhr- H_2. As H_2Sim considers the fuel and waste disposal costs separately, based on DOE forecasts, the non-fuel O&M is 1.35 \$/MWhr-

[13] Several hundred potential thermochemical reactions exist; NAS (2004) state that the two most likely cycles for the production of hydrogen from water are the sulfur-iodine (S-I) and calcium-bromine-iron (CU-CI) cycles.

H_2. Schultz estimates that for a 50% efficient process, the cost of produced hydrogen is 1.43 \$/kg.[14]

Thermochemical Concentrated Solar Power

The CSP estimates rely heavily on the assumptions for the nuclear thermo-chemical facility for cost estimates for the S-I cycle. In reality, a different cycle may be preferred for use with CSP technologies for a number of reasons, including:

- the intermittent, diurnal nature of terrestrial solar resources may favor cycles with efficient heat recovery, solid phase reactants, and a low ratio of fixed to variable costs.

- the ability to heat reactants via direct illumination (photons), unique to concentrating solar technologies, reduces the materials obstacles associated with very high operating temperature cycles (e.g. the Zn/ZnO cycle operating at 1700 °C[15])

However, until the study for CSP is complete and performance and cost estimates for commercial plants developed, the best available information about thermochemical hydrogen production comes from the nuclear studies. Consequently, the basis for the CSP inputs used in this model is the same as for the nuclear thermochemical case--based on the sulfur-iodine cycle cost and performance information from Schultz (2003).

Thermal storage technologies enable a nominally 25% capacity factor solar resource to be 'spread' out to produce a 69 – 72% capacity factor that operates at lower output. This technology was proven at the Solar Two plant (Pacheco et al, 2002, and Reilly and Kolb, 2001) and uses fully commercial technology and commodity materials. Current thermal storage technology is low-cost molten-nitrate salt useful up to about 650 °C, but higher temperature options may be applicable in some cases. It is assumed that a thermochemical cycle similar to the Sulfur-Iodine cycle is found that is compatible with current or future thermal storage technologies. This enables us to use fairly well defined cost and performance inputs to the model.

[14] Schultz's assumptions include: regulated utility with a CRF of 12.6%, 90% capacity factor, 3 year construction period, and a 10% interest rate. The results assume a HHV of hydrogen of 142 MJ/kg H_2.
[15] A solar chemical reactor concept with a windowed rotating cavity-receiver lined with ZnO particles that are held by centrifugal force has been tested. With this arrangement, ZnO is directly exposed to high-flux solar irradiation and serves simultaneously the functions of radiant absorber, thermal insulator, and chemical reactant. The direct irradiation concept provides a very efficient means of heat transfer directly to the reaction site and permits durable metals (rather than ceramics) to be used for reactor wall construction [Haueter et al., 1999].

Based on the work of Sargent and Lundy (2003), the estimated capital cost of the CSP facility is $403 million and the H_2 thermochemical facility is $428 million.[16] Based on the projected hydrogen output of the facility, the combined capital cost is 593 $/kW- H_2. In this version of the model, O&M estimates are assumed to be identical to the nuclear plant.[17]

Non-catalytic Partial Oxidation (NPO)

Another method of production, widely used by refineries, is partial oxidation of hydrocarbons such as crude oil or natural gas. This process is widely used at European refineries to produce hydrogen additives for fuels, petrochemicals, and other hydrogen uses. The basic process is carried out at temperatures of 1200 – 1450 degrees C and requires pure oxygen. The NPO process is inherently less efficient than steam reforming.

Based on existing technology, a refinery hydrogen unit, using crude oil as a feedstock and a rated output of 100 MW- H_2 has a capital cost of $50 million, or an overnight capital cost of approximately 500.5 $/kW- H_2 (CONCAWE, 1999). Based on a thermal efficiency of 36.8%, the crude oil input for this facility is estimated at 8.6 million GJ per year, or 3.1 million GJ -H_2. The O&M costs are difficult to separate from that of the refinery itself; H_2Sim initially assumes annual O&M costs for the hydrogen refinery unit is 4% of the overnight capital costs.

While the costs for the other production facilities in H_2Sim are estimates for 2020, the NPO estimates are for a facility built today. This study assumes no large changes in these costs (adjusted for inflation) by 2020. The real room for improvement with NPO is the overall efficiency.

[16]This estimate assumes a 1.4 GWt solar plant, with a 69% capacity factor and an efficiency of 45% for the H2 thermochemical facility.
[17] These estimates will be further refined in year 2 of this project.

Carbon Capture and Sequestration

If hydrocarbons are used for the production of hydrogen, whether as a feedstock or for the production of electricity, then there will be emissions of carbon dioxide. In reality, cars using hydrogen produced via coal gasification could release higher amounts of carbon dioxide than current vehicles. As concerns about climate change are often mentioned as a driver for moving to a hydrogen economy, it is important to discuss the carbon implications of various strategies and whether or not carbon capture and sequestration is a viable option.

Dealing with possible CO_2 emissions involves first capturing the CO_2 from the production process, and then transporting the CO_2 to a suitable site, such as geologic formations or perhaps the deep ocean, where a large percentage of the CO_2 is expected to remain indefinitely. Ongoing demonstration projects in Norway and Canada may provide needed additional detail regarding the feasibility of long term storage of CO_2 in deep geologic formations. In addition, CO_2 is routinely injected into partially depleted oil wells as a means of increasing the amount of oil ultimately recoverable from the wells. This process, termed enhanced oil recovery, has not, however, demonstrated the long term viability of carbon storage. One of the largest projects involves piping the CO_2 800 km from southwestern Colorado to West Texas.

Capturing CO_2 released from the production of electricity is a complicated and expensive process. Recent estimates on the costs of capturing CO_2 from electricity production range from 54 $/tC for integrated gas combined cycle plants to 110 $/tC for pulverized coal facilities (DOE/EPRI 2000). Such costs would add significantly to the costs of generating electricity and hence utilizing electrolysis for electricity. A 50 $/tC carbon charge would increase the cost of electricity from IGCC and coal facilities by 1.16 and 0.49 cents/kWhr, respectively (Drennen et al., 2003)

Technically, it is far simpler to remove the CO_2 from either natural gas reformation or coal gasification. The details of CO_2 removal specific to each process are discussed below. Once the CO_2 is captured, the next step is to transport the gas to a suitable disposal site; the details of this are discussed following the sections on capturing the gas.

Carbon Capture from Coal Gasification

H_2Sim relies on a methodology outlined by Ogden (2002). Ogden's analysis considers carbon capture from large scale hydrogen and electricity facilities utilizing either natural gas or coal as a feedstock. The captured carbon is then compressed to 15 MPa for pipeline transmission as a supercritical fluid and injected into underground reservoirs.

Williams provides a detailed analysis of required plant modifications for capturing the CO_2 from a 1000 MW-H2 hydrogen and electricity facility. These modifications increase the estimate overnight costs by approximately 14.8% (Williams, 2001). Williams also estimates there is a 2.6% efficiency penalty associated with the carbon capture. In Williams' analysis, CO_2 emissions are reduced to 2.62 kgC/GJ_{H2} from 36.33, a 92% reduction in CO_2 emissions. The recent NAS study (2004) is more conservative, assuming that future technologies will capture up to 87% of the CO_2 that would be vented in the absence of the carbon capture modifications.

Carbon Capture from Natural Gas Reformation

During the steam reformation of natural gas, a large percentage of the CO_2 is already separated. According to Blok et al. (1997), CO_2 normally leaves the plant in two streams: "in a diluted stream as a component of the reformer stack gases (about 30% of the total) and in a concentrated stream that is separated from the hydrogen in the pressure swing adsorption (PSA) units." Accordingly, very little additional capital is required to capture the CO_2 exiting the plant in the concentrated stream. Based on Blok et al., the additional capital cost is on the order of 2.8% of the capital cost of the reformation facility.

Both Williams (2001) and NAS assume a higher percentage of CO_2 is captured, 84%. The estimated costs of capturing this additional CO_2 are not minimal. Williams estimates capital costs increase about 32%. Based on this, H_2Sim assumes that the removal of 84% of the CO_2 will increase the capital costs for the reformation plant from 501 $/kW-H2 to 661.2 $/kW-H2. H2Sim assumes O&M costs of 4% on the additional costs. It also assumes an efficiency penalty of 3% associated with the carbon capture.

Carbon Transport and Disposal

Once captured, the CO_2 must be transported to the eventual storage site and injected into wells. Ogden (2002) notes these disposal costs (C_D) are the sum of the pipeline transport costs (C_{PT}), the costs of drilling and operating the disposal wells (C_{DW}), and any surface piping that connects various disposal wells in large operations (C_{SP}):

$$C_D = C_{PT} + C_{DW} + C_{SP} \qquad (5)$$

For pipeline transport costs, Ogden estimates the following relationship:

$$C_{PT} = C_{PT(o)} * \left(\frac{Q}{Q_o}\right)^{-0.52} * \left(\frac{L}{L_o}\right)^{1.24} \qquad (6)$$

where: $C_{PT(0)}$ = 3.51 \$/tCO_2
Q_0 = 445.9 tCO_2/hr
L_0 = 100 km

Ogden estimates the cost of the disposal wells (C_{DW}), in millions of dollars, as:

$$C_{DW} = 1 + 1.25 * D_W \quad (7)$$

where: D_w = depth of well.

For a two km deep well, Ogden's base and the default case in H_2Sim, the capital cost would be \$3.5 million. This capital cost is handled in the same manner as are all other capital costs in H_2Sim.

In the case of large sequestration projects, there will also be additional piping connecting the various surface wells. Ogden assumes that each well can handle about 2500 tCO_2/day. For greater quantities, additional wells are needed. The cost of each additional well is calculated using equation 8. The cost of surface piping for rates above 2500 tCO_2/day is given by (Williams, 2001):

$$C_{SP} = 0.138 * (Q - 104.17)^{0.253} \quad (8)$$

End use

Hydrogen can be used in both vehicles and stationary sources. The current version of H_2Sim focuses mainly on end use in the transportation sector. Future versions may contain additional analysis of stationary options.

Vehicles

H_2Sim compares costs of existing vehicle types (conventional internal combustion engines (ICE), hybrid, and electric (EV)) with 2020 forecasted technologies (fuel cell vehicles (FCVs), hybrids running on hydrogen (H_2Hybrid) and FCVs with onboard reformation (FCV OB)). The purpose of comparing various future technologies with current technologies is to allow the user to understand how these future technologies compare to current technologies. Of course, current technologies may also improve dramatically by 2020. The fuel efficiency of ICE vehicles, for example, may increase dramatically if there is a large shift to lighter weight materials.

The default assumptions for each vehicle type are summarized in Table 4. The assumed cost and performance of the gasoline hybrid and electric vehicles are based on current technology. The hybrid price and estimated mileage is based on the average retail price and efficiencies of the three existing hybrid vehicles on the market – the Honda Insight, the Honda Civic, and the Toyota Prius. The cost and performance of the EV is based on the recently retired GM EV1.

Estimated costs of FCVs are from Weiss et al. (2000) at M.I.T. who publish estimates of new mid-size vehicles in 2020. However, whereas Weiss et al. suggests fuel efficiencies for FCVs above 90 miles per gallon gas equivalent (mpgge) in their 2000 study and even higher in an updated 2003 study, we've chosen a more conservative estimate for fuel efficiency of 67 mpgge. This is 2.5 times the assumed efficiency of the ICE vehicle; the implications of this assumption are explored in the sensitivity results section of this paper. H_2Sim assumes H_2Hybrid vehicles will be comparably priced to ICE vehicles ($18,000) once mass produced, as the technology is not significantly more advanced. Maintenance, insurance, and licensing costs are all based on estimates of Weiss et al. (2000).

Table 4. Default Vehicle Assumptions

Vehicle	Technology Year	Vehicle Price	Maintenance	Insurance	License and Registration	Fuel Efficiency
		$	$/yr [2]			mpg
ICE	2003	18000	696	972	384	27.8
Hybrid		19736	696	972	384	55.0
EV		33995	696	972	384	46.5
H_2 Hybrid	2020	18000	696	972	384	45.0
FCV		22100	696	1104	480	69.5
FCV OB		25910 [1]	696	1104	480	61.0

[1]Includes a vehicle cost of $22,100 and a reformer cost of $3,810.

[2]Based on the vehicle being driven 12,000 miles per year.

Onboard reformation of gasoline solves many of the problems associated with the lack of a hydrogen infrastructure. Drivers would continue to fuel their vehicles the same way they do now. The fuel would then be reformed onboard the vehicle, providing hydrogen for the fuel cell. Proponents of this option suggest onboard reformation might be a good transition strategy; once sufficient cars are equipped with fuel cells, the hydrogen infrastructure could develop. This option does not resolve concerns about CO_2 emissions.

While it is technically possible to use fuels other than gasoline, such as methanol, for this process, H_2Sim initially assumes onboard reformers would utilize gasoline.

A.D. Little (2001) estimates that a reformer sized to fuel a 50 kW fuel cell would cost approximately $3810, or 76 $/kW, assuming an operating efficiency of 48.1%. This capital cost is added to the assumed cost of the fuel cell vehicle and amortized over the life of the vehicle. The extra weight of the reformer means that this vehicle will be less fuel efficient that the FCV. H_2Sim assumes a default fuel efficiency of 61 mpgge. The rated input for this reformer is 136.9 kJ/s gasoline; based on an efficiency of 48.1%, the hydrogen output is 103.9 kJ/s.[18] The cost of hydrogen is then given by:

$$P_H = P_G \frac{Gas_{in}}{H_{Out} LHV_H} \tag{9}$$

where:
- P_H = hydrogen production cost ($/GJ)
- P_G = wholesale gasoline cost ($/gal)
- Gas_{in} = gasoline flow rate (gal/hr)
- H_{out} = hydrogen flow rate (kg/hr)
- LHV_H = hydrogen Lower Heating Value (GJ/kg)

The next section addresses the carbon emissions associated with the fuel choices in H_2Sim.

[18] 50 kW = 50 kJ/s/.481 = 103.9 kJ-H/sec

Carbon Emissions

H_2Sim calculates the carbon emissions associated with each fuel choice. Table 5 summarizes the carbon coefficients, in million metric tons carbon per Quad (MtC/Quad), used in H_2Sim.[19] These coefficients do not include carbon emissions associated with car manufacture or fuel delivery, and hence understate total carbon emissions. Actual emissions are determined by the efficiency of the conversion process as well as the use. For example, the total emissions from a vehicle using hydrogen produced by electrolysis are determined by the efficiency of the electricity production, electrolysis process, and fuel cell vehicle.

Table 5. Fuel Carbon Coefficients

Fuel	Carbon Coefficient (MtC/Quad)
Coal	25.76
Natural Gas	14.47
Gasoline	19.36
Crude Oil	20.24

The following section examines the methodology used in H_2Sim for storage and delivery of hydrogen.

[19] Carbon coefficients from DOE (1999), Table B1.

Distribution

Once hydrogen is produced at a centralized facility, it must be delivered to the fueling station. Depending on the delivery method, there may be storage costs at both the production facility and at the fueling stations. The cost of getting the hydrogen to the fueling station can be quite expensive, and may determine the overall viability of the hydrogen option. The purpose of this section is to outline the various options for distribution and how these options are included in H_2Sim.

While several authors estimate the costs of hydrogen storage and transportation, few provide the formulas used to derive those costs. Simbeck and Chang (2003) of SFA Pacific report costs associated with the handling and storage of compressed gas and liquefied hydrogen as well as the costs associated with three of the most likely hydrogen transportation options: pipeline, compressed gas tube trailers via truck, and liquefied hydrogen cryogenic tanks via truck. They estimate these costs for several different pathways, including production, storage, transportation, and dispensation of hydrogen as well as the option of on-site, or forecourt, production. Their analysis reports the results for a narrow range of assumptions regarding compression pressures, production rates, and transportation distances and options. While their analysis is based on a simulation model that allows the user to vary key assumptions, the model is proprietary and their report provides limited information for a few key assumptions.

A 2002 analysis by Thomas et al. from Directed Technologies Inc. focuses on the cost of a hydrogen infrastructure compared to the costs associated with maintaining the current gasoline infrastructure. Their analysis focuses on three main fueling options: gasoline, methanol, and hydrogen. The team from Directed Technologies examined the possibilities of on-site steam methane reformation of natural gas using the existing infrastructure as well as on-site hydrogen production and the reformation of methanol. They conclude that the cost of building and supporting an infrastructure that would allow for the on-site reformation of natural gas for the production of hydrogen was significantly less expensive than the costs associated with maintaining the current gasoline infrastructure.

Thomas et al. also discuss the costs associated with the compression of hydrogen, an integral part of the fueling station cost. The analysis includes formulas used to determine the energy and power requirements of compression as well as a comparison of different storage tank options with regards to the construction materials as well as compression levels. They consider both cascade compressors, which use stages to compress hydrogen to its final pressure, and booster compressors at fueling stations that allow for gas at a low compression level to be dispensed into the fuel cell vehicle followed by further compression during dispensation. While their analysis provides a great deal of detail for the costs of compression and storage at the fueling station, it provides limited detail regarding the costs associated with storage at the production site and transportation to fueling stations.

In a 1998 report published by the National Renewable Energy Laboratory, Wade Amos examines possible storage and transportation options for hydrogen. Amos presents a detailed economic analysis of the capital and operating costs for currently available technologies. The analysis includes four potential storage options: compressed gas above ground, compressed gas underground, liquefied, and metal hydride storage. This storage is presumed to occur at the site of centralized hydrogen production. Additionally, he examined eight options for hydrogen transport: truck and rail transport for each of the three phases of hydrogen (compressed gas, liquid, and metal hydride), ship transport for liquefied hydrogen, and pipeline transport of gaseous hydrogen. For each, Amos presents results for a base case scenario, with assumption specifications and a range of production levels, storage times, and transportation distances. Furthermore, he presents the equations and sizing factors used to determine the costs associated with each option, which allows for an easy reconstruction and the potential to vary some of the key assumptions.

The storage and transportation cost results from Amos' analysis are compared to the results from Simbeck and Chang's analysis, Table 6. This comparison assumes a production rate of 150,000 kg/day (enough to serve approximately 225,000 vehicles), storage time of 12 hours, compression from 1 MPa (145 psi) to 21.5 MPa (3000 psi) and a transport distance of 150 km. A transport pressure of 3000 psi is lower than the expected 5,000 – 10,000 psi range of pressures for use in vehicles.

Table 6. SFA and Amos Transportation Results Comparison ($/kg)

	SFA	Amos
	Production Rate = 150,000 kg/day Storage Time = 12 hr Compression from 1 MPa - 21.5 MPa Transport Distance = 150 km	
Storage		
Compressed Gas	0.44	0.07
Liquefied	1.31	0.10
Transportation		
Pipeline	2.94	0.10
GH Truck	2.09	1.32
LH Truck	0.18	0.06

The SFA results are significantly higher than those presented by Amos, and highlight the huge degree of uncertainty associated with various transport options. For example, whereas Amos estimates hydrogen could be delivered for about 0.10 $/kg by pipeline, the SFA study estimates costs of 2.94 $/kg. They do follow a similar pattern, with compressed gas storage and liquefied hydrogen truck transport the least expensive options for these parameters. In the case of pipeline transportation, SFA assumes that there is a factor of four penalty in building the pipeline infrastructure because rather than transporting the hydrogen through a single pipeline, which Amos assumes, Simbeck and Chang present costs associated with transporting hydrogen from one site in four different directions. Neither Amos nor Simbeck and Chang account for capital financing costs in their analysis. In addition to the options summarized in Table 6, Amos examines storage and transportation of metal hydrides, which are not included in Simbeck and Chang's analysis.

This section outlines the equations used in the model to determine the costs associated with on-site storage and transportation of hydrogen. While several of these equations are from the Amos study, others were derived by the modeling team or other sources, as indicated. When using the work of Amos, we included the cost of capital financing, something Amos did not include.

Storage

Unless hydrogen is produced on demand, such as via electrolysis at the fueling station, it will require storage. Hydrogen can be stored in three different phases: compressed gas, liquefied, and within metal hydrides. Each option has different costs associated with transforming the hydrogen from its production state to its storage state as well as the cost to maintain the storage in that form. The total cost of storage is based on two primary factors: production rate and storage time. Additionally, the storage time is partly a function of the production rate and is also a function of the transportation distance. When a production facility produces a low quantity of hydrogen and the transport time is long, the hydrogen is likely to be stored for a longer period of time at the production facility before the transportation unit is full. This section summarizes assumptions and formulas used to derive the costs of storage for each of the three phases of hydrogen.

Compressed Gas

Compressed gas storage of hydrogen can occur, either above ground in tanks or below ground in some type of cavern. Both gaseous storage options require the compression of the hydrogen, and thus require the cost of the compressor, and the energy associated with compression. Amos provides base case assumptions as well as sizing factors for the cost of the compressor. These assumptions are summarized in Table 7.

Table 7. Compressor Assumptions (Amos, 1998)

Description	Unit	Assumption
Base Case Compressor Cost	$/kW	1000
Base Case Compressor Size	kW	4000
Base Case Compressor Pressure	MPa	20
Compressor Sizing Exponent		0.8
Compressor Pressure Factor		0.18
Compressor Power Requirement	kWh/kg	2.205
Compressor Cooling Water Requirement	gal/kg	13.23

These variables are used to determine the costs associated with the compression of hydrogen for both types of gaseous storage using a multi-stage compressor. The energy required (kW) for isothermal compression is a function of the production rate as well as the inlet and outlet pressures:

$$W = \left(\frac{m * R * T}{\eta}\right) * \ln\left(\frac{PInlet}{DP}\right) \qquad (10)$$

where: m = mass flow rate (g/hr)
R = hydrogen gas constant (J/g*K)
T = temperature (K)
η = efficiency (initially 80%)
PInlet = inlet pressure (MPa)
DP = delivery pressure (MPa)

The total capital cost of the compressor is determined using sizing factors to adjust from the baseline size (4000 kW) and cost (1000 $/kW) provided by Amos (1998). Specifically, the total capital cost of the compressor (C_{Cap}) is determined partly by the energy and cooling water requirements:

$$C_{Cap} = CC * CS * \left(\frac{E}{CS}\right)^{CompExp} * \left(\frac{P}{P_0}\right)^{CPExp} \qquad (11)$$

where: CC = base compressor cost ($/kW)
CS = base compressor size (kW)
E = compressor power (kW)
CompExp = compressor sizing exponent
P = operating pressure (MPa)
CPExp = compressor pressure factor
P_0 = baseline operating pressure (MPa)

The variable costs for storage include the energy and cooling water costs, both a function of the desired level of pressurization, compressor efficiency, and electricity cost.

In addition to the compressor capital and variable costs, each type of compressed gas storage has other costs associated with it that are unique to that storage type. These relationships are defined in the following sections.

Above Ground Pressurized Tanks

Above ground storage of compressed gas requires high pressure storage tanks. Using a baseline tank size of approximately 225 kg and cost of approximately 1300 $/kg, the capital cost of the tank is determined using a sizing factor, given by Amos (1998), based on a baseline operating pressure of 20 MPa, Table 8.

Table 8. Above Ground Compressed Gas Storage Assumptions (Amos, 1998)

Description	Unit	Assumption
Base Case Tank Cost	$/kg	1323
Base Case Tank Capacity	kg	226.76
Base Case Tank Pressure	MPa	20
Tank Sizing Exponent		0.75
Tank Pressure Factor		0.44

Total capital costs for tank storage are given by:

$$T_{Cap} = (TC * TS) * \left(\frac{SC * \frac{TP}{P}}{TS} \right)^{0.75} * \left(\frac{P}{TP_0} \right)^{0.44} \tag{12}$$

where: TC = base tank cost ($/kW)
TS = base tank capacity (kg)
SC = storage capacity (kg)
TP_0 = baseline tank pressure (MPa)
P = operating pressure (MPa)

Amos assumes the capital costs are divided evenly over the life of the unit, which ignores financing costs. H_2Sim treats the capital costs associated with storage the same way it does for capital costs associated with production. The total capital costs are multiplied by the capital recovery factor to give the annual capital costs associated with the storage units. The total cost of above ground compressed gas storage per kilogram of hydrogen is given by the sum of the annual cost components (capital, energy, and cooling water) distributed over the total annual production.

The following section explains the costs associated with the storage of hydrogen as a compressed gas in an underground facility.

Underground Pressurized Caverns

Underground storage provides an alternative option for compressed gas storage. However, this option is available in very limited locations, as it requires the existence of some type of cavern. The costs of underground storage are determined by the cost of hydrogen compression as well as the cost of the cavern. Amos assumes a capital storage cost of $8.82 per kilogram of storage capacity, regardless of cavern size. Therefore, storage costs are a function of facility size and storage pressure:

$$CV_{Cap} = UC * \left(CS * \left(\frac{TP}{P} \right) \right) \tag{13}$$

where: UC = underground cavern cost ($/kg)
CS = cavern capacity (kg)
TP = baseline storage tank pressure (MPa)
P = operating pressure (MPa).

Again, the total capital cost is determined by the sum of the compressor cost and the underground storage cavern cost. The calculation for the total annual cost of the depreciating capital is found using the total capital cost and accounting for financing with the CRF. The total cost per kilogram for gaseous underground storage is determined by the total capital and variable costs divided over the annual production of the hydrogen facility.

One of the biggest problems with hydrogen stored as a compressed gas is its very low volumetric density and the resulting need for large storage facilities. Liquefied hydrogen provides one solution to this problem.

Liquefied

Liquefied hydrogen storage options allow for the storage of larger quantities of hydrogen in smaller spaces than is possible with compressed gas hydrogen. However, it also requires very low temperatures to prevent boil-off, which occurs when the hydrogen reaches a temperature at which it evaporates into a gaseous state. The costs associated with liquefied hydrogen storage include the liquefaction cost, the capital costs of the storage tanks, and operation and maintenance costs. Note that the power requirements for liquefaction are significant; Amos assumes 9.92 kWh/kg. The default assumptions in H_2Sim for determining liquefied storage costs are summarized in Table 9.

Table 9. Liquefied Hydrogen Storage Base Case Assumptions (Amos, 1998)

Description	Unit	Assumption
Base Case Liquefier Cost	$/(kg/hr)	44100
Base Case Liquefier Size	kg/hr	454
Liquefier Sizing Exponent		0.65
Liquefier Power Requirement	kWh/kg	9.92
Liquefier Cooling Water Requirement	gal/kg	165
Base Case Dewar Cost	$/kg	441
Base Case Dewar Capacity	kg	221
Dewar Sizing Exponent		0.70
Boil Off Rate	%/day	0.10

The costs associated with liquefied hydrogen storage are determined by the production rate, storage time, and boil-off rate. Equation (14) is used to determine the net production accounting for the losses incurred from the boil-off effect:

$$F_{BOR} = F * \left(1 + \left(1 - e^{(-BOR*ST)}\right)\right) \tag{14}$$

where: F = production rate (kg/hr)
BOR = boil-off rate (%/day)
ST = storage time (days).

In addition to the variable energy and cooling water costs, the total cost of liquefied hydrogen storage includes the capital costs of the liquefier as well as the dewars, or liquefied hydrogen storage tanks. The cost of the liquefier varies with the production rate and uses a sizing exponent to determine the capital cost:

$$L_{Cap} = LC * LS * \left(\frac{F_{BOR}}{LS}\right)^{0.65} \tag{15}$$

where: LC = base liquefier cost ($/(kg/hr))
LS = base liquefier size (kg/hr)
F_{BOR} = production rate including boil-off (kg/hr).

The capital cost of the dewar is also determined using a sizing exponent and the ratio of the base cost and size to the actual storage capacity of the dewar:

$$D_{Cap} = DC * DS * \left(\frac{SC}{DS}\right)^{0.70} \qquad (16)$$

where: DC = base dewar cost ($)
DS = base dewar size (kg)
SC = storage capacity (kg)

The total capital cost must then be adjusted for depreciation to determine the annual capital cost using the CRF. The total cost of liquefied hydrogen storage is the sum of the liquefier, dewar, energy, and cooling water costs.

An alternative to gaseous and liquefied storage of hydrogen is as a solid, in the form of a metal hydride. The costs associated with this option are addressed in the next section.

Metal Hydride

Metal hydrides provide a solid-state storage option in which hydrogen is absorbed into the lattice of the metal. This option for storage is probably the least understood at this time, but in many ways could prove to be the most appealing of the storage options. For example, it might someday be to use the metal hydrides to both store hydrogen and as the vehicle frame itself.

The cost of metal hydride storage includes the cooling water cost, heating cost, the equipment necessary to create the hydrogen absorption and release, and the metal hydride itself. Table 10 provides the base case assumptions used in determining the total cost of metal hydride hydrogen storage.

Table 10. Metal Hydride Storage Base Case Assumptions (Amos, 1998)

Description	Unit	Assumption
Metal Hydride Cost	$/kg	2205
Metal Hydride Heat Requirement	kWhr/kg	6.46
Metal Hydride Cooling Water Requirement	gal/kg	55

Storing hydrogen in metal hydride form requires both cooling and heating. Cooling is required for the absorption of the hydrogen into the metal, and steam heat is required to release the hydrogen. Both costs are included in Amos' analysis. The annual cost associated with this energy consumption is determined by the assumed heating requirement, the energy cost, and the annual production rate. Similarly, the annual cost for cooling water is calculated based on the assumed water requirement, cost of water, and production rate.

Amos assumes that the capital cost is independent of facility storage size, eliminating the need for a sizing exponent, which was required in determining the costs of gaseous and liquefied hydrogen storage. Annual capital costs are again found by multiplying the total financed costs by the capital recovery factor. The total cost of metal hydride storage is the sum of the annual capital, steam, and cooling water costs distributed over the annual production rate.

In summary, the three main storage options for hydrogen are: compressed gaseous storage, either above or below ground; liquefied storage in tanks; and metal hydride storage. As mentioned above, storage may take place in more than one place. For example, for certain production processes, it may make sense to store the hydrogen at the production site prior to transport. Additional storage may be required at the fueling site. It may also be possible to avoid storage at the production site; this may be the case with the gas is shipped via pipelines.

The next section discusses options for transporting the hydrogen.

Transportation

Hydrogen produced at a centralized facility must be transported to a fueling station. It may or may not need to be stored prior to transport. There are a wide variety of options for transporting hydrogen, ranging from gaseous or liquefied truck transport to large scale pipelines. Getting the hydrogen to the end use site may also require multiple modes of transport, including large, regional pipelines that connect to either smaller, local pipelines or to trucks, ships, or rail cars.

H_2Sim provides a variety of options for the transportation of hydrogen. Each option includes the likely storage option most suitable for that transport option. This section summarizes the relevant assumptions associated with each of these nine transport options, Table 11. As an example, option 1 utilizes underground, gaseous storage of hydrogen in caverns, with large pipelines (9-14 inch) delivering carrying the gaseous hydrogen to a series of smaller, local pipelines (2-4 inches), which deliver the hydrogen to a fueling station that includes gaseous storage tanks,

Table 11. Distribution Options in H_2Sim

Option	Storage	Transport 1	Transport 2	Fueling Station
1	Underground, Gaseous	Pipeline, Large	Pipeline, Local	Gaseous
2	Tanks, Gaseous	Pipeline, Large	Pipeline, Local	Gaseous
3	Tanks, Gaseous	Truck, Gaseous	None	Gaseous
4	Tanks, Liquefied	Truck, Liquid	None	Liquefied
5	Tanks, Gaseous	Pipeline, Large	Truck, Gaseous	Gaseous
6	Metal Hydride	Truck, Metal Hydride	None	Metal Hydride
7	Tanks, Gaseous	Rail, Gaseous	Truck, Gaseous	Gaseous
8	Tanks, Liquefied	Ship, Liquid	Truck, Liquid	Gaseous
9	Tanks, Liquefied	Rail, Liquid	Truck, Liquid	Gaseous

Some of the assumptions used for truck and rail transport remain constant for gaseous, liquefied, and metal hydride transport. These assumptions are summarized in Table 12.

Table 12. Truck and Rail Transport Assumptions (Amos, 1998)[20]

Description	Unit	Assumption
Truck Undercarriage Cost	$	60000
Truck Cab Cost	$	90000
Truck Average Mileage	mi/gal	6
Truck Average Speed	mi/hr	50
Truck Load/Unload Time	hr	2
Truck Daily Availability	hr/day	24
Truck Trailer Depreciation Time	yr	6
Truck Tractor Depreciation Time	yr	4
Truck Driver Wages and Benefits	$/hr	28.75
Truck Driver Daily Availability	hr/day	12
Diesel Price	$/gal	1
Rail Undercarriage Cost	$	100000
Rail Freight Cost	$	400
Rail Average Speed	mi/hr	25
Rail Load/Unload Time	hr	24
Rail Availability	hr/day	24

[20]The numbers in this table are in 1995: they were not converted to 2003 $ as the original numbers were rounded.

Compressed Gas

As a compressed gas, hydrogen can be transported by truck, ship, rail, or pipeline, or some combination of the above. Each option is first considered separately. The option of combining options is discussed as a special case.

Truck

The total cost of truck transport includes the capital cost of the trucks, compressed gas handling tubes, and the labor and fuel costs associated with driving the truck from the production site to the fueling station. The total annual capital cost is based, in large part, on the number of trucks necessary to transport the hydrogen, which is determined by the transport rate, truck capacity, and truck transport characteristics. Initially, the gaseous hydrogen truck tube cost is assumed to be $100,000 and the capacity is assumed to be 180 kilograms. The low capacity is a result of the necessary weight of the tube trailers and the low density of compressed hydrogen. This low density results in a large number of trips and ultimately a large quantity of trucks to transport seemingly small quantities of hydrogen. Based on the required number of trips and trucks, determined by the annual production, truck capacity, distance, and transport speed, the annual capital cost are:

$$CC_{Annual} = \left(T * \left(TC_{GH2} + TC_{Under}\right) * TrailerCRF\right) + \left(\left(T * TC_{Cab}\right) \cdot TractorCRF\right) \qquad (17)$$

where:	T	= required number of trucks
	TC_{GH2}	= gaseous hydrogen tube cost ($)
	TC_{Under}	= truck undercarriage cost ($)
	TrailerCRF	= trailer capital recovery factor (%)
	TC_{Cab}	= truck cab cost ($)
	TractorCRF	= cab capital recovery factor (%)

In addition to the capital costs associated with truck transport of gaseous hydrogen, annual fuel costs are based on the number of trips required, the travel distance, and the price of diesel. The final cost that is included in the total transportation cost is the labor cost:

$$C_{Labor} = W * TR * \left(\left(\frac{TW}{TS}\right) + TL\right) \qquad (18)$$

where: TR = annual trips
TW = two way transport distance (miles)
TS = average truck speed (mi/hr)
TL = truck load/unload time (hr)
W = driver wage and benefits ($/hr)

In summary, the total cost per kilogram for transporting hydrogen is the total annual capital, fuel, and labor costs, divided by the annual production rate.

The next section discusses the basic assumptions for rail transport of gaseous hydrogen.

Rail

The total cost of rail transport is determined by two costs: capital cost and freight cost, which includes such variables as the rail conductor wage. The default assumption is that each railcar gaseous storage container costs $200,000 and has a capacity of 450 kg of hydrogen. Again, much depends on the number of trips required which is a function of the annual production rate and the capacity of the hydrogen railcars. The required number of trips is then used to determine the total delivery time, required number of railcars, and ultimately the total capital cost. Total delivery time, which includes the return time of the railcars, is found using:

$$Time = TR * \left(\left(\frac{TW}{RS} \right) + RL \right) \qquad (19)$$

where: TR = trips required annually (#/yr)
TW = two way delivery distance (miles)
RS = average rail speed (mi/hr)
RL = rail load/unload time (hr)

This delivery time is used to determine the required number of railcars and the annual capital cost accounting for financing using the CRF:

$$DepCost = \left(\frac{Time}{RA * OpDays}\right) * \left(RC_{GH2} + RC_{Under}\right) * RailCRF \qquad (20)$$

where:
- Time = total delivery time (hr/yr)
- RA = rail availability (hr/day)
- OpDays = days of operation (days/yr)
- RC_{GH2} = gaseous hydrogen railcar container cost ($)
- RC_{Under} = railcar undercarriage cost ($)
- RailCRF = railcar capital recovery factor (%)

In summary, the total cost for rail transport of gaseous hydrogen is found by combining annual capital costs for the rail cars and the per load freight costs.

The next section discusses how liquid hydrogen transport differs from gaseous transport.

Liquefied

Liquefied hydrogen requires less volume than gaseous hydrogen but requires very low temperatures to avoid boil-off, or the evaporation of hydrogen. The formulas used to determine the cost of liquefied hydrogen transport are very similar to the cost of transporting gaseous hydrogen via truck or rail, except for the need to account for the boil-off of liquefied hydrogen. The differences in the methodologies are explained in this section. Additionally, the option of ship transport is examined in this section.

Truck

Because of the nature of liquefied hydrogen, the capital cost of a transport unit is higher than the cost of a gaseous transport unit, but the capacity is also higher. Initially, the cost is assumed to be $350,000 per truck with a capacity of 4,082 kilograms. Substituting the liquefied hydrogen truck capacity for the gaseous hydrogen truck capacity determines the number of trips required to transport the hydrogen, which determines the required number of trucks and the total capital cost of the vehicles. Approximately 0.3 percent per day of the liquefied hydrogen is lost due to boil-off. Total delivered hydrogen is given by:

$$Delivered = AP * e^{\left(-TruckBOR*\frac{\left(\frac{D}{TS}\right)}{24}\right)} \quad (21)$$

where: AP = annual production of hydrogen (kg/yr)
TruckBOR = truck boil-off rate (%/day)
D = one way transport distance (miles)
TS = average truck speed (mi/hr)

With all other formulas remaining the same as those that determine compressed gas truck transport costs, the total delivered cost per kilogram is found using the recalculated capital, fuel, and labor costs and dividing those costs by the delivered quantity of hydrogen, accounting for the boil-off. The variations that apply to the calculations for truck transport also apply to the calculations used to determine the costs of liquefied hydrogen rail transport.

Rail

The transportation cost of liquefied hydrogen via rail is found in much the same way as the cost of rail transport of compressed gas, but the capacity size is 9070 kilograms of hydrogen. For rail transport the total boil-off effect is greater because of the increased transport time. The delivered quantity of hydrogen accounting for boil-off is calculated using:

$$Delivered = AP * e^{\left(-RailBOR*\left(\frac{\left(\frac{D}{RS}\right)}{24}\right)\right)} \quad (22)$$

where: D = one way transport distance (miles)
RS = average rail speed (mi/hr)
AP = annual production of hydrogen
RailBOR = rail boil-off rate (%/day)
TT = one way transport time (days)

The total cost per kilogram of liquefied hydrogen transported by rail can be determined in the same way that it is for compressed gas and metal hydrides, but accounting for the losses due to boil-off.

Ship

Ship transport is an option that exists only for liquefied hydrogen. Table 13 summarizes the initial assumptions that are used in determining the costs of ship transport.

Table 13. Ship Transport Assumptions (Amos, 1998)

Description	Unit	Assumption
Liquefied Ship Cost	$	350000
Liquefied Ship Capacity	kg	4082
Ship Speed	mi/hr	10
Ship Load/Unload Time	hr	48
Ship Availability	hr/day	24
Ship Freight	$	3000
Ship Boil Off Rate	%/day	0.3

The cost of ship transport has two components: capital cost and freight cost. The delivered cost must be adjusted for the boil-off that occurs during transport. The delivered hydrogen is then found using the equation:

$$Delivered = AP * e^{\left(-ShipBOR*\left(\frac{\left(\frac{D}{SS}\right)}{24}\right)\right)} \tag{23}$$

where: D = one way travel distance (miles)
SS = average ship speed (mi/hr)
AP = annual production of hydrogen
ShipBOR = ship boil-off rate (%/day)
TT = one way transport time (days)

The capital cost is a function of production level, ship capacity, load time, and freight cost. Freight cost is given by:

$$FC = \left(\frac{AP}{SS_{LH2}}\right) * SF * 2 \tag{24}$$

where: AP = annual production of hydrogen (kg/yr)
SS_{LH2} = liquefied hydrogen ship capacity (kg)
SF = ship freight cost ($)

Therefore, the total cost per kilogram of ship transport of liquefied hydrogen can be found in the same way that other transportation costs are determined, dividing the annual cost over the annual production accounting for boil-off.

Metal Hydride

Metal hydrides provide a solid-state transport option for hydrogen and can be transported either by trucks or rail. The formulas used to determine these costs are very similar to those used to determine the cost of gaseous hydrogen transport. The difference between the cost of transporting gaseous hydrogen and metal hydrides is that the cost of the vehicle is in terms of dollars per kilogram of hydrogen transported rather than one absolute cost. Therefore, this section focuses on the equations that differ from those used for gaseous hydrogen and those used for metal hydride transport by truck and rail.

Truck

The capital cost associated with the trucks uses two assumptions: the estimated initial capital cost is $2200 per kilogram (1000$/lb) of hydrogen for a truck capacity of 450 kg. By using the size of the metal hydride truck and the total transport distance, the necessary number of trips and the required number of trucks for metal hydride transport can be calculated. The formula used to determine the total capital cost, however, changes due to the units used for the cost of the metal hydride truck. The annual capital cost is calculated by:

$$DepCost = \left(\left(T * \left(\left(TC_{MH2} * TS_{MH2}\right) + TC_{Under}\right)\right) * TrailerCRF\right) + \left(T * TC_{Cab} * TractorCRF\right) \tag{25}$$

where:
- T = metal hydride required number of trucks
- TC_{MH2} = metal hydride truck container cost ($/kg)
- TS_{MH2} = metal hydride truck container capacity (kg)
- TC_{Under} = truck undercarriage cost ($)
- $TrailerCRF$ = truck trailer capital recovery factor (%)
- TC_{Cab} = truck cab cost ($)
- $TractorCRF$ = truck tractor capital recovery factor (%)

The fuel and labor costs of metal hydride truck transport are found using the same calculations as those used for gaseous hydrogen transport, adjusting for the number of trips necessary based on the capacities of the vehicles. Therefore, total cost is found in the same way, with the annual capital cost adjusted for the unit differences.

Metal hydrides can also be transported by rail; these costs are discussed in the next section.

Rail

Costs of rail transport of metal hydrides are determined in much the same way as rail transport of gaseous hydrogen. The only difference, again, is that the unit in which the railcar cost is measured is dollars per kilogram, changing the capital cost calculation in the same way that the capital cost was calculated for truck transport. Using the metal hydride rail size, initially assumed to be 900 kilograms and the production rate determines the required number of trips annually. The formula used to determine total delivery time remains the same and the annual capital cost is calculated using:

$$DepCost = \left(\frac{Time}{RA * OpDays}\right) * \left(\left(RC_{MH2} * RS_{MH2}\right) + RC_{Under}\right) * RailCRF \qquad (26)$$

where:	Time	= total delivery time (hr/yr)
	RA	= rail availability (hr/day)
	OpDays	= days of operation (days/yr)
	RC_{MH2}	= metal hydride railcar cost ($/kg)
	RS_{MH2}	= metal hydride railcar capacity (kg)
	RC_{Under}	= railcar undercarriage cost ($)
	RailCRF	= railcar capital recovery factor (%)

Initially, the cost of the metal hydride rail car is assumed to be $2200 per kilogram of hydrogen. Therefore, the total annual cost is the sum of the freight cost, found in the same way as other rail transport options, and capital cost can be distributed though the hydrogen produced annually.

The next section looks at the cost of transporting compressed hydrogen through pipelines.

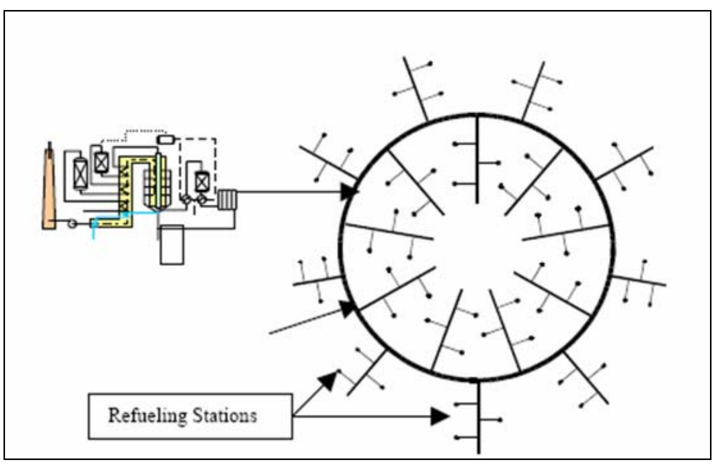
Pipeline

Pipeline transport may allow for the widespread transport of gaseous hydrogen. Pipeline transportation costs are divided into three cost components: energy, compressor capital cost, and pipeline capital cost. Pipeline transportation costs are affected by the pipeline characteristics, compressor characteristics, production rate, transportation distance, and hydrogen properties. Unlike other transportation options the methodology used in H_2Sim to determine pipeline transportation costs is not drawn from Amos' (1998) work, as it offers users considerable more options than just a single pipeline. The basic assumptions regarding the pipeline and compressor characteristics are summarized in Table 14.

Table 14. Pipeline and Compressor Characteristic Assumptions

Variable	Unit	Assumption
Pipeline Temperature	K	283
Pipeline Friction Factor		0.005
Hydrogen Gas Constant	J/kg*K	4.124
Compressor Temperature	K	300
Compressor Baseline Cost	$/kW	1000
Compressor Baseline Size	kW	4000
Compressor Baseline Pressure	MPa	20
Compressor Sizing Exponent		0.80
Compressor Pressure Factor		0.18

Hydrogen pipelines may follow a pattern similar to that illustrated in Figure 4, for which one large pipeline (initially 12 inches in diameter) is used to transport the hydrogen from the production facility to the city gate and around the delivery area and multiple small pipelines (initially 3 inches in diameter) are used for local delivery. Alternatively, the larger pipeline may be a long straight line, branching out to either smaller, local pipelines or connecting to truck, rail, or ship. Figure 5 illustrates the case of large pipelines and local truck transport. In the case of smaller pipelines, H_2Sim allows the user to set the number of local pipelines that come from the large pipeline. Doing this will automatically determine the flow rate through the local pipelines, using the total flow rate set by the user.



Source: Mintz et al. 2002

Figure 4. Hydrogen Pipeline Distribution Schematic

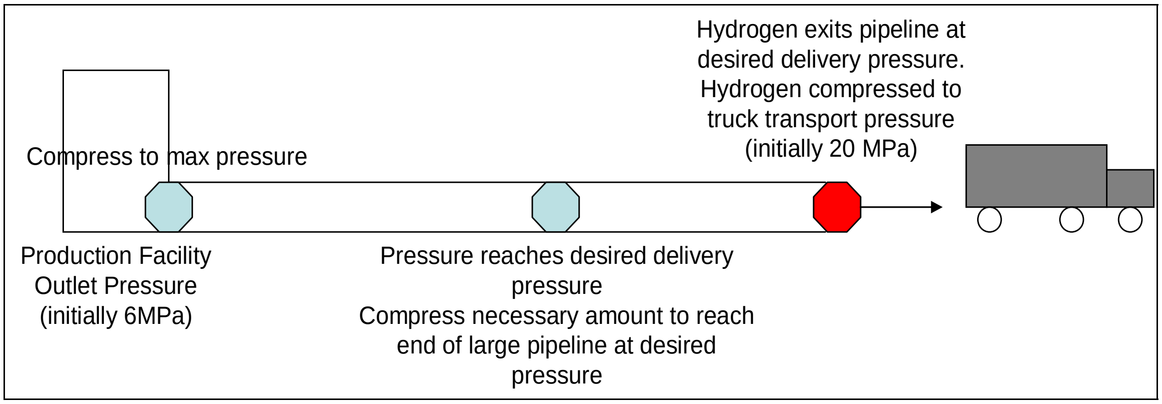


Figure 5. Large Pipelines and Local Truck Transport

The number of compressors necessary along the pipeline is a function of several variables, including output pressure of the production option, the desired delivery pressure, maximum allowed pipe pressure, and pipeline length. Whether or not compressors are required in both the large and small pipelines depends on the delivery distance and pressure.

Pipeline transport requires a number of compressors; the first is located at the production site. Depending on the overall pipeline distance, compressors are placed throughout the large pipeline to compress the hydrogen along the way and deliver it at the desired pressure (initially assumed to be 2 MPa) to the local pipelines. The hydrogen is compressed to the maximum pressure allowed in the pipeline (initially 6.7 MPa (1,000 psi)) unless *PInlet* (equation 27) calculates that a lower pressure is required for delivery. Compressors are placed throughout the pipeline whenever the pipeline pressure falls below the desired delivery pressure. The necessary inlet pressure (MPa) to reach the desired outlet pressure is determined using the equation:

$$PInlet = \frac{\sqrt{\left(\frac{4 * FF * D * Flux^2 * RH2 * T}{PD}\right) + DP^2}}{1000000} \tag{27}$$

where:
- FF = friction factor
- D = transport distance (m)
- Flux = hydrogen flux through pipeline ($kg/m^2 * s$)
- RH2 = hydrogen gas constant (N*m/kg*K)
- T = temperature (K)
- PD = pipe diameter (m)
- DP = delivery pressure (Pa)

Using Equation (27), solving for the distance, and assuming *PInlet* is equal to the maximum allowed pressure of the pipeline, H_2Sim calculates the distance before a new compressor is needed based on the desired delivery pressure. At this point a new compressor is added, which compresses the hydrogen to either the maximum pressure or the necessary pressure for the remainder of the transportation distance, determined by *PInlet*. This process is continued such that the final compressor will likely be smaller and only compress the hydrogen to the necessary pressure to result in the desired delivery pressure at the end of the large pipeline. In addition to the last compressor being smaller, the first compressor is also likely to be smaller, as the necessary compression is determined by the pressure of the hydrogen after production. For example, some production options release the hydrogen at a pressure of 6 MPa. In some cases this will be enough pressure to travel the entire transportation distance. If not, the first compressor will only be required to compress the hydrogen from 6 MPa to the maximum allowed pressure.

At the end of the large pipeline there is one more compressor, which compresses the hydrogen to the level required for local transportation. For the case of local pipeline distribution, this pressure loss is the difference between *PInlet*, calculated for the characteristics of the local pipeline, and the desired delivery pressure. If *PInlet* for local delivery is greater than the maximum pressure allowed in local pipelines (initially 6.7 MPa) there are compressors placed along the pipeline in the same fashion as the large pipeline. For the case of local transport by trucks, the compressors located at the end of the pipeline must be large enough to compress the hydrogen to the desired truck delivery pressure, initially assumed to be 20 MPa.

Once the number of compressors is determined, the work requirement (kW) for these compressors is found using Equation (10). This work requirement, or necessary compressor size is used to determine the total energy requirement for the compressor, based on the capacity factor. It is also used to determine the capital cost of the compressor using the same method as the compressors in hydrogen storage.

In addition to the capital cost of the compressors, H_2Sim calculates the capital cost of the pipelines. This is determined by the diameter, and length of the pipeline. The diameter of the pipeline can be set by the user or determined by the model based on the flow rate. Estimates for pipeline costs are summarized in Table 15.

Table 15. Pipeline Cost Estimates

Diameter (inches)	Pipeline Cost ($/mile)
3	400,000
9	900,000
12	1,000,000
14	1,400,000

Source: Mintz et al. 2002.

The pipeline costs used in the model take the value of the higher diameter it is between two of the options (i.e. a 10 inch pipeline is assumed to cost $1,000,000 per mile).

For the cost of local pipelines the total length must be considered, so the average length of each local pipeline must be multiplied by the number of local pipelines to determine the total capital cost. The total capital cost of the pipeline and the compressors are then annualized using the pipeline capital recovery factor, calculated in the model.

Finally, the total cost per kilogram for hydrogen transport via pipeline is found in the same way that other options are calculated, by dividing the total annual cost by annual production.

The next section presents the estimated costs of hydrogen storage and delivery based on the formulas in this section as well as a detailed sensitivity analysis for key variables.

Results and Sensitivity Analysis

This section summarizes the main results from H_2Sim based on the default assumptions. As the results are highly dependent on those initial assumptions, a detailed sensitivity analysis of those results is included.

Production

Table 16 summarizes H_2Sim's results for centralized production of hydrogen based on the model's default assumptions. The estimated hydrogen production costs range from 0.68 $/kg for coal gasification to as high as 5.64 $/kg for centralized electrolysis using solar PV. These costs do not include storage or transportation.

Table 16. Base Case Results for Produced Hydrogen ($/kg)

	Production Cost ($/kg)
Steam Methane Reformation	1.12
Coal Gasification	0.68
Electrolysis[1]	1.98 - 5.64
Thermochemical CSP	1.83
Thermochemical Nuclear	1.38
NPO	1.69

[1]Depends on the electrical generating source used. Lower end assumes use of coal and upper end is for solar PV.

Two of the options, SMR and electrolysis, could be used for decentralized, or onsite, production of hydrogen, such as at the fueling station or home level. The benefit of onsite production is avoidance of the transportation costs and probably some of the storage costs. Table 17 summarizes onsite hydrogen production costs for both options. This analysis assumes the smaller, onsite methane reformers have a higher capital cost per unit ($/kW- H_2) than a larger size centralized reformer.

Using equation (2), the estimated capital costs for a reformer with a rated output of 1,000 kg per day (enough for a small fueling station) are about 2000 $/kW. Based on natural gas prices at the fueling station of 4.47 $/MBtu[21], the hydrogen production cost is 1.86 $/kg. This compares to 1.12 $/kg for the larger, centralized facility. The question is whether the higher costs (0.74 $/kg) for the decentralized facility are offset

[21] DOE forecasted price for utilities in 2020 (EIA AEO 2003). The forecasted price of natural gas for commercial customers is 7.01 $/MBtu, which would significantly increase the cost of hydrogen production from smaller units.

by the storage and transport costs associated with the centralized facility. Based on the storage and transport results presented in the next section, the decentralized option may be cost competitive with the centralized option.

Table 17. Onsite Hydrogen Production Costs ($/kg)

Production Option	Production Cost ($/kg)
Steam Methane Reformation	1.86
Electrolysis[1]	
Nuclear	3.33
Coal	2.92
Gas CC	3.09
Gas CT	4.07
Solar PV	6.58
Solar Thermal	5.41
Wind	3.17

[1]Assumes a 2 cent/kWh transmission and distribution cost.

The estimated costs for hydrogen produced via electrolysis are highly dependent on the cost of delivered electricity. Table 18 shows the likely hydrogen costs using electricity from newly constructed generating plants[22] with transmission and distribution costs of two cents/kWhr. The estimated hydrogen production costs range from 2.92 $/kg for electricity from a coal plant to 6.58 $/kg for the solar PV option. If the electricity source is located onsite, thus avoiding the transmission and distribution costs, such as may be the case for solar PV, the production cost would be lowered by approximately 0.94 $/kg.

Based on the analysis here, it appears that natural gas reformation makes more sense than electrolysis for onsite production of hydrogen. However, this result is dependent on the default assumptions. As will be discussed later in the sensitivity analysis section, the reformation numbers are far less certain than the electrolysis numbers and several of the electrolysis options produce significantly lower carbon emissions.

Sensitivity Analysis

As there is considerable uncertainty in many of the assumptions for various technologies, H_2Sim is designed to allow the user to easily change them. This section summarizes the effect on hydrogen production costs of changes in key component costs, fuel prices, or process efficiency.

[22] This analysis assumes new electricity facilities are constructed in 2020 and assumes EIA estimates of capital, O&M, and fuel costs for calculation of electricity production costs. .

H_2Sim was built using Powersim Studio 2001, a dynamic simulation package. Powersim solves the model equations by integrating them with respect to some variable, normally time. H_2Sim uses the capital cost as the dynamic variable, rather than time. The advantage of this choice is that the integration automatically produces a parameter study with respect to capital cost.

Since there is no relation between the capital cost and any of the other model parameters, the hydrogen production cost is directly proportional to the capital cost. Figure 6 and Table 18 illustrate the overall sensitivity of the results to assumptions about capital costs.[23] The relative slope of each technology's line indicates the capital recovery factor, which varies among the different technologies due to the different construction times, lifetimes, and capacity factors.

Ideally, future work on the model would investigate the connection between capital cost and hydrogen production rate. For example, the capital cost of steam methane reforming may be linked to the production rate as in equation (2), which will provide a more complicated trade-off.

As an example of the type of analysis Figure 6 or Table 18 allows, consider the case of electrolysis. H_2Sim initially assumes the capital costs of electrolysis will drop from about 600 \$/kW now to 300 \$/kW by 2020. This anticipated reduction in capital cost is projected to cut the cost to produce hydrogen from 2.59 to 2.39 \$/kg, about 20 cents per kg.

Figure 6 also illustrates breakeven points. For example, a SMR facility costing 600 \$/kW- H_2 is cost competitive with coal gasification facilities with capital costs above about 1350 \$/kW- H_2, all else constant. Thermochemical nuclear capital costs would have to fall below approximately 450 \$/kW to be competitive with the same SMR facility, again all else constant.

Figure 6 also allows the user to answer questions regarding uncertain capital cost assumptions. For example, the capital cost of thermochemical nuclear is projected to be 669 \$/kW- H_2. However, some suggest that this figure is on the optimistic side; it's possible that the actual capital cost could be as high as two times that assumption. In that case, the production of hydrogen would cost close to 2.25 \$/kg.

[23] This analysis option is included in H_2Sim on the "Production, Capital Sensitivity" screen.

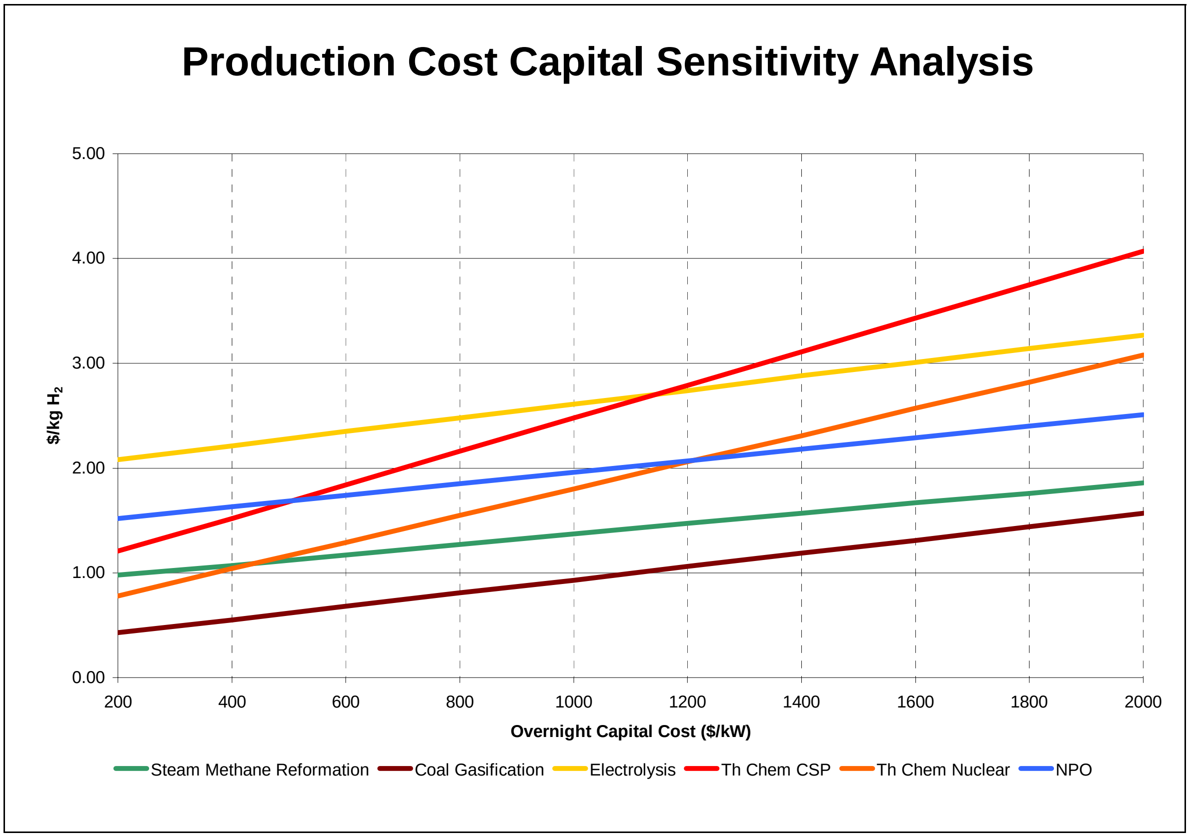


Figure 6. Capital Cost Sensitivity Analysis

Table 18. Hydrogen Production Costs ($/kg): Capital Cost Sensitivity

Capital ($/kW)	Steam Methane Reformation	Coal Gasification	Electrolysis[1]	Th Chem CSP	Th Chem Nuclear	NPO
200	0.98	0.43	2.08	1.21	0.78	1.52
400	1.07	0.55	2.21	1.52	1.04	1.63
600	1.17	0.68	2.35	1.84	1.29	1.74
800	1.27	0.81	2.48	2.16	1.55	1.85
1000	1.37	0.93	2.61	2.48	1.80	1.96
1200	1.47	1.06	2.74	2.79	2.06	2.07
1400	1.57	1.19	2.88	3.11	2.31	2.18
1600	1.67	1.31	3.01	3.43	2.57	2.29
1800	1.76	1.44	3.14	3.75	2.82	2.40
2000	1.86	1.57	3.27	4.07	3.08	2.51

[1]Assumes use of electricity from natural gas combined cycle without transmission and distribution costs.

The base case results are also sensitive to fuel prices and the overall efficiency of the process. Tables 19 – 23 show the relative sensitivity of SMR, coal gasification, electrolysis, NPO, and thermochemical nuclear to fuel costs and thermal efficiency.

SMR results are particularly sensitive to fuel price assumptions, Table 19. Natural gas prices have historically exhibited fairly strong price volatility. For example, while the EIA forecasts natural gas prices for utilities will be about 3.40 $/MBtu in 2005 and are expected to reach 4.47 $/MBtu in 2020, natural gas prices have averaged much higher in 2003, 5.57 $/MBtu (EIA, 2004). For the default SMR efficiency of 70%, each $1 increase in natural gas prices increases produced hydrogen costs by 0.16 $/kg. A doubling of predicted prices in 2005 would increase hydrogen production costs by 0.55 $/kg.

Table 19. SMR Fuel and Efficiency Sensitivity on Hydrogen Production Costs ($/kg)

Natural Gas Price ($/MBtu)	Default Efficiency	10% Higher Efficiency	10% Lower Efficiency
2	0.72	0.69	0.76
3	0.89	0.84	0.94
4	1.05	0.99	1.12
5	1.21	1.14	1.30
6	1.37	1.28	1.48
7	1.54	1.43	1.66
8	1.70	1.58	1.84
9	1.86	1.73	2.02
10	2.02	1.88	2.20
11	2.19	2.02	2.38
12	2.35	2.17	2.56

Table 20 summarizes the sensitivity of hydrogen from coal gasification to coal prices and overall process efficiency. The EIA forecasts coal prices of 1.17 $/MBtu by 2020; a doubling of these prices would increase hydrogen production costs by 0.19 $/kg. The results are also not particularly affected by small changes in efficiency (+/- 10%).

Table 20. Coal Gasification Fuel Price and Efficiency Sensitivity on Hydrogen Production Costs ($/kg)

Coal Price ($/MBtu)	Default Efficiency	10% Higher Efficiency	10% Lower Efficiency
0.50	0.57	0.56	0.58
0.75	0.61	0.60	0.62
1.00	0.65	0.63	0.67
1.25	0.69	0.67	0.71
1.50	0.73	0.71	0.76
1.75	0.77	0.74	0.80
2.00	0.81	0.78	0.85
2.25	0.85	0.82	0.89
2.50	0.89	0.85	0.94
2.75	0.93	0.89	0.98
3.00	0.97	0.93	1.03

Hydrogen production costs from electrolysis are highly dependent on electricity prices, Table 21. At an electrolyzer efficiency of 70%, each one cent increase in electricity prices increases the produced hydrogen cost by 0.47 $/kg. At the average price paid for electricity by residential users in 2003 (8.23 cents/kWhr[24]), it would cost about $4.12/kg to produce hydrogen based on the 2020 capital cost projection of 300 $/kW-$H_2$. Proponents of this option have argued it would make economic sense to produce hydrogen by electrolysis using cheap off peak electricity. Using 1 cent/kWhr electricity, hydrogen production costs are just 0.72 $/kg. There are two problems with this assumption. First, the large scale use of off peak electricity for hydrogen production would lead to increased prices for this electricity. Second, this off peak electricity would only be available a few hours per day; if the electrolyzer was only used during these hours, the capacity factor would fall, increasing hydrogen production prices. For example, whereas an electrolyzer operating 24 hours per day with electricity costing 1 cent/kWhr would produce hydrogen at 0.72 cents/kWhr, operating the same electrolyzer just 6 hours per day would increase the produced hydrogen cost to 2.77$/kg. The results are also quite sensitive to efficiency of the process; for an electricity price of 5 cents/kWhr, hydrogen production costs range from 2.36 $/kg to 2.89 $/kg for efficiencies of 10% higher or lower than the default assumption of 70%.

[24] EIA, Monthly Energy Review, August 2003.

Table 21. Electrolysis Electricity Price and Efficiency Sensitivity on Hydrogen Production Costs ($/kg)

Electricity Cost (cents/kWh)	Default Efficiency	10% Higher Efficiency	10% Lower Efficiency
1	0.72	0.65	0.80
2	1.19	1.08	1.32
3	1.66	1.51	1.84
4	2.13	1.94	2.37
5	2.60	2.36	2.89
6	3.07	2.79	3.41
7	3.54	3.22	3.93
8	4.01	3.65	4.46
9	4.48	4.07	4.98
10	4.95	4.50	5.50
11	5.42	4.93	6.02
12	5.89	5.35	6.54
13	6.36	5.78	7.07
14	6.83	6.21	7.59
15	7.30	6.64	8.11

Hydrogen produced at refineries using the NPO process is quite sensitive to both the price of the crude oil and the overall efficiency of the process, Table 22. At current prices of around 40 $/bbl for crude oil, improving the efficiency from 37 to 47% would drop the cost of hydrogen by 0.47 $/kg. At the default efficiency of 37%, each 5 $/bbl decrease in crude oil price reduces hydrogen production costs by 0.26 $/kg.

Table 22. NPO Fuel Price and Efficiency Sensitivity on Hydrogen Production Costs ($/kg)

Crude Oil Price ($/bbl)	Default Efficiency	10% Higher Efficiency	10% Lower Efficiency
10	0.81	0.76	0.87
15	1.07	1.00	1.16
20	1.34	1.24	1.46
25	1.61	1.49	1.75
30	1.87	1.73	2.05
35	2.14	1.97	2.35
40	2.41	2.21	2.64
45	2.67	2.45	2.94
50	2.94	2.70	3.23

Hydrogen produced by a thermochemical nuclear process is sensitive to the price of uranium, as well as the efficiency of the process, Table 23. A ten percent increase in efficiency at current uranium prices of 0.43 $/MBtu results in a 0.13 $/kg decrease in the price of hydrogen while a ten percent decrease in the efficiency results in a 0.15 $/kg increase in the price of hydrogen. At the assumed efficiency of 43% an increase in the price of uranium of 0.50 $/MBtu results in an increase of approximately 0.41 $/kg of hydrogen.

Table 23. Thermochemical Nuclear Uranium Price and Efficiency Sensitvity on Hydrogen Production Costs ($/kg)

Uranium Price ($/MBtu)	Default Efficiency	10% Higher Efficiency	10% Lower Efficiency
0.00	1.03	0.94	1.15
0.50	1.44	1.31	1.60
1.00	1.84	1.67	2.05
1.50	2.24	2.04	2.49
2.00	2.65	2.41	2.94
2.50	3.05	2.77	3.39
3.00	3.45	3.14	3.84

Figures 7-10 graphically illustrate the sensitivity of the results to feedstock prices and capital costs. In each graph, the feedstock for one technology varies along the X-axis, while all other technologies are held constant. This allows one to see the feedstock prices at which other technologies become cost competitive. In addition, these results illustrate how sensitive the results are to assumptions about capital costs.

The first graph, Figure 7 compares hydrogen production costs from SMR at various natural gas prices to the costs from the other technologies using the default assumptions. The graph also illustrates the sensitivity of these results to capital cost assumptions by including lines indicating results for +/- 20% of the default capital costs. This analysis shows that SMR is only competitive with coal gasification (using the default assumptions) if natural gas prices fall below 2 $/MBtu. Thermochemical nuclear competes with SMR for natural gas prices above approximately $6/MBtu. Electrolysis does not become competitive with centralized SMR unless natural gas prices reach approximately 11 $/MBtu. Of course, as the default electrolysis option in H_2Sim is natural gas combined cycle, higher fuel costs would also significantly increase the cost of producing hydrogen. These results are not particularly sensitive to a +/- 20% capital cost change for the SMR technology.

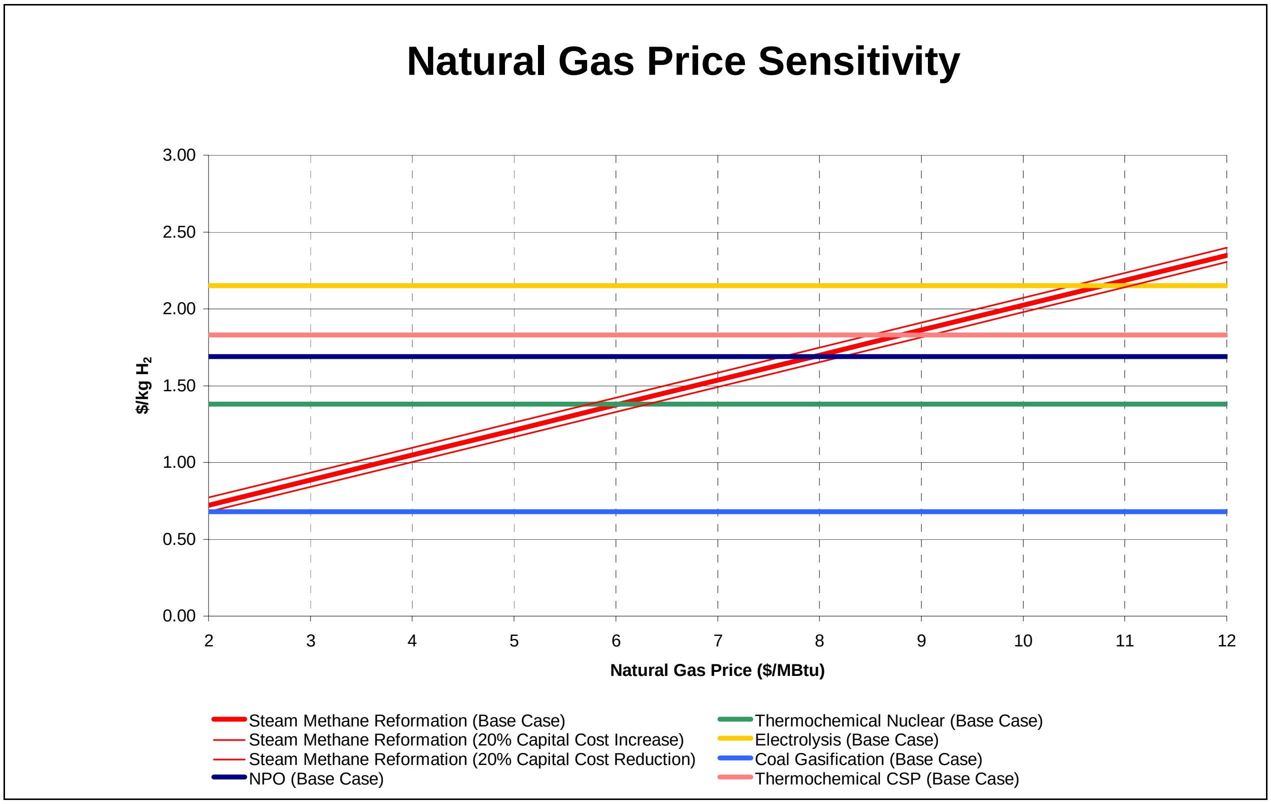


Figure 7. SMR Sensitivity of Natural Gas Prices on Hydrogen Production Costs ($/kg)

Figure 8 illustrates the sensitivity of the gasification results to coal prices. SMR only becomes cost competitive with coal gasification when coal prices exceed 3.00 $/MBtu. It also illustrates that because coal prices are so low, it will be difficult for any of the other technologies to compete.

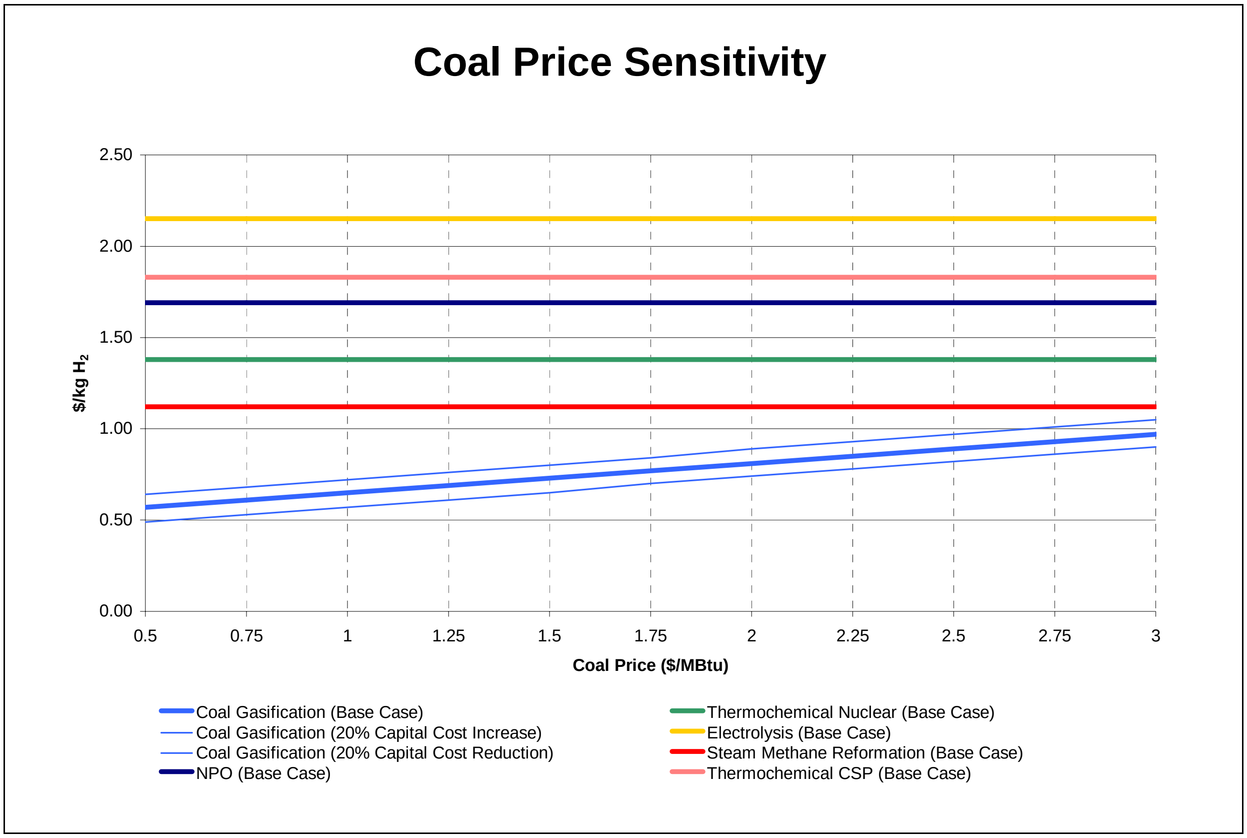


Figure 8. Coal Gasification Sensitivity to Coal Prices

Figure 9 illustrates the sensitivity of the NPO results to crude oil prices. Given the existing technology, crude oil prices would have to drop below about 15 $/bbl to be competitive with SMR in 2020 and below 9 $/bbl to be competitive with coal gasification in 2020. Electrolysis competes with NPO at crude oil prices above 35 $/bbl.

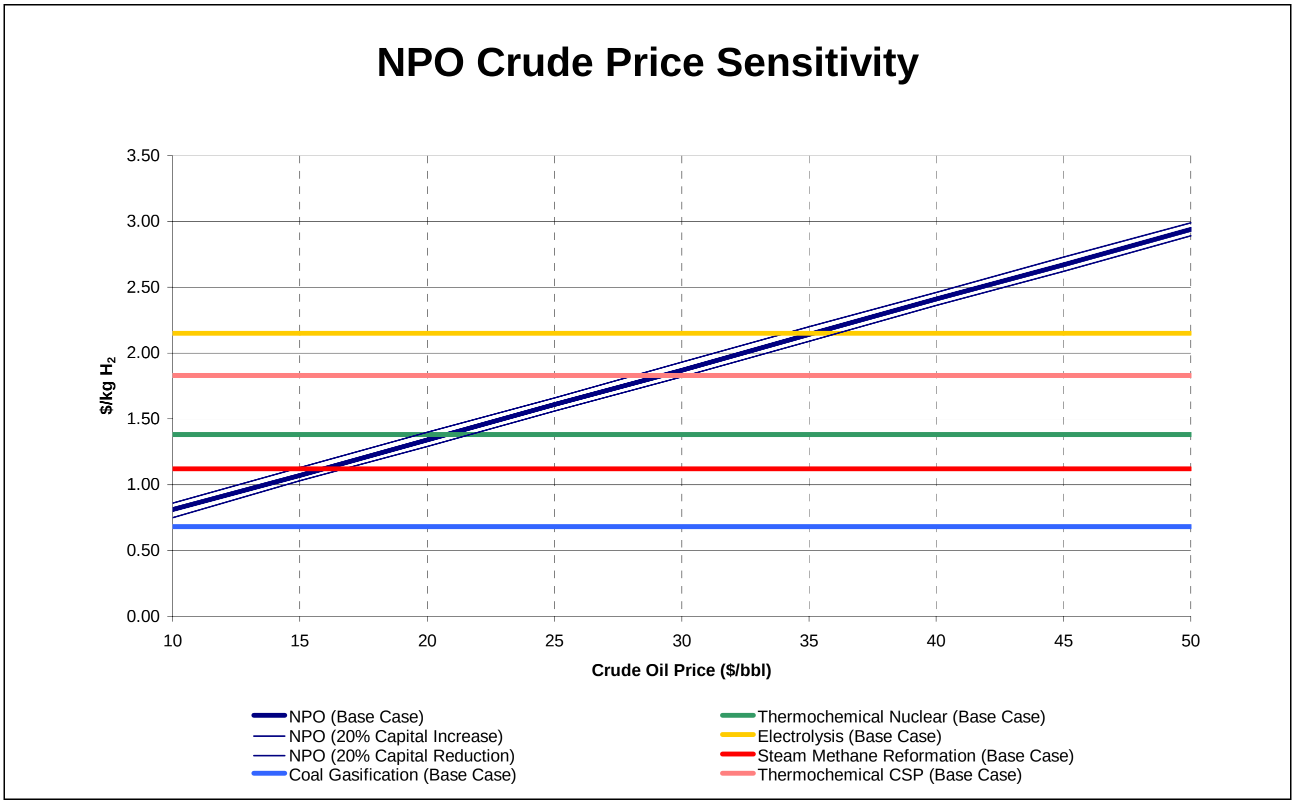


Figure 9. NPO Sensitivity to Crude Oil Prices

Thermochemical nuclear production of hydrogen is sensitive to the price of uranium, Figure 10. At the current price of uranium of 0.43 $/MBtu, thermo-chemical nuclear is competitive with all hydrogen production options except coal gasification and steam methane reformation. The price of uranium would have to be very low, below 0.10 $/MBtu, for thermochemical nuclear to become cost competitive with steam methane reformation, and there is no uranium price at which it is competitive with coal gasification. For every one dollar increase in the price of uranium, the cost hydrogen increases by approximately 0.80 $/kg. At a uranium price of 1.00 $/MBtu, thermochemical nuclear is no longer competitive with any production option except electrolysis. Figure 10 also indicates that increasing or decreasing the capital cost by 20% changes the results by 0.20 $/kg.

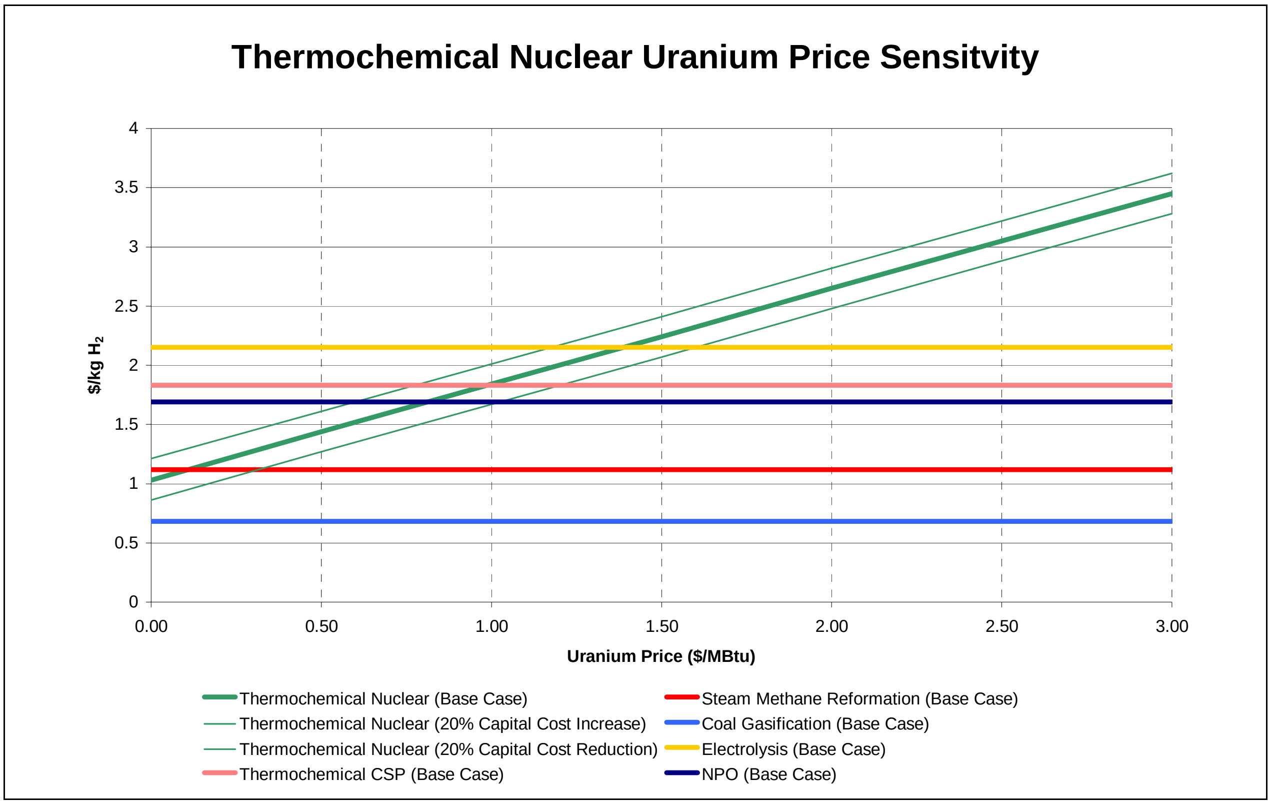


Figure 10. Thermochemical Nuclear Sensitivity to Uranium Prices

Hydrogen Distribution

Hydrogen distribution costs include storage, transportation, and fuel station costs. H_2Sim includes nine possible scenarios, as summarized in Table 11. Table 24 summarizes estimated distribution costs for the default H2Sim scenario of low production (100,000 kg/day) and short delivery distance (100 miles). Estimated costs for high production (1,000,000 kg/day) and long distance (500 miles) are summarized in Table 25. Each option assumes hydrogen is stored for one day. As indicated in the tables, the hydrogen distribution costs may be significant, suggesting that the future viability of a hydrogen economy may depend on achieving reductions in these storage and transportation costs.

The NAS (2004) recently reached a similar conclusion. Specifically, they found that pipeline shipment and dispensing would be the lowest cost option, costing 0.96 $/kg, "…which is essentially equal to the cost of production." They conclude that "even with possible future improvements in shipping and distribution, this cost is much more than today's gasoline dispensing and distribution costs, at 0.19 $/gal." And they note that their analysis "demonstrates the realities of shipping H_2 gas versus the much more efficient shipment of a liquid."

Table 24. Hydrogen Distribution Costs for Nine H2Sim Scenarios: Low Production (100,000 kg/day), Short Distance (100 miles)

SCENARIOS[1]	UND PIPE-LARGE PIPE-LOCAL FS	GH PIPE-LARGE PIPE-LOCAL FS	GH TRUCK-GH NONE FS	LH TRUCK-LH NONE FS	GH PIPE-LARGE TRUCK-GH FS	MH TRUCK-MH NONE MH	GH RAIL-GH TRUCK-GH FS	LH SHIP-LH TRUCK-LH FS	LH RAIL-LH TRUCK-LH FS
STORAGE 1	0.13	0.23	0.23	0.78	0.23	0.84	0.23	0.78	0.78
DELIVERY 1	0.44	0.44	1.36	0.07	0.50	0.87	3.05	1.70	0.20
LOCAL DELIVERY	0.13	0.13	0.00	0.00	0.61	0.00	0.61	0.03	0.03
END STORAGE	0.41	0.41	0.41	0.50	0.41	0.84	0.41	0.50	0.50
TOTAL	1.11	1.20	2.00	1.35	1.74	2.56	4.29	3.00	1.50

[1]Scenarios written Storage 1/Delivery 1/Local Delivery/End Storage.

UND = Underground, GH = Gaseous Hydrogen, LH = Liquefied Hydrogen, MH = Metal Hydride, FS = Fueling Station.

For the default case (Table 25), estimated costs range from a low of 1.11 $/kg to over 4.00$/kg. At the low end is the case of underground storage of compressed gas with large pipelines connected to a series of smaller pipelines which deliver the hydrogen to a fueling station with compressed gaseous storage (option 1). Another lower cost option (option 4), at 1.35 $/kg, is the case of liquid storage, with truck delivery. Transporting the liquid hydrogen by truck is fairly inexpensive (0.07 $/kg); the largest cost, included here in the storage costs (0.78$/kg) are the liquefaction costs. Distribution of gaseous hydrogen by truck or rail would be considerably more expensive (2.00 – 4.00 $/kg) due to the low volumetric density of the hydrogen. Note that while the estimated fueling station costs are significant (0.41 $/kg) for gaseous storage and dispensing; 0.50 $/kg for liquid storage and dispensing), other sources, including Ogden (1999) suggests that such costs could add as much as 0.52 – 0.78 $/kg to the costs presented here.

Table 25. Hydrogen Distribution Costs for Nine H2Sim Scenarios: High Production (1,000,000 kg/day), Long Distance (500 miles)

SCENARIOS[1]	UND PIPE-LARGE PIPE-LOCAL FS	GH PIPE-LARGE PIPE-LOCAL FS	GH TRUCK-GH NONE FS	LH TRUCK-LH NONE FS	GH PIPE-LARGE TRUCK-GH FS	MH TRUCK-MH NONE MH	GH RAIL-GH TRUCK-GH FS	LH SHIP-LH TRUCK-LH FS	LH RAIL-LH TRUCK-LH FS
STORAGE 1	0.11	0.17	0.17	0.57	0.17	0.84	0.17	0.57	0.57
DELIVERY 1	0.85	0.85	5.22	0.27	0.89	3.27	3.05	1.93	0.20
LOCAL DELIVERY	0.50	0.50	0.00	0.00	0.61	0.00	0.61	0.03	0.03
END STORAGE	0.41	0.41	0.41	0.50	0.41	0.84	0.41	0.50	0.50
TOTAL	1.87	1.93	5.80	1.34	2.08	4.95	4.24	3.03	1.30

[1]Scenarios written Storage 1/Delivery 1/Local Delivery/End Storage.
UND = Underground, GH = Gaseous Hydrogen, LH = Liquefied Hydrogen, MH = Metal Hydride, FS = Fueling Station.

For greater quantities of hydrogen (Table 25), whereas it may make sense to use gaseous truck transport for local delivery (option 5), gaseous truck transport becomes prohibitively expensive for long distances. For the case of pipelines, whereas distance has increased five times and the flow rate eight times, pipeline delivery costs only doubled as pipeline capacity is more adequately utilized. These results also suggest the cost of delivering liquid hydrogen actually drops, largely due to economies of scale associated with the liquefaction process. A close look at the differences between the two scenarios suggests picking the low cost option for any particular region will require some type of optimization that take the key factors into account. For example, for less densely populated areas, the low cost option may not include pipelines. For higher levels of demand, some combination of pipeline and/or truck delivery may minimize costs. The results also show where further work is necessary in H_2Sim; one specific example is that the model currently suggests rail transport costs are identical in both cases, as distance is not explicitly taken into account.

The next section presents a detailed sensitivity analysis for key variables affecting distribution costs.

Sensitivity Analysis

This section further analyzes the sensitivity of the distribution results to several key variables including storage time, hydrogen production rates, and transport distances.

Storage costs are highly dependent on the type of storage, storage time, and hydrogen production rates, Figures 11-12.

Figure 11 shows how production rate affects projected storage costs. Storage costs are generally lowest for underground storage options, although this option requires the existence of underground caverns suitable for storage. With the exception of metal hydride storage, costs decrease as the production rate increases, due to economies of scale. Above ground gaseous storage is the second cheapest option; however, it is more expensive to transport hydrogen in a gaseous form due to its low density.

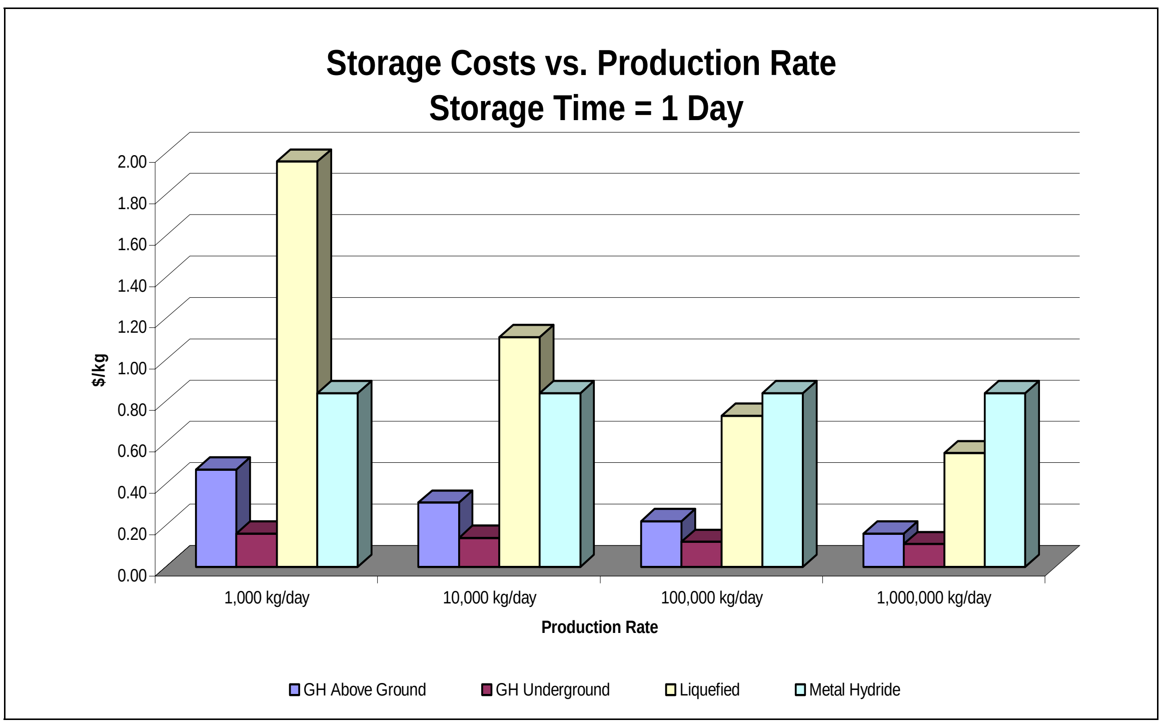
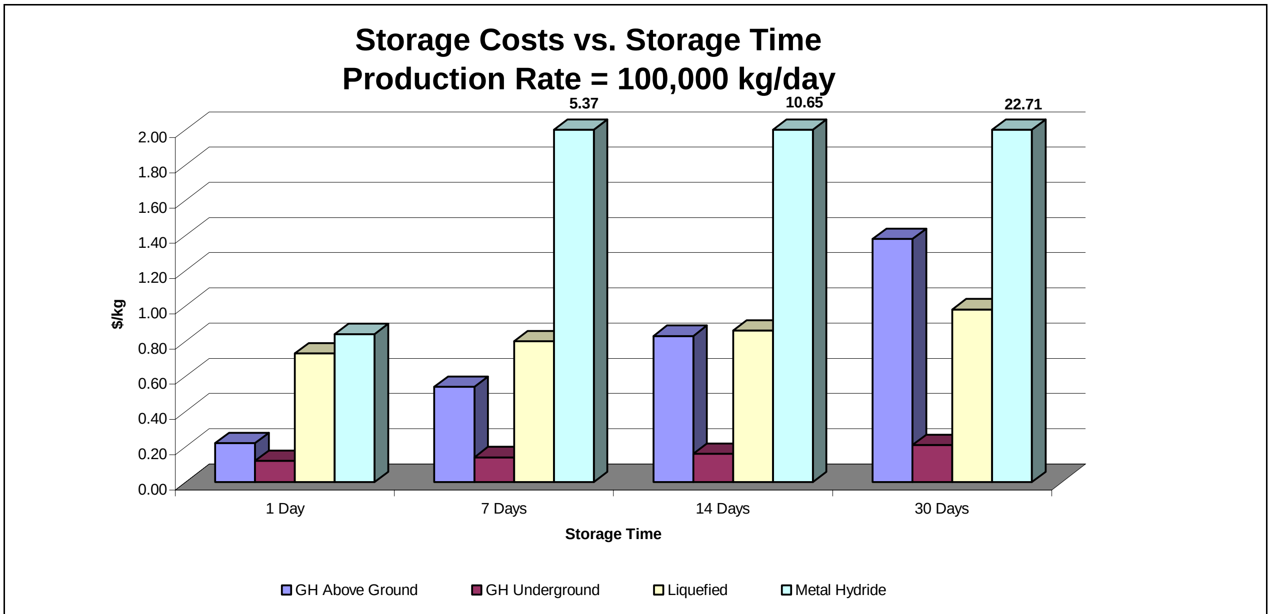


Figure 11. Storage Costs as a Function of Hydrogen Production Rate

As the storage time and the necessary capacity increases the costs of some storage options are greatly affected while others are less sensitive, Figure 12. While the low cost of underground gaseous storage remains essentially unchanged, costs for above ground storage increase, as increased storage time requires a larger number of tanks.

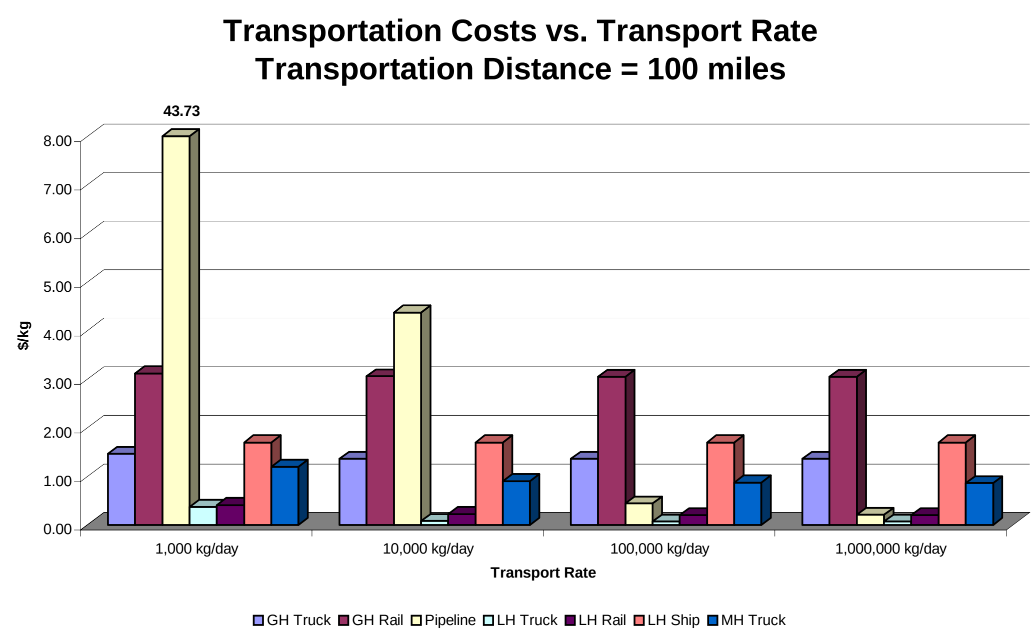
Because liquefied hydrogen storage is less sensitive to storage time than above ground gaseous storage, it becomes the least cost, consistently available option for long storage times, while underground gaseous storage remains the least expensive option when geographically possible. In contrast, metal hydride storage is extremely sensitive to storage time, becoming progressively more expensive than other options as storage time increases.



Note: Metal hydride storage costs exceed the scale for storage times of 7 days or more.

Figure 12. Storage Costs as a Function of Storage Time

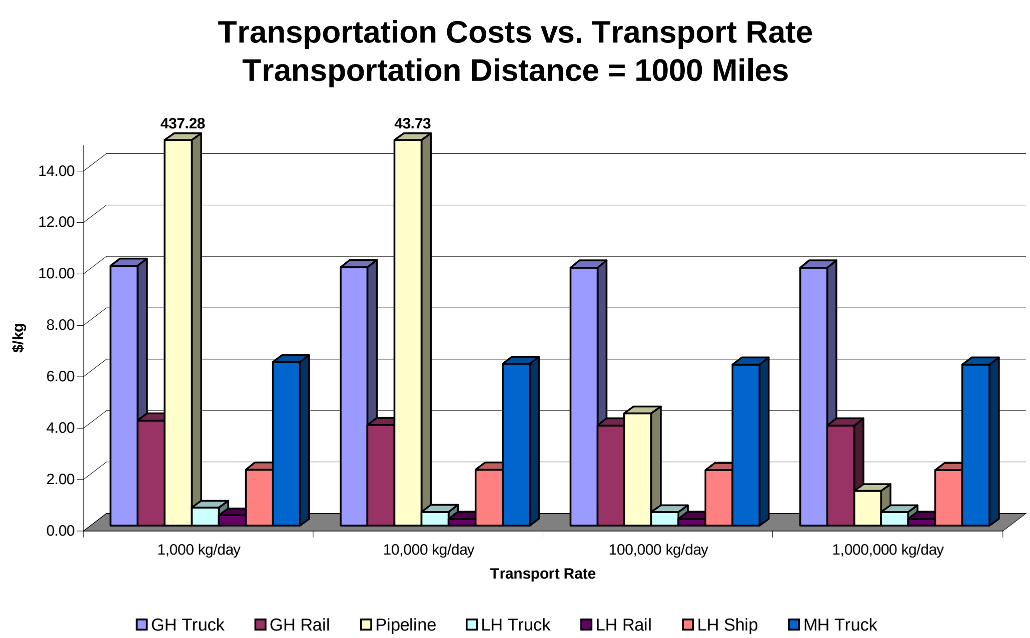
Hydrogen transportation costs are determined by two primary factors: transport rate and transportation distance. Figure 13 illustrates the relationship between transportation costs and transport rate for hydrogen delivered 100 miles (H_2Sim's default setting). Liquefied hydrogen and pipeline transport are the two options most affected by transportation rates. With the exception of pipeline transport, costs level off at rates greater than 10,000 kg/day. The cost of the other options level off after reaching a transport rate of 10,000 kilograms per day. Pipeline transport is the most sensitive, due to the high capital cost of the pipelines, which is spread over a larger delivered quantity as the production rate increases. With all other transport options the quantity of trucks and railcars is easily varied to meet the demand.



Note: Pipeline transportation costs exceed the scale for a transport rate of 1,000 kg/day.

Figure 13. Transportation Costs for 100 Miles as a Function of Hydrogen Transport Rate

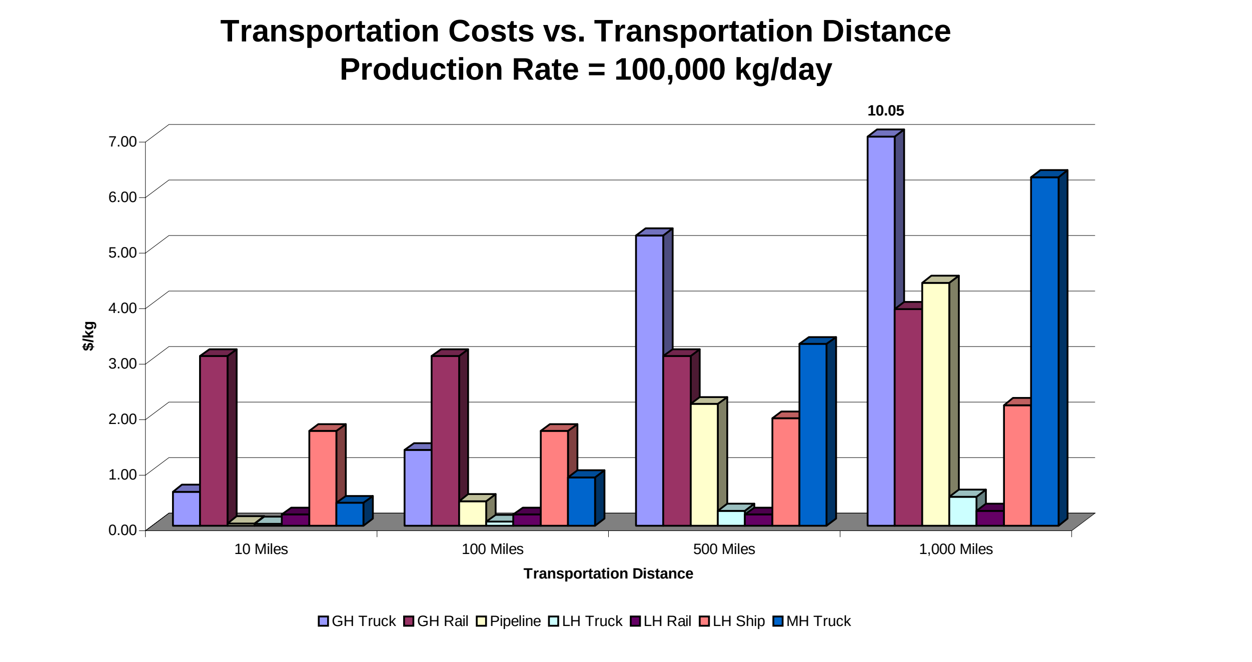
As transport distance increases, so do transportation costs. Figure 14 illustrates the sensitivity of transportation options to transport rates for a higher transportation distance of 1000 miles. For example, gaseous hydrogen transport by truck would cost about 10 $/kg for a transportation distance of 1000 miles compared to a cost of just over 1 $/kg for a transportation distance of 100 miles (Figure 14) regardless of the transportation rate. As with shorter transportation distances, pipeline transportation is very sensitive to the flow rate, costing far more than any other option in the two lower transportation rate scenarios. However, as the flow rate increases, costs decrease, reaching 1.36 $/kg for a flow rate of 1,000,000 kg/day. Minimizing the pipeline costs for this high transport, high flow rate requires utilizing a larger pipeline (14 inch) than is assumed for the other cases (12 inch). For the case of 12 inch pipelines, H_2Sim suggests pipeline transport costs are minimized in the 1000 mile case at flow rates of around 500,000 kg/day (1.37 $/kg). Liquefied transport costs are also fairly low, but when coupled with liquefaction and storage costs, would not be less expensive than pipeline transport.



Note: Pipeline transportation costs exceed the scale for transport rates of 10,000 kg/day or less.

Figure 14. Transportation Costs for 1000 Miles as a Function of Hydrogen Transport Rate

Transportation costs increase across the board as distance increases. Figure 15 examines this relationship further, showing the sensitivity of each transportation option to the transportation distance at a constant transport rate. At the shortest distance of ten miles, which could be used for local hydrogen distribution, pipelines and liquefied hydrogen trucks provide the least expensive options, but the cost of transporting liquefied hydrogen via rail or truck transportation of gaseous hydrogen or metal hydrides also have low costs, adding less than 0.50 $/kg. This cost also does not include the liquefaction costs, which are significant. However, for this relatively low flow rate, as the transportation distance increases, the cost of some options increase greatly, while others remain fairly constant. While pipeline was very inexpensive at a low transportation distance, it is highly sensitive and therefore costs increase quickly with respect to longer transport distances. The same is true for other gaseous hydrogen transportation options and metal hydride transport. However, all liquefied hydrogen transportation options, especially rail, are relatively insensitive to distance and liquefied hydrogen is therefore the least cost option when distances reach 1,000 miles at the H_2Sim default transport rate of 100,000 kg/day.



Note: GH Truck costs exceed the scale for a distance of 1,000 miles.

Figure 15. Transportation Costs as a Function of Distance

End Use Costs

H_2Sim compares the end use cost of using hydrogen in either fuel cell vehicles (FCV) or hybridized, direct hydrogen combustion vehicles (H_2HYB) in 2020 with today's internal combustion engine (ICE) vehicles, hybrid, and electric vehicles (EV). It also considers a 2020 fuel cell vehicle with on-board production of hydrogen (FCV OB). The default costs associated with each of the vehicles included in H_2Sim were summarized in Table 4 of the production section of this paper. This section focuses on the fuel and the total end use costs associated with each vehicle based on fuel and vehicle cost sensitivity analysis.

Table 26 summarizes fuel costs, in cents per mile driven, for the various vehicle types. These results use the default values in H_2Sim, including the assumption of low hydrogen production and short distance. These costs do not include any carbon capture and sequestration. Depending on the distribution option selected, the estimated fuel costs will change as hydrogen production rates and distances increase. Obviously, the cost of hydrogen does not affect the operating costs of the ICE, hybrid, FCV OB, or EV vehicles. The EV, which is fueled by electricity, has the lowest fuel cost per mile (1.05 cents/mile), followed by hybrid vehicles (1.80 cents/mile) because of their high fuel efficiencies. The conventional ICE vehicle has the highest fuel cost (3.6 cents per mile) because of its lower fuel efficiency.

Of the various hydrogen options, H_2Sim suggests that fuel costs for a FCV may be as low as 2.80 cents/mile for hydrogen from coal gasification delivered by large regional pipelines and smaller local pipelines. This compares favorably to the fuel costs for the conventional ICE vehicle (3.56 cents/mile), but is more expensive than for the hybrid vehicles. At higher flow rates (800,000 kg/day delivered 100 miles), the hydrogen fuel costs fall as low as 2.30 cent/mile. For the H_2Hybrid vehicle, the estimated fuel costs for the default values is 4.33 cents/mile, somewhat higher than the FCV option due to the lower overall vehicle efficiency. The FCV with onboard processing has estimated costs of 2.3 cents/mile. In terms of yearly fuel costs, it would cost $427 for the conventional ICE vehicle compared to $336 for the FCV, an annual savings of just $91, suggesting a simple payback in excess of 40 years for the FCV.

Table 26. Fuel Costs (Cents/Mile) for ICE, Hybrid, EV, H_2Hybrid, FCV, and FCV OB, Assuming the Default Vehicle Efficiencies Summarized in Table 4

	STORAGE AND DELIVERY METHOD[1]									
VEHICLE/ PROD METHOD[2]	UND PIPE-LARGE PIPE-LOCAL FS	GH PIPE-LARGE PIPE-LOCAL FS	GH TRUCK-GH NONE FS	LH TRUCK-LH NONE FS	GH PIPE-LARGE TRUCK-GH FS	MH TRUCK-MH NONE MH	GH RAIL-GH TRUCK-GH FS	LH SHIP-LH TRUCK-LH FS	LH RAIL-LH TRUCK-LH FS	NONE
ICE	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56
Hybrid	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80
EV	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05
H_2 Hybrid										
SMR	5.42	5.66	7.60	5.92	6.96	9.00	13.21	9.95	6.29	2.75
Coal Gas	4.33	4.56	6.50	4.82	5.86	7.90	12.11	8.86	5.20	1.65
Electrolysis[3]	7.92	8.16	10.10	8.42	9.46	11.49	15.71	12.45	8.79	5.24
Th CSP[4]	7.15	7.38	9.33	7.65	8.69	10.72	14.94	11.68	8.02	4.47
Th Nuclear	6.05	6.28	8.22	6.54	7.58	9.62	13.83	10.58	6.92	3.37
NPO	6.80	7.03	8.97	7.29	8.33	10.37	14.58	11.33	7.68	4.12
FCV										
SMR	3.51	3.66	4.92	3.83	4.51	5.82	8.55	6.44	4.07	1.78
Coal Gas	2.80	2.95	4.21	3.12	3.80	5.11	7.84	5.74	3.37	1.07
Electrolysis[3]	5.13	5.28	6.54	5.45	6.12	7.44	10.17	8.06	5.69	3.40
Th CSP	4.63	4.78	6.04	4.95	5.62	6.94	9.67	7.56	5.19	2.90
Th Nuclear	3.91	4.07	5.32	4.24	4.91	6.23	8.96	6.85	4.48	2.18
NPO	4.40	4.55	5.81	4.72	5.40	6.71	9.44	7.33	4.96	2.67
FCV OB	2.32	2.32	2.32	2.32	2.32	2.32	2.32	2.32	2.32	2.32

[1]Scenarios written Storage 1/Delivery 1/Local Delivery/End Storage.

UND = Underground, GH = Gaseous Hydrogen, LH = Liquefied Hydrogen, MH = Metal Hydride, FS = Fueling Station.

[2]ICE, Hybrid, EV are vehicle technology in 2003. H_2 Hybrid, FCV, FCV OB are vehicle technology in 2020.

ICE = Internal Combustion Engine, EV = Electric Vehicle, FCV = Fuel Cell Vehicle, FCV OB = Fuel Cell Vehicle with Onboard Reformer.

[3]Assumes the use of electricity from gas combined cycle.

[4]Th = Thermochemical.

Focusing on fuel costs per mile (or even aggregate) is rather misleading, however, as the fuel costs are a small component of total driving costs. The total cost per mile is determined by the cost of the vehicle, license and registration, insurance, maintenance, and fuel. Table 27 summarizes the total costs per mile for each vehicle in H_2Sim. As previously mentioned, H_2Sim compares predicted 2020 costs for the hydrogen vehicles with current costs for the ICE, hybrid, and electric vehicle technologies. The results here must be interpreted carefully as existing vehicles will also experience technological improvements which may increase their overall efficiency.

For the case of the least expensive hydrogen production option (coal gasification), the H_2Hybrid vehicle is the least expensive hydrogen vehicle to operate overall and is competitive with today's ICE vehicle (with 2020 wholesale gasoline prices). However, if other hydrogen production options are used, today's ICE vehicle and today's hybrid are the lowest cost. Today's EV and the 2020 FCV OB have the highest end use costs because of the EV battery costs and the FCV OB's on board reformer cost (which adds almost $4,000 to the vehicle cost). Despite the lower overall fuel costs, H_2Sim estimates FCVs will cost nine to 11 cents more per mile to operate than conventional ICE vehicles. This is an important result; despite higher fuel efficiency and lower fuel costs, FCVs will have a difficult time competing with conventional ICE or hybrid technologies. The actual cost of delivered hydrogen is not that important in terms of the overall economic competitiveness of the FCV.

Table 27. Total End Use Costs

Vehicle	Total Cost ($/mile)	Vehicle Cost
ICE	0.55	18000
Hybrid	0.56	19736
EV[1]	0.82 - 0.84	33995
H_2Hybrid[2]	0.55 - 0.59	18000
FCV[2]	0.64 - 0.66	22100
FCV OB	0.70	25910 [3]

[1]Ranges from least expensive to most expensive electricity production options; does not include T&D costs.
[2]Ranges from least expensive to most expensive hydrogen production options; assumes distribution option 1.
[3]Includes a vehicle cost of $22,100 and a reformer cost of $3,810.

The next section will focus on the sensitivity analysis for end use of hydrogen vehicles including fuel and vehicle price sensitivity.

Sensitivity Analysis

Figure 16 illustrates breakeven costs for the various vehicle types as a function of hydrogen price. Based on the default assumptions of H_2Sim, 2020 H_2Hybrid vehicles become competitive with ICE vehicles, using today's technologies, when the delivered price of hydrogen is 1.60 $/gallon gas equivalent (gge)[25]. Based on the default assumptions about FCVs, they can't compete with ICE or hybrid technologies, even if the hydrogen is free. The implication is that for FCVs to compete with other technologies, will require further reductions in vehicle costs or significant increases in gasoline prices, whether it be through the markets or as a result of government policy. Alternatively, the FCV will have to offer the consumer something that existing vehicles don't, something that consumers are willing to pay more for, whether performance, emissions profile, or some other factor. The remainder of the sensitivity analysis looks at the issue of vehicle price and gasoline costs as a factor in the overall competitiveness of the FCV.

[25] Compared on a Btu basis.

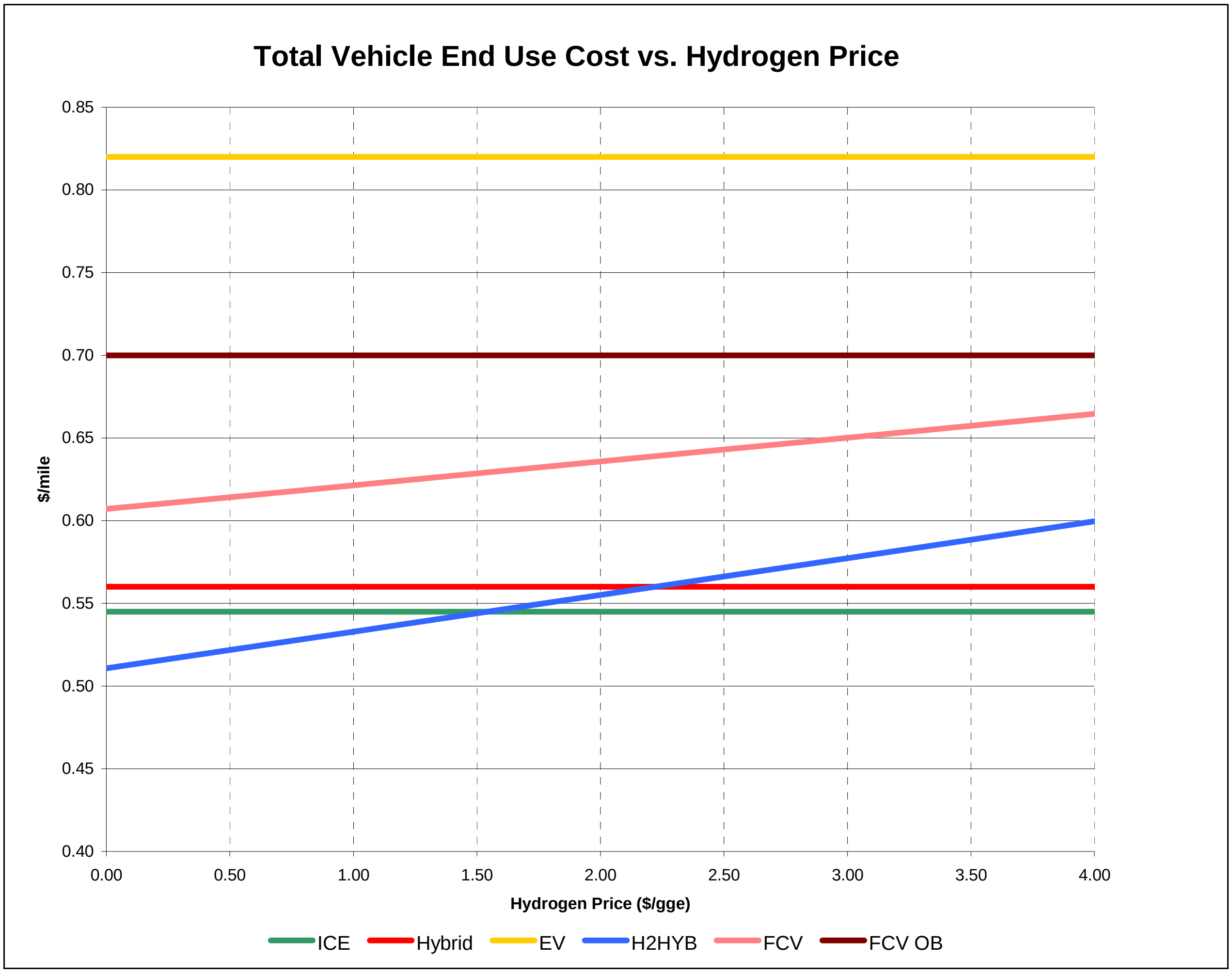


Figure 16. Hydrogen Price End Use Sensitivity

As Table 27 showed, it is vehicle price rather than fuel price that dominates the total cost per mile. Figure 17 illustrates the vehicle costs required for advanced technologies to be competitive with existing conventional ICE vehicles. This analysis assumes the hydrogen is produced from coal gasification, without carbon capture and sequestration, and distribution option 1 (underground gaseous storage, large central pipeline, small, local pipeline connecting to fueling stations.) Based on the default assumptions for the ICE technology, this analysis shows that hybrids must be at a price of $18,900 and electric vehicles at a price of $19,300, to become competitive with the default ICE vehicle. FCVs and H_2Hybrid vehicles, however, are only competitive at prices of $17,000 or less, a decrease of $5,100 and $1,000 from the default values, respectively. The price of the FCV with OB reformation would have to fall to around $18,000, including the cost of the onboard reformation system.

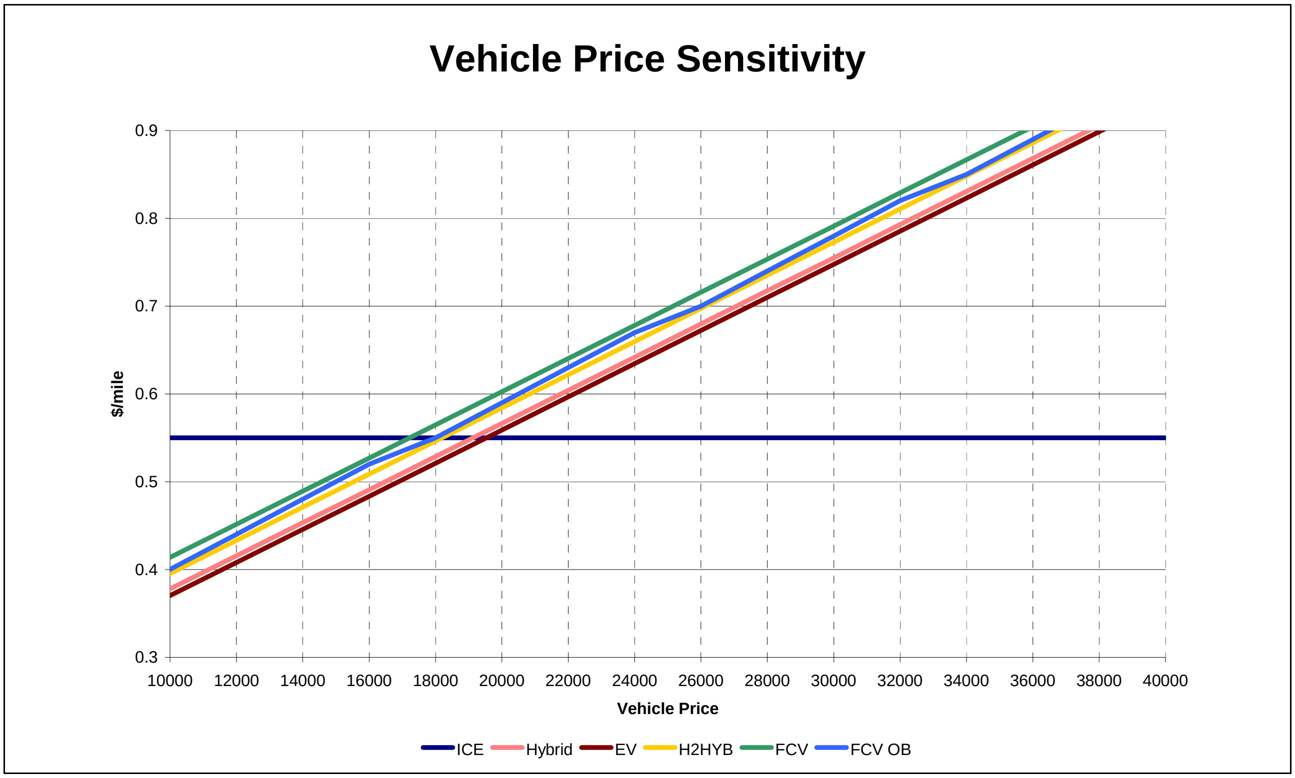


Figure 17. Vehicle Price Sensitivity

The relative competiveness of hydrogen vehicles to gasoline vehicles is sensitive to the price of gasoline. As gasoline prices increase, so do gasoline vehicle end use costs, especially for today's less efficient ICE vehicles, Figure 18. The greater efficiencies of today's hybrids and FCV OBs makes them less susceptible to gasoline price variations. H_2Hybid vehicles fueled with hydrogen from a centralized coal gasification facility with liquefied storage and truck transport, are the least expensive hydrogen option. H_2Hybrid vehicles become cost competitive with hybrids and ICEs when wholesale gasoline prices reach approximately 1.00 $/gal and 1.30 $/gal, respectively. Fuel cell vehicles, using the same delivered hydrogen option, however, do not become cost competitive with ICE vehicles until wholesale gasoline prices exceed 3.50 $/gal. Gasoline prices would have to exceed 4.00 $/gal before FCVs were competitive with existing hybrids, a highly unlikely scenario for the U.S. in the absence of higher taxes. Furthermore, FCV OB and today's EV vehicles are not competitive with hydrogen, ICE, or hybrid vehicles at any gasoline price.

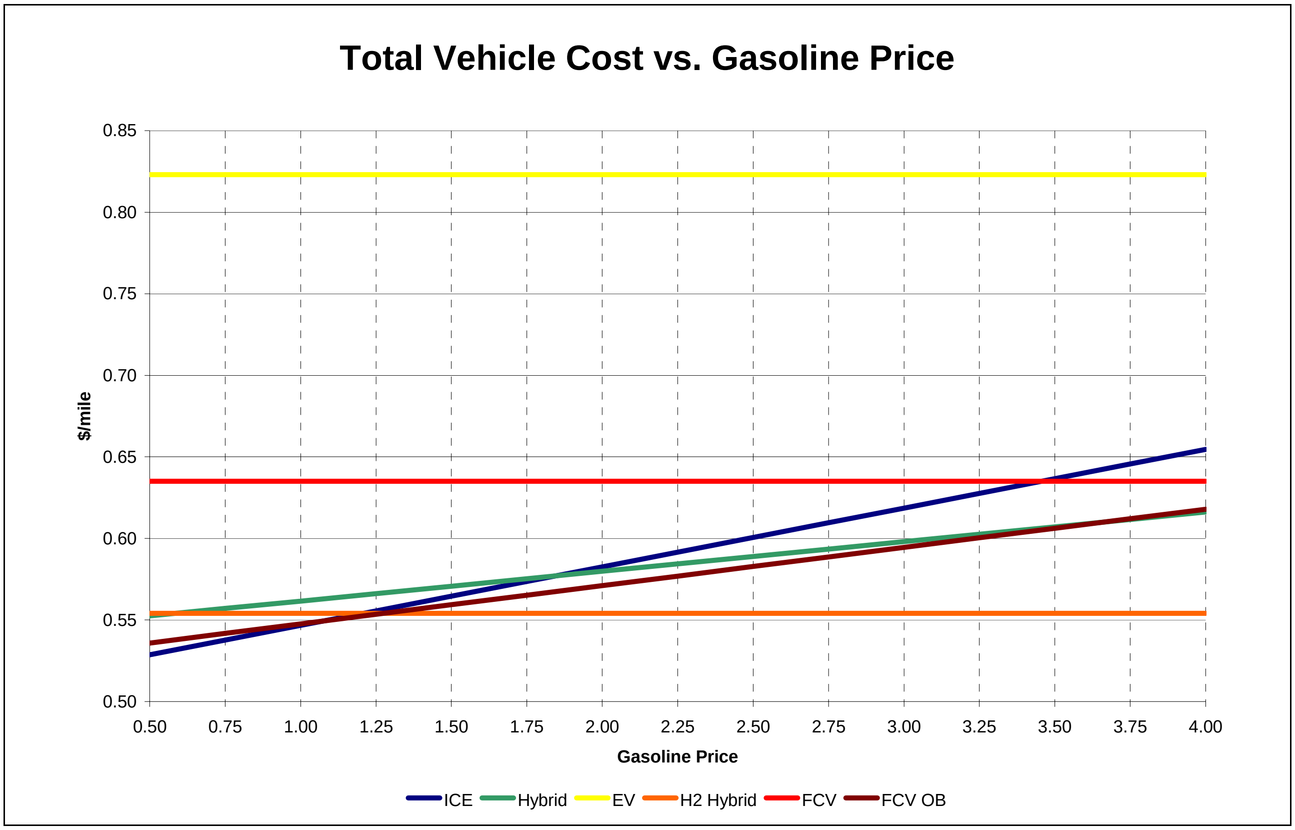


Figure 18. Wholesale Gasoline Price End Use Sensitivity

The next section discusses the potential impact on carbon emissions of using the various vehicle types.

Carbon Emissions

One of the potential benefits of hydrogen is a decrease in carbon emissions, thought to be the leading anthropogenic contributor to global climate change. Conventional ICE vehicles emit approximately 1.04 tons of carbon (tC) annually, based on the default assumptions about efficiency and miles driven, Table 4. Hydrogen vehicles offer the potential for zero carbon emissions if the hydrogen is produced using electrolysis from a non-carbon emitting source or a thermochemical process. Hydrogen produced using coal gasification or steam methane reformation will result in significant carbon emissions unless these options include some form of carbon capture and sequestration.

Table 28 summarizes estimated costs, in terms of \$/kg – H_2, for carbon capture and sequestration. The results indicate an 87% reduction in carbon emissions from coal gasification will add \$0.16 to each kg of hydrogen produced from this option. For natural gas reformation, estimates range from \$0.09 to \$0.22 \$/kg – H_2 depending on the percentage of CO_2 removed. These results do not change the fundamental results, shown in Table 27. Coal gasification remains the cheapest option for producing hydrogen, even with 87% CO_2 capture and sequestration. There is, however, considerable uncertainty about sequestration possibilities; ongoing demonstration projects should help establish the long term viability of storing large amounts of carbon produced from the production of hydrogen.

Table 28. Carbon Capture and Sequestration Costs (\$/kg - H_2)

	Reformation 70% Reduction	Reformation 84% Reduction	Gasification 87% Reduction
CAPITAL	0.01	0.08	0.06
VARIABLE O&M	0.00	0.05	0.02
FUEL	0.03	0.03	0.01
PIPELINE	0.02	0.03	0.05
DISPOSAL WELL	0.03	0.03	0.02
TOTAL	**0.09**	**0.22**	**0.16**

Estimated annual carbon emissions by vehicle type and fuel source are summarized in Table 29. Existing hybrid vehicles emit half as much carbon as current ICE vehicles, explainable by the difference in assumed fuel efficiencies. For the EV, annual carbon emissions depend on the source of the electricity. Annual estimates range from zero for non-carbon based electricity sources to 0.58 tons per year if coal is used to produce electricity.

Estimated carbon emissions for the various future technologies depend on the source of hydrogen and whether or not the carbon is captured and sequestered. In the absence of carbon sequestration, carbon emissions may be greater than from existing hybrid vehicles (0.75 tC per year for hydrogen from coal gasification. However, with carbon sequestration, the same FCV would release 90% less than existing vehicles (0.10 tC per year). If fueled with hydrogen from electrolysis using carbon based electricity, annual emissions would actually be greater than existing vehicles (1.57 tC/year), clearly illustrating that wide scale adoption of FCVs does not guarantee lower carbon emissions.

Table 29. Total Carbon Emissions by Vehicle Type

Vehicle/Fuel Option	Carbon Emissions (metric tons C/yr)
ICE	1.04
Hybrid	0.52
EV [1]	0.00 - 0.58
H_2Hybrid	
Steam Methane Reformation[2]	0.65/0.11
Coal Gasification[2]	1.16/0.16
Electrolysis[1]	0.00 - 2.42
Thermochemical CSP	0.00
Thermochemical Nuclear	0.00
NPO	1.74
FCV	
Steam Methane Reformation[2]	0.42/0.07
Coal Gasification[2]	0.75/0.10
Electrolysis[1]	0.00 - 1.57
Thermochemical CSP	0.00
Thermochemical Nuclear	0.00
NPO	1.13
FCV OB	0.82

[1]Depends on generating source. Lowest levels are from Nuclear, Solar PV, Solar Thermal, and Wind. Highest emissions are from coal.

[2]Without Sequestration/With Sequestration

Discussion

The results show that coal gasification is the lowest cost hydrogen production option ($0.68/kg). This basic result does not change if carbon capture and sequestration costs are added ($0.16/kg). This result is fairly insensitive. For example, coal prices would have to more than triple or the assumed capital cost would have to increase by more than 2.5 times for natural gas reformation to become the cheaper option. Alternatively, natural gas prices would have to fall below $2/MBtu to compete with coal gasification. The electrolysis results are highly sensitive to electricity costs, but electrolysis only becomes cost competitive with other options when electricity drops below 1 cent/kWhr. While the possibility might exist to produce some electricity off-peak for that price, if this means that hydrogen plant capacity utilization must fall substantially, this higher cost could more than off-set off peak prices.

In addition to fuel price sensitivity, there is considerable uncertainty about most of the projected capital costs, including thermochemical nuclear. The estimates provided by Schultz (2003) which are the basis for H_2Sim estimates, are for an unproven technology. For example, it is possible that the costs of thermochemical nuclear could be twice as high as those estimated by Schultz. In that case, thermochemical nuclear become the most expensive production options and are no longer close to cost competitive.

H_2Sim allows the user to determine the delivered cost of hydrogen as well as the end use cost of hydrogen vehicles for a range of supply and end use options. The cost of delivered hydrogen is the sum of the production, storage, and transportation costs. Table 30 summarizes delivered hydrogen costs for three of the most often mentioned delivery options. These three options are: options 1 (underground storage with regional and local pipelines), 3 (gaseous storage and truck transport), and 4 (liquid storage and truck transport. These costs do not include either carbon capture and sequestration or estimated fueling station costs.

For each option, Table 30 includes estimated delivery costs for a low distance, low production rate (100 miles, 100,000 kg/day) and a long distance, high production rate (1000 miles, 1,000,000 kg/day). For example, for H_2 produced from coal gasification and delivered using option 1, estimated costs range from 1.37 $/kg for the low distance, low production case to 2.68 for the long distance, high distance case. If coal sequestration and fueling station costs are added in, the range increases to 1.92 – 3.23 $/kg.

Table 30 also emphasizes the large contribution of distribution costs to total hydrogen costs. Coupled with the fact that several of the delivery options, particularly the pipeline options, require large infrastructure investments, makes a more distributed option for hydrogen production look more favorable. Based on the results of H_2Sim, the least cost distributed option would be steam methane reformation (1.86 $/kg), Table 17. Options involving electrolysis do not appear to make economic sense. An alternative in the early phases of a hydrogen economy appears to be liquefied storage and truck transportation, with delivered cost estimates ranging from 1.48 – 1.50 $/kg (Table 30).

One of the strongest capabilities of H_2Sim is that it allows the user to quickly compare various options to one another. For example, suppose hydrogen can be delivered at a cost of around $2.00/kg (excluding taxes.) While considerably more than the assumed wholesale gas price of $0.99, H_2Sim shows that for the fuel cost per mile driven to be the same (FCV vs. ICE), the efficiency ratio for the FCV compared to the current ICE technology has to be about two, lower than the projected ratio of 2.5 in the default scenario. So in terms of fuel costs, H_2Sim suggests it may be feasible for the FCV to meet the fuel costs of existing ICE vehicles.

Table 30. Summary of Results for Three Lowest Cost Distribution Options

PRODUCTION METHOD	PRODUCTION COST ($/kg)	DELIVERED COST ($/kg)[1]		
		STORAGE & DELIVERY METHODS[2]		
		UNDERGROUND PIPELINE-LARGE PIPELINE-LOCAL	GASEOUS TRUCK-GASEOUS NONE	LIQUID TRUCK-LIQUID NONE
Reformation	1.12	1.81 - 3.12	2.70 - 6.51	1.92 - 1.94
Gasification	0.68	1.37 - 2.68	2.26 - 6.07	1.48 - 1.50
Electrolysis	2.15	2.84 - 4.15	3.73 - 7.54	2.95 - 2.97
Therm-CSP	1.83	2.52 - 3.83	3.41 - 7.22	2.63 - 2.65
Therm-Nuclear	1.38	2.07 - 3.38	2.96 - 6.77	2.18 - 2.20
NPO	1.69	2.38 - 3.69	3.27 - 7.08	2.49 - 2.51

[1]Costs range from a flow rate of 100,000 kg/day and delivery of 100 miles to 1,000,000 kg/day and 500 miles.
[2]Scenarios written Storage 1/Delivery 1/Local Delivery. End storage not included.

Press reports and public policy discussions tend to focus on the delivered price of hydrogen compared to gasoline. But since hydrogen fuel is not a substitute for gasoline in existing ICE vehicles, consumers must purchase a new fuel/vehicle combination to move into the hydrogen economy. As previously shown, fuel cost (determined by both fuel price and fuel efficiency) is only a very small portion of total end-use fuel-vehicle cost, especially during the first few years of a car's life. H_2Sim suggests that it may be difficult for FCVs to be competitive with ICE vehicles, regardless of FCV efficiency. For example, Weiss et al. (2000) predicts that ICE vehicles will have an average efficiency of 43 mpg in 2020. Using the default assumptions about vehicle costs and the least expensive delivered hydrogen (coal gasification with pipeline transportation), there is no FCV efficiency that would make FCVs cost competitive with the ICE vehicle. Alternatively, if the FCV averages 68 mpg, the FCV vehicle cost would have to fall below $17,400 to be competitive with today's ICE vehicles. The analysis does suggest that H_2Hyrbid vehicles may make more economic sense than FCVs. It also suggests that onboard reformation of gasoline to fuel a FCV makes little economic sense.

One other variable that could contribute to the economic cost competitiveness of hydrogen is a change in the price of gasoline. The wholesale gasoline price assumption in 2020 is 0.99 $/gal ($2003 real dollars). The sensitivity analysis showed that for today's ICE technology vehicle at 27 mpg, gasoline prices, either as a result of market forces or government intervention, would have to approach 3.50 $/gge before the 2020 FCV would be competitive.

One of the often mentioned benefits of a hydrogen economy is a reduction in carbon emissions. While the results suggest coal gasification is the low cost option, this option would actually increase carbon emissions unless it includes carbon capture and sequestration.

In summary, there are several key variables and uncertainties that affect the economic competitiveness of hydrogen vehicles: feedstock costs, capital costs, transportation distance, production rate, vehicle cost, and gasoline cost. H_2Sim allows the user to examine situations that make hydrogen vehicles competitive as well as those that will hinder the entrance of hydrogen into the transportation market. Furthermore, it allows a comparison of different stages of the hydrogen economy evolution through decentralized and centralized production.

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