A Realistic Look at Hydrogen Price Projections
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Introduction. For the past half century, most cities of population over 100,000 in industrialized nations have had dozens of industrial and research users regularly purchasing pressurized hydrogen gas in heavy steel cylinders containing about 0.5 kg H\textsubscript{2} per cylinder. The price of this hydrogen has been reasonably stable at about $100/kg plus cylinder rental. One of the basic assumptions underlying the putative "hydrogen economy" is that this cost can be reduced to a few dollars per kilogram even while hydrogen production costs rapidly increase over the next 30 years. There appear to be serious problems with this assumption.

Clearly, the question of the cost of hydrogen fuel to the consumer 15 to 50 years from now is of critical importance in any discussion of the possibility of a "hydrogen economy". A number of studies have been carried out over the past seven years on the cost of hydrogen, but there are major problems with most of these studies that are not widely appreciated. The four biggest problems with many hydrogen cost projections are:

1. The rate of introduction of hydrogen-fueled vehicles is currently nearly two orders of magnitude lower than was generally expected 4 to 8 years ago [1], and it seems likely to remain at such a depressed rate for at least several more decades [2]. This is largely because the costs of light-weight proton exchange membrane fuel cell (PEMFC) stacks (with maintenance) is proving to be about $7,000/kW [3], which is two orders of magnitude higher than was officially expected in the late '90's [4]. Also, their lifetime under road conditions is still 20% that of diesel engine, and they achieve under 35% efficiency.

2. North America is facing natural gas (NG) shortages that will steadily worsen over the coming decades [5]. The price of NG has increased by a factor of 10 in the past 30 years and a factor of three in the last six years [6]. Its cost is likely to increase by more than another factor of two (in constant dollars) within 15 years.

3. Small hydrogen-dispensing stations [7] are costing about $600K each, which is ten times more than was initially expected for stations an order of magnitude larger [8] and is thus another error in assumptions of two orders of magnitude.

4. Hydrogen storage costs by all methods (at least for quantities below tens of thousands of kilograms) are two orders of magnitude greater than for liquid hydrocarbon fuels [9]. This is clearly not appreciated in many published studies which have often referenced erroneous earlier works [4, 8].

There are also a number of other significant issues which were not well appreciated in earlier studies, such as (1) the increase in pipeline costs to avoid hydrogen embrittlement failures [10], (2) the significance of flash losses associated with dispensing moderate quantities (100-1000 kg) from trailer-truck tankers of liquid hydrogen, and (3) failure to consider the implications of taxes, including the imposition of a fossil-carbon tax or similar disincentive to the use of fuels such as fossil hydrogen.

Most hydrogen studies over the past several years contain a mixture of facts and advocacy. As note, there have been at least four common errors of at least an order of magnitude in many published hydrogen-economy studies over the past decade – FC costs, rate of introduction of hydrogen vehicles, hydrogen storage costs, and fuel dispensing costs. All of these errors have been in the direction to make hydrogen seem more attractive as a fuel. However, it is important to point out that several thorough and generally accurate infrastructure studies have been carried out [9, 11]. But even the rather scholarly works are often misused by hydrogen advocates who fail to carefully note their clearly stated assumptions. For example:
1. NG costs were usually assumed to be $3.5/GJ – compare to today's $5.5/GJ at the well head, $7/GJ at the city gate, and probably $15/GJ at the city gate in 2020.
2. Dispensing stations were often assumed to be filling 300 vehicles each per day – about two orders of magnitude more than seems likely for at least 15 years.
3. Often 300,000 hydrogen vehicles were assumed within 100 km of the central station with a total demand of 150 tons/day – three orders of magnitude more vehicles than seems likely for several decades.

The above FC price estimates (and that is all they can be called) for road-qualified PEMFCs will surprise most readers because the DOE and the hydrogen lobby have been saying for three years that PEMFCs cost as little as $1200/kW, but that is simply not true. It is true that PEMFCs with 30-35% HHV electrical efficiency are now commercially available in the range of $3000-5500/kW for combined heat and power (CHP) applications [12], but these FCs have inadequate environmental and vibrational tolerance for small vehicles, in addition to being much too large and massive. Best estimates from available financial data from Ballard Power (who has made over 80% of the FCs for vehicles over the past decade) are that road-qualified PEMFCs actually still cost well over $10,000/kW to produce [13].

Manufacturing scale-up from current, moderately large, FC operations (where four large firms have each been spending $100M/year) cannot be expected to achieve more than an order of magnitude reduction in costs. It has been suggested that the show-stopper issues of FC-stack cost and reliability can be avoided by using hydrogen-fueled internal combustion engines (ICEs). Indeed, such have been demonstrated, but it does not appear that they can achieve efficiencies above 24% [3] – 70% that of the gasoline engine [14]. Moreover, hydrogen ICEs still have all the fuel-cost, fuel-storage, and safety issues of hydrogen FC vehicles [12].

There are, of course, a number of possible sources of hydrogen other than NG – coal, nuclear breeder reactors, wind farms in ideal locations, biomass (pyrolysis and water shift), and solar electrolysis. Of these, only coal currently begins to compete economically with NG, but generating LH2 from coal produces 8 kg of carbon (29 kg of CO2) per kilogram of H2 [12]. When a realistic future (fossil) carbon tax of $0.1/kg of carbon is included, coal is likely to remain uncompetitive. Hence, the focus here will NG, even though most discussions of a hydrogen economy assume NG will not be an acceptable source of H2 for more than 40 years because of its increasing cost and CO2 release. A few comments on some challenges presented by the other options will be included near the end.

**Gas and Oil Price Projections.** For the past five years, the DOE/EIA have demonstrated a callous disregard for objectivity when it comes to projections of both U.S. and world oil and gas reserves and likely pricing trends. Here, their projections for oil and gas prices have been proven wrong by huge amounts year after year, with five-year NG price projections from 4 to 7 years ago now proving too low by more than a factor of two. Most experts outside the U.S. have done a much better job.

While there are theoretically abundant NG reserves worldwide for at least the next 50 years, the shortages in North America are becoming critical, as Canada is cutting back on exports (at the rate of at least 2%/year) to preserve their domestic resources – especially for use in recovery of oil from oil sands (or tarsands) [15, 16]. This is forcing the U.S. to frantically develop the infrastructure needed to import liquefied NG (LNG) from the Persian Gulf, East Caspian, Northern Africa, South Pacific, Western Siberia, Nigeria, and other places where NG is currently abundant and cheap [17]. It is worth noting that in the past year the DOE/EIA have nearly quadrupled their projections 12-years-out of LNG imports while cutting their projections of NG imports from Canada in half [18]. And since then, El Paso Corp has revised their proved natural gas reserves downward by 35% and the first major methane-hydrate project (Deadhorse, Alaska, one of the "North Slope" projects the DOE/EIA have been banking on) has ended in complete failure, so additional downward corrections seem very likely over the next few years.
Even though stranded NG is quite abundant world wide (i.e., in locations where it cannot be economically piped to market), the assumption by the EIA that LNG will be able to be imported at very low prices is fundamentally flawed. The prices of LNG and petroleum have stayed remarkably close per unit energy for the past several years, and it is clear that LNG will not drop below petroleum prices. World-wide oil demand is beginning to exceed oil production. This will steadily drive oil prices up, and world oil prices (the dominant market) will establish minimum international LNG prices. As carbon taxes begin to be imposed, LNG prices will exceed oil prices.

The data are quite compelling that the world-wide oil shortage will force dramatic increases in oil prices within 2-9 years. (A severe world-wide recession or dramatic increases in vehicle efficiency and in the production of biofuels or liquid fuels from NG could delay a critical shortage). The assessment of oil reserves by the Association for Peak Oil [19] is now internationally recognized (except within the U.S.) as the gold standard in this field. There is good reason to believe that the Middle East reserves are massively overstated [20]. Dutch Royal/Shell, partly for this reason, has recently revised their oil and gas reserves estimates downward 20% [16], and there are indications that other major oil companies will be required to make similar adjustments before long.

The price of oil will trend toward the price of the replacements, which seems likely to be about $60/bbl for next-generation biofuels (biodiesel from switchgrass, poplars, and high-oil algae). A similar price can be expected for oil from coal when fossil carbon taxes (which seem likely to be widely imposed with 15 years) are included. The target price of $60/bbl has also been publicly advocated over a shorter term (perhaps within five years) by some ministers and economists from oil-producing nations [21], and some extremists leaders have recently advocated $140/bbl. Some mainstream Wall Street economists have recently begun warning that oil prices could exceed $45/bbl by September 2004.

The primary problems in the latest oil and gas price projections by the DOE/EIA [22] are:

1. They overestimate the ability of the U.S. to control oil prices [21]. Stated differently, they underestimate the resolve that is beginning to arise among oil exporters to save some of their limited resources for their great-grand-children; and they greatly overestimate the amount of oil we'll be able to pump out of Iraq – over the next 3 years, the next 15, and the next 50 [20].
2. They greatly underestimate the rate at which costs of developing new oil production capacity are increasing [15]. (Deep water, heavy, and polar oil and oil sands are an order of magnitude more expensive than were many conventional oil wells two decades ago. Oil shale and gas hydrates will be even more expensive [15, 19].)
3. They greatly underestimate the political pressure the world will be able to place on the U.S. to limit fossil CO₂ release [23, 24, 25].
4. They underestimate the costs and difficulties of increasing our imports of LNG [26].
5. They underestimate growth of demand in the former Soviet Union, China, and India [27].
6. They overestimate the long-term value of the dollar relative to other major currencies [28].
7. There are also several flaws in EIA projections affecting oil prices in the other direction:
8. They underestimate the growth in use of renewables worldwide – especially in the U.S.
9. They underestimate the efficiency gains that are likely, especially in the U.S., over the next two decades.

Clearly, the first six points greatly outweigh the second two in their effect on oil and gas prices. If oil is $60/bbl 16 years from now (in 2004 dollars), be at least $11/GJ (more likely $12/GJ, assuming a modest carbon tax). The DOE/EIA have a radically different opinion on the price of NG in 2020 ($4/GJ) [22], but most experts outside the U.S. differ regarding readily available oil resource limitations. Of course, there will be places in the world where natural gas will be available locally at a very small price (perhaps $1/GJ), and this will permit enormous profits for many LNG producers for several more decades until this resource too is exhausted. When such conditions exist, it can lead corrupt leaders to fabricate reasons for pre-emptive wars, as we have seen in the recent past, and this could radically alter price projections for a while.
Projecting the price of electricity is slightly more risky because it depends more strongly on the magnitude of the fossil carbon tax. Assuming $0.1/kg carbon tax by 2020, electricity will likely be about $0.08/kWh.

**Hydrogen Storage.** A fundamental advantage of liquid hydrocarbon fuels compared to hydrogen is in the cost of storage. A 10-gallon automobile fuel tank costs about $150. Hydrogen storage by metal hydride in small quantities currently costs $16,000/kg (of H$_2$ stored) [3] and is 20 times as massive as the common diesel tank. One reference indicates metal-hydride storage in large quantities (400 kg H$_2$) costs only $2600/kg H$_2$ [9]. A common 120-gallon compressed-air tank, which can store 0.57 kg of hydrogen at 15 atm., costs $730 [29]. At $1300/kg, this is only 85 times as expensive as the diesel tank per energy storage, but it is 40 times more massive and over 200 times larger. Fifty (very large) 3000 psi aluminum scuba tanks could provide 10 kg of H$_2$ storage for under $14,000 and only 750 kg [30]. Pricing data from the high-volume production of these tanks suggest high-volume production of 5000-10,000 psi tanks for storage of 3-8 kg of H$_2$ might cost $600/kg of H$_2$, which is about 30% less than suggested in an earlier study [9].

Light-weight tanks made of carbon-fiber composites are considerably more expensive (at least $2000/kg), though some cost reduction (perhaps to $1400/kg) could be expected in high-volume production of larger tanks. However, there are serious safety issues with light-weight tanks because of their low impact strength. For over half a century, the standard commercial limit for pressurized gases (in tanks of high impact strength) has been 2000 psi for safety reasons. The mechanical energy alone (ignoring the chemical energy) in a 5000 psi fuel tank may be five times that of a 50-caliber armor-piercing artillery shell. It is not at all clear that light-weight 5000 psi tanks could ever be acceptable in production vehicles from a safety perspective [12], even with extensive protective structures.

A 180-liter liquid-nitrogen (LN2) dewar, which could store 12.8 kg of liquid hydrogen (LH2), costs only $2040 [31], or $160/kg. While these dewars have daily boiloff of only 1.5% for LN2, the daily boiloff with LH2 is about 15%, primarily because its heat of vaporization per liter is 10% that of LN2. Satisfactory LH2 dewars of similar size, which cut the daily loss to ~2% for LH2 and meet safety requirements, cost about $600/kg [9]. Of course, production of LH2 wastes ~40% of the available energy in liquefaction. Moreover, losses on filling a dewar of this size are typically another 25% [9]. The unit cost of qualified LH2 storage does not drop very rapidly with increasing size, as 10,000 kg LH2 vessels (for rail tankers) are still ~$60/kg [9].

**Hydrogen from Natural Gas – Production Distribution, and Dispensing.** Bulk, wholesale prices at the plant for hydrogen from NG depend mostly on NG price and plant size. The data below, in 2004 dollars, are for 99.999%+ hydrogen in bulk at the plant, pre-tax [32].

<table>
<thead>
<tr>
<th>NG price /GJ</th>
<th>Plant size tons/day</th>
<th>Plant Cost, $</th>
<th>H$_2$ bulk gas $/kg</th>
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<tbody>
<tr>
<td>3.5</td>
<td>22</td>
<td>23M</td>
<td>1.8</td>
</tr>
<tr>
<td>7.0</td>
<td>22</td>
<td>23M</td>
<td>2.4</td>
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<tr>
<td>15.0</td>
<td>22</td>
<td>23M</td>
<td>4.1</td>
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<tr>
<td>3.5</td>
<td>80</td>
<td>44M</td>
<td>1.2</td>
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<tr>
<td>7.0</td>
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<td>44M</td>
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<tr>
<td>15.0</td>
<td>80</td>
<td>44M</td>
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<tr>
<td>3.5</td>
<td>600</td>
<td>210M</td>
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There is steadily increasing awareness of the need to reduce \( \text{CO}_2 \) emissions to limit global warming [23, 24]. There is reason to expect that within 15 years we will see a fossil carbon tax (at least in some countries) of approximately $0.1/kg of carbon and probably more for low-efficiency power plants [25]. Production of \( \text{H}_2 \) from NG in very large plants releases approximately 2.6 kg of carbon (9.5 kg of \( \text{CO}_2 \)) [12, 33], and this increases to about 3.5 kg in small plants. (The chemical energy in the \( \text{H}_2 \) produced at very large plants is about 70% that in the NG feed stock, but efficiencies below 50% are obtained in small plants [32].) Hence, the above bulk \( \text{H}_2 \) costs would likely be increased by $0.26-0.35/kg by 2020 when a reasonable carbon tax is included.

Liquefaction of \( \text{H}_2 \) adds $1.3-3/kg to the above prices for \( \text{H}_2 \) gas, depending on plant size and energy costs [9]. Moreover, liquefaction using coal-fired power plants releases another 2.8 kg of carbon. Thus, bulk LH2 from NG at a very large plant with a 0.1/kg fossil carbon tax and cheap power ($0.06/kWhr) can be expected to cost $1.8/kg more than shown above for pre-tax bulk \( \text{H}_2 \) gas. LH2 from NG at a small (22 tons/day) plant with higher power costs ($0.08/kWhr) and the carbon tax would cost $3.6/kg more than indicated in the above table.

The data in the above Table from Padro and Putsche [32] is basically in agreement with that by Simbeck and Chang [11], though here it is sometimes a bit confusing. For example, Simbeck and Chang obtain detailed studies (from three sources) for a 27 t/day plant with distribution to 30 dispensing stations, each 1000 kg/day. They give the cost of this pipeline distributed (but not dispensed) hydrogen as $3.2/kg for NG at $3.5/GJ. For the case with liquid distribution and with commercial power for the liquefaction costing $0.045/kWhr, they give the distributed cost to the dispensing stations as $4/kg. (Again, the above prices are corrected for 2004 dollars.) Later, they begin assuming 150 ton/day plants. This less supported data for a fully developed hydrogen economy (300,000 vehicles per plant) apparently forms the basis of most of their summary, Figure 1, and their Table 8, but scale and market penetration seem to vary (somewhat ambiguously) with the various pathways throughout the study.

According to Padro and Putsche, one would expect hydrogen to cost $2.2/kg more at a 27 tons/day plant for NG costing $15/GJ than at $3.5/GJ. Hence, Simbeck and Chang should expect hydrogen from a 27 t/d plant, with NG at the city gate costing $15/GJ, to cost (including fossil carbon tax, which may be $0.3/kg of \( \text{H}_2 \)) $5.7/kg delivered to dispensing stations by pipeline. For power costing $0.08/kWhr rather than $0.045/kWhr, the cost of LH2 increases by another $0.8/kg [9]. Hence, their LH2 could be expected to cost $7.3/kg (4 + 2.2 + 0.8 + 0.3) by tanker in 2020 from a 27 t/d plant.

Of course, these costs drop with larger scale assumptions, but it's hard enough to imagine a city with 50,000 hydrogen vehicles (averaging 50 miles/kg, 25 miles/day) in the next 30 years, so let's go back and correct some of the numbers that need adjusting to have real usefulness 15, 30 or even 50 years from now. (We'll also ignore the pipeline estimates, and assume, as virtually everyone else has, that the method of distribution for at least the next 30 years will be LH2 by tanker truck.)

Major problems with the LH2 estimates by Simbeck and Chang arise from their assumption of 30 huge stations, each dispensing 1000 kg/day, servicing 50,000 vehicles in a large city. Many current (and planned) dispensing stations have storage capacities in the range of 100 to 1000 kg. Tanker LH2 distribution costs increase rapidly for deliveries below ~500 kg (~1700 gallons). The tankers must be maintained slightly above atmospheric pressure to prevent the formation of devastating ice blockages. Depressurization for dispensing and cool-down of the transfer lines results in unavoidable waste of about 1% of the tanker's load every time liquid is dispensed. Both the liquid density and the heat of vaporization per liter of LH2 are about one-tenth those of LN2. From experience in the well established LN2 industry, one can estimate that tanker distribution costs of 1000 kg LH2 to a dispensing station would be about $250, or ~$0.25/kg, assuming there are three more stations in the region to take the rest of load from the 4300 kg tanker. (This estimate is quite close to that by Simbeck and Chang.) However, the distribution cost of 200 kg of LH2 to each of 20 dispensing stations in a large city would be about $200, or ~$1/kg. And when the total demand in any city drops below 4000 kg per week, the tanker delivery costs skyrocket. Basically, LH2 dis-
tribution analysis suggests it is impractical to start a hydrogen program below 4000 kg per week per city (~1000 vehicles per city) without substantial, continuing federal subsidies. Some believe gas pipelines might be less expensive in the distant future, but studies generally show this option to be more expensive at least up to the level of several hundred thousand vehicles per city [11, 12].

Looking more closely at the hydrogen dispensing costs shows even greater problems here. Available dispensing stations, and those planned for the foreseeable future, have capacities of 25-60 kg/day for servicing 6 to 20 customers per day [7, 34] and will cost about $0.5-1M. A $600K station consuming 150 kWhr of energy per day (primarily for pressurization), with half the salary burden of a single attendant (24/7), needs a net daily margin of at least $500 to break even, assuming a 15 year loan at 5% interest and low equipment maintenance and land costs. Of course, if there are 20 dispensing stations in each of 100 cities in 2035, the costs of the dispensing stations will be lower. It may be reasonable to expect the cost of a 200 kg/day dispensing station to cost $200K at this level of mass production and drop further with increased volume.

Other Sources of Hydrogen. Hydrogen production from coal necessitates a large central plant to adequately handle the problems of sulfur separation/disposal and CO₂ sequestration. The central-plant approach also generally argues for liquefaction for distribution [11]. Current hydrogen production costs from coal in large plants are about 20% higher than from natural gas, and such plants do not include sequestration [11]. The amount of carbon released is typically a little over 5 kg per kg of FC-grade gaseous H₂. With liquefaction, the H/C ratio increases to about 8. Carbon sequestration costs have been estimated over a very wide range, from $0.05 to $0.8/kg, but perhaps $0.1/kg is reasonable for a very large plant 25 years from now, which would add $0.8/kg to the cost of hydrogen from coal and thus probably keep this source of hydrogen more expensive than NG for at least 20 years.

Hydrogen from biomass (pyrolysis and water shift) using waste biomass (from logging, paper mills, farming, and clearing) is about 10% more expensive than from coal without sequestration [11], but this is not likely to be a real possibility, as waste biomass is limited and is likely to be more valuable in the production of methanol [35]. Hydrogen from biomass crops (switch grass, poplars, eucalyptus, pines) is likely to be about 30% more expensive than hydrogen from waste biomass, and again this is not a real option, as this biomass is likely to be much more valuable for methanol or ethanol [36, 37].

Electrolysis from wind farms, nuclear power plants, and solar is also a possibility. Simple calculations show that for electricity at $0.05/kWh, with 75% electrolysis efficiency and 85% compression efficiency (both are optimistic figures), the power bill alone for compressed hydrogen gas by this method is $3/kg. Simbeck and Chang estimate the bulk cost of gaseous H₂ by electrolysis, for power at $0.045/kWhr, to be $5.4/kg at a very large plant when capital equipment costs are properly included. For LH2, the cost becomes $6.4/kg [11]. There is reason to believe that the electrolysis equipment maintenance costs may be significantly reduced in the future [12], which might reduce the cost of H₂ by electrolysis (either gaseous or LH2) by up to $1/kg.

Nuclear energy could be used to generate hydrogen by either of several processes, including hydrolysis and thermo-chemical reactions [12]. Both have serious cost and societal acceptance issues in addition to the fact that economical sources of sufficient uranium to power several hundred more nuclear reactors for a sufficiently long time to justify their construction (at least 30 years, starting at least 15 years from now) may not be assured without the use of breeder reactors. The rapid progress in robotics over the past decade and the expected continued advances in this field seem to significantly increase the proliferation concerns with plutonium production in breeder reactors by greatly reducing the personnel risk associated with clandestine bomb-making operations from spent fuel from breeder reactors. Hence, it will likely become even more difficult to muster the political will for breeder reactors.

Many fusion physicists now believe it could be technically possible to have the first commercial, 500 MW nuclear fusion power plant (a tokamak) ready to come on-line in 2050 [38]. What they always fail to mention is that the envisioned power plant would have an operating lifetime of
only a few years and would cost at least 50 times as much as a 500 MW biomass power plant. Moreover, these costs are inherent to the design (requiring 20,000 tons of Nb$_3$Sn superconducting magnet windings, for example) and there are no known ways for significantly reducing these costs. Alternatively, perhaps the plant could have a lifetime of 20 years (by using isotopically depleted construction materials) at a cost of at least 10,000 times that of the reference biomass power plant. On the other hand, there seems a reasonable possibility that inertial confinement concepts could prove more viable from an economic perspective, but here there are still a number of basic, technical feasibility issues [39].

Wind energy could be a viable power option in specific localities (especially in the Dakotas) within a decade. If used for hydrogen production without a hydrogen gas line to the wind farm, the hydrogen would need to be liquefied for transport. To generate and liquefy 10 tons/day (one rail-tanker per day on average) would require at least 100 MW installed capacity (30% capacity factor), or 200 wind turbines of 39 m span in a Class 5 site [40]. Here, the capital cost of the wind turbines (installed) would be about $60-90M, and the effective power cost is expected to be about $0.06/kWh [40]. This could make the wholesale cost of LH$_2$ at a very large wind farm (at a choice location) as low as $6.9/kg within 10 years, assuming substantial progress in cost reduction of electrolysis equipment [12] and some further progress in wind turbine technology (especially, for non-synchronous power applications, as for hydrogen or ammonia production).

Current estimates of the cost of photovoltaic (PV) power range from $0.25-$0.50/kWh for a 20-year service life [41], which would raise the cost of bulk H$_2$ gas at a large PV plant to at least $17/kg. However, the DOE expects the cost to drop to $3 to $4 per peak watt by 2010 [42]. Assuming a 20 year lifetime, no maintenance or other costs, and 4% interest (for present-value calculations), this would bring the cost of PV power down to $0.13/kWh in generally sunny locations. The cost of PV-generated bulk H$_2$ at a large plant then might be $10.5/kg in 2010. Although the assumption of no other costs is not realistic, this does at least suggest PV may compete with wind and NG in 20 to 30 years.

Finally, a few influential space scientists are still suggesting (even before congressional committees) it will be possible to build PV factories on the moon, set up huge PV arrays there, and beam the power back to earth for less cost than we could build the solar arrays here. This energy could then be used to electrolyze water. Most scientists and engineers rate the chances of this proving true similar to those for cold fusion.

**Summary:** Because of the enormous complications of moderate-scale hydrogen storage, distribution, and dispensing compared to liquid hydrocarbon fuels, there is very little correlation between bulk hydrogen costs at a large plant and what the consumer can expect to pay at the dispensing station.

Although it has now been ten years since the first FC vehicle was delivered, there are fewer than 100 FC vehicles on the road today (partially because few last more than two years). The very recent (and highly commendable) report by the National Academy of Engineering points out the serious challenges facing fuel cells and notes that it is unlikely they will have a significant effect on oil imports or CO$_2$ emissions during the next 25 years [12]. Ballard Power seems likely to be bankrupt (or effectively so) within three years. Very few experts today are expecting more than 500 FC vehicles on the road six years from now. Honda and GM have each indicated within the past six months they expect to sell one million FC vehicles by 2020, but they are already backing away from those estimates. Those projections, like many other "hydrogen economy" projections over the past decade, may prove too high by two orders of magnitude. Personally, I think it unlikely to expect more than a few thousand hydrogen vehicles on the road 16 years from now, but perhaps there will be unforeseen breakthroughs. It is worth noting that there are about 100 cities with populations over one-half million in the wealthy, industrialized countries throughout the world where one could expect to sell some hydrogen vehicles. So it seems highly unlikely to find many cities with more than 1000 FC vehicles by 2030.
The following four possible scenarios, spanning a range of 1000 to 300,000 hydrogen vehicles per city, are based on realistic distribution costs, dispensing costs, and city-gate NG costs ($15/GJ in 2020, $18/GJ in 2035, and $20/GJ in 2050). Of course, it is possible that the price of NG in 2020 will be 70% of what I have assumed, and this could reduce the break-even costs in 2020 by about $1/kg. However, it seems quite unlikely that the longer-range NG price estimates are too high by more than 25%. The first two scenarios assume there is sufficient additional industrial demand in the city for the hydrogen produced by the central plant to keep it operating near full capacity, otherwise the hydrogen prices will be higher by up to $3/kg. Scenario #4 is, in scale, close to that considered in reference [11]. In all cases below, I assume electrical power to be $0.08/kWhr and the fossil carbon tax to be only $0.05/kg of carbon. The greatest uncertainties in these scenarios lie in the hydrogen market penetration assumptions and dispensing costs. Selling prices would of course need to be about 15% higher than the break-even prices given below for the station to be a viable business operation.

1. $600K fueling stations dispensing up to 50 kg per day in a city with 1000 hydrogen vehicles and 15 fueling stations in 2020 (where stations could expect to buy LH2 for $8/kg from a 22 t/d plant) would need to charge $19/kg (current dollars) to break even.

2. $200K fueling station dispensing up to 200 kg per day in a city with 4000 hydrogen vehicles and 20 fueling stations in 2035 (where stations could expect to buy LH2 for $7.8/kg from a 27 t/d plant) would need to charge $11/kg (current dollars) to break even.

3. $100K fueling stations dispensing up to 200 kg per day in a city with 50,000 hydrogen vehicles and 200 fueling stations in 2050 (where stations could expect to buy LH2 for $8/kg from a 27 t/d plant) would need to charge $10.5/kg (current dollars) to break even.

4. $80K fueling stations dispensing up to 500 kg per day in a city with 300,000 hydrogen vehicles and 400 fueling stations in 2060 (where stations could expect to buy LH2 for $7.5/kg from a 150 t/d plant) would need to charge $9.5/kg (current dollars) to break even.

Of course, one can imagine that the hydrogen price could be reduced if there were a large fertilizer, gasoline, or chemical plant in the city to justify the construction of a large hydrogen plant. Hence, LH2 could be delivered to fueling stations for as little as $4/kg in 2020 in large cities near gas wells that have large LH2 plants for other industrial markets (note this price is very close to that predicted by most other studies). However, these plants would normally locate near gas fields to further reduce the cost of natural gas. If we include a reasonable profit margin, consumers in these lucky cities could expect to fuel their vehicles for $18/kg in Scenario #1, $8.7/kg in Scenario #2, $8/kg in Scenario #3, and $7.5/kg in Scenario #4.

For comparison, the current U.S. pre-tax cost of diesel for the individual consumer at the local station is about $0.5/kg. Of course, one needs 2.8 kg to equal the energy of one kg of H2, but that still leaves about an order of magnitude cost advantage for diesel per unit energy. Moreover, it appears diesel engines (some of which will be over 60% efficiency by 2020) will continue to get higher efficiency than road-qualified, production-quality PEMFCs for at least several decades. Estimates suggest the pre-tax price of bio-diesel from either bio-methanol or high-oil algae could ultimately be below $0.6/kg and either route promises ample capacity [43].

Personally, I doubt we'll ever see anything beyond the first of the above hydrogen scenarios. By then at the very latest, it will be abundantly clear that next-generation liquid biofuels (bio-diesel from bio-methanol or high-oil algae, bio-jet-fuel, and cellulosic ethanol) offer a far cheaper, safer, cleaner, and more convenient option.
References

27. Wall Street Journal, 11/14/03, reports China will be the world's second largest oil importer next year. China has had over 8% annual growth rate for most of the past decade, and growth rates are now 8% in both India and the former Soviet Union.


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