What Will Power the Hydrogen Economy?

Present and Future Sources of Hydrogen Energy

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The author alone is responsible for the contents of this report.

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Abbreviations and Acronyms

AC = alternating current
ATR = autothermal reforming
C. = Celsius
CH_4 = methane
CHP = combined heat and power
CNG = compressed natural gas
CO = carbon monoxide
CO_2 = carbon dioxide
DC = direct current
DOE = U.S. Department of Energy
DTI = Directed Technologies Inc.
EIA = Energy Information Administration
EJ = exajoule or exajoules
EV = electric vehicle
FCV = fuel cell electric vehicle
FERCO = Future Energy Resources Corporation
ft^2 = square foot or feet
GHG = greenhouse gas
GJ = gigajoule or gigajoules
GREET = Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation
HHV = higher heating value
HI = hydrogen iodide
H_2 = hydrogen
H_2SO_4 = sulfuric acid
I_2 = iodine
ICE = internal-combustion engine
IBGFC = integrated biomass gasification fuel cell
IRR = internal rate of return
kg = kilogram or kilograms
kW = kilowatt or kilowatts
LEM = lifecycle emissions model
LHV = lower heating value
m^2 = square meter or meters
MCFC = molten carbonate fuel cell
MSW = municipal solid waste
MW = megawatt or megawatts
N_2 = nitrogen
NOx = oxides of nitrogen
NM^3 = normal cubic meter or meters
NRC = National Research Council
NREL = National Renewable Energy Laboratory
PEC = photo-electrochemical

Abbreviations and Acronyms (cont'd)

PEM = proton-exchange membrane
PM = fine particulate matter
PO_x = partial-oxidation PSA = pressure swing adsorption
psi = pounds per square inch
PV = photovoltaic
Quad = quadrillion British thermal units
R&D = research and development
RFG = reformulated gasoline
scf = standard cubic foot or standard cubic feet
SMR = steam methane reforming
SO_2 = sulfur dioxide
SOFC = solid oxide fuel cell
U.S. = Unites States
VOC = volatile organic compounds
WGS = water gas shift reaction

Executive Summary

Hydrogen is an abundant element that can be produced in molecular form from many different sources, and in many different ways. In the context of energy systems, hydrogen is best thought of as an energy carrier, more akin to electricity than the fossil fuels that we extract from the earth's crust. Hydrogen can be produced from any "hydrocarbon" fuel because by definition these fuels contain both hydrogen and carbon. Hydrogen can also be produced from various biological materials and from water. This "water splitting" process is called electrolysis, and it is the oldest electrochemical process known. Thought of in this way, hydrogen supplies are virtually unlimited – unlike fossil fuels that someday will run out.

Potential Sources of Hydrogen

The main hydrogen production options currently known are as follows, including a short technical and economic characterization of each production source.

Steam Methane Reforming

Steam reformation of natural gas (or methane from other sources) produces a hydrogen rich gas that is typically on the order of 70-75% on a dry basis, along with smaller amounts of methane (2-6%), carbon monoxide (7-10%), and carbon dioxide (6-14%). Costs of hydrogen from steam methane reforming vary with feedstock cost, scale of production, and other variables and range from about $2-5 per kilogram at present (delivered and stored at high pressure). Delivered costs as low as about $1.60 per kilogram are believed to be possible in the future based on large centralized production and pipeline delivery, and delivered costs for small-scale decentralized production are projected to be on the order of $2.00-2.50 per kilogram.

Gasification of Coal and Other Hydrocarbons

In the partial oxidation (POx) process, also known more generally as "gasification," hydrogen can be produced from a range of hydrocarbon fuels, including coal, heavy residual oils, and other low-value refinery products. The hydrocarbon fuel is reacted with oxygen in a less than stoichiometric ratio, yielding a mixture of carbon monoxide and hydrogen at 1200° to 1350° C. Hydrogen can be produced from coal gasification at delivered costs of about $2.00-2.50 per kilogram at present at large scale, with delivered costs as low as about $1.50 per kilogram believed to be possible in the future.

Nuclear-Based Options

Various nuclear energy based hydrogen production schemes are possible, including nuclear thermal conversion of water using various chemical processes such as the sodium-iodine cycle, electrolysis of water using nuclear power, and high-temperature electrolysis that additionally would use nuclear system waste heat to lower the electricity required for electrolysis. Few cost studies of these schemes have yet been conducted, but at large scale and in the future, nuclear thermal conversion of water is believed to be capable of producing delivered hydrogen at costs of about $2.33 per kilogram.

Electrolysis of Water

Hydrogen can be produced via electrolysis of water from any electrical source, including utility grid power, solar photovoltaic (PV), wind power, hydropower, nuclear power, etc. Grid power electrolysis in the United States (U.S.) would produce hydrogen at delivered costs of $6-7 per kilogram at present, with future potential of about $4 per kilogram. Wind electrolysis-derived hydrogen would cost about $7-11 per kilogram at present, with future potential of delivered costs as low as below $3 per kilogram. Solar hydrogen would be more expensive, on the order of $10-30 per kilogram at present, with future delivered costs of $3-4 per kilogram estimated to be possible.

Hydrogen from Biomass

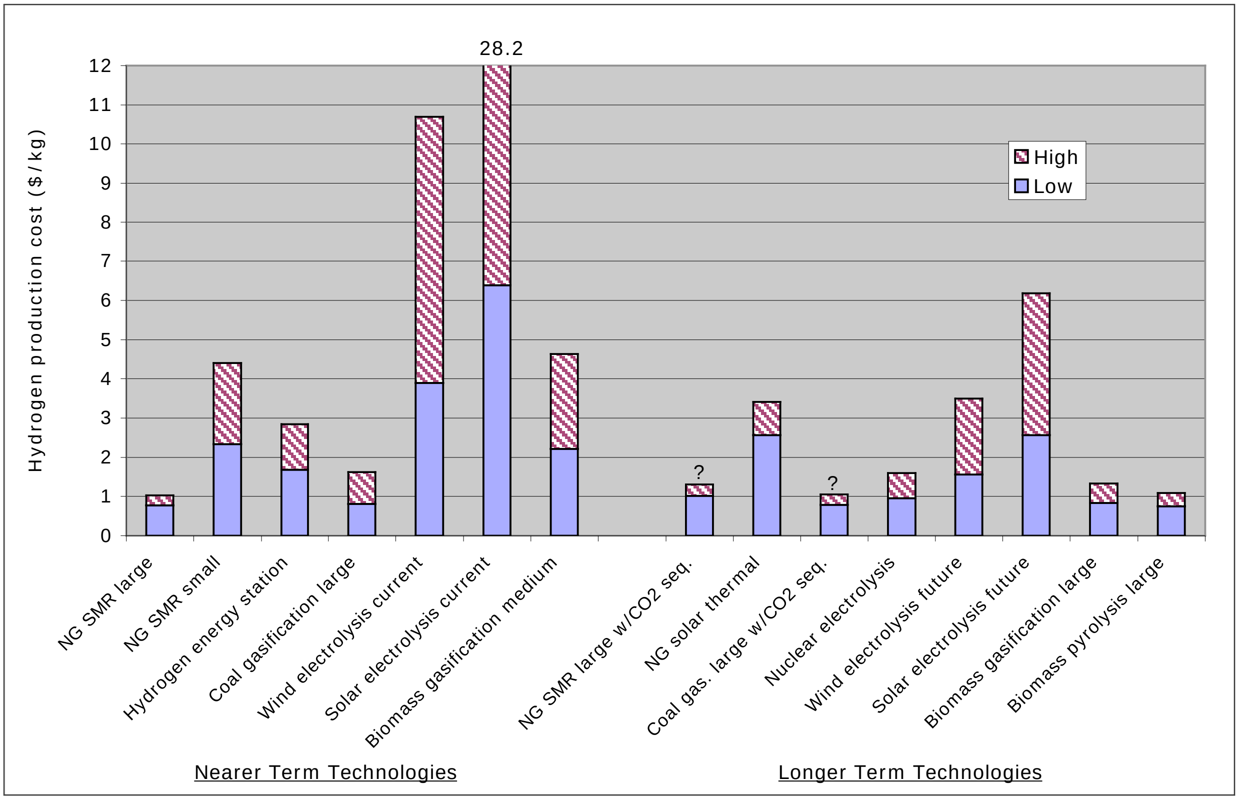
Biomass conversion technologies can be divided into thermo-chemical and biochemical processes. Thermo-chemical processes tend to be less expensive because they can be operated at higher temperatures and therefore obtain higher reaction rates. They also can utilize a broad range of biomass types. In contrast, biochemical processes are limited to wet feedstock and sugar-based feedstocks. At medium production scale and liquid distribution by tanker truck, current delivered costs of hydrogen from biomass would be in the $5-7 per kilogram range. However at larger production scales and coupled with pipeline delivery, delivered costs as low as $1.50 to $3.50 per kilogram are believed possible. Pyrolysis of biomass, another production option, also offers potentially low costs of delivered hydrogen, with costs as low as about $1 per kilogram possible with large-scale production and pipeline delivery.

Other Hydrogen Production Options

Hydrogen can also be produced through various other methods, such as direct solar thermal dissociation of water, from municipal solid waste “landfill gas” and waste gases from water treatment plants, and from hydrogen producing algae.

Figures ES-1 and ES-2 present ranges in hydrogen production and delivered hydrogen costs from the technical literature. These results are directly taken from various studies, and have not been adjusted for different assumptions in the studies (with regard to interest rates, feedstock costs, etc.) to make them more directly comparable.

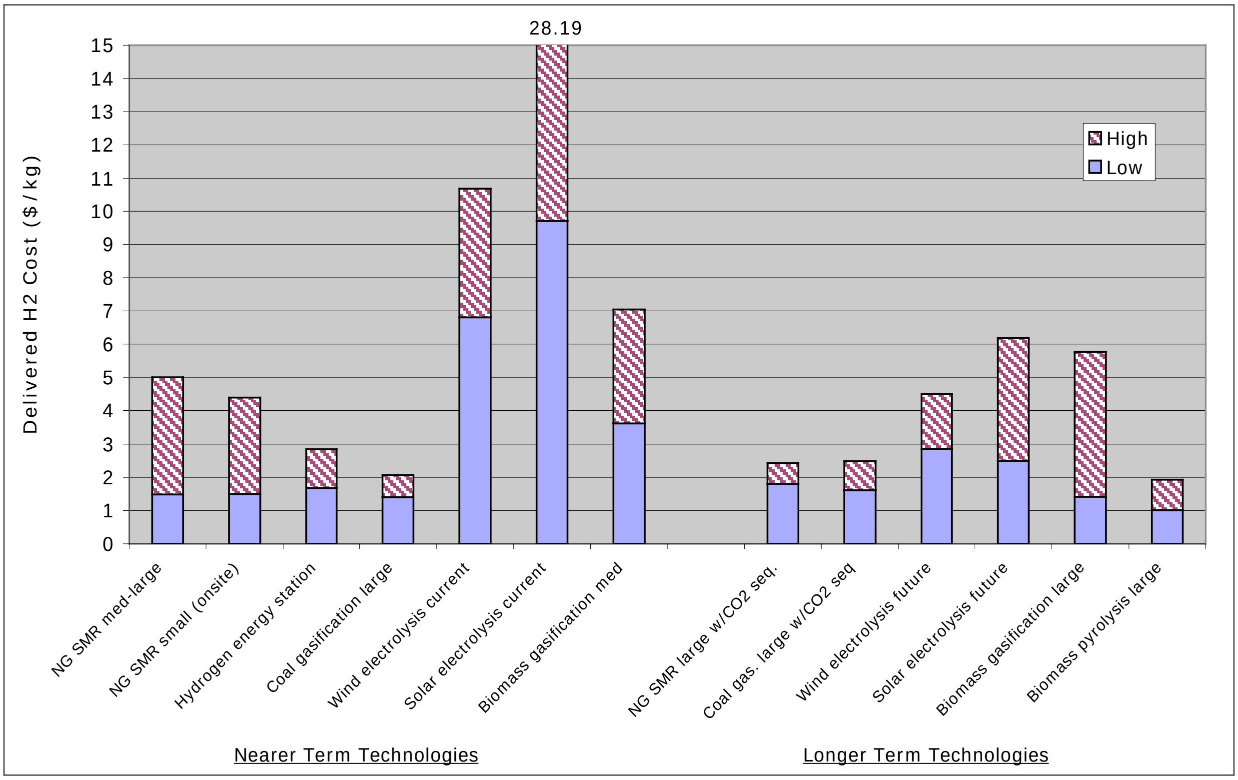
Figure ES-1: Ranges in Onsite Hydrogen Production Cost Estimates



Note: Various sources – see Table A-1 for details.

NG = natural gas; SMR = steam methane reforming; "?" = Costs of effective carbon sequestration from fossil fuels are uncertain because sequestration technologies and methods are still in the R&D phase.

Figure ES-2: Ranges in Delivered Hydrogen Cost Estimates



Notes: Various sources - see Appendix for details. The ranges shown are taken from many different sources, including those with assumptions that may be somewhat inconsistent with regard to production scale, interest rates, etc. Wider and narrower ranges between high and low costs thus tend to reflect the relative numbers of studies for each pathway, rather than inherent uncertainties in costs for each pathway.

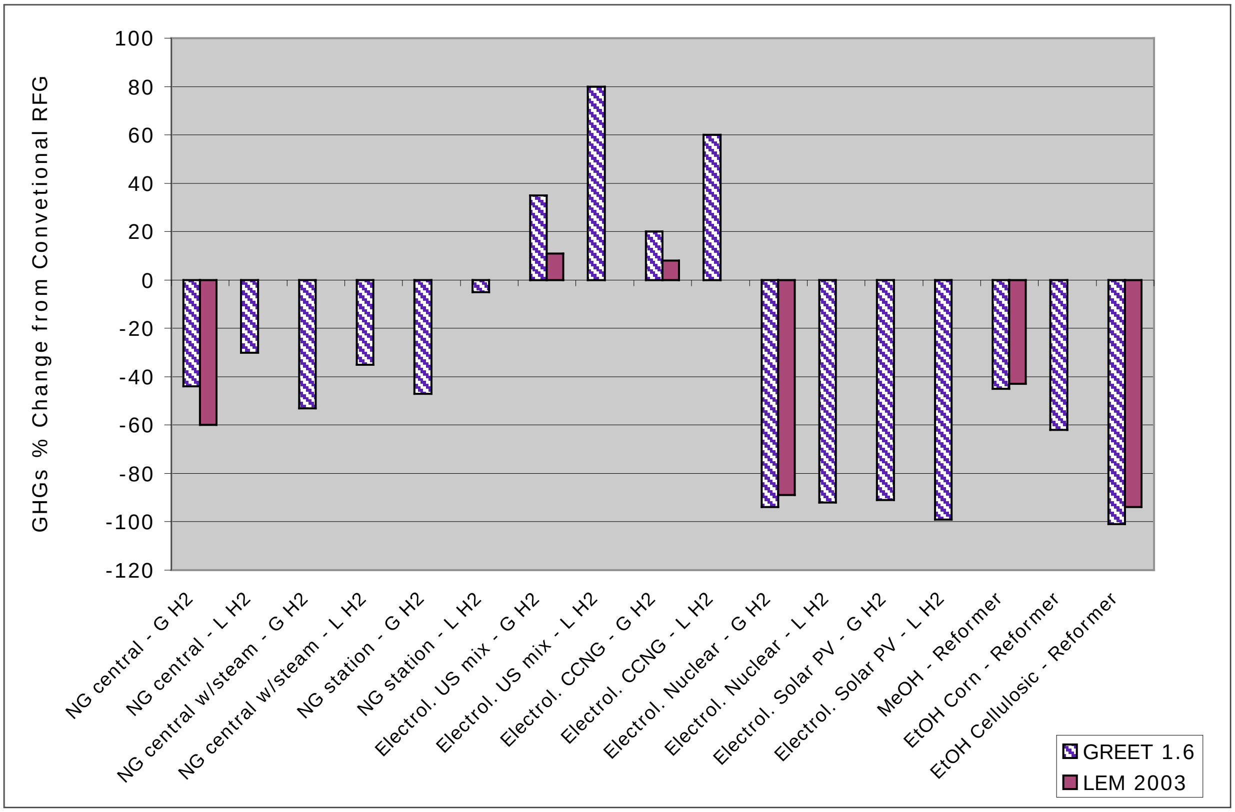
Environmental Impacts of Hydrogen Production

In addition to the economics of production and distribution, additional important considerations for hydrogen production methods include the environmental implications of various hydrogen production methods. These include greenhouse gas (GHG) emissions, local pollutant emissions, soil and water emissions, and land, water, and other non-feedstock resource requirements.

In general, the GHG and air pollutant impacts of various hydrogen production pathways have been reasonably well-studied, at least for the most prominent potential production pathways, but other environmental considerations have been less well characterized. Additional studies are therefore desirable, both to more fully characterize the potential environmental impacts of hydrogen production in general, and to more carefully examine the environmental impacts of hydrogen production for specific regions as these impacts will vary regionally to some extent.

Figure ES-3 presents estimates of full fuel-cycle GHG emissions from various hydrogen production and distribution pathways, for hydrogen used in fuel cell vehicles (FCVs) relative to the GHG emissions of conventional vehicles running on reformulated gasoline. As shown in the figure, the GHG emissions associated with the production and use of hydrogen for vehicles can vary greatly depending on the production method.

Figure ES-3: Relative Fuel-Cycle Greenhouse Gas Emissions of Hydrogen Fuel Pathways



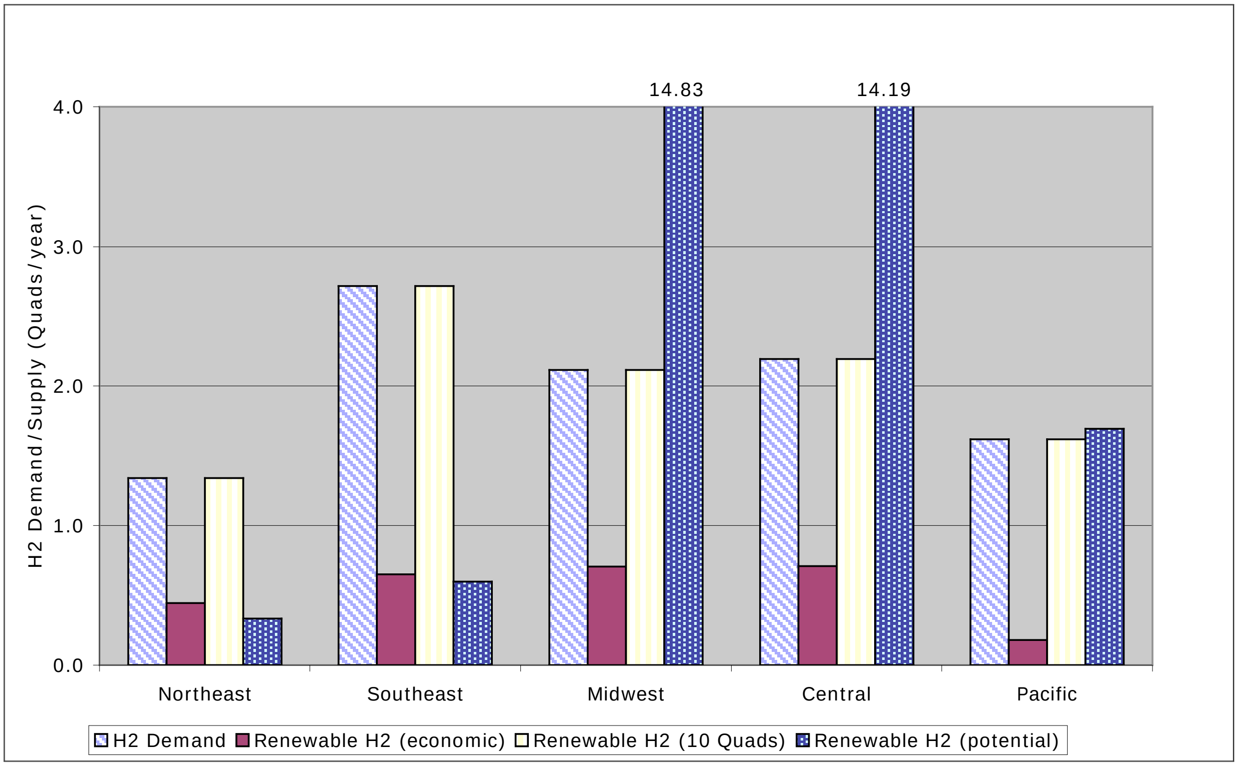
Notes: GREET 1.6 is the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model. LEM 2003 is the Lifecycle Emission Model. CCNG = combined cycle natural gas power plant; EtOH = ethanol; G = gaseous; L = liquid; NG = natural gas; MeOH = methanol; PV = photovoltaics; RFG = reformulated gasoline.

Renewable Hydrogen Potential in the U.S.

The overall technical potential for producing hydrogen from renewable sources in the U.S. is great, with estimated potential of renewable hydrogen energy of more than the current petroleum consumption in the U.S. for transportation. However, much of this renewable hydrogen production potential is based on wind and solar resources that are unlikely to become economically competitive with other sources, except perhaps in the long term. The most economical sources of renewable hydrogen include dedicated energy crops, municipal solid waste, agricultural and livestock residues, and certain wind resources that are located close enough to demand centers to be relatively attractive.

Figure ES-4 presents a hypothetical regional demand and supply picture for renewable hydrogen for the year 2040. This scenario assumes that hydrogen demand in the U.S. reaches 10 Quads (10.5 exajoules) by this time, and that the demand in each U.S. state is proportional to current gasoline consumption (first set of bars). The figure shows three potential levels of renewables-based hydrogen supply. The second set of bars – "Renewable H2 (economic)" -- shows the amount of hydrogen that could be dispensed to consumers at a cost of $3.00 per kilogram or less ($21.30 per gigajoule and $1.50 per gallon of gasoline equivalent on a per-mile basis in 2x efficiency hydrogen vehicles). Some hydrogen in the Northeast and Southeast is supplied from other nearby regions in this scenario. The third set of bars shows the total hydrogen demand in each region, totaling 10 Quads, being met by renewable sources. The fourth set of bars – "Renewable H2 (potential)" – shows the total technical potential of nearly 32 Quads of production, with much of this potential in the Midwest and Central regions.

Figure ES-4: Hypothetical Year 2040 Regional U.S. Hydrogen Demand of 10 Quads Per Year and Renewable Production Potential



Notes: "Northeast" includes CT, ME, MA, NH, NJ, NY, PA, RI, and VT; "Southeast" includes AL, DE, FL, GA, KY, MD, MI, NC, SC, TN VA, and WV; "Midwest" includes IA, IL, IN, KS, MI, MN, MO, NB, ND, OH, SD, and WI; "Central" includes AR, AZ, CO, ID, LA, MT, NV, NM, OK, TX, UT, and WY; "Pacific" includes AK, CA, HI, OR, and WA. However, the analysis did not consider production potential from AK and HI, and only CA, OR, and WA production potentials are shown. "Economic" renewable hydrogen potential includes resources that can be used to produce delivered hydrogen to customers for $3.00 per kg or less.

Source: Meyers et al. (2003) and additional analysis conducted by the author.

Conclusions

In conclusion, hydrogen can be produced in a variety of different ways, from a large number of potential feedstocks. Unlike the crude oil used to produce gasoline, the myriad potential sources of hydrogen are generally well distributed around the U.S. and the world. Certain regions have greater or lesser availability and suitability for specific hydrogen feedstocks and production methods, but virtually all regions have at least a few and many have several possibilities for hydrogen production.

The feedstock diversity for hydrogen is a critical characteristic in that it suggests the potential for much greater reliance on local resources for energy production around the world, particularly with regard to petroleum use in the transportation sector (if practical hydrogen vehicles can be realized). The diversity also raises another critical issue in that it suggests that in places such as the U.S., where *multiple* hydrogen production options are possible, strategic decisions about hydrogen production can be made based on multi-criteria analysis of the costs and benefits of various options.

Based on this present and future hydrogen production and distribution assessment, the following recommendations are made with regard to potential future directions for hydrogen energy research and development.

Hydrogen Production:

Hydrogen from Coal – This pathway is potentially economically attractive, especially without inclusion of externalities, but entails inherently large greenhouse gas, air pollutant, and mining impacts. Carbon sequestration is a potentially promising long-term option to mitigate GHG impacts, but at present has large uncertainties with regard to cost and ultimate effectiveness.

Hydrogen from Natural Gas – This pathway is a front-runner as a transition fuel in many areas, but faces distribution and supply concerns, as well as cost issues with natural gas in the U.S. presently at ~2x historical cost levels. Natural gas is probably best thought of as a transition fuel to cleaner and more renewable hydrogen production options, and should be utilized near-term due to the extensive natural gas infrastructure -- but in the context of a longer-term hydrogen production strategy and cognizant of technological “lock-in” concerns. Distributed production of hydrogen from natural gas appears to be among the most attractive near-term options, as it obviates the need for transportation of hydrogen, but also precludes the possibility of carbon capture and sequestration.

Hydrogen from Nuclear Energy– This pathway faces critical and perhaps even overwhelming (in the U.S.) public acceptance, safety, and access to capital issues. Costs could be competitive at production level but, like other centralized production options, hydrogen production at large-scale nuclear plants implies high distribution costs.

Hydrogen from Renewable Energy Sources – This is the only fully sustainable “end-game.” Renewable energy-based hydrogen offers multiple benefits including fuel diversity and security, and clean and low-GHG hydrogen production. Strategies that emphasize renewable feedstocks and distributed production (to avoid distribution costs and energy penalties), and that are developed in the context of a regional resource base, may be critical to maximizing the potential benefits of transitioning to hydrogen. Electrolyzer and solar PV costs remain key issues for the electrolysis-based options, but hydrogen from biomass using a wide range of potential renewable feedstocks offers another attractive set of options.

Infrastructure Development:

Distributed vs. Centralized Production – In the early years of the hydrogen transition, a mix of distributed production with small-scale reformers and electrolyzers, coupled with some "mobile vehicle refueler" and liquid hydrogen delivery by truck, appears to be the best strategy. Once hydrogen demand has reached the scale and level of concentration to begin to justify pipeline delivery, then the development of larger-scale plants can be pursued, potentially with carbon sequestration.

Integration of Hydrogen Infrastructure and Distributed Power Systems – The potential for expanded use of hydrogen is relevant to both the transportation and stationary power sectors, and as a result interesting synergies are possible. These include co-production of electricity and hydrogen for vehicles with "hydrogen energy stations," using distributed power generation to provide electricity for hydrogen production through electrolysis, and even using hydrogen-powered vehicles for backup power, peak power, and/or grid ancillary services such as spinning and non-spinning reserves.

Distribution Systems and Onboard Vehicle Storage – As highlighted by the recent National Research Council (2004) study, further progress with regard to onboard hydrogen storage is required in order for hydrogen-powered vehicles to become more practical. While hydrogen storage as a compressed gas is the dominant onboard storage system at present, this type of system suffers from bulkiness, significant electricity requirements for hydrogen compression, and potential safety concerns due to the high storage pressures. Other onboard storage systems such as those based on metal and alkaline hydrides, cryogenic liquid hydrogen, and carbon nanotubes are under development.

Policy / Institutional Roles and Priorities:

Incentives for "Clean" Hydrogen Production – Given the many possible ways of making hydrogen, and the widely varying environmental and social impacts that these pathways imply, federal, state, and local governments should consider incentivizing the production of hydrogen in ways that minimize social costs. These incentives could be in the form of reduced or eliminated taxes on hydrogen produced from renewables and other clean and "climate-friendly" sources, and tax breaks on investments in hydrogen production capital equipment.

Role of Government Agencies and the Private Sector – In addition to potentially providing incentives for the development of clean hydrogen production systems and distribution infrastructure, the public sector can play several other important roles. These include public education and outreach on hydrogen safety issues, development and implementation of codes and standards for hydrogen infrastructure, support for hydrogen systems research and development,

> incorporating hydrogen vehicles into government fleets where practical, and potentially using other government assets to assist in hydrogen systems development (e.g. allowing roadside "rights-of-way" to be used for hydrogen stations and pipelines).

In conclusion, hydrogen is a highly promising energy carrier and fuel for vehicles and stationary power generation, but the potential expanded use of hydrogen involves a host of issues and challenges. Primary among these is the fundamental issue of how the hydrogen is itself produced and distributed. One of hydrogen's chief advantages – the ability to be made in various ways and with a diverse array of feedstocks – also complicates decision-making with regard to planning for the development of hydrogen production and distribution infrastructure.

I. Introduction

Hydrogen is the most abundant element in the known universe. The hydrogen molecule (H_2) is a colorless gas at room temperature, and being light relative to other gases, it moves quickly unless contained and disperses rapidly upward through and then out of the atmosphere. As well as being produced "artificially" for various commercial and industrial uses, hydrogen is formed through various natural processes on earth. Since it readily rises through and escapes from the atmosphere, it only tends to persist underground where it is formed by the action of bacteria on ancient vegetable and animal remains. In fact, surprising recent research suggests that the underground stores of hydrogen may be much more considerable than previously thought (Freund et al., 2002). However, the economic and environmental costs of attempting to make use of these underground stores of hydrogen are likely to be considerable, and probably unattractive due to the deep underground and highly diffuse nature of the resource.

In the context of energy systems, hydrogen is best thought of as an *energy carrier*, more akin to electricity than the fossil fuels that we extract from the earth's crust. Hydrogen can be produced from any "hydrocarbon" fuel because by definition these fuels contain both hydrogen and carbon. Hydrogen can also be produced from various biological materials and from water. This "water splitting" process is called *electrolysis*, and it is the oldest electrochemical process known. Thought of in this way, hydrogen supplies are virtually unlimited – unlike fossil fuels that someday will run out.

Hydrogen has been considered as a fuel for many years, but over the past ten to fifteen years advances in fuel cell technology have spurred an enormous wave of interest in hydrogen. Fuel cells have the remarkable ability to convert hydrogen to electricity efficiently by using special electrolyte membrane materials and an electrochemical rather than combustion process. Over the past decade or so, billions of dollars have been spent on research and development of hydrogen technologies, mainly in the private sector but also among government research labs and programs. These investments have spurred significant technological improvements, but have also revealed the many difficulties of designing fuel cell and hydrogen storage and dispensing systems that are practical, cost-effective, and safe to operate.

Fuel cells are being considered for a wide range of potential applications, from very small-scale portable electronics at the level of watts or even milliwatts, all the way up to large powerplants in sizes of one or more megawatts (MW). The application that has garnered the most attention is the prospect of incorporating fuel cell systems into electric vehicles (EVs), meaning that they could operate on hydrogen rather than by recharging their batteries. Particularly in recent months, following the announcement of the Bush Administration of plans to spend $1.2 billion over the next 5 years on the development of fuel cell vehicles (FCVs) under the FreedomCAR program, the merits of FCVs relative to other options for reducing pollution and oil consumption have been hotly debated. Some analysts argue that the emphasis on FCVs and other hydrogen-powered vehicles is well placed, given their tremendous potential to simultaneously address several concerns related to energy use in the transportation sector. These include air pollutant emissions, emissions of greenhouse gases (GHGs), issues of oil dependency, and even the prospects for reducing vehicle noise.

Meanwhile, others argue that FCVs are a chancy proposition that may not "pan out" and that efforts instead should focus on or at least be complemented by emphasizing more conventional technologies with a higher chance of success and with a more immediate impact. These include technologies such as hybrid EVs that run on gasoline but that can be made more efficient by also incorporating an electric motor and battery system that works in conjunction with the gasoline engine (Doniger et al., 2002; Weiss et al., 2003). Other hydrogen-based concepts include hydrogen combustion engines for internal combustion engine (ICE) vehicles and hybrid-electric vehicles, hydrogen engines and/or turbines for heavy-duty transportation applications (fork-lifts, maritime vessels, etc.) where they can substitute for diesel engines, and hydrogen gas turbines for stationary applications.

Options for using hydrogen cleanly and efficiently thus exist apart from fuel cells, and use of hydrogen as a fuel may well continue to expand even in scenarios where fuel cells do not ultimately become widely adopted, or where they perhaps operate on natural gas and methanol to a large extent (for example, solid-oxide and direct-methanol fuel cells respectively), rather than on hydrogen directly. Hydrogen used in this way could lead to development of a hydrogen distribution infrastructure in advance of, or perhaps even in place of, the success of fuel cells in some market segments, thereby helping to lead the development of the hydrogen economy in a complementary fashion.

This report considers the important question of where the hydrogen will come from to operate these various types of fuel cells and combustion systems that use hydrogen directly. At present, natural gas is the leading "feedstock" for hydrogen production, but hydrogen can be produced in myriad ways from a large number of potential sources. Since natural gas is a non-renewable resource, one that is not evenly distributed geographically, and that also is subject to market price fluctuations and supply limitations, efforts to consider alternative sources of hydrogen production are warranted. Also, unless and until efforts are successful to remove the carbon dioxide (CO_2) and other GHGs from the hydrogen production process, hydrogen production or "reforming" from natural gas releases significant quantities of CO_2 and methane (CH_4), thus potentially contributing to climate change. These GHG emissions may be less than those associated with conventional fuel-based baseline but they may still be significant cases (such as with hydrogen FCVs vs. gasoline vehicles -- see Section V below for GHG emissions estimates for various hydrogen production pathways).

Technologies are evolving rapidly for hydrogen production from renewable and other sources, including electrolyzers, small-scale reformers, and biomass and coal gasification systems. As these other technologies begin to become competitive with natural gas reforming, as they may in due course, they can complement the use of natural gas as a hydrogen source and add fuel diversity and insulation against price fluctuations and supply limitations. Careful consideration of the relative costs and benefits of various hydrogen pathways (including environmental and human health impacts of lifecycle pollutant emissions) are thus important so that hydrogen can be produced in the most benign ways from an overall social perspective.

This report first considers various methods for producing hydrogen, including discussion of the production potential for the United States (U.S.). Next, hydrogen distribution and delivery options are briefly summarized and discussed, including discussion of the environmental pollutant emissions implications and land and water use impacts of different production options. Also discussed are potential regional hydrogen production strategies around the U.S., and potential for regional hydrogen production from renewable sources. Finally, policy implications are discussed in the conclusions section, in light of the hydrogen production option costs and benefits that are reviewed and described in the report.

II. Hydrogen Production Methods

Unlike most conventional fuels that are found, extracted from the earth's crust, and then refined, hydrogen is not found but rather is created from other primary fuels and feedstocks. There are believed to be significant quantities of hydrogen underground, formed by bacterial activity, but these stores of hydrogen are predominantly deep underground, most likely at depths of about 20 kilometers (Freund et al., 2002), and therefore probably not economical to extract. Hydrogen production is thus in some ways more akin to electricity production than the production of fossil fuels, but compared with electricity hydrogen has the advantage of being more readily storable, or "packable" in pipelines.

Hydrogen production is largely of interest due to the use of hydrogen being electrochemically converted into electricity in fuel cells with high efficiency, or of being combusted relatively cleanly and efficiently. Some fuel cell types would require relatively high-grade hydrogen as input (e.g., proton exchange membrane [PEM] fuel cells with relatively low carbon monoxide [CO] tolerance), while other high-temperature fuel cells could actually input natural gas directly.

The temperatures internal to these high temperature fuel cells (such as solid oxide and molten carbonate fuel cells -- SOFCs and MCFCs) are sufficient to thermally dissociate or "internally reform" the CH_4 into hydrogen and carbon compounds. Thus, the "hydrogen" requirements of various fuel cell types are rather diverse, and only some types of fuel cells require hydrogen to be produced prior to being introduced into the fuel cell stack.

At present, hydrogen is produced mainly from natural gas and oil, but production possibilities involving other sources such as from coal and through electrolysis have garnered attention in recent years. At present, about half of the 500 billion normal cubic meters (Nm^3) of hydrogen produced globally on an annual basis comes from natural gas (U.S. DOE, 2003). Table 1, below, presents recent data on global hydrogen production from various sources.

Table 1: Annual Worldwide Hydrogen Production Share by Source

Source	Nm^3 (billions)/Year	Share
Natural gas	240	48%
Oil	150	30%
Coal	90	18%
Electrolysis	20	4%
Total	500	100%

Source: U.S. DOE, 2003
Note: Nm^3 are normal cubic meters of hydrogen.

Hydrogen Production from Fossil Fuels

Hydrogen production from fossil fuel sources is the most mature means of hydrogen production today, and the least expensive. Large amounts of hydrogen are produced globally from fossil sources at present, mostly for use in oil refineries and production of fertilizers and chemicals. Approximately 500 billion Nm^3, or about 50 million metric tons (and about 9 million metric tons in the U.S.), per year of industrial hydrogen is produced for these uses globally, almost entirely by the steam reformation of natural gas (Moore and Raman, 1998; U.S. DOE, 2003).

Hydrogen can be produced from natural gas and other fossil fuels through various reformation processes (as well as through electrolysis if the fossil fuels are first used to generate electricity, as discussed below). These reformation processes include basic steam methane reforming (SMR), catalytic or "autothermal" reformer (ATR) processes, and partial-oxidation (POx) processes. In general, SMR and ATR processes are suitable for reforming light hydrocarbons, such as methane, butane, propane, and (with a special catalyst) naphtha, while the POx process can be applied to a broader range of hydrocarbon feedstocks (see below).

The basic endothermic SMR process using natural gas as a feedstock and steam for process heat and additional hydrogen, and produces a hydrogen rich gas that is typically on the order of 70-75% on a dry basis, along with smaller amounts of methane (2-6%), carbon monoxide (7-10%), and carbon dioxide (6-14%) (Hirschenhofer et al., 2000; Sircar et al., 1999). Additional subsequent processes to improve the hydrogen yield and reduce impurities include exothermic water-gas shift (WGS) reactions and pressure-swing adsorption (PSA) processes.

The WGS reactions, typically in two steps – a "high temperature WGS" step and a "low temperature WGS" step – convert most of the carbon monoxide in the SMR product gas to hydrogen and carbon dioxide. Subsequent PSA "cleanup" steps produce high-purity hydrogen (99.999+%) for uses where high purity hydrogen is important. The PSA process typically recovers on the order of 70-85% of the incoming hydrogen from the WGS processes (Sircar et al., 1999), and the PSA waste gases include the removed impurities along with the un-recovered hydrogen. Overall, hydrogen can be produced at up to 75-80% efficiency with SMR systems (higher heating value [HHV] basis), based on the use of natural gas as a feedstock, but efficiencies of around 70% are more likely for smaller-scale systems (Simbeck, 2001; Williams, 2002).

ATRs rely on catalytic reactions that occur adjacently along honeycomb-structured beds of catalytic metals, such as platinum, in a reactor vessel. By injecting air into the reactor, 30 to 40% of the fuel is oxidized with the aid of the catalyst and this releases heat that then is used to convert the remaining fuel along with steam into hydrogen, carbon dioxide, and carbon monoxide. ATRs have the advantages of not needing external burners and being simpler and less expensive than SMRs, but they suffer from somewhat lower efficiency levels of 65-75% (Rampe et al., 2000).

In the POx process, also known more generally as "gasification," hydrogen can be produced from a range of hydrocarbon fuels, including coal, heavy residual oils, and other low-value refinery products. The hydrocarbon fuel is reacted with oxygen in a less than stoichiometric ratio, yielding a mixture of carbon monoxide and hydrogen at 1200° to 1350° Celsius (C.) (Moore and Raman, 1998). The gas mixture is then cooled, subjected to WGS reactions similar to those described above, and finally purified by PSA (if pure hydrogen is desired). Waste products from this process include a low pressure waste hydrogen steam, and excess steam. Unless these waste products can be used locally, the economics of hydrogen from POx processes are not typically attractive, as hydrogen production yields are only about 55-60% -- or about 75% as high as those for SMR systems (Hirschenhofer et al., 2000).

Considerable attention has been paid in recent years to developing very small-scale POx-type reformers for use in producing hydrogen onboard vehicles from gasoline, but though prototype vehicles have been built, these efforts have apparently yet to yield a practical system. This has been due to the difficulties involved with of reforming complex fuels at very small scale, meeting the demands the dynamic operational requirements of fuel cell vehicles, and providing sufficient reformer gas clean-up onboard the vehicle to meet the low CO and sulfur tolerance requirements of PEM fuel cells.

Hydrogen Production from Natural Gas

Hydrogen can be produced from fossil fuels at various scales through these reformation processes. Most mature are SMR technologies for producing hydrogen at large scales of ~100-120 million standard cubic feet (scf) per day (241,000-290,000 kilograms [kg]/day), but smaller-scale reformers have also been developed for hydrogen production in a more decentralized fashion (such as at vehicle refueling stations), and for even smaller-scale applications such as for providing hydrogen fuel to stationary fuel cells in the 5-250 kilowatt (kW) size range.

Large Scale Centralized Production

Assuming industrial natural gas costs of about $3.00 per gigajoule (GJ), large SMR plants with capacities on the order of 60 million scf per day (145,000 kg/day) can produce hydrogen at efficiency levels of 76% to 81%, and at costs of $0.78 to $1.04 per kg ($5.50 to 7.30/GJ), by varying estimates (Ogden et al., 2003; Simbeck, 2001; Williams, 2002).

One principal advantage of large-scale hydrogen production from fossil fuels is that it is in principle possible to capture or "sequester" the carbon dioxide that is produced, whereas this is unlikely to be economical for smaller-scale production. A research group at Princeton University has been studying the prospects for hydrogen production with CO_2 capture in recent years, and they estimate that CO_2 capture would add about $0.24 per kg ($1.70/GJ) to the cost of hydrogen produced from large-scale SMR plants as above, raising the total hydrogen production cost from (by their estimate) $0.78 per kg ($5.50/GJ) to $1.02 per kg ($7.20/GJ) (Williams, 2002).

The National Research Council (NRC) has recently examined hydrogen production via SMR for very large (1.1 million kg of hydrogen per day) and medium-sized plants (24,000 kg of hydrogen per day), including cases where product CO_2 is vented or sequestered. The NRC estimates are shown in Table 2, below, including also estimates for small-scale distributed production at a scale of 480 kilograms of hydrogen per day.

Table 2: National Research Council Estimates for Hydrogen Produced via SMR of N. Gas

Scale / Case	**Hydrogen Production Cost ($/kg and $/GJ HHV)**	
	Current Technology	Future Technology
Large Scale – CO_2 vented (1.1 million kg/day)	$1.03/kg ($7.26/GJ)	$0.92/kg ($6.49/GJ)
Large Scale – CO_2 seq. (1.1 million kg/day)	$1.31/kg ($9.24/GJ)	$1.10/kg ($7.76/GJ)
Medium Scale – CO_2 vented (24,000 kg/day)	$1.38/kg ($9.73/GJ)	$1.21/kg ($8.53/GJ)
Medium Scale – CO_2 seq. (24,000 kg/day)	$1.76/kg ($12.41/GJ)	$1.55/kg ($10.93/GJ)
Small Scale - CO_2 vented (480 kg/day)	$3.51/kg ($24.75/GJ)	$2.33/kg ($16.43/GJ)

Source: NRC, 2004

Small Scale – Decentralized Production

Moore and Raman (1998) of Air Products and Chemicals, Inc. have examined the costs of medium-sized natural gas reformer systems constructed on-site. They estimate a facility cost of $9.6 million for a station that can support refueling of 500 vehicles per day. These stations would produce 2,700 kg of hydrogen per day, at an estimated net cost of $3.57 per kg ($25.14/GJ) (Moore and Raman, 1998).

Smaller-scale SMR production has also been examined, for example in the context of hydrogen production from natural gas at gasoline service stations for refueling FCVs. At a production scale of 470 kg of hydrogen per day (or about enough for 100 FCVs), Simbeck and Chang (2002) estimate that hydrogen can be produced and sold for $4.40 per kg ($30.99/GJ), assuming a natural gas cost of $5.25 per GJ. Table 2, above, presents the NRC estimates for production at a similar scale, including both “current technology” and “future technology” cases.

Also, the Praxair Corporation is working with DOE to develop practical small SMR units. The program has the goal of developing systems that can produce hydrogen at rates of 58 to 290 kg per day (1,000 to 5,000 scf per hour), at an aggressive cost target of $1.19 per kg ($8.40/GJ). Achievement of this ambitious cost goal will require the use of "design for manufacturing and assembly" techniques, a high level of system integration, and volume production of system components (Bollinger and Aaron, 2002).

Small Scale - Hydrogen Energy Stations

Thomas et al. (2001) of Directed Technologies Inc. (DTI) have analyzed small natural gas production systems that also include the use of fuel cells to produce electricity for local uses using the same natural gas reformer as the one supplying hydrogen for FCVs. They analyze these systems based on the number of hydrogen system components that are produced, assuming economies of scale in their production, and conclude that hydrogen could initially be sold at $2.60 per kg ($18.31/GJ), with hydrogen sales of $1.68 per kg ($11.83/GJ) possible if system components were manufactured in volumes of 10,000 units.

Lipman et al. (2003) examined similar systems using somewhat more conservative cost estimates, and have found that the economics of producing hydrogen and electricity with small hydrogen "energy stations" are difficult at small service station locations where only 10 to 50 vehicles per day are serviced, but with hydrogen sales prices of $20 per GJ ($2.84/kg) begin to become favorable when at least 50 vehicles per day are refueled. However, at office building type energy stations in "high electricity cost" states such as California, with hydrogen production being subsidized from the electricity cost savings from the use of the fuel cell, hydrogen can be sold at lower costs and additional facility energy cost savings can be realized in some cases. These improved economics at office building energy stations are possible due to higher electrical loads (200-500 kW), the use of larger fuel cell systems that have lower costs per kW, and because cogeneration of hot water for local uses is possible.

Figure 1 presents a picture of a hydrogen energy station that is operating in Las Vegas. In addition to producing electricity using a stationary fuel cell, the station is capable of dispensing pure hydrogen and compressed natural gas (CNG) for vehicle refueling, as well as CNG/hydrogen blends (City of Las Vegas, 2002).

Figure 1: The Las Vegas H_2E-Station

Source: Air Products and Chemicals, Inc.

Thermal Decomposition of Hydrogen From Natural Gas

In addition to these reformation processes, hydrogen can be produced from natural gas by thermally decomposing it into hydrogen and carbon. One method for doing this would use a concentrating solar reactor, or heliostat, to provide the heat needed for the decomposition reaction. Spath and Amos (2002) have analyzed one type of solar reactor system that would allow concentrated sunlight from the heliostat to enter a quartz outer reactor tube, and then irradiate a solid graphite reactor tube that would in turn heat an inner porous graphite reactor tube. The natural gas would be fed through this heated inner graphite tube where the decomposition reaction would then take place. Product hydrogen, carbon, and un-reacted natural gas would then enter a baghouse filter in order to remove the carbon. Assuming that this co-product "carbon black" is sold for industrial purposes at \$0.66 per kg, and assuming a target natural gas conversion of 70%, Spath and Amos (2002) estimate that hydrogen produced in this manner with a large 8,750 square meter (94,200 ft^2) heliostat could be at costs on the order of \$2.56 per kg (\$18/GJ), also assuming a natural gas price of \$3.72 per GJ. With smaller heliostats of 2,188 and 4,375 square meters (23,550 and 47,100 ft^2), the corresponding hydrogen production costs are estimated to be \$3.41 per kg (\$24/GJ) and \$2.84 per kg (\$20/GJ), respectively (Spath and Amos, 2002).

Hydrogen Production From Coal

Hydrogen can also be produced via coal gasification POx processes, and while these systems are less mature than SMR for hydrogen production, they are also relatively well established. For example, Simbeck (2001) reports that over 15 coal gasifier systems are in operation around the world that produce hydrogen for ammonia fertilizer manufacture, mostly in China but also in the U.S., Germany, Japan, and India. There are various types of coal gasification systems available at present, with primary differences being the gasifier type (moving-bed, fluidized-bed, or entrained-bed), the product gas temperature, and the composition of the product gas (Hirschenhofer et al., 2000). All of these gasifier types use steam and air or oxygen to partially oxidize coal into a gas product, and make use of the exothermic gasification reactions to produce process heat. Table 3, below, shows a comparison of typical effluent streams from POx-based reformation of coal, compared with SMR of natural gas.

Table 3: Typical Reformer Effluent for SMR of Natural Gas and POx Reformation of Coal
(Percent By Volume Basis)

Reformer Effluent	**SMR of Natural Gas**		**Fluidized-Bed POx Reformation of Coal**	**Entrained-Bed POx Reformation of Coal**[a]
	Reformer Effluent	**Shifted Reformate**		
H_2	46.3	52.9	28.3	28.0
CO	7.1	0.5	33.1	47.9
CO_2	6.4	13.1	15.5	6.2
CH_4	2.4	2.4	4.6	0.2
N_2	0.8	0.8	0.6	1.6
H_2O	37.0	30.4	16.8	14.0
Total	**100.0**	**100.0**	**98.9**	**97.9**

Source: Hirschenhofer et al., 2000

Note: [a] Reformer effluent values shown are the average of four different entrained-bed coal reformation technologies. These emissions vary somewhat by technology.

As with all hydrogen production pathways that use fossil fuels as feedstocks, but even more so with the use coal, post-processing of the effluent gas is typically required to remove compounds that are contaminants for most fuel cell types. These include hydrogen disulfide and other sulfur compounds, ammonia, carbon monoxide, and tars, oils, and phenols. The various systems needed to remove these compounds depend on the composition of the coal used but all add cost and complexity to the production process, and in many cases have specific temperature requirements that necessitate the extensive use of heat exchanger systems (Hirschenhofer et al., 2000).

Williams (2002) estimates that hydrogen can be produced via coal gasification at large scale for costs as low as \$0.88 per kg (\$6.25/GJ), assuming a coal price of \$1.17 per GJ. However, the CO_2 emissions associated with producing hydrogen in this manner are considerable. Table 3 above provides a comparison of typical natural gas reforming and coal gasification effluent compositions on a volume basis, with CO_2 plus CO levels on the order of double those of hydrogen in the coal systems, and with three to four times *more* hydrogen than CO_2 plus CO produced with the natural gas systems.

This suggests that for coal gasification for hydrogen production to be practical in the long term, these CO_2 emissions (once the CO is converted to CO_2) would need to be captured and stored. By Williams' (2002) estimates, this would raise the cost of hydrogen production by \$0.55 to \$1.25 per kg (\$3.87 to \$8.80/GJ), or to a total of \$1.43 to \$2.13 per kg (\$10.07 to \$15.00 per GJ), depending on whether or not hydrogen sulfide emissions are allowed to be captured and stored along with the CO_2 (this reduces the costs of capture and storage and results in the lower-end cost estimates).

Gray and Tomlinson (2002) and Ogden et al. (2004) calculate similar large-scale hydrogen production costs from coal. By Gray and Tomlinson's estimates, hydrogen can be produced at a cost of \$0.92 per kg (\$6.48/GJ) with CO_2 emissions vented to the atmosphere, and \$1.10 per kg (\$7.75/GJ) with CO_2 sequestered at a cost of \$10 per ton of carbon. With future "advanced gasification" techniques, they estimate that hydrogen could be produced from coal more efficiently and with costs as low as \$0.79 per kg (\$5.56/GJ), including the costs of carbon sequestration at \$10 per ton. At similar production scales (e.g. about 600,000 kilograms of hydrogen per day compared with 300,000 to 400,000 kilograms per day for Gray and Tomlinson), Ogden et al. (2004) estimate hydrogen costs of \$0.81 per kg (\$5.69/GJ) without CO_2 sequestration, and \$1.05 per kg (\$7.36/GJ) with CO_2 sequestered.

The NRC estimates similar coal-to-hydrogen production costs as those of Gray and Tomlinson (2002) and Ogden et al. (2004), although at somewhat larger scale production of 1.2 million kilograms of hydrogen per day. These estimates are \$0.96 per kg (\$6.77/GJ) with current technology and CO_2 vented, \$0.71 per kg (\$5.01 per GJ) with future technology and CO_2 vented, \$1.19 per kg (\$8.39/GJ) with current technology and CO_2 sequestered, and \$0.92 per kg (\$6.49 per GJ) with future technology and CO_2 sequestered (NRC, 2004).

Finally, at somewhat smaller production scale of 150,000 kg of hydrogen per day (compared with approximately 300,000 to 500,000 kg per day in the above estimates), Simbeck and Chang (2002) estimate costs of \$1.62 per kg (\$11.41/GJ), without CO_2 sequestration.

Hydrogen Production from Nuclear Power

Nuclear power has been proposed for use in hydrogen production in a few different ways. First, like any electricity-generation source, nuclear power can be used to produce hydrogen via the electrolysis of water. This could be performed at ambient temperatures, or at higher temperatures as "hot electrolysis." These nuclear power based electrolysis prospects are discussed along with other electrolytic hydrogen production options in the following section. Second, hydrogen could be produced through steam reformation of natural gas, using heat from nuclear power plants to produce the steam. This reduces the natural gas requirements associated with operating a boiler to raise the steam, and leads to hydrogen production with less natural gas input. Third, hydrogen could be produced from water by using heat from nuclear plants to thermally dissociate water molecules into hydrogen and oxygen.

Nuclear-assisted steam reforming is an option for hydrogen production, whereby the heat required for the endothermic reforming process is provided by the high-temperature heat from the nuclear reactor rather than from the combustion of natural gas. In this case, the natural gas input acts only as a source for hydrogen. This type of system is in the research and development stage at present, with the main development activity occurring in Japan. In a research program that was initiated in 2001, Japanese researchers have been experimenting with coupling a steam reformer to a 30 MW high-temperature test reactor with a peak temperature of 950° C. (Forsberg, 2003).

Hydrogen can also be produced from nuclear energy through thermo-chemical processes that use high-temperature heat to dissociate water molecules. This can be accomplished in various ways, and in fact over 100 potential cycles have been identified, with one leading concept being the use of an iodine-sulfur process (Brown et al, 2002; Forsberg, 2003). In this type of system, water is combined with sulfur dioxide (SO_2) and iodine (I_2) to produce sulfuric acid (H_2SO_4) and hydrogen iodide (HI). The sulfuric acid is decomposed into water, sulfur dioxide, and oxygen by adding heat from the nuclear reactor at 800° to 1000° C., and the hydrogen iodide is converted to hydrogen and iodine. The iodine and sulfur dioxide are then re-used in the first reaction, with the oxygen being vented or potentially captured for industrial uses. The following reactions are involved in this type of system:

Iodine-Sulfur Process Reactions
$I_2 + SO_2 + 2\ H_2O \rightarrow 2\ HI + H_2SO_4$
$H_2SO_4 + \text{heat} \rightarrow H_2O + SO_2 + 1/2\ O_2$
$2\ HI + \text{heat} \rightarrow H_2 + I_2$

Overall:
$H_2O + \text{heat} \rightarrow H_2 + 1/2\ O_2$

By one estimate, the costs of producing hydrogen from this type of system could be as low as \$1.30 per kg (\$9.15/GJ), assuming a combined capital cost of \$686 per kW (thermal) for the nuclear reactor (\$371/kW) and hydrogen plant (\$315/kW) and assuming 50% system efficiency (Henderson, 2002). Another recent estimate by the NRC estimates somewhat higher costs of \$1.63 per kg (\$11.50/GJ), assuming a production plant capital cost of \$2.5 million for a production capacity of 1.2 million kilograms of hydrogen per day (NRC, 2004). By another estimate, the exact costs of producing hydrogen through this cycle are not specified but are estimated to be about 60% of the costs of hydrogen production via electrolysis (Forsberg, 2003).

The Process of Electrolysis to Produce Hydrogen

Electrolysis is the process of producing hydrogen by splitting water molecules. Electrolysis has a long history, dating back to experiments by Carlisle and Nicholson around the year 1800, and in fact is the oldest electrochemical process known (Adreassen, 1998). However, it was not until the early 1900s that commercial electrolyzers were developed for hydrogen production. The uses for this early hydrogen production were primarily in the fertilizer industry, and there were approximately 400 electrolyzers in operation in 1902 (Adreassen, 1998).

The most mature electrolyzer technologies are based on alkaline electrolytes, typically composed of potassium hydroxide. However, additional electrolyzer technologies are now being developed based on three more advanced technologies: 1) solid polymer electrolyte membrane-based electrolysis (the same membranes used in PEM fuel cells); 2) high-temperature steam electrolysis; and 3) natural gas assisted steam electrolysis.

The solid polymer electrolyte-based PEM electrolyzers are currently characterized by significantly higher capital costs than the alkaline designs, but these costs are expected to decline as the technology matures and moves into higher volume production. However, PEM electolyzers have the advantages of higher operational efficiencies than alkaline electrolyzers, and the ability to operate reversibly as PEM fuel cells to produce electricity from the generated hydrogen.

The high-temperature steam electrolyzers benefit from the fact that much lower electrolyzer cell voltages are needed to split water at temperatures of 900° to 1000° C than are required at ambient temperatures (Ogden and Nitsch, 1993). These high-temperature electrolyzers would use primarily ceramic electrode materials, but the high operational temperatures of these devices present formidable material and fabrication problems, and their overall complexity has thus far been a barrier to commercialization.

Natural gas assisted steam electrolysis has recently been investigated by the Lawrence Livermore National Laboratory. In this scheme, natural gas is supplied to the anodes of high-temperature steam electrolyzers instead of air. The natural gas on the anode side of the electrolyzer reduces the amount of electricity that needs to be supplied, relative to conventional steam electrolysis. This is because the oxygen ion charge-carrier in this type of system (from the water molecule) more readily crosses the membrane due to the affinity of the oxygen ion to react with and oxidize the methane molecules, and this allows electrolysis to occur at lower cell voltages than with conventional electrolyzer systems (by up to a full volt or more per cell). This reduction in electricity requirements with natural gas assisted electrolysis can result in hydrogen production at 60 to 75% efficiency, in terms of primary energy input, compared to about 40% efficiency for conventional alkaline electrolysis using U.S. average grid electricity (Pham et al., 2002).

Hydrogen can be produced from electrolysis at a range of scales. An important potential advantage of electrolysis is that small-scale production of hydrogen by electrolysis is practical, and this can reduce or even eliminate the need for hydrogen distribution. However, large-scale electrolysis, such as in the nuclear power assisted case discussed below, would require the hydrogen to be delivered by truck as compressed gas or liquid, or distributed with pipeline networks. All of these options entail significant costs for hydrogen distribution, as discussed in Section III of this report.

The following chemical equations show how hydrogen is produced from water using both the alkaline electrolyte and solid polymer electrolyte technologies (Adreassen, 1998).

Alkaline Electrolyzer Electrode Reactions
Cathode: $2\ H_2O + 2\ e^- = H_2 + 2\ OH^-$
Anode: $2\ OH^- = 1/2\ O_2 + H_2O + 2\ e^-$
Overall: H_2O + energy = $H_2 + 1/2\ O_2$

Solid Polymer Electrolyzer Electrode Reactions
Cathode: $2\ H^+ + 2\ e^- = H_2$
Anode: $H_2O = 1/2\ O_2 + 2\ H^+ + 2\ e^-$
Overall: H_2O + energy = $H_2 + 1/2\ O_2$

Electrolyzers have the advantages of producing pure hydrogen, the ability to produce hydrogen at relatively high pressures directly from the electrolyzer (in the case of PEM electrolyzers), and the ability to use any primary fuel that can be used to produce electricity. Disadvantages include relatively high capital costs (particularly for low-temperature PEM electrolyzers that like PEM fuel cells require platinum-based catalysts), hydrogen production efficiencies that decline with the rate of hydrogen production for a given system, and uncertain durability of the novel PEM electrolyzers that are now starting to be commercialized.

The costs of producing hydrogen from electrolysis depend on the electrolyzer type (and corresponding capital cost and efficiency), as well as the costs of the required electricity and other inputs. For large scale production using conventional alkaline electrolysis, Norsk Hydro electrolyzers reports potential costs of $2.96 per kg of hydrogen ($20.9/GJ), assuming a plant that produces 4,000 Nm^3 of hydrogen per hour, electrolyzer system capital costs of $13.0 million, and electricity costs of $0.029 per kWh (Anreassen, 1998).[1]

For PEM electrolyzers costs at present are high at about $3,000 to 4,000 per kW, or similar to those of PEM fuel cells. This is not surprising as electrolyzers and fuel cells are similar devices that essentially operate in reverse of one another. DOE has set development goals for PEM electrolyzers of $600 per kW for systems that can produce about 25 kg (10,000 scf) of hydrogen per day and that are manufactured in quantities of 10,000 units per year. Smaller units that can produce about 2.5 kg (1,000 scf) of hydrogen per day have a cost goal of $1,200 per kW, again in production volumes of 10,000 units per year. In larger volume production of 100,000 units per year, costs for the 25 kg per day units have a cost target of $300 per kW (Padro, 2002). Note that these figures are simply cost targets, and not manufacturing cost estimates based on detailed analysis.

Discussed below are various technologies to produce electricity that can then be used to directly electrolyze water and produce hydrogen. Hydrogen production can be closely coupled to any one of these methods, or from a "grid mix" of different sources on a utility grid. Given the current mix of powerplants in the U.S., direct electrolysis of grid power is not favored in terms of energy use and greenhouse gas emissions, but the situation would improve with future reductions in powerplant emissions and can be highly favorable when coupled with renewable and nuclear power systems.

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[1] Costs converted from Norwegian kroner to dollars using a conversion factor of 1 dollar = 6.9 kroner.

Hydrogen From Electrolysis Using Grid Power

Hydrogen can be produced via electrolysis using utility grid power, with the regional "generation mix" being important to the resulting economics and environmental impacts. Particularly where regional utility grids include large proportions of coal-based electricity generation, the environmental impacts of producing hydrogen in this manner may be unattractive. Where utility grids are "greener" and include significant amounts of renewable or other clean electricity production, the environmental impacts of producing hydrogen from grid power can be more attractive. The important point is thus that the environmental impacts of grid power electrolysis can vary widely, and also vary depending on the overall efficiency of the electrolyzer system.

The NRC has analyzed the costs of producing hydrogen from grid power at two different scales and based on current and future electrolyzer technology. At medium scale of 24,000 kilograms of hydrogen produced per day and with wholesale electricity costs of $0.045 per kWh, the NRC estimates current hydrogen production costs of $4.70 per kg ($33.15/GJ) and future potential costs of $2.30 per kg ($16.22/GJ). At smaller production scale of 480 kilograms of hydrogen per day, and with commercial electricity costs of $0.07 per kWh, the NRC estimates current costs of $6.58 per kg ($46.41/GJ) and future potential costs of $3.93 per kg ($27.72/GJ) (NRC, 2004).

Hydrogen From Electrolysis Using Nuclear Power

Nuclear energy production is relatively capital-intensive, and only practical in large plant sizes, but has relatively low operating costs (plant decommissioning and long-term waste disposal/storage costs being another matter, and one that can significantly increase the overall costs of nuclear energy). With these relatively low operating costs once installed, nuclear energy is best suited for "baseload" electricity generation. At times of low or "off-peak" demand, nuclear power plants and other baseload power plants could supply electricity for electrolysis, particularly if demand dips below the level of power that the baseload plants are capable of supplying. Thus, particularly compared to the alternative of turning down baseload power plants, hydrogen production from nuclear power via electrolysis may be attractive.

In addition to simply using the electricity generated from nuclear power for electrolysis, hot electrolysis is another option and one that is favorable for use in conjunction with nuclear power because of the availability of the necessary heat from nuclear reactors. Electrolysis at these higher temperatures (700° to 1000° C.) requires less electrical input because some of the electrical input required for ambient temperature electrolysis is replaced with thermal energy. This thermal energy is less costly than the electrical energy that it replaces, and these systems can in theory produce hydrogen at reduced costs. However, these hot electrolysis systems are in an early stage of development, and are characterized by high capital costs that are on the order of twice the costs of lower-temperature electrolyzer systems (Forsberg and Peddicord, 2002), as well as likely high associated hydrogen delivery costs due to the remote locations of most nuclear plants.

Hydrogen From Electrolysis Using Renewable Sources

Hydrogen can be produced from renewable sources via three primary pathways. First, electricity generated from renewable sources, such as wind and solar photovoltaics (PV), can be used to split water molecules via electrolysis as discussed here. Second, hydrogen can be thermally dissociated from water using renewable sources that generate large amounts of heat, such as solar thermal technologies, without the addition of electricity. Third, biomass and other feedstocks can be used to produce hydrogen via gasification processes, similar to the coal gasification processes described above. The second and third options will be discussed in the following sections.

Hydrogen Production by Electrolysis from Wind Power

Hydrogen production from wind power is a particularly interesting proposition for two primary reasons. First, among renewable sources of electricity, wind power is particularly competitive economically with electricity costs of 4 to 5 cents per kWh in good sites. This means that hydrogen produced with electrolyzers that are connected to wind farms can generate hydrogen at lower costs than with some other options such as solar power. Second, the availability of wind power tends to be highly variable diurnally, and also fluctuates seasonally. This makes wind power a somewhat difficult resource to depend on, but at the same time hydrogen production from wind power that is available at off-peak times can help to in effect even-out this wind power potential. Coupled with the use of fuel cells, producing hydrogen from off-peak wind power can make wind a more dispatchable resource by acting as a storage or "buffer" system. Similar to pumped hydro storage, hydrogen production in this way can make effective use of wind power at times when it is otherwise not valuable, such as late at night or at times of the year when electricity demands are relatively low.

Hydrogen storage costs are highly variable depending on the type of storage system, the hydrogen flow rate, and the duration of storage. The primary potential storage methods include compressed gas storage, liquid storage, metal hydride storage, and underground storage. Of these, underground storage is generally the most economical, with costs on the order of $0.10-0.20 per kg of hydrogen stored, but this type of storage is only possible with the presence of suitable underground caverns. Compressed gas and liquid storage are the next most economical, with compressed gas storage being cheaper for low flow rates and storage times (on the order of $0.30-2.00 per kg for 14 days of storage depending on flow rate) and liquid storage having costs of about $0.50-2.00 per kg depending on flow rate but irrespective of storage duration. Metal hydride storage costs scale linearly with storage duration and flow rate, and are only economically competitive with the other methods for low flow rates and storage times (Mann et al., 1998).

Based on future projections that were made about 10 years ago, Ogden and Nitsch (1993) estimate that hydrogen could be produced at "excellent" wind sites (with wind speeds of about 20 miles per hour or 10 meters per second) for approximately $1.56 per kg ($11.00/GJ) assuming a 6% real discount rate and $2.27 per kg ($16.00/GJ) using a 12% discount rate. At "good" wind sites (with wind speeds of about 17 miles per hour or 8.5 meters per second), the corresponding hydrogen production costs are estimated to be $2.41 per kg ($17.00/GJ) assuming a 6% real discount rate and $3.55 per kg ($25.00/GJ) using a 12% real discount rate. These estimates are for "stand-alone" hydrogen production from wind power, unassisted by additional power from the utility grid.

Mann et al. (1998) estimate that hydrogen can be produced from wind power in a stand-alone configuration for $7.10 per kg ($50.00/GJ) near-term, and $4.00 per kg ($28.20/GJ) by the 2010 timeframe. Coupling wind/hydrogen systems with the electrical grid appears to improve the economics of hydrogen production, especially for the near term, where some of the electricity for electrolysis comes from the grid. Such systems are estimated to potentially produce hydrogen for $3.90 per kg ($27.50/GJ) near term and $3.00 per kg ($21.10/GJ) circa 2010. These estimates assume wind power costs of $900 per kW in 2000 and $700 per kW in 2010, and wind capacity factors of 35% (2000) and 40% (2010).

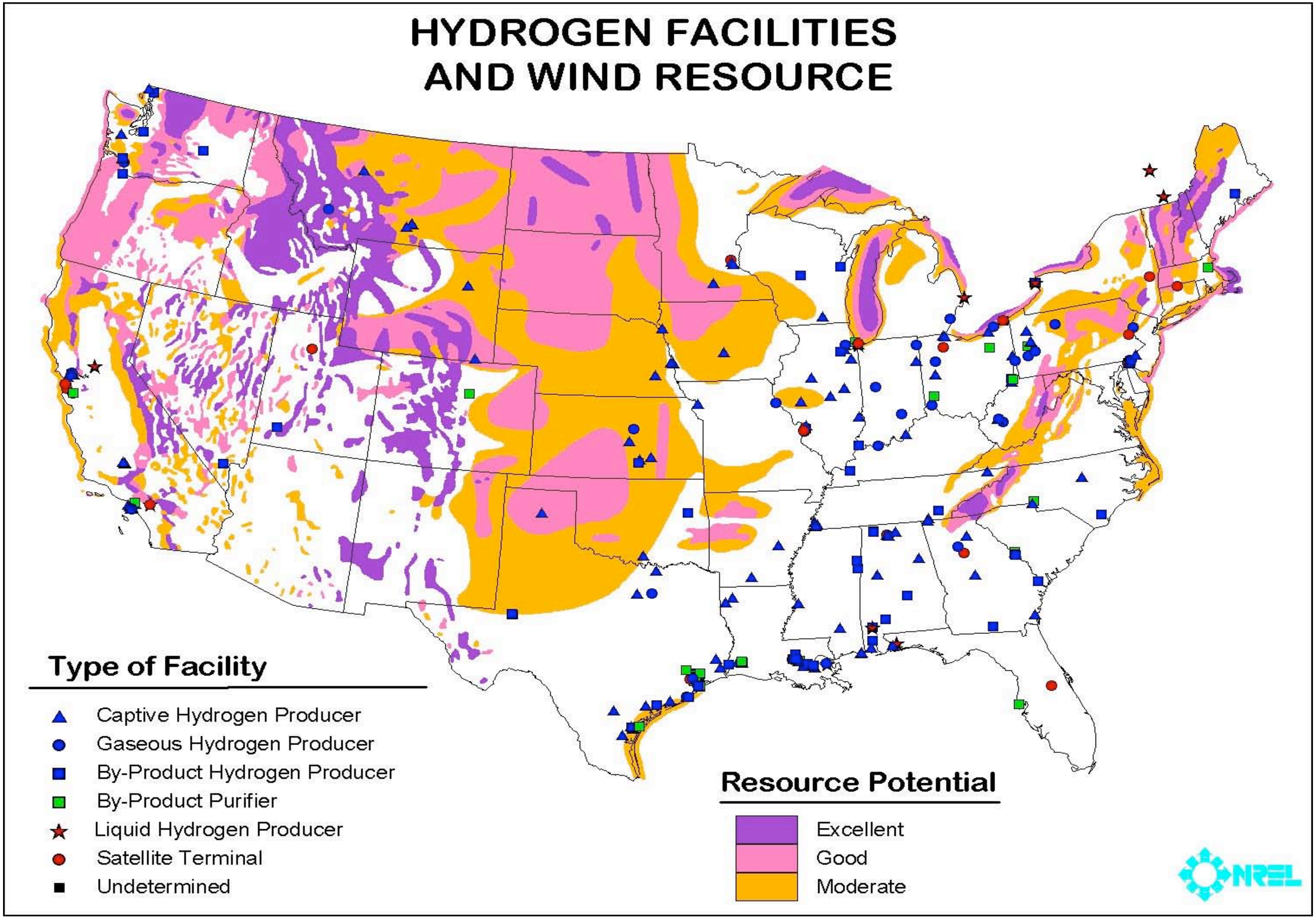
Padro (2002) has also published estimates of hydrogen costs from wind power, with estimates as low as $1.14 per kg ($8.00/GJ) in small stand-alone settings, and from $1.86 to 2.63 per kg ($13.00 to $18.50/GJ) in small to medium scale grid-tied applications and with various system design and economic assumptions. Padro also includes estimates of hydrogen production costs from wind power that include the effects of a 15% "internal rate of return" target and a 37% taxation rate (see Table A-1 for details).

Finally, the NRC reports estimates of hydrogen production costs from wind power that range from $10.69 per kg ($75.39/GJ) for current technology and stand-alone production, to $6.81 per kilogram ($48.03/GJ) for current technology and grid-assisted production. With future improvements, the NRC is projecting particularly large production cost reductions for stand-alone systems ($2.86 per kg of hydrogen or $20.17 per GJ), with significant reductions also projected for the grid-tied systems ($3.50 per kg of hydrogen or $24.68 per GJ). These estimates are for production at scales of 480 kg per day for grid-tied production and 1,200-16,00 kg per day for stand-alone production (NRC, 2004).

Hydrogen From Wind Production Potential in the U.S

The potential for hydrogen production from wind power in the U.S. is well distributed, with significant resources in the Midwestern, Northeastern, and Western parts of the country (see Figure 2). Ogden and Nitsch (1993) estimate that the total annual production of hydrogen in the U.S. from wind power could be approximately 220 billion kg per year (31.3 EJ/year), with leading states in terms of their production potential including North Dakota (24.7 billion kg/year), Texas (24.3 billion kg/year), Kansas (21.8 billion kg/year), South Dakota (21.1 billion kg/year), Montana (20.9 billion kg/year), Nebraska (17.7 billion kg/year), Wyoming (15.3 billion kg/year), and Oklahoma (14.8 billion kg/year). With the total hydrogen requirements for a U.S. fleet of light-duty FCVs in 2010 estimated by Ogden and Nitsch (1993) at approximately 33.8 billion kg/year (4.8 EJ/year), this wind hydrogen potential alone is approximately 6.5 times the requirement for light-duty vehicles in the U.S. if the fleet were to be converted to operate on hydrogen fuel cells.

Figure 2: Hydrogen From Wind Power Availability Map of the U.S.



Hydrogen Production by Electrolysis from Solar Power

Hydrogen can be produced from solar power by generating electricity with solar photovoltaic (PV) systems, and then using the electricity to electrolyze water, or through high temperature processes where water is dissociated thermally without the addition of electricity. The solar electrolytic processes can either be at ambient temperature, or at higher temperatures where the water is first converted to steam before being electrolyzed. The electrolysis-based methods of producing hydrogen from solar energy are discussed below, and the thermal solar systems are discussed in a subsequent section.

With solar PV electrolysis, hydrogen is produced when the solar resource is available by using the generated electricity to split water with the use of an electrolyzer, as described above. The costs of producing hydrogen through solar PV electrolysis are higher than with most other methods, but are expected to decline with continued reductions in PV module costs and electrolyzer system costs. Glatzmaier et al. (1998) estimate that solar PV systems in the 10 MWe size range can produce hydrogen for $6.39 per kg, $12.21 per kg, and $25.84 per kg ($45/GJ, $86/GJ, and $182/GJ) assuming PV system costs of $750 per kW, $2,000 per kW, and $5,000 per kW, respectively, and electrolyzer costs of $450 per kW of direct current (DC) power. These estimates assume an electrolyzer efficiency of 82%, and a capacity factor of 0.28.

Ogden and Nitsch (1993) estimated similar costs for solar hydrogen production in the early 1990s. Their estimates range from $6.39 to $23.71 per kg ($45-167/GJ), depending on interest rate and other assumptions, but they also forecast much lower potential future costs based on PV module and electrolyzer component cost reductions. They project that hydrogen produced in sunny areas with a solar insolation of about 270 watts per square meter could have future costs of $1.42 to $2.27 per kg ($10-16/GJ) using a real discount rate of 6%, and $2.13 to $3.55 per kg ($15-25/GJ) with a more conservative 12% real discount rate. These estimates assume future PV module costs of $30 to $55 per square meter, and PV module efficiencies of 12 to 18%. Lower costs could be achieved with higher PV module efficiencies of closer to 20%, lower PV module costs, or a combination of the two.

In addition to using solar PV systems to meet the electricity needs of electrolysis, additional solar-based technologies such as solar dish-Stirling systems and solar "power towers" can also produce electricity for renewable hydrogen production. With solar dish-Stirling systems, concentrated solar power is used to produce heat to power a Stirling engine, which then operates a generator to produce alternating current (AC) power. The solar "power tower" systems also produce AC power using concentrated solar energy and a generator. The AC power from either of these systems is then rectified to DC before being used in the electrolyzer cells, with hydrogen production then proceeding as above (Glatzmaier et al., 1998).

Solar power can also produce hydrogen through high-temperature steam electrolysis, where heat from concentrating solar systems first produces steam to reduce the electricity requirements for electrolysis, and then supplies the electricity required for electrolysis of the steam. One concept for this type of system would use a high-temperature electrolyzer similar in design and construction to a solid-oxide fuel cell, operating "in reverse" as an electrolyzer (Glatzmaier et al., 1998). A solar "power tower" used in conjunction with the electrolyzer would produce both heat to raise steam as well as AC power, which would then be converted to DC to operate the electrolyzer. Glatzmaier et al. (1998) estimate that this type of system could produce hydrogen for \$5.68 to \$6.25 per kg (\$40-44/GJ) assuming electrolyzer costs of \$500 per kW, and \$7.67 to \$11.42 per kg (\$54-79/GJ) assuming electrolyzer costs of \$2,000 per kW, depending on the current density at which the electrolyzer is operated.

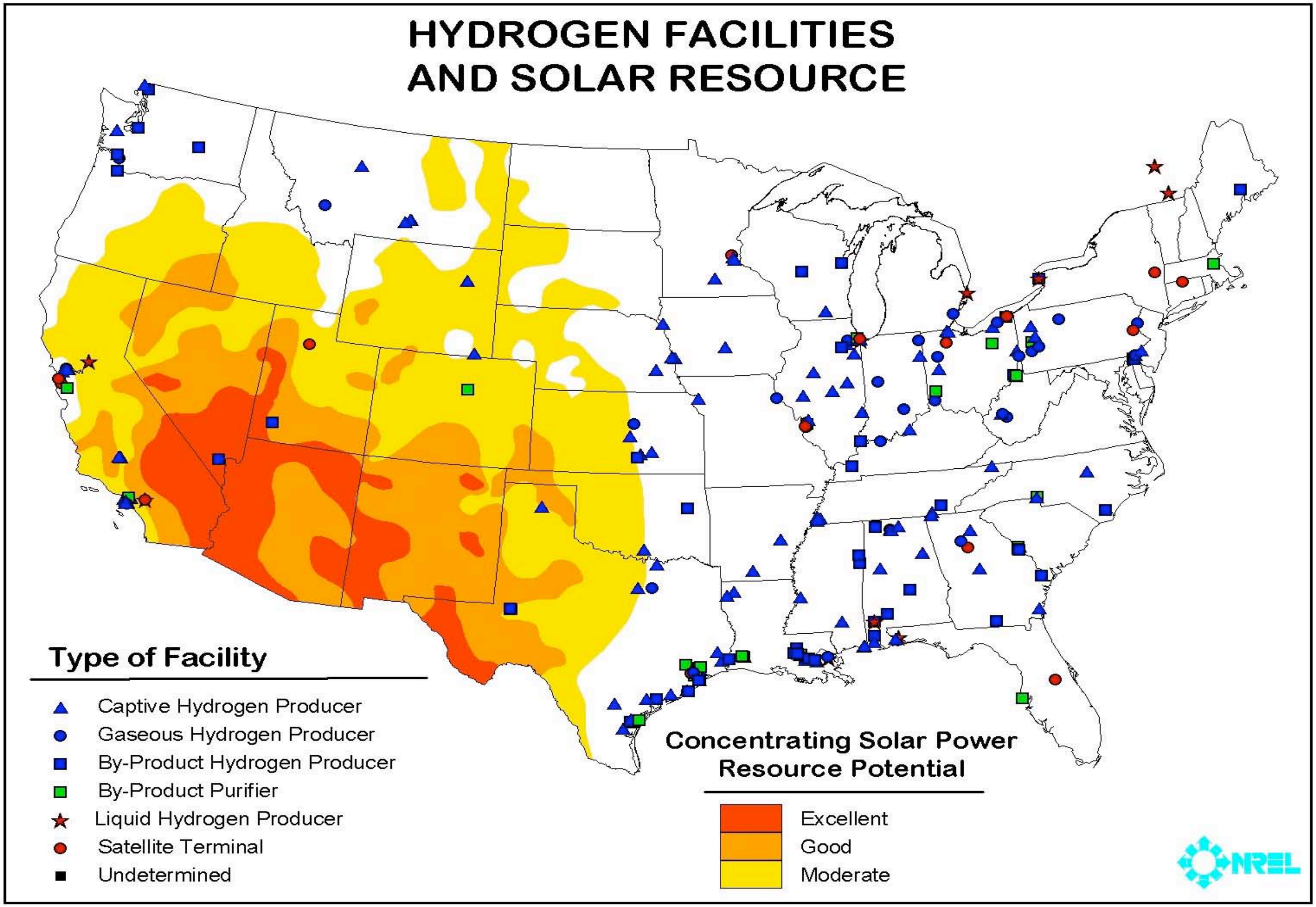
Mann et al. (1998) estimate that hydrogen can be produced from solar PV systems in a stand-alone configuration for \$17.60 per kg (\$124.00/GJ) near-term, and \$7.50 per kg (\$52.80/GJ) by the 2010 timeframe. With solar PV/hydrogen production systems coupled to the electrical grid, estimated costs are considerable lower because some of the electricity comes from the utility grid at lower cost. Such systems are estimated to potentially produce hydrogen for \$7.40 per kg (\$52.10/GJ) near term and \$4.50 per kg (\$37.10/GJ) circa 2010. These estimates assume solar power costs of \$3,133 per kW in 2000 and \$1,662 per kW in 2010, and PV plant capacity factors of 28% (near term) and 30% (in 2010).

Finally, the NRC estimates and projects hydrogen production costs from solar PV including estimates of \$28.19 per kg (\$198.81/GJ) for current technology and stand-alone production, \$6.18 per kg (\$43.58/GJ) for future technology and stand-alone production, \$9.71 per kg (\$68.48/GJ) for current technology and grid-tied production, and \$4.37 per kg (\$30.82/GJ) for future technology and grid-tied production. These estimates are for production scales of 2,400 kilograms of hydrogen per day for the stand-alone systems and 480 kilograms of hydrogen per day for the grid-tied systems (NRC, 2004).

Hydrogen From Solar Production Potential in the U.S

Solar hydrogen potential in the U.S. is more geographically constrained than either wind power or biomass, with the greatest resource in the southwest and additional resources in the west and Midwest (see Figure 3). Leading states for solar PV based hydrogen production potential include Texas (4.41 exajoules [EJ]/year), California (2.77 EJ/year), New Mexico (2.57 EJ/year), Arizona (2.41 EJ/year), Nevada (2.24 EJ/year), Montana (2.19 EJ/year), and Colorado (2.01 EJ/year), with the total estimated resource even larger than the wind power potential at 47.56 EJ/year (Ogden and Nitsch, 1993). Using Ogden and Nitsch's (1993) estimate of 4.8 EJ/year for a fleet of light-duty FCVs in the U.S., this solar hydrogen potential is approximately 10 times larger than that requirement.

Figure 3: Hydrogen From Concentrating Solar Power Availability Map of the U.S.



Hydrogen Production by Electrolysis from Hydropower

Hydrogen can also be produced from hydropower by generating electricity with turbines that operate along waterways. With low "off-peak" hydropower rates that can be as low as \$0.02-0.03 per kWh, hydrogen production from this source can be economical. Hydrogen production in this manner is an interesting alternative to "pumped storage," where each day water is pumped to higher elevation reservoirs "off peak" and then released "on peak" for delivery, particularly if there is a use for the hydrogen in the nearby area. However, it is important to note that for electricity markets in the U.S. there tends to be high demand for this inexpensive but constrained resource. Production of hydrogen would have to compete with other electricity uses to secure the hydropower supply.

Direct Hydrogen Production from Renewable Resources

In addition to being used to produce electricity for electrolysis, renewable resources can be used to produce hydrogen directly. This can be done through biomass conversion/gasification, and through other biological process. These methods are briefly discussed below, along with the potential biomass-to-hydrogen production potential in the U.S.

Hydrogen From Biomass Gasification

Hydrogen production from biomass is potentially attractive for several reasons. First, biomass is a near-term option for use of a renewable resource that can be produced in large quantities and indefinitely. The International Institute for Applied Systems Analysis (IIASA) estimates that biomass potentials are about 250 EJ on a global basis at present (about 3.5 EJ in the U.S.), with potential of over 350 EJ by 2050 (Mann and Overend, 2003). These values compare with the approximate global use of fossil fuels at present of about 300 EJ, and projected global non-electric fuel demand of about 286 EJ by 2025 and 289 EJ by 2050 (Ogden and Nitsch, 1993, based on Intergovernmental Panel on Climate Change scenarios). In other words, in terms of energy content, the near-term global biomass potential is roughly on par with global fossil fuel use at present, and could be expanded to be in excess of the total non-electric energy needs of the world in the 2025 to 2050 timeframe.

Estimates for the U.S. suggest that 7-8 EJ of biomass could be supplied by 2020, depending on the biomass price and with contributions from all of the primary sources -- energy crops and crop residues, and forest, animal, and urban residues (EIA, 2002; Mann and Overend, 2003). Second, since biomass growth removes CO_2 from the atmosphere, producing hydrogen from biomass fundamentally releases that CO_2 back into the atmosphere with no net additions -- depending on the use of fertilizer additions and other factors -- unlike fossil fuels burning or reforming that steadily adds CO_2 to the atmosphere. Third, unlike some renewable sources of hydrogen that are geographically constrained due to resource availability, biomass resources are relatively widely distributed both within the U.S. and globally. Fourth, biomass production can also produce valuable co-products, in addition to waste heat, such as adhesives, carbon black, activated carbon, polymers, fertilizers, ethanol, various acids, Fischer-Tropsch diesel fuel, waxes, and methanol (Mann and Overend, 2003). Exploiting these co-product values, as they are more fully explored and developed, is likely to improve the economics of hydrogen production from biomass.

Biomass conversion technologies can be divided into thermo-chemical and biochemical processes. Thermo-chemical processes tend to be less expensive because they can be operated at higher temperatures and therefore obtain higher reaction rates. They also can utilize a broad range of biomass types. In contrast, biochemical processes are limited to wet feedstock and sugar-based feedstocks. Milne et al. (2002) provide a state-of-the art assessment of these processes and of hydrogen from biomass technologies in general, and Spath et al. (2000) present a detailed analysis of the economics of hydrogen production from three leading types of thermo-chemical systems.

With regard to thermo-chemical hydrogen production systems, "producer gas" is the name given to the combustible gases that are produced from biomass. This producer gas consists of CO, CO_2, nitrogen (N_2), and hydrogen, and is about 10-15% of the heating value of natural gas (Larson, 1993). These producer gases are similar to the "synthesis gas" that is produced from coal for application in synthesizing chemicals and fuels. Hydrogen yields can be increased by subjecting producer gas to WGS reactions, and high purity hydrogen can be produced by adding a PSA step to the end of the production process.

The first common thermo-chemical option for hydrogen production from biomass is indirectly heated gasification coupled with steam reforming. These are then followed by WGS reaction, and a PSA step to produce pure hydrogen if desired. A second option is oxygen-blown gasification coupled with steam reforming, whereby pure oxygen is reacted rather than air. Finally, another option is pyrolysis coupled with steam reforming, along with co-product production (Mann, 2003). As with gasification/SMR, these processes can be coupled with PSA or other hydrogen purification steps to produce pure hydrogen, such as for vehicle refueling, or they could be used in conjunction with electricity production systems (such as some types of high-temperature fuel cells) that can operate directly on producer gas.

The production of hydrogen from biomass through the gasification processes begins with pre-processing, depending on the type of biomass, to dry and condense the biomass material prior to gasification. Then in the gasification step, in indirectly heated gasification hot sand circulates between the char combustor and gasification vessel, and provides heat for the endothermic gasification process. The gasification producer gas is then cooled (and pressurized if a PSA purification unit is to be used) and the processed in SMR and WGS units to provide high hydrogen yields (Spath et al., 2000). Overall thermal efficiencies of hydrogen production from these indirectly heated systems can be as high as 69% on an HHV basis (Larson, 1993).

One type of indirectly heated gasifier was developed by Battelle Columbus Laboratories, with the rights now owned by Future Energy Resources Corporation (FERCO). FERCO is now demonstrating the technology at a plant in Burlington, Vermont. In an economic analysis of this system type, Spath et al. (2000) estimate plant-gate hydrogen selling prices that range from \$1.12/kg (\$7.90/GJ) to \$1.19/kg (\$8.41/GJ) with no internal rate of return (i.e., production costs only) and from \$2.31/kg (\$16.28/GJ) to \$2.87/kg (\$20.18/GJ) with a 20% internal rate of return, depending on production scale (see Table A-1 for details).

The second type of gasifier is the oxygen-blown type, similar to the above but incorporating the use of an air-separation unit to produce relatively pure oxygen for use in the gasifier. These systems also differ in that the gasifier is fired directly rather than indirectly, and in that the gasifier is operated at much higher pressure. The thermal efficiency of hydrogen production is lower with this type of gasifier system than with the indirectly heated type, on the order of 57% on an HHV basis (Larson, 1993). With regard to production costs, again depending on production scale and internal rate of return, estimated hydrogen selling prices for these oxygen-blown gasifier systems can range from \$1.19/kg (\$8.40/GJ) to \$1.20/kg (\$8.48/GJ) with 0% internal rate of return and from \$2.67/kg (\$18.77/GJ) to \$3.52/kg (\$24.81/GJ) with a 20% internal rate of return (Spath et al, 2000).

The NRC has also estimated the current and potential future costs of hydrogen from oxygen-blown biomass gasification, at a medium production scale of 24,000 kilograms of hydrogen per day. These cost estimates are for \$4.63 per kg (\$32.65/GJ) for current technology and \$2.21 per kg (\$15.59/GJ) with future technology, with the produce CO_2 vented. If the CO_2 is captured and sequestered, the NRC estimates costs of \$5.08 per kg (\$35.83/GJ) for current technology and \$2.53 per kg (\$17.84/GJ) with future technology (NRC, 2004).

Hydrogen From Pyrolysis of Biomass

The third type of thermo-chemical hydrogen production from biomass is based on pyrolysis, which uses heat at temperatures of 400° to 800° C. in to volatilize organic solids to gases and liquids. Since biomass is typically 70-90% volatile matter, pyrolysis can be used effectively for biomass gasification (Larson, 1993). In one pyrolysis-based scheme, the biomass is first dried and then converted to an oil through "fast pyrolysis" where a fluidized bed reactor is used to convert the heated biomass particles into bio-oils, gases, and char. The char and gases are combusted to supply heat, and the bio-oils are cooled, condensed, and then converted to hydrogen through SMR and WGS processes. This process also produces a phenol co-product that can be used in the manufacture of phenol formaldehyde resins that are used as wood adhesives. Overall thermal efficiency of biomass-to-hydrogen production is estimated at 47.9% for this type of pyrolysis system, on an HHV basis (Iwasaki, 2003).

Including credit for the phenol co-product, estimated hydrogen costs from this type of pyrolysis system are relatively low, and range from \$0.75 to \$0.93 per kg (\$5.30/GJ to \$6.57/GJ) with 0% internal rate of return, to from \$1.39 to \$1.62 per kg (\$9.79/GJ to \$11.41/GJ) with a 15% internal rate of return (Spath et al, 2000). By another estimate, hydrogen can be produced from biomass via pyrolysis for \$1.09 per kg (\$7.70/GJ), assuming that the phenol co-product is sold for \$0.44 per kg (French et al., 2000).

Hydrogen From Biological Gasification

Other than these thermo-chemical processes, the other primary type of biomass conversion system is biological gasification, or anaerobic digestion, of wet feedstocks using fermentative bacteria. This process produces "biogas", consisting of methane and CO_2. The biogas stream can then be converted to a hydrogen-rich gas stream through SMR and WGS processes, as in the above cases. Besides the production of fuel gases, biomass digesters also yield co-product effluents that can be used in fertilizers (Larson, 1993).

Hydrogen From Agricultural and Livestock Residues

As well as dedicated energy crops, hydrogen can be produced from both agricultural residues and manure from livestock. These are both relatively economic sources, with delivered hydrogen costs as low as $2.30 per kg ($16.32 per GJ) for production from manure and $2.65 per kg ($18.80 per GJ) for production from agricultural residues, by one set of estimates (Meyers et al., 2003).

Biomass and High Temperature Fuel Cells

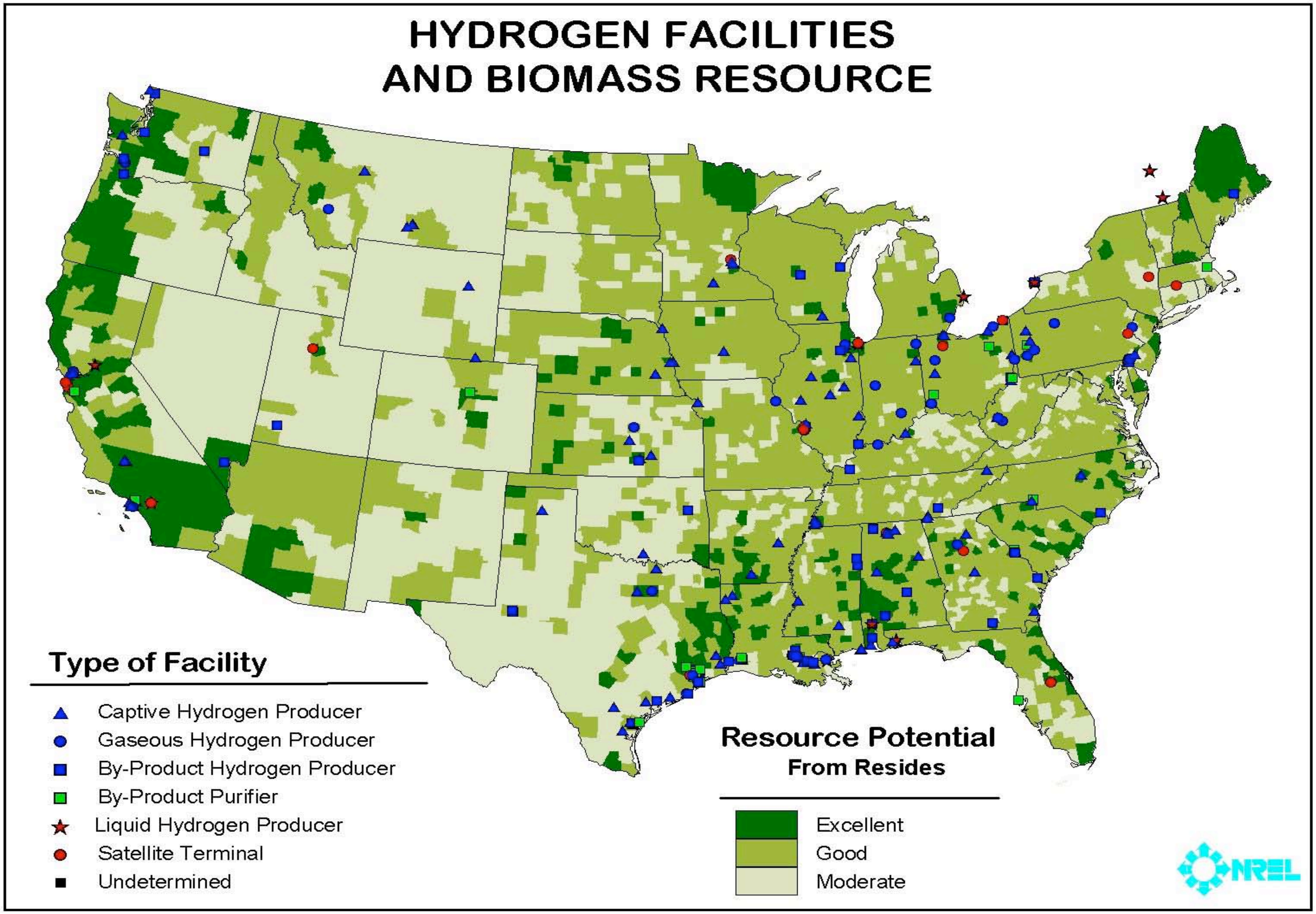
Finally, one interesting type of biomass-based system for electricity production from hydrogen would combine a biomass gasifier, a molten-carbonate fuel cell (a high-temperature fuel cell type with similar thermal characteristics to the gasifier), and a turbine-based bottoming cycle. These integrated biomass gasification fuel cell (IBGFC) systems would produce electricity from biomass residues with overall projected efficiency levels of 55%, or higher in the overall thermal efficiency sense if used in conjunction with waste heat recovery. These systems would not produce pure hydrogen at any stage, but would use hydrogen-rich gas from the biomass gasifier to operate the high-temperature fuel cell. Applications of this technology include converting sugar cane bagasse to electricity with efficiencies of 44 to 47% (lower heating value [LHV] basis), with the potential for readily increasing this to 53% efficiency assuming a biofuel containing 15% moisture (Knight et al., 1998).

Hydrogen From Biomass Production Potential in the U.S.

Hydrogen can be produced from biomass residues in most areas of the U.S. (see Figure 4), and additional hydrogen production possible from dedicated energy crops. Forecasts for potential hydrogen production from biomass in the U.S. have been made out to 2020, and other forecasts have been made for global production as far out as 2050. The 2020 U.S. potential has been estimated at 28.8 billion kg per year (4.1 EJ/year) of hydrogen from 7 EJ of biomass energy, by one analysis that assumes a 50% energy conversion ratio on an LHV basis (Mann and Overend, 2003). Another, nearer-term analysis suggests the potential for production of 19.4 billion kg per year (2.76 EJ/year) of hydrogen from biomass energy crops in the U.S., with the greatest potential resources in Texas, North Dakota, Kansas, Montana, South Dakota, Iowa, and Colorado (Ogden and Nitsch, 1993).

The amount of biomass that can be supplied depends on the price of the biomass fuel, as higher prices allow more of the resource to be economically harvested or recovered. The U.S. DOE's Energy Information Agency (EIA) estimates that the 7 EJ of biomass by 2020 suggested above would correspond to a field-edge biomass price of about $3 per GJ, with up to 7.5 EJ possible at prices of $4 per GJ and only small increases possible at higher prices (EIA, 2002). This includes urban and mill residues, energy crops, forest residues, and agricultural residues. In comparison, a field-edge biomass price of $2 per GJ would yield about 3 EJ of biomass supply, or less than half of the supply at $3 per GJ (EIA, 2002).

Figure 4: Hydrogen From Biomass Residues Availability Map of the U.S.



Solar Thermal Processes

In addition to production via either ambient temperature or high temperature electrolysis, hydrogen can be produced from solar power by using concentrated solar energy to super-heat steam to temperatures of over 2000 Kelvin (1727° C.) where it thermally dissociates into hydrogen and oxygen. The production of hydrogen in this manner is favored at higher temperatures, with greater amounts of hydrogen produced as temperatures increase toward 3000 Kelvin (2727° C.) and at lower pressures (Glatzmaier et al., 1998). Thus, in the absence of materials and operating constraints and overall energy balance considerations, solar thermal hydrogen production should be conducted at high temperature and low pressure levels. In order to make the process somewhat more efficient, the enthalpy of the separated hydrogen and oxygen high temperature can be recovered with a heat exchanger to raise the temperature of incoming water, thereby reducing the requirements for providing heat from the solar thermal system (such as a solar power tower).

Glatzmaier et al. (1998) describe general designs of solar thermal systems for hydrogen production, but they do not quantitatively analyze such systems because of their early stage of development and lack of knowledge of the potential materials and methods for producing hydrogen in this manner. Ogden and Nitsch (1993) do provide estimates of hydrogen production from solar thermal systems, assuming production in the Southwestern U.S. They estimate that hydrogen could be produced in the future ("post 2000") with solar thermal systems at costs of \$2.56 to \$3.55 per kg (\$18-25/GJ) assuming a 6% discount rate, and \$3.83 to \$5.11 per kg (\$27-36/GJ) assuming a 12% discount rate.

Hydrogen Production from Other Renewable Sources

Hydrogen can be produced from municipal solid wastes (MSW) and landfill gases. Capital costs for these systems are typically higher than for biomass plants due to the additional processing requirements for this type of feedstock, but due to no or even negative feedstock costs (i.e., avoided disposal costs) levelized lifecycle costs for MSW plants could be comparable to those of other biomass-based hydrogen production facilities (Williams, 2002). Meyers et al. (2003) estimate that delivered hydrogen can be produced from MSW and landfill gases for about \$2.50 per kilogram across much of the U.S.

Landfill gas in particular has been successfully utilized to produce electricity with stationary hydrogen fuel cells in several of the landfill gas recovery sites in the U.S. Phosphoric acid fuel cells have been the most used fuel cell technology to-date in these settings, but solid oxide and molten carbonate fuel cells show greater promise for use with landfill gas because they are more tolerant of impurities and would integrate better with land fill gas reformer technologies (Xenergy, 2002).

Finally, hydrogen can also be produced through natural biological processes by eukaryotic green algae. The algae species *Chlamydomonas reinhardtii* produces molecular hydrogen, particularly when the algae is deprived of inorganic sulfur and saturated with light, and when oxygen evolution from photosynthesis is separated from hydrogen production (Melis et al., 2000). In recent research, novel methods have been developed to regulate this hydrogen production process from green algae (Melis et al., 2000). This research is noteworthy because it shows that there are practical methods for producing hydrogen from algae continuously for several days, rather than in the trace amounts for short periods that had been previously detected.

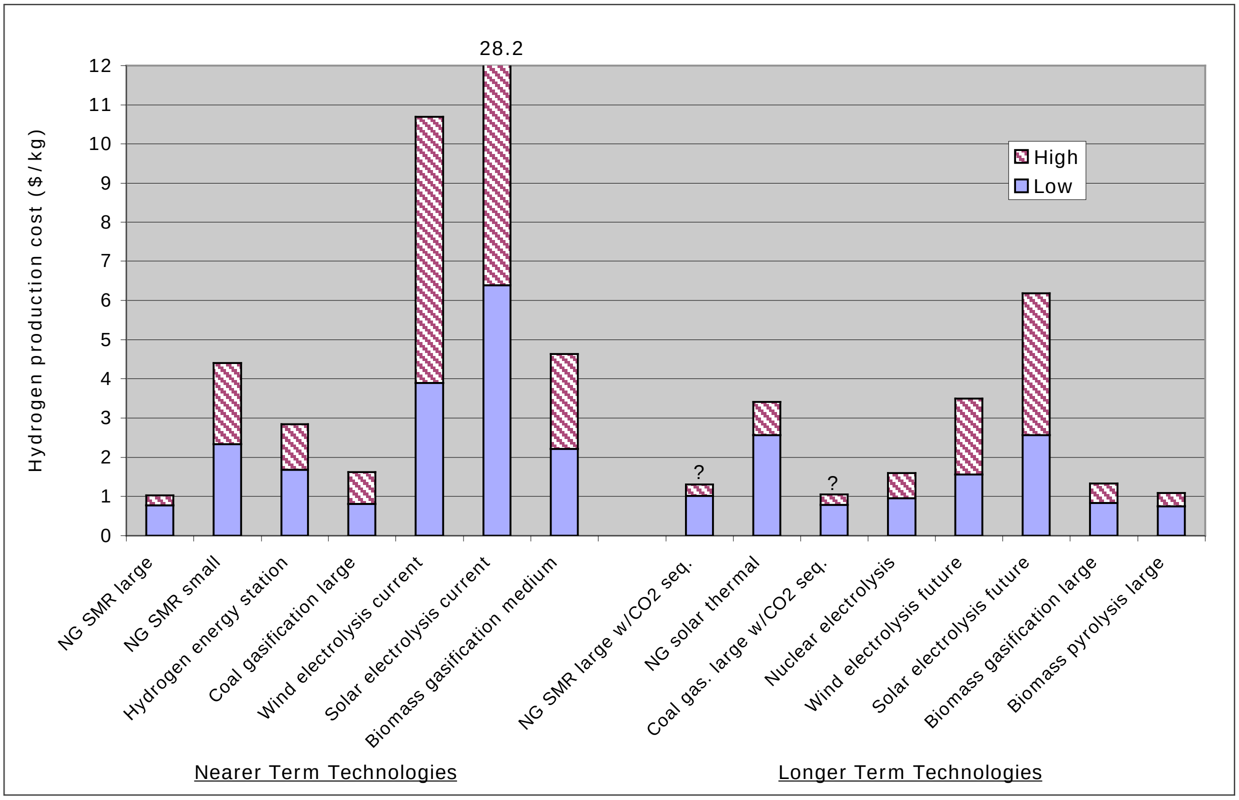
Melis et al. (2000) have demonstrated hydrogen production levels of 140 milliliters of hydrogen per liter of algae culture, over an 80-hour period, and they believe that significant increases in this production rate are possible with continued research. Commercial systems for producing hydrogen in this way have not yet been developed, but DOE has established development goals for algal hydrogen production at $16 per kg ($113/GJ) in the mid-term, with a longer-term "continuous" system target of $1.30 to $2.30 per kg ($9.15-16.20/GJ) (Padro, 2002).

Summary of Hydrogen Production Costs from Various Methods

Hydrogen can be produced from a wide range of sources, with onsite production costs as low as $0.75-1.00 per kg ($5.28-7.04/GJ) from sources such as large-scale natural gas reformation, biomass gasification, and coal gasification. Other methods such as wind and nuclear electrolysis can produce hydrogen for costs that may be competitive in some settings, and solar electrolysis costs continue to decline but are still relatively high, on the order of $6.50 to $25.80 per kg ($46-182/GJ) depending on a variety of factors such as the solar resource and the interest rate applied to the project. See the following section for a further discussion of hydrogen costs, including delivered hydrogen cost estimates that include the costs of distribution to points of end use.

Figure 5, below, presents a summary of onsite hydrogen production costs. Table A-1 in the Appendix presents the cost estimates from which this chart is derived, including further details with regard to the assumptions behind each estimate. Note that this figure presents onsite production costs only. See Figures 6 and 7 and Table A-2 for delivered hydrogen cost estimates.

Figure 5: Ranges in Onsite Hydrogen Production Cost Estimates



Note: Various sources – see Table A-1 for details.

NG = natural gas; SMR = steam methane reforming; "?" = Costs of effective carbon sequestration from fossil fuels are uncertain because sequestration technologies and methods are still in the R&D phase.

III. Hydrogen Distribution and Supply Systems

The technologies for distributing and supplying hydrogen for various uses are generally well known and established, with the exception of very high-pressure (10,000 pounds per square inch [psi]) hydrogen storage and dispensing systems and other innovative hydrogen storage systems. These very high-pressure systems are currently in the research and development stage, and offer high storage densities but at slightly higher compression energy losses. On the other hand, lower pressure compressed-gas storage systems for hydrogen of 3,600-5,000 psi are well proven and are currently being used in many prototype FCVs around the globe.

Hydrogen distribution and supply systems can be classified as being associated with "centralized" production, with significant needs for distribution, and "decentralized" production with much lower or no needs for distribution but potentially significant requirements for storage (depending on the relationship between the operation of the production system and end-use requirements). The various hydrogen production methods discussed in the previous section thus imply some differences with regard to hydrogen delivery, particularly with regard to the scale and distribution of production, along with the relative purity of the hydrogen produced. Further, these systems can be distinguished by their potential for near-term deployment, versus being longer-term options.

With regard to near-term options for hydrogen distribution, centralized production systems can be coupled with either truck delivery by liquid or high pressure gas "tube trailers," pipeline delivery, or for hydrogen-powered vehicles in particular, refillable hydrogen "trailers" that can be filled with compressed gas onsite and then placed at off-site locations until refilling is required. For on-site production from SMR and electrolysis, or in the case of chemical plant by-product hydrogen, hydrogen can simply be used as it is produced, or compressed, stored, and dispensed for refueling hydrogen-powered vehicles and/or producing electricity with stationary or automotive fuel cell systems.[2]

Longer-term options for hydrogen distribution and supply include the above possibilities along with more futuristic concepts. These include supplying hydrogen as a component of superconductive electricity delivery, using hydrogen as the cooling fluid for the superconductivity as well as a distributed fuel (Gehl and Rastler, 2001), as well as systems associated with hydrogen production with carbon sequestration and large-scale renewable power systems. In the case of large-scale hydrogen production through electrolysis (with either renewable or nuclear power), either the hydrogen or the electricity could be transported to the point of end use. In the latter case, electricity would be transmitted to the point of end-use, particularly during "off-peak" periods when electrical transmission systems are unconstrained, where electrolyzers would then produce hydrogen for local uses.

Delivered Hydrogen Cost Estimates

Several studies of delivered hydrogen costs have been conducted. The discussion below focuses on the most recent and comprehensive of these, and the results of some additional analyses are reported in Table A-2. In general, these studies are difficult to compare in "apple to apple" terms because of the many assumptions that go in to each study, and therefore the ranges of estimates discussed here and shown in Figure 7 and Table A-2 are simply reported "as is." In other words, as with the production cost estimates discussed above, no attempt has been made to correct the studies for differing assumptions to make them more directly comparable.

In one recent and comprehensive study, Simbeck and Chang (2002) of SFA Pacific, Inc. have performed a detailed economic analysis of different hydrogen production and distribution systems, with a particular focus on near-term options. Included are various options for both central plant and distributed production of hydrogen, including natural gas, petroleum coke, coal, biomass, grid power electrolysis, and other renewable feedstocks, and liquid hydrogen, pipeline, tube trailer, and decentralized distribution.

They conclude that for large-scale options (on the order of 150,000 kg per day), natural gas based production at can produce delivered hydrogen for \$3.66 to \$5.00 per kg (\$25.77 to \$35.21/GJ), petroleum coke based production coupled with pipeline delivery can produce delivered hydrogen costing \$5.35 per kg (\$37.68/GJ), coal-based production can produce delivered hydrogen for \$4.51 to \$5.62 per kg (\$31.76/GJ to \$39.58/GJ), biomass-based

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[2] This latter possibility has come to be known as "vehicle-to-grid" or V2G power. See Kempton and Letendre, (1997); Kempton et al. (2002); and Lipman et al. (2004) for details with regard to various possibilities for different types of electric-drive vehicles.

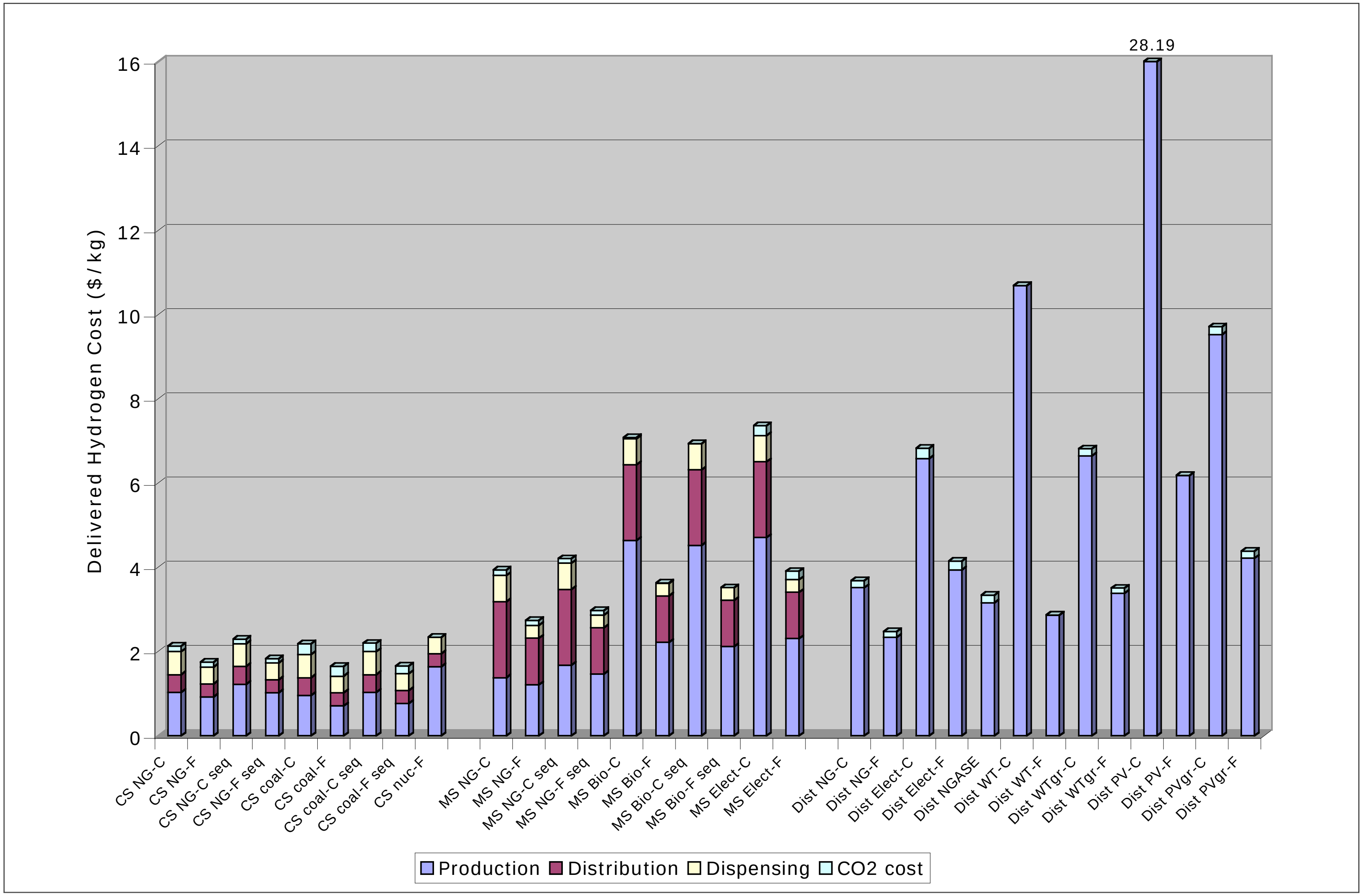
production can produce delivered hydrogen for \$4.98 to \$6.29 per kg (\$35.07/GJ to \$44.30/GJ), and large-scale electrolysis with commercial grid power can produce hydrogen for \$7.62 to \$9.13 per kg (\$53.66-64.30/GJ). For smaller-scale, distributed options (on the order of 500 kg of hydrogen produced per day), estimated delivered costs of hydrogen are \$4.40 per kg (\$30.99/GJ) for natural gas SMR, and \$12.12 per kg (\$85.35/GJ) for water electrolysis (using grid power at \$0.07/kWh).

In general, Simbeck and Chang (2002) find that for the centralized options at the scale examined, the costs of hydrogen delivery are lowest for liquid hydrogen distribution by tanker truck, followed by tube trailer delivery, followed by delivery by pipeline. With regard to centralized versus decentralized production of hydrogen from natural gas, decentralized production is found to be competitive to the centralized options, with costs identical to tube trailer delivery, and somewhat more than liquid hydrogen delivery by tanker truck and somewhat less than pipeline delivery.

With regard to additional recent studies of delivered hydrogen costs from natural gas, Ogden (1999) estimates that the delivered cost of pure hydrogen as a transportation fuel are about the same for onsite “advanced” SMR and centralized SMR with “high density” pipeline delivery, assuming relatively large-scale dispensing of 2,400 kg per day (1 million scf/day). In these cases, delivered hydrogen costs of about \$1.70 per kg (\$12/GJ) are estimated, versus about \$2.13 per kg (\$15/GJ) for SMR production with “low density” pipeline delivery, about \$2.70 per kg (\$19/GJ) for centralized SMR and liquid hydrogen delivery by truck, and about \$3.55 per kg (\$25/GJ) with onsite hydrogen production from advanced electrolysis (Ogden, 1999).

Based on the hydrogen production model developed by SFA Pacific, the NRC has recently estimated the total delivered costs of hydrogen from various production methods. These are based on the production costs discussed above and in Table A-1, and assume that large central station production options are coupled with pipeline delivery and that medium-scale production options are coupled with liquid hydrogen delivery by tanker truck. See Figure 6 below for a graphical depiction of these NRC cost estimates, including breakdown of costs by production, delivery, and dispensing to FCVs, as well as approximate carbon-related costs (e.g., a \$50 per ton carbon tax and/or carbon separation and sequestration costs of \$10 per ton of carbon).

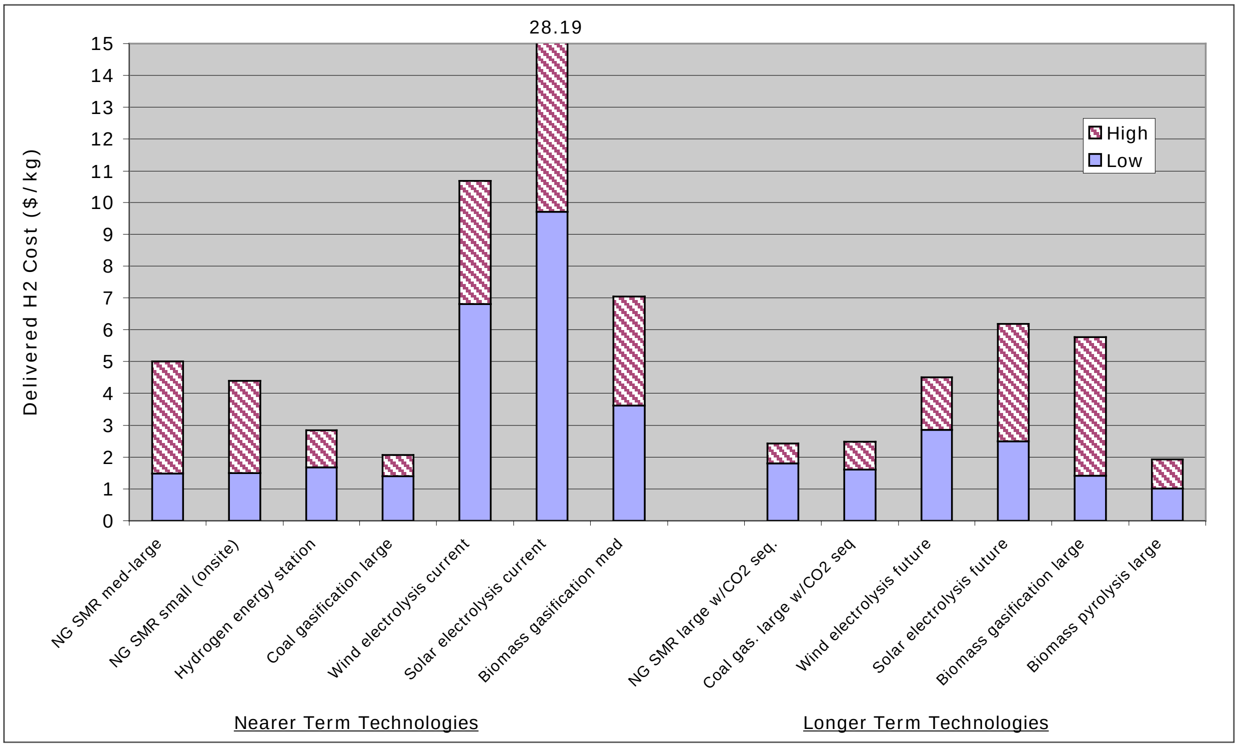
Figure 6: One "Internally Consistent" Set of Delivered Hydrogen Cost Estimates



Source: NRC, 2004. Notes: Bio = biomass gasification; C = current technology; CS = large central station; Dist = distributed production at small scale; Elect = grid-power electrolysis; F = future technology; gr = grid assisted electrolysis; MS = medium-scale; NG = natural gas SMR; PV = solar photovoltaic powered electrolysis; seq = with carbon sequestration; WT = wind turbine powered electrolysis. CO_2 cost = carbon disposal cost and/or carbon tax of $50 per ton.

Figure 7 presents ranges of production plus delivery and dispensing costs from the technical literature. Note that the ranges in the delivered cost estimates are somewhat narrower than the ranges in the production-only estimates shown in Figure 5, above, primarily because fewer delivered hydrogen cost studies have been presented in the public domain. Finally, see Table A-2 for more details of these and other delivered hydrogen cost estimates.

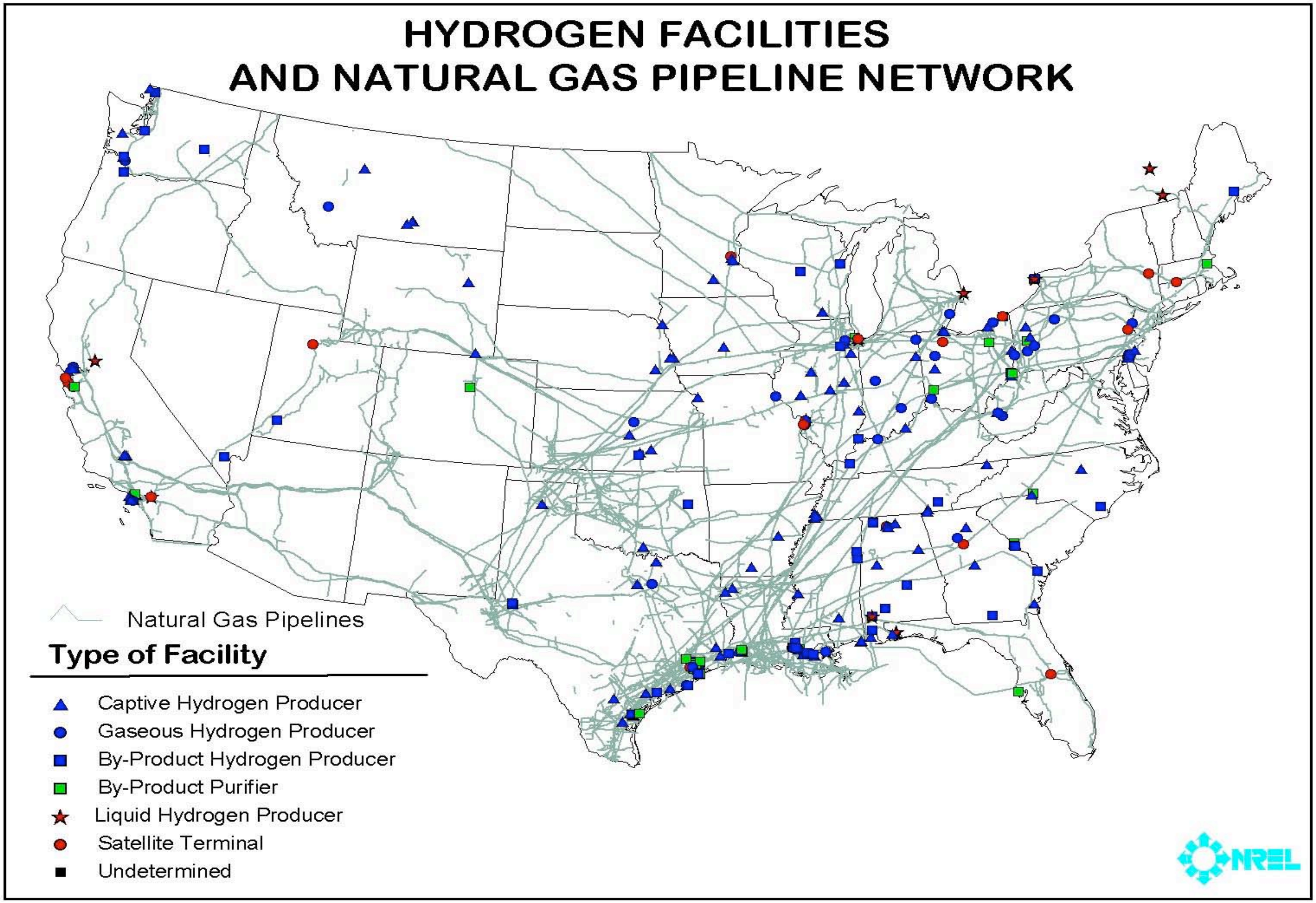
Figure 7: Ranges in Delivered Hydrogen Cost Estimates



Notes: Various sources - see Appendix for details. The ranges shown are taken from many different sources, including those with assumptions that may be somewhat inconsistent with regard to production scale, interest rates, etc. Wider and narrower ranges between high and low costs thus tend to reflect the relative numbers of studies for each pathway, rather than inherent uncertainties in costs for each pathway.

Figure 8, below, presents a map of the existing hydrogen production facilities in the U.S., along with the major natural gas pipelines in the country. Most of the current hydrogen production facilities in the U.S. are in the Midwest and Gulf Coast regions.

Figure 8: Current Hydrogen Production Facilities in the U.S.



IV. Hydrogen from Hydrocarbons and Carbon Sequestration

Hydrocarbon sources of hydrogen are attractive due to their relatively low costs. However, since one potential "selling point" of hydrogen is the potential for low environmental impacts, the GHG emissions from these sources are an important concern. One potential solution is to produce hydrogen from hydrocarbons at large, centralized sites and to "sequester" the CO_2 emissions in some way to prevent these emissions from reaching the atmosphere.

CO_2 emissions can be sequestered in a variety of different ways. These include terrestrial, microbial, underground, and oceanic storage solutions. Terrestrial and microbial solutions include enhancing photosynthesis and other processes in biological systems as a means of increasing CO_2 uptake from the atmosphere. Underground storage in geologic formations includes the prospects of storing carbon in mined coal beds and salt domes, deep aquifers, and depleted oil and gas reservoirs, and as mineral carbonates or bicarbonates. Oceanic storage techniques include pipeline "droplet plumes," pipelines towed by ships, dry ice-based transfer schemes, and deep-water platform pumping stations with underwater CO_2 "lakes."

These systems all have varying associated issues and potential costs, with costs in particular being uncertain at this time. Cost predictions of $30 per ton of CO_2 in the long term have been estimated (equivalent for reference purposed to an additional $13 per barrel of oil or $0.25 per gallon of gasoline), but sequestration costs would be higher in the near term (Lackner, 2003).

With regard to underground storage options, coal beds offer potentially low cost carbon storage but the technologies for doing this are immature. Salt domes are also potentially attractive storage sites, but use of these structures would entail relatively high costs. Deep saline aquifers offer large potential storage capacity, but uncertain storage integrity, while depleted oil and gas reservoirs are expected to provide greater storage integrity but are of limited capacity. The neutralization of carbonic acid to form carbonates and bicarbonates is another option, and one with an expected high degree of safety but also relatively high costs (Lackner, 2003).

The oceanic storage options are mainly classified by the method of carbon dioxide insertion, along with the potential for carbon dioxide mixing in the ocean or the prospect of creating deep ocean carbon dioxide "lakes" where the CO_2 would pool at the bottom of the ocean. The droplet plume option would have CO_2 delivered into the ocean at the end of a land-based pipeline, at depths of perhaps 1,000-2,000 meters. This would have uncertain effects on oceanic ecosystems, and would also result in some leakage back to the atmosphere. Pipelines towed by ships could inject CO_2 at similar depths and with similar potential drawbacks. Meanwhile, dry ice deposition of CO_2 would rely on simple technology, but entails relatively high costs and uncertain environmental impacts and leakage concerns. Finally, using deep-water pumping stations to inject CO_2 to depths of 3,000 meters or greater would create deep-ocean CO_2 "lakes." These lakes would likely separate the CO_2 from the atmosphere for thousands of years, but the technology for sequestering carbon with this method is at an immature stage.

Finally, carbon/GHG emission sequestration strategies have thus far focused on CO_2, but other GHG emissions associated with hydrogen production are of concern as well. Emissions of CH_4 and other GHGs associated with hydrogen production from fossil fuels could potentially also be mitigated but -- since these options have been less studied -- with even less pathway and cost certainty than for carbon dioxide.

V. Environmental Impacts of Hydrogen Production Methods

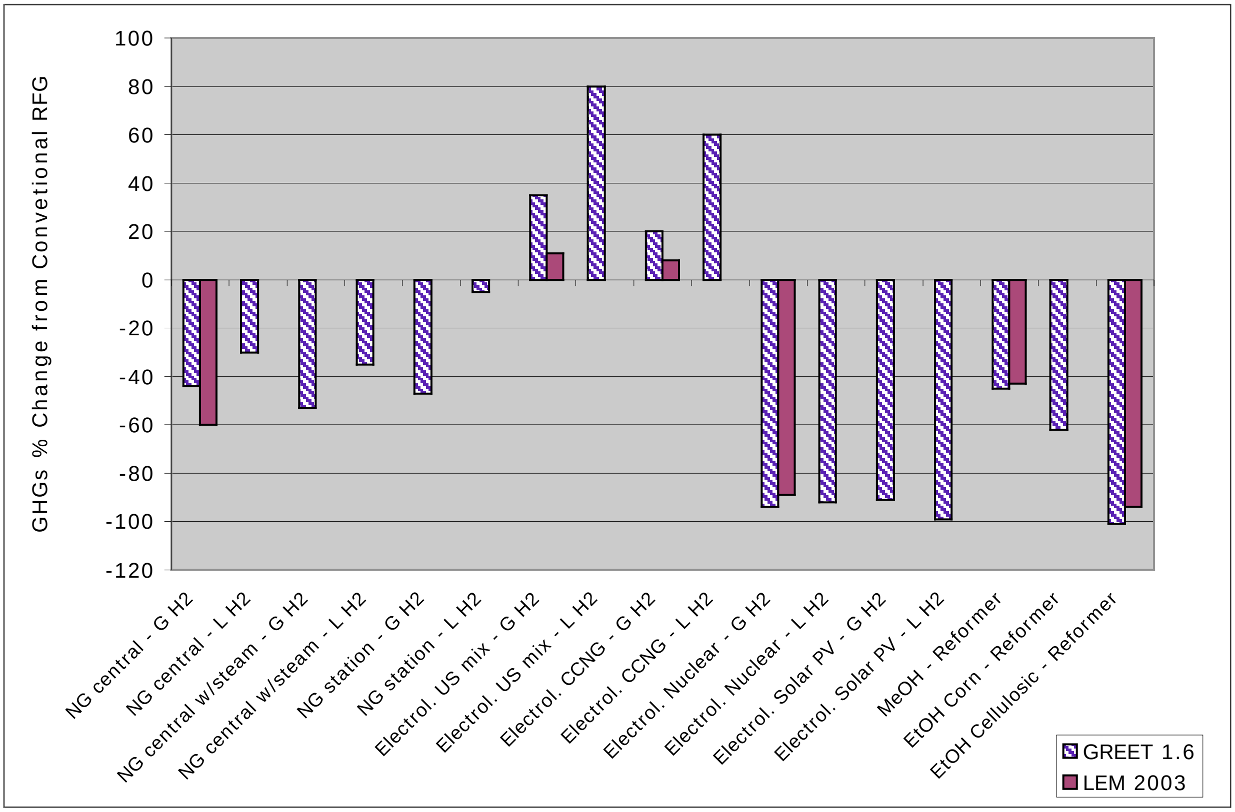
Additional important considerations for potential hydrogen production methods other than costs and feedstock requirements include the environmental implications of various hydrogen production methods. These include GHG emissions, local pollutant emissions, soil and water emissions, and land, water, and other non-feedstock resource requirements.

Greenhouse Gas Emissions Estimates from Hydrogen Fuel Pathways

Various hydrogen production strategies have dramatically differing implications with regard to the greenhouse gas emissions implications of end-use, as shown in Figure 9 below. The results reported in the figure compare the results of two well-known GHG analysis models, for various hydrogen production and distribution pathways. These models include the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) Model developed by Argonne National Lab (ANL, 2001), and the Lifecycle Emission Model (LEM) developed at UC Davis (Delucchi, 2003). The results shown are CO_2-equivalent emissions of several combined GHGs, for hydrogen used to fuel FCVs in comparison with using reformulated gasoline (RFG) in conventional vehicles.

These results show that the GHG emissions implications of hydrogen production and use in vehicles can vary enormously relative to the emissions from the use of gasoline in conventional vehicles. Depending on the hydrogen production and distribution pathway, emissions can be as high as 80% of the level of emissions from conventional vehicles (using the U.S. average grid power mix to produce liquid hydrogen via electrolysis), and as low as 0% with biomass and some other renewable pathways. If one goal of the use of hydrogen is to reduce GHG emissions, then the method of hydrogen production and distribution chosen is clearly critical to achieving that goal.

Figure 9: Greenhouse Gas Emissions from Hydrogen Fuel Cell Vehicle Refueling Pathways



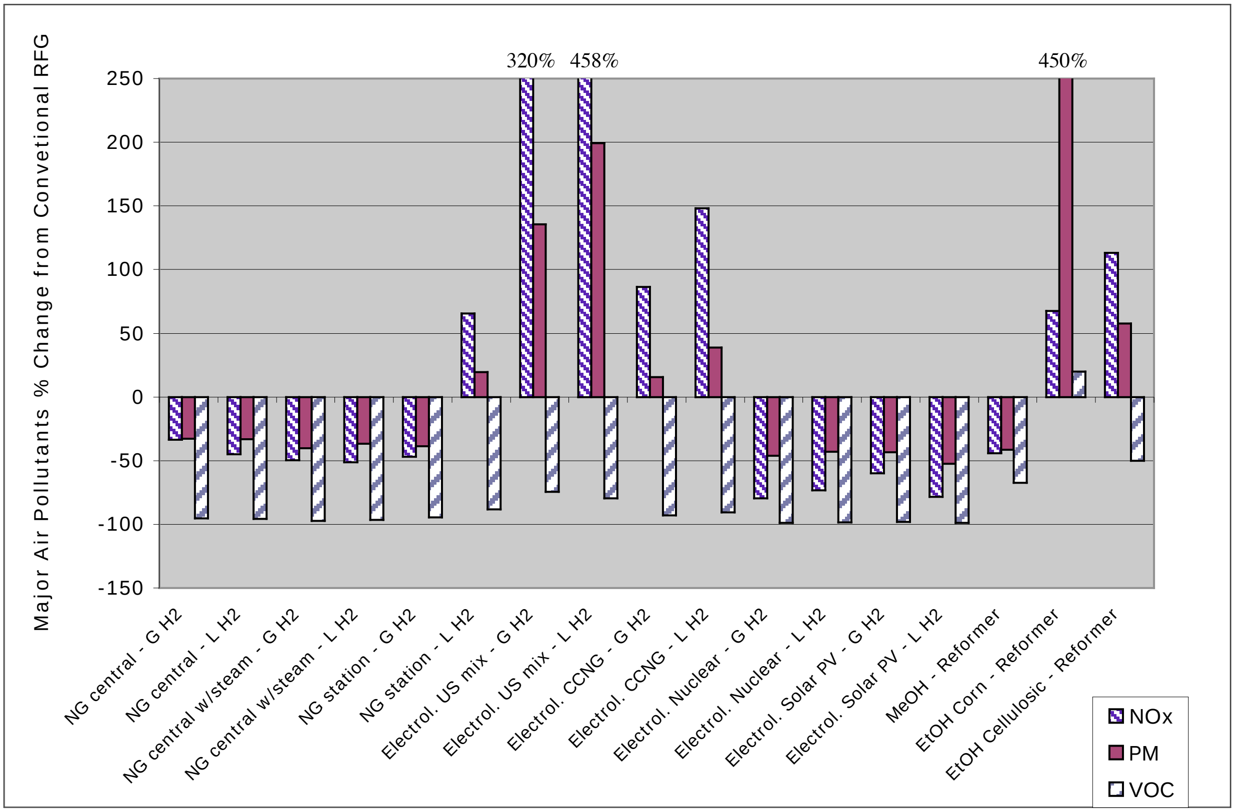
Notes: GREET 1.6 is the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model. LEM 2003 is the Lifecycle Emission Model. CCNG = combined cycle natural gas power plant; EtOH = ethanol; G = gaseous; L = liquid; NG = natural gas; MeOH = methanol; PV = photovoltaics; RFG = reformulated gasoline.

Air Pollutant Emissions and Soil and Water Impacts from Hydrogen Fuel Pathways

Air pollutant emissions and soil and water impacts of hydrogen production and distribution pathways also can vary widely for various methods, and unlike GHG emissions have important local and regional environmental quality implications. These impacts have generally been studied in less detail than potential GHG emissions, particularly with regard to soil and water impacts. The social and environmental welfare impacts of air pollutant emissions also vary in part depending on population exposure levels, adding even more uncertainty with regard to these potential impacts.

Figure 10, below, presents an analysis of major air pollutant emissions from the same hydrogen production and distribution pathways shown in Figure 9. Shown are total pollutant emissions of oxides of nitrogen (NOx), fine particulate matter less than 10 microns in diameter (PM), and volatile organic compounds (VOC) from the full fuel cycle for each pathway. As shown in the figure, the relative air pollutant emissions from transportation uses of hydrogen also vary widely depending on the hydrogen production pathway, with most pathways producing significant reductions but some – particularly electrolyzer pathways coupled with either average grid mix or combined cycle natural gas plants – producing significant increases in NOx and PM emissions. See ANL (2001) for more details of these estimates, disaggregation of results by "in basin" and "out of basin" emissions, and additional results for emissions of CO and oxides of sulfur. Additional air pollutant emissions analyses from hydrogen pathways include those conducted by Delucchi (2003) and Contadini (2002).

Figure 10: Air Pollutant Emissions from Hydrogen Fuel Cell Vehicle Refueling Pathways



Source: GREET Model v1.6 (ANL, 2001). CCNG = combined cycle natural gas power plant; EtOH = ethanol; G = gaseous; L = liquid; NG = natural gas; MeOH = methanol; PV = photovoltaics; RFG = reformulated gasoline.

With regard to land and water resource requirements, Ogden and Nitsch (1993) have estimated land and water resource requirements for renewable hydrogen production options and found that resource requirements for wind, solar PV, solar thermal electric, biomass, and hydroelectric based production are relatively well-defined, except for significant uncertainties in land requirements for wind and hydroelectric power. In general, hydroelectric and wind power require the largest amounts of land, and hydroelectric Table 4, below, presents the results of the Ogden and Nitsch analysis.

Table 4: Land and Water Requirements for Renewable Hydrogen Production Methods

	Land Requirements (m^2/GJ/yr)	**Water Requirements** (liters/GJ HHV)
Electrolytic Production		
Solar PV	1.89	63
Solar thermal electric	5.71	63
Wind	6.3-33	63
Hydroelectric	11-500	>63
Biomass Production	50	37,000-74,000

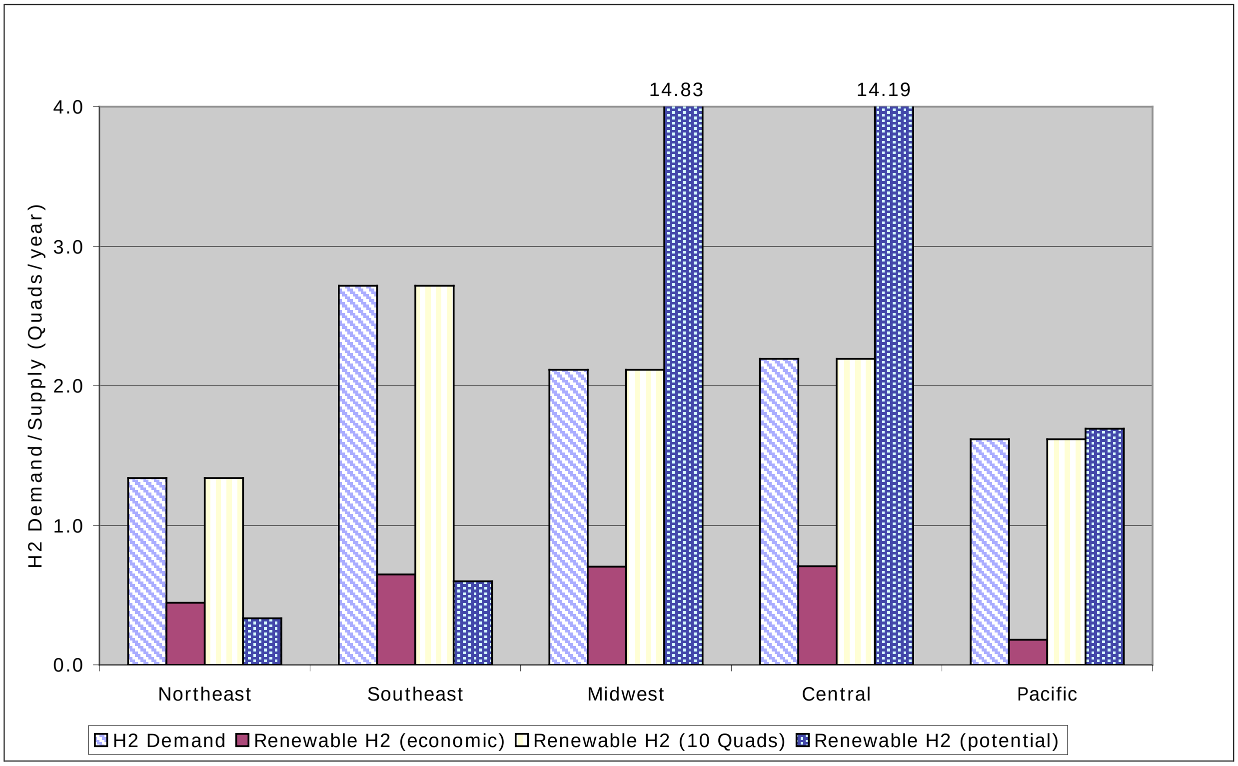
Notes: HHV = higher heating value; GJ = gigajoules; m^2 = square meters; PV = photovoltaic; yr = year.
Source: Ogden and Nitsch, 1993

VI. Renewable Hydrogen Potential and Regional Production Strategies

The overall technical potential for producing hydrogen from renewable sources in the U.S. is great, with approximately 32 quadrillion British thermal units (Quads) per year of renewable hydrogen production possible in the 2030-2050 timeframe according to one recent estimate (Meyers et al., 2003). This is an enormous quantity of potential energy production, equal to 33.6 EJ per year, and this compares with current total transportation sector petroleum consumption in the U.S. of about 27 Quads per year (Davis and Diegel, 2003). However, much of this renewable hydrogen production potential is based on wind and solar resources that are unlikely to become economically competitive with other sources, even during this extended timeframe. As discussed above, more economical sources of renewable hydrogen include dedicated energy crops, MSW, agricultural and livestock residues, and certain wind resources that are located close enough to demand centers to be relatively attractive.

Figure 11 presents a hypothetical regional demand and supply picture for renewable hydrogen for the year 2040. This scenario assumes that hydrogen demand in the U.S. reaches 10 Quads (10.5 EJ) by this time, and that the demand in each U.S. state is proportional to current gasoline consumption (first set of bars). The figure shows three potential levels of renewables-based hydrogen supply. The second set of bars – “Renewable H2 (economic)” -- shows the amount of hydrogen that could be dispensed to consumers at a cost of $3.00 per kg or less ($21.30 per GJ and $1.50 per gallon of gasoline equivalent on a per-mile basis in 2x efficiency hydrogen vehicles). Some hydrogen in the Northeast and Southeast is supplied from other nearby regions in this scenario. The third set of bars shows the total hydrogen demand in each region, totaling 10 Quads, being met by renewable sources. If all of this hydrogen demand were supplied by hydrogen from renewables, the average nationwide cost of that hydrogen is estimated to be about $4.00 per kg ($28.40 per GJ) in this future scenario. This scenario implies considerable transport of hydrogen from states in the Midwest and Central that are closest to the Northeast, Southeast, and Pacific regions. The fourth set of bars – “Renewable H2 (potential)” – shows the total technical potential of nearly 32 Quads of production, with much of this potential in the Midwest and Central regions (Meyers et al., 2003).

Figure 11: Hypothetical Year 2040 Regional U.S. Hydrogen Demand of 10 Quads Per Year and Renewable Production Potential

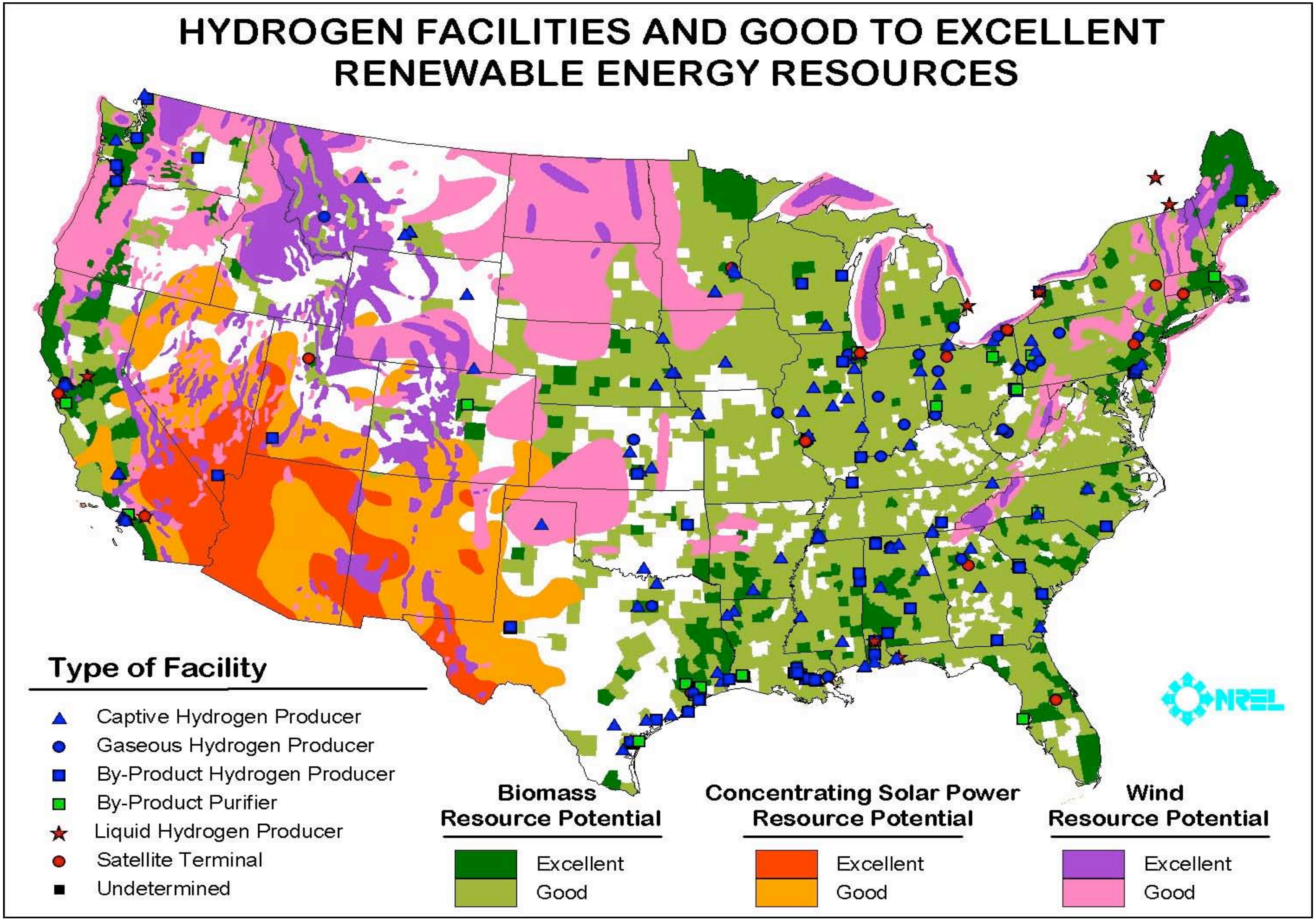


Notes: "Northeast" includes CT, ME, MA, NH, NJ, NY, PA, RI, and VT; "Southeast" includes AL, DE, FL, GA, KY, MD, MI, NC, SC, TN VA, and WV; "Midwest" includes IA, IL, IN, KS, MI, MN, MO, NB, ND, OH, SD, and WI; "Central" includes AR, AZ, CO, ID, LA, MT, NV, NM, OK, TX, UT, and WY; "Pacific" includes AK, CA, HI, OR, and WA. However, the analysis did not consider production potential from AK and HI, and only CA, OR, and WA production potentials are shown. "Economic" renewable hydrogen potential includes resources that can be used to produce delivered hydrogen to customers for $3.00 per kg or less.

Source: Meyers et al. (2003) and additional analysis conducted by the author.

Regional strategies for hydrogen production should consider this regional renewable hydrogen potential along with production potential from other sources. The Midwest and Central regions have vast renewable hydrogen potential, largely in the form of biomass, that could be used to produce hydrogen at attractive cost levels for these regions and nearby states in other regions. These areas also have great wind power resources, and these resources could produce large amounts of hydrogen, but at somewhat higher costs. The Northeast, Southeast, and Pacific regions have more modest renewable hydrogen potential. In the Northeast and Southeast, as in the Midwest and Central, these are mainly biomass resources that can be used to produce delivered hydrogen at or below $3.00 per kg ($21.30 per GJ). In the Pacific region, much of the renewable hydrogen potential is in the form of solar and wind electrolysis, with comparatively high costs. Success in lowering the costs of electrolyzer-based hydrogen could therefore be important to complementing imports of biomass-based hydrogen from the Central and Midwest regions with hydrogen produced within the Pacific region itself. Figure 12, below, presents a map that shows the overall renewable hydrogen potential in the U.S. from a combination of wind, solar, and biomass sources.

Figure 12: Overall Renewable Hydrogen Potential in the U.S.



VII. Conclusions

In conclusion, hydrogen can be produced in a variety of different ways, from a large number of potential feedstocks. Unlike the crude oil used to produce gasoline, the myriad potential sources of hydrogen are generally well distributed around the U.S. and the world. Certain regions have greater or lesser availability and suitability for specific hydrogen feedstocks and production methods, but virtually all regions have at least a few and many have several possibilities for hydrogen production.

The feedstock diversity for hydrogen is a critical characteristic in that it suggests the potential for much greater reliance on local resources for energy production around the world, particularly with regard to petroleum use in the transportation sector (if practical hydrogen vehicles can be realized). The diversity also raises another critical issue in that it suggests that in places such as the U.S., where *multiple* hydrogen production options are possible, strategic decisions about hydrogen production can be made based on multi-criteria analysis of the costs and benefits of various options.

This report has focused on the economic costs of hydrogen production, and only briefly discussed the broader picture of full environmental and social costs. However, it should be recognized that at present there is an inherent bias toward hydrogen production options that have the highest environmental and social costs. This is because many of these costs are "externalities" that are not presently valued in energy and fuel markets. Thus, in deciding on hydrogen production options as the development of the hydrogen economy unfolds, analyzing these options in ways that value as many of their actual environmental and human health impacts as possible will be important. This is to make sure that individual countries or regions pursue options for hydrogen production that *maximize the overall social benefits of the moving to hydrogen*, as it may be only in that way the overall hydrogen strategy becomes a truly compelling one.

The main hydrogen production pathways currently known are as follows, including a short technical and economic characterization of the pathway.

> <u>Steam Methane Reforming</u>
> Steam reformation of natural gas (or methane from other sources) produces a hydrogen rich gas that is typically on the order of 70-75% on a dry basis, along with smaller amounts of methane (2-6%), carbon monoxide (7-10%), and carbon dioxide (6-14%). Costs of hydrogen from SMR vary with feedstock cost, scale of production, and other variables and range from about \$2-5 per kilogram at present (delivered and stored at high pressure). Delivered costs as low as about \$1.60 per kilogram are believed to be possible in the future based on large centralized production and pipeline delivery, and delivered costs for small-scale decentralized production are projected to be on the order of \$2.00-2.50 per kilogram.
>
> <u>Gasification of Coal and Other Hydrocarbons</u>
> In the POx process, also known more generally as "gasification," hydrogen can be

produced from a range of hydrocarbon fuels, including coal, heavy residual oils, and other low-value refinery products. The hydrocarbon fuel is reacted with oxygen in a less than stoichiometric ratio, yielding a mixture of carbon monoxide and hydrogen at 1200° to 1350° C. Hydrogen can be produced from coal gasification at delivered costs of about $2.00-2.50 per kilogram at present at large scale, with delivered costs as low as about $1.50 per kilogram believed to be possible in the future.

Nuclear-Based Options

Various nuclear energy based hydrogen production schemes are possible, including nuclear thermal conversion of water using various chemical processes such as the sodium-iodine cycle, electrolysis of water using nuclear power, and high-temperature electrolysis that additionally would use nuclear system waste heat to lower the electricity required for electrolysis. Few cost studies of these schemes have yet been conducted, but at large scale and in the future, nuclear thermal conversion of water is believed to be capable of producing delivered hydrogen at costs of about $2.25-2.50 per kilogram.

Electrolysis of Water

Hydrogen can be produced via electrolysis of water from any electrical source, including utility grid power, solar PV, wind power, hydropower, nuclear power, etc. Grid electrolysis would produce hydrogen at delivered costs of $6-7 per kilogram at present, with future potential of about $4 per kilogram. Wind electrolysis-derived hydrogen would cost about $7-11 per kilogram at present, with future potential of delivered costs as low as about $2.75-3.00 per kilogram. Solar hydrogen would be more expensive, on the order of $10-30 per kilogram at present, with future delivered costs of $3-4 per kilogram believed to be possible.

Hydrogen from Biomass

Biomass conversion technologies can be divided into thermo-chemical and biochemical processes. Thermo-chemical processes tend to be less expensive because they can be operated at higher temperatures and therefore obtain higher reaction rates. They also can utilize a broad range of biomass types. In contrast, biochemical processes are limited to wet feedstock and sugar-based feedstocks. At medium production scale and liquid distribution by tanker truck, current delivered costs of hydrogen from biomass would be in the $5-7 per kilogram range. However at larger production scales and coupled with pipeline delivery, delivered costs as low as $1.50 to $3.50 per kilogram are believed possible. Pyrolysis of biomass, another production option, also offers potentially low costs of delivered hydrogen, with costs as low as about $1 per kilogram possible with large-scale production and pipeline delivery.

Other Hydrogen Production Options

Hydrogen can also be produced through various other methods, such as direct solar thermal dissociation of water, from municipal solid waste “landfill gas” and waste gases from water treatment plants, and from hydrogen producing algae. These options are at various stages of research and development, with production costs that are either unclear at present or that vary significantly depending on the particular setting in question.

Based on this present and future hydrogen production and distribution assessment, the following recommendations are made with regard to potential future directions for hydrogen energy research and development.

Hydrogen Production:

Hydrogen from Coal – This pathway is potentially economically attractive, especially without inclusion of externalities, but entails inherently large greenhouse gas, air pollutant, and mining impacts. Carbon sequestration is a potentially promising long-term option to mitigate GHG impacts, but at present has large uncertainties with regard to cost and ultimate effectiveness.

Hydrogen from Natural Gas – This pathway is a front-runner as a transition fuel in many areas, but faces distribution and supply concerns, as well as cost issues with natural gas in the U.S. presently at ~2x historical cost levels. Natural gas is probably best thought of as a transition fuel to cleaner and more renewable hydrogen production options, and should be utilized near-term due to the extensive natural gas infrastructure -- but in the context of a longer-term hydrogen production strategy and cognizant of technological "lock-in" concerns. Distributed production of hydrogen from natural gas appears to be among the most attractive near-term options, as it obviates the need for transportation of hydrogen, but also precludes the possibility of carbon capture and sequestration. In order to support use for hydrogen production as well as growing electrical energy needs, natural gas distribution capacity should be judiciously expanded but also optimized through end-use efficiency with combined heat and power (CHP) and other distributed power generation and demand reduction strategies.

Hydrogen from Nuclear Energy– This pathway faces critical and perhaps even overwhelming (in the U.S.) public acceptance, safety, and access to capital issues. Costs could be competitive at production level, but large-scale plants imply high distribution costs. This appears to be a "non-starter" at present in the U.S., but the nuclear industry is working to push these options and some level of research and development (R&D) is arguably justified due to the long term potential (especially with nuclear fusion-based systems that avoid the legacy waste and safety issues).

Hydrogen from Renewable Energy Sources – This is the only fully sustainable "end-game." Renewable energy-based hydrogen offers multiple benefits including fuel diversity and security, and the potential for clean and low-GHG hydrogen production. Strategies that emphasize renewable feedstocks and distributed production (to avoid distribution costs and energy penalties), and that are developed in the context of a regional resource base, may be critical to maximizing the potential benefits of transitioning to hydrogen. Electrolyzer and solar PV costs remain key issues for the electrolysis-based options, but hydrogen from biomass using a wide range of potential renewable feedstocks offers another attractive set of options.

Infrastructure Development:

Distributed vs. Centralized Production – In the early years of the hydrogen transition, a mix of distributed production with small-scale reformers and electrolyzers, coupled with some "mobile vehicle refueler" and liquid hydrogen delivery by truck, appears to be the best strategy. Once hydrogen demand has reached the scale and level of concentration to begin to justify pipeline delivery, then the development of larger-scale plants can be pursued, potentially with carbon sequestration.

Integration of Hydrogen Infrastructure and Distributed Power Systems – The potential for expanded use of hydrogen is relevant to both the transportation and stationary power sectors, and as a result interesting synergies are possible. These include co-production of electricity and hydrogen for vehicles with "hydrogen energy stations," using distributed power generation to provide electricity for hydrogen production through electrolysis, and even using hydrogen-powered vehicles for backup power, peak power, and/or grid ancillary services such as spinning and non-spinning reserves. The potential technical and economic issues associated with these schemes have only begun to be analyzed, but initial research has been promising -- particularly for areas with high electricity costs. This suggests that these potential "integrated transportation and energy solutions" are worth exploring further, as one way of helping to solve the "chicken-or-egg" problem with regard to the development of hydrogen infrastructure for vehicles.

Distribution Systems and Onboard Vehicle Storage – As highlighted by the recent NRC (2004) study, further progress with regard to onboard hydrogen storage is required in order for hydrogen-powered vehicles to become more practical. While hydrogen storage as a compressed gas is the dominant onboard storage system at present, this type of system suffers from bulkiness, significant electricity requirements for hydrogen compression, and potential safety concerns due to the high storage pressures. Other onboard storage systems such as those based on metal and alkaline hydrides, cryogenic liquid hydrogen, and carbon nanotubes are under development, and the potential emergence of a new type of storage that ultimately becomes dominant has important implications for the design and development of optimal hydrogen distribution and dispensing schemes. Careful attention must therefore be paid to the interplay between hydrogen production, hydrogen distribution, and hydrogen storage onboard vehicles, but again this is complicated by the many possibilities in each of these areas and the potential for future breakthroughs especially in the storage area.

Policy / Institutional Roles and Priorities:

Incentives for "Clean" Hydrogen Production – Given the many possible ways of making hydrogen, and the widely varying environmental and social impacts that these pathways imply, federal, state, and local governments should consider incentivizing the production of hydrogen in ways that minimize social costs. These incentives could be in the form of reduced or eliminated taxes on hydrogen produced from renewables and other clean and "climate-friendly" sources, and tax breaks on investments in clean hydrogen production, distribution, and storage capital equipment.

Role of Government Agencies and the Private Sector – In addition to potentially providing incentives for the development of clean hydrogen production systems and distribution infrastructure, the public sector can play several other important roles. These include public education and outreach on hydrogen safety issues, development and implementation of codes and standards for hydrogen infrastructure, support for hydrogen systems R&D, incorporating hydrogen vehicles into government fleets where practical, and potentially using other government assets to assist in hydrogen systems development (e.g. allowing roadside "rights-of-way" to be used for hydrogen stations and pipelines).

While much of the burden of developing hydrogen infrastructure should and will fall on the private sector, some level of government assistance and the development of public/private partnerships are likely to be critical during the early stages of the hydrogen transition. This initial level of assistance could give hydrogen systems a chance to compete in the marketplace against more established incumbent technologies. Then, if technological progress proceeds in such a way that hydrogen vehicles, stationary power systems based on hydrogen, and/or other hydrogen end-use technologies become more promising and viable, then the "business case" for hydrogen will be more clearly defined and an increasingly dominant private sector role should follow.

In conclusion, hydrogen is a highly promising energy carrier and fuel for vehicles and stationary power generation, but the use of hydrogen involves a host of issues and challenges. Primary among these is the fundamental issue of how the hydrogen is itself produced and distributed. One of hydrogen's chief advantages – the ability to be made in various ways and with a diverse array of feedstocks – also complicates decision-making with regard to planning for the development of hydrogen production and distribution infrastructure.

In this report we have compiled estimates with regard to the potential costs and environmental impacts associated with different hydrogen production methods and pathways. However, hydrogen production and distribution strategy and planning decisions involve many local and regional variables, and the application of community values. These additional factors should also be a critical part of any hydrogen energy planning and deployment process. Also needed are better and more extensive analysis of the overall lifecycle environmental impacts of different hydrogen production pathways and strategies in regional contexts, and for different hydrogen end-use applications, so that key decisions related to the development of hydrogen energy systems can be informed by a broad set of social and environmental criteria as well as economic cost considerations.

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Appendix A: Summary Tables of Hydrogen Production and Delivered Hydrogen Costs

Table A-1: Summary of Recent Hydrogen Production Cost Estimates

Production Method	Scale of Production	Production Cost (HHV basis)	Key Details and Market Status	Source
Natural Gas				
Steam Methane Reforming	239 kg/day 884 kg/day 2,390 kg/day *Small-Medium*	\$5.39/kg (\$37.96/GJ) \$2.76/kg (\$19.44/GJ) \$1.92/kg (\$13.52/GJ)	*Near Term*	Ogden et al., 1996
Steam Methane Reforming	625 kg/day *Small*	\$2.60/kg (\$18.31/GJ) Single station \$1.93/kg (\$13.59/GJ) 100 stations \$1.68/kg (\$11.83/GJ) 10,000 stations	NG at \$6.16/GJ "Energy station" with 100 kW of power sold to grid *Near Term*	Thomas et al., 2001
Steam Methane Reforming	609,000 kg/day (1 GW_{H2}) *Large*	\$0.78/kg (\$5.50/GJ) (NG@\$3.00/GJ) \$0.94/kg (\$6.60/GJ) (NG@\$3.90/GJ) \$0.97/kg (\$6.85/GJ) (NG@\$4.10/GJ)	NG at \$3.00-4.10/GJ 81% SMR efficiency *Commercial*	Williams, 2002
Steam Methane Reforming	609,000 kg/day (1 GW_{H2}) *Large*	\$1.02/kg (\$7.20/GJ)	NG at \$3/GJ 81% SMR efficiency 85% of CO_2 emissions captured *Research and Devt.*	Williams, 2002
Steam Methane Reforming	470 kg/day *Small*	\$4.40/kg (\$30.99/GJ)	NG at \$5.25/GJ Small-scale prod. *Near Term*	Simbeck and Chang, 2002
Steam Methane Reforming	609,000 kg/day (1 GW_{H2}) *Large*	\$0.90/kg (\$6.33/GJ)	NG at \$3.67/GJ CO_2 vented *Commercial*	Ogden et al., 2004
Steam Methane Reforming	609,000 kg/day (1 GW_{H2}) *Large*	\$1.14/kg (\$8.04/GJ)	NG at \$3.67/GJ 85% of CO_2 emissions captured *Research and Devt.*	Ogden et al., 2004
Steam Methane Reforming	480 kg/day *Small*	\$3.51/kg (\$24.75/GJ) Current \$2.33/kg (\$16.43/GJ) Future	NG at \$6.16/GJ SMR efficiency: 60% (current) 70% (future) *Near Term/Future*	NRC, 2004
Steam Methane Reforming	24,000 kg/day *Medium*	\$1.38/kg (\$9.73/GJ) Current \$1.21/kg (\$8.53/GJ) Future	NG at \$4.27/GJ SMR efficiency: 72% (current) 77% (future) *Near Term/Future*	NRC, 2004
Steam Methane Reforming	24,000 kg/day *Medium*	\$1.76/kg (\$12.41/GJ) Current \$1.55/kg (\$10.93/GJ) Future	NG at \$4.27/GJ CO_2 sequestered SMR efficiency: 69% (current) 72% (future) *Near Term/Future*	NRC, 2004
Steam Methane Reforming	1.1 million kg/day *Large*	\$1.03/kg (\$7.26/GJ) Current \$0.92/kg (\$6.49/GJ)	NG at \$4.27/GJ SMR efficiency: 76.2% (current)	NRC, 2004

		Future	80% (future) *Near Term/Future*	
Steam Methane Reforming	1.1 million kg/day *Large*	\$1.31/kg (\$9.24/GJ) Current \$1.10/kg (\$7.76/GJ) Future	NG at \$4.27/GJ CO_2 sequestered SMR efficiency: 72% (current) 78% (future) *Near Term/Future*	NRC, 2004
Natural Gas/Solar Assist				
Concentrating Solar NG Reactor	250 kg/day 450 kg/day 748 kg/day *Small*	\$2.56/kg (\$18/GJ) (8,750 m^2 heliostat) \$2.84/kg (\$20/GJ) (4.375 m^2 heliostat) \$3.41/kg (\$24/GJ) (2,188 m^2 heliostat)	NG at \$3.72/GJ *Research and Devt.*	Spath and Amos, 2002
Coal				
Oxygen-blown Gasification	313,090 kg/day *Large*	\$0.92/kg (\$6.48/GJ)	CO_2 vented 63.7% effic. (HHV) 20.4 MW net power *Commercial*	Gray and Tomlinson, 2002
Oxygen-blown Gasification	284,410 kg/day *Large*	\$1.10/kg (\$7.75/GJ)	CO_2 sequestered for \$10/ton of carbon 59.0% effic. (HHV) 26.9 MW net power *Research and Devt.*	Gray and Tomlinson, 2002
Advanced Gasification With Hot Gas Cleanup	377,620 kg/day *Large*	\$0.79/kg (\$5.56/GJ)	CO_2 sequestered for \$10/ton of carbon 75.5% effic. (HHV) 25.0 MW net power *Research and Devt.*	Gray and Tomlinson, 2002
Oxygen-blown Gasification	150,000 kg/day *Large*	1.62/kg (\$11.41/GJ)	Coal at \$29.11/ton CO_2 vented *Commercial*	Simbeck and Chang, 2002
Oxygen-blown Gasification	609,000 kg/day (1 GW_{H2}) *Large*	\$0.89/kg (\$6.25/GJ)	Coal at \$1.17/GJ CO_2 vented *Commercial*	Williams, 2002
Oxygen-blown Gasification	1.2 million kg/day *Large*	\$0.96/kg (\$6.77/GJ) Current \$0.71/kg (\$5.01/GJ) Future	Coal at \$1.16/GJ CO_2 vented *Commercial/Future*	NRC, 2004
Oxygen-blown Gasification	1.2 million kg/day *Large*	\$1.19/kg (\$8.39/GJ) Current \$0.92/kg (\$6.49/GJ) Future	Coal at \$1.16/GJ CO_2 sequestered *Commercial/Future*	NRC, 2004
Oxygen-blown Gasification	609,000 kg/day (1 GW_{H2}) *Large*	\$0.81/kg (\$5.69/GJ)	CO_2 vented *Commercial*	Ogden et al., 2004
Oxygen-blown Gasification	609,000 kg/day (1 GW_{H2}) *Large*	\$1.05/kg (\$7.36/GJ)	CO_2 sequestered *Research and Devt.*	Ogden et al., 2004
Petroleum Coke				
Gasification	150,000 kg/day *Large*	\$1.35/kg (\$9.51/GJ)	CO_2 vented 21.0 MW net power *Near Commercial.*	Simbeck and Chang, 2002

Nuclear				
SI-MHR	n.s. *Large*	$0.95-1.60/kg ($6.69-11.28/GJ)	5-15% interest rate *Research and Development*	Brown et al., 2002
SI-MHR	n.s. *Large*	$1.30/kg ($9.15/GJ)	$686/kW cap. cost 10% interest rate *Research and Devt.*	Henderson, 2002
Nuclear Thermal of Water	1.2 million kg/day *Large*	$1.63/kg ($11.50/GJ) Future	$2.5 million plant capital cost *R&D/Future*	NRC, 2004
Biomass				
Battelle Gasifier	147,900 kg/day *Large*	$0.84/kg ($5.9/GJ) ($2/GJ biomass, 6% DR) $1.21/kg ($8.5/GJ) (($4/GJ biomass, 6% DR) $0.97/kg ($6.8/GJ) (($2/GJ biomass, 12% DR) $1.33/kg ($9.4/GJ) (($4/GJ biomass, 12% DR)	Biomass at $2-4/GJ 70% thermal effic. *Demonstration*	Ogden and Nitsch, 1993
Pyrolysis	Not specified	$1.09/kg ($7.70/GJ)	Phenolic co-product sold for $0.44/kg *Commercial*	French et al., 2000
Battelle/FERCO Gasifier	22,737 kg/day *Medium*	$1.12/kg ($7.90/GJ) *$2.43/kg ($17.08/GJ)* *With 15% after tax IRR*	$54 mill. cap. Cost *Demonstration*	Spath et al, 2000
Battelle/FERCO Gasifier	75,790 kg/day *Medium*	$1.25/kg ($8.81/GJ) *$2.19/kg ($15.39/GJ)* *With 15% after tax IRR*	$129 mill. cap. Cost *Demonstration*	Spath et al, 2000
Battelle/FERCO Gasifier	113,685 kg/day *Large*	$1.19/kg ($8.41/GJ) *$2.03/kg ($14.29/GJ)* *With 15% after tax IRR*	$172 mill. cap. Cost *Demonstration*	Spath et al, 2000
IGT Gasifier	22,737 kg/day *Medium*	$1.19/kg ($8.40/GJ) *$2.93/kg ($20.64/GJ)* *With 15% after tax IRR*	$72 mill. cap. cost *Demonstration*	Spath et al, 2000
IGT Gasifier	75,790 kg/day *Medium*	$1.27/kg ($8.95/GJ) *$2.50/kg ($17.61/GJ)* *With 15% after tax IRR*	$169 mill. cap. cost *Demonstration*	Spath et al, 2000
IGT Gasifier	113,685 kg/day *Large*	$1.20/kg ($8.48/GJ) *$2.29/kg ($16.16/GJ)* *With 15% after tax IRR*	$227 mill. cap. cost *Demonstration*	Spath et al, 2000
Pyrolysis	22,737 kg/day *Medium*	$0.93/kg ($6.57/GJ) *$1.45/kg ($10.24/GJ)* *With 15% after tax IRR*	$19 mill. cap. cost *Commercial*	Spath et al, 2000
Pyrolysis	75,790 kg/day *Medium*	$0.75/kg ($5.30/GJ) *$1.23/kg ($8.69/GJ)* *With 15% after tax IRR*	$59 mill. cap cost *Commercial*	Spath et al, 2000
Gasifier	24,000 kg/day *Medium*	$4.63/kg ($32.65/GJ) Current $2.21/kg ($15.59/GJ) Future	Biomass at: $2.85/GJ (current) $1.91/GJ (future) CO_2 vented *Near Term/Future*	NRC, 2004
Gasifier	24,000 kg/day *Medium*	$5.08/kg ($35.83/GJ) Current $2.53/kg ($17.84/GJ) Future	Biomass at: $2.85/GJ (current) $1.91/GJ (future) CO_2 sequestered *Near Term/Future*	NRC, 2004

Wind				
Electrolysis	1,267 kg/day *Small-Medium*	$1.56/kg ($11.0/GJ) (6% DR) $2.27/kg ($16.0/GJ) (12% DR)	Excellent sites (630 W/m^2) *Near Commercial*	Ogden and Nitsch, 1993
Electrolysis	1,267 kg/day *Small-Medium*	$2.41/kg ($17.0/GJ) (6% DR) $3.55/kg ($25.0/GJ) (12% DR)	Good sites (350 W/m^2) *Near Commercial*	Ogden and Nitsch, 1993
Electrolysis	n.s. 10 MW of wind power *Small-Medium*	$3.90/kg ($27.5/GJ) Year 2000 $3.00/kg ($21.1/GJ) Year 2010	Grid-Tied Wind power: $900/kW (2000) $700/kW (2010)	Mann et al., 1998
Electrolysis	n.s. 10 MW of wind power *Small-Medium*	$7.10/kg ($50.0/GJ) Year 2000 $4.00/kg ($28.2/GJ) Year 2010	Stand-Alone Wind power: $900/kW (2000) $700/kW (2010)	Mann et al., 1998
Electrolysis	n.s. *Small-Medium*	$1.86-2.63/kg ($13.00-18.50/GJ) *$3.20-3.98/kg* *($22.50-28.00/GJ)* *w/15% IRR, 37% taxation*	Grid-Tied Various Design and Econ. Assumption	Padro, 2002
Electrolysis	n.s. *Small*	$1.14/kg ($8.00/GJ) *$4.33/kg ($30.50/GJ)* *w/15% IRR, 37% taxation*	Stand-Alone	Padro, 2002
Electrolysis	1,600 kg/day Current 1,200 kg/day Future *Small-Medium*	$10.69/kg ($75.39/GJ) Current $2.86/kg ($20.17/GJ) Future	Stand-Alone *Near Term/Future*	NRC, 2004
Electrolysis	480 kg/day *Small*	$6.81/kg ($48.03/GJ) Current $3.50/kg ($24.68/GJ) Future	Grid-Tied *Near Term/Future*	NRC, 2004
Solar				
PV Electrolysis	1,267 kg/day *Small-Medium*	$6.39-14.34/kg ($45-101/GJ) (6% DR) *$10.37-23.71/kg* *($73-167/GJ) (12% DR)*	ca. 1991 Southwest U.S. *Near Commercial*	Ogden and Nitsch, 1993
PV Electrolysis	1,267 kg/day *Small-Medium*	$1.42-2.27/kg ($10-16/GJ) (6% DR) *$2.13-3.55/kg ($15-25/GJ)* *(12% DR)*	Future Projection Southwest U.S. *Near Commercial*	Ogden and Nitsch, 1993
PV Electrolysis	10 MWe *Small-Medium*	$25.84/kg ($182/GJ) $12.21/kg ($86/GJ) $6.39/kg ($45/GJ)	PV at $5,000/kW PV at $2,000/kW PV at $750/kW *Near Commercial*	Glatzmaier et al., 1998
Solar Dish-Stirling Electrolysis	10 MWe *Small-Medium*	$11.64/kg ($82/GJ) $10.79/kg ($76/GJ)	Year 2010 Year 2020 *Demonstration*	Glatzmaier et al., 1998
Solar Power-Tower Electrolysis	200 MWe *Medium*	$7.10/kg ($50/GJ) $5.96/kg ($42/GJ)	Year 2010 Year 2020 *Demonstration*	Glatzmaier et al., 1998

High-Temperature Electrolysis	200 MWe *Medium*	$5.68-6.25/kg ($40-44/GJ) $7.67-11.42/kg ($54-79/GJ)	$500/kW electrolyzer $2,000/kW electrolyzer *Research and Devt.*	Glatzmaier et al., 1998
PV Electrolysis	n.s. 10 MW of solar power *Small-Medium*	$7.40/kg ($52.1/GJ) Year 2000 $4.50/kg ($37.1/GJ) Year 2010	Grid-Tied Solar power: $3,133/kW (2000) $12,662/kW (2010) *Near Term/Future*	Mann et al., 1998
PV Electrolysis	n.s. 10 MW of solar power *Small-Medium*	$17.60/kg ($124.0/GJ) Year 2000 $7.50/kg ($52.8/GJ) Year 2010	Stand-Alone Solar power: $3,133/kW (2000) $12,662/kW (2010) *Near Term/Future*	Mann et al., 1998
PV Electrolysis	n.s. *Small-Medium*	$2.13-2.91/kg ($15.00-20.50/GJ) *$4.83-5.54/kg* *($34.00-39.00/GJ)* *w/15% IRR, 37% taxation*	Grid-Tied Various Design and Econ. Assumption *Future*	Padro, 2002
PV Electrolysis	n.s. *Small*	$1.78/kg ($12.50/GJ) *$8.24/kg ($58.00/GJ)* *w/15% IRR, 37% taxation*	Stand Alone *Future*	Padro, 2002
PV Electrolysis	2,400 kg/day *Small-Medium*	$28.19/kg ($198.81/GJ) Current $6.18/kg ($43.58/GJ) Future	Stand-Alone *Near Term/Future*	NRC, 2004
PV Electrolysis	480 kg/day *Small*	$9.71/kg ($68.48/GJ) Current $4.37/kg ($30.82/GJ) Future	Grid-Tied *Near Term/Future*	NRC, 2004
Grid Power				
Electrolysis	24,000 kg/day *Medium*	$4.70/kg ($33.15/GJ) Current $2.30/kg ($16.22/GJ) Future	Electricity at $0.045/kWh *Near Term/Future*	NRC, 2004
Electrolysis	480 kg/day *Small*	$6.58/kg ($46.41/GJ) Current $3.93/kg ($27.72/GJ) Future	Electricity at $0.07/kWh *Near Term/Future*	NRC, 2004
Solar Photo-Electrochemical				
PEC Water Splitting	n.s. *Variable*	$2.60/kg ($17.50/GJ) *$11.00/kg ($77.50/GJ)* *w/15% IRR, 37% taxation*	Year 2010 Estimate *Research and Devt.*	Padro, 2002
PEC Water Splitting	n.s. *Variable*	$1.21/kg ($8.50/GJ) *$5.11/kg ($36.00/GJ)* *w/15% IRR, 37% taxation*	Year 2020 Estimate *Research and Devt.*	Padro, 2002

Notes: Production costs are on HHV basis unless otherwise specified. For delivered hydrogen cost estimates, see Table A-2. DR = discount rate (see list of acronyms at front of report for other abbreviations).

Table A-2: Summary of Recent Delivered Hydrogen Cost Estimates

Production Method	Scale of Production	Delivered H_2 Cost (HHV basis)	Notes	Source
Natural Gas				
Steam Methane Reforming	2,455 kg/day (2.7 tons/day)	$3.57/kg ($25.14/GJ)\	Distributed production	Moore and Raman, 1998
Steam Methane Reforming	24,550 kg/day (27 tons/day)	$3.35/kg ($23.59/GJ)	Central production Liquid H_2 delivery	Moore and Raman, 1998
Steam Methane Reforming	24,550 kg/day (27 tons day)	$2.91/kg ($20.49/GJ)	Central production Pipeline H_2 delivery	Moore and Raman, 1998
Steam Methane Reforming	Conv. SMR Advanced SMR 2,390 kg/day	$1.92/kg ($13.54/GJ) $2.76/kg ($19.46/GJ)	Distributed production	Ogden et al., 1998
Steam Methane Reforming	High demand Low demand 239,000 kg/day	$1.49/kg ($10.51/GJ) $1.93/kg ($13.61/GJ)	Central production Pipeline delivery	Ogden et al., 1998
Steam Methane Reforming	470 kg/day	$4.40/kg ($30.99/GJ)	Distributed production High pressure storage	Simbeck and Chang, 2002
Steam Methane Reforming	150,000 kg/day	$3.66/kg ($25.77/GJ)	Central production Liquid H_2 delivery	Simbeck and Chang, 2002
Steam Methane Reforming	150,000 kg/day	$5.00/kg ($35.21/GJ)	Central production Pipeline delivery	Simbeck and Chang, 2002
Steam Methane Reforming	150,000 kg/day	$4.39/kg ($30.92/GJ)	Central production Tube trailer delivery	Simbeck and Chang, 2002
Steam Methane Reforming	480 kg/day	$3.51/kg ($24.75/GJ) *Current* $2.33/kg ($16.43/GJ) *Future*	Distributed production High pressure storage	NRC, 2004
Steam Methane Reforming	24,000 kg/day	$3.81/kg ($26.87/GJ) *Current* $2.62/kg ($18.48/GJ) *Future*	Central production Tanker truck delivery (liquid H_2)	NRC, 2004
Steam Methane Reforming	24,000 kg/day	$4.18/kg ($29.48/GJ) *Current* $2.95/kg ($20.81/GJ) *Future*	Central production with CO_2 sequestered Tanker truck delivery (liquid H_2)	NRC, 2004
Steam Methane Reforming	1.1 million kg/day	$1.98/kg ($13.96/GJ) *Current* $1.61/kg ($11.35/GJ) *Future*	Central production Pipeline delivery	NRC, 2004
Steam Methane Reforming	1.2 million kg/day	$2.26/kg ($15.94/GJ) *Current* $1.80/kg ($12.69/GJ) *Future*	Central production with CO_2 sequestered Pipeline delivery	NRC, 2004
Coal				
Oxygen-blown Gasification	609,000 kg/day (1 GW_{H2})	$2.21/kg ($15.57/GJ)	Central production CO_2 vented	Ogden et al., 2004
Oxygen-blown Gasification	609,000 kg/day (1 GW_{H2})	$2.45/kg ($17.24/GJ)	Central production CO_2 sequestered	Ogden et al., 2004
Gasification	150,000 kg/day	$4.51/kg ($31.76/GJ)	Central production Liquid H_2 delivery	Simbeck and Chang, 2002
Gasification	150,000 kg/day	$5.62/kg ($39.58/GJ)	Central production Pipeline delivery	Simbeck and Chang, 2002
Gasification	150,000 kg/day	$5.18/kg ($36.48/GJ)	Central production Tube trailer delivery	Simbeck and Chang, 2002

Gasification	1.2 million kg/day	$1.91/kg ($13.47/GJ) *Current* $1.40/kg ($9.87/GJ) *Future*	Central production Pipeline delivery	NRC, 2004
Gasification	1.2 million kg/day	$2.15/kg ($15.16/GJ) *Current* $1.61/kg ($11.35/GJ) *Future*	Central production Pipeline delivery With CO_2 sequestered	NRC, 2004
Petroleum Coke				
Gasification	150,000 kg/day	$5.35/kg ($37.68/GJ)	Central production Pipeline delivery	Simbeck and Chang, 2002
Nuclear				
Nuclear Thermal Conversion of Water	1.2 million kg/day	$2.33/kg ($16.43/GJ) *Future*	Central production Pipeline delivery	NRC, 2004
Wind				
Electrolysis	n.s. (10 MWp)	$3.17/kg ($22.3/GJ) *(6% DR)* $4.32/kg ($30.4/GJ) *(12% DR)*	Future projection Demonstration Scale	Ogden and Nitsch, 1993
Electrolysis	n.s. (750 MWp)	$3.42/kg ($24.1/GJ) *(6% DR)* $4.50/kg ($31.7/GJ) *(12% DR)*	Future projection City supply scale	Ogden and Nitsch, 1993
Electrolysis	1,600 kg/day Current 1,200 kg/day Future	$10.69/kg ($75.39/GJ) *Current* $2.86/kg ($20.17/GJ) *Future*	Distributed production Stand-Alone	NRC, 2004
Electrolysis	480 kg/day	$6.81/kg ($48.03/GJ) *Current* $3.50/kg ($24.68/GJ) *Future*	Distributed production Grid-Tied	NRC, 2004
Solar				
PV Electrolysis	n.s. (10 MWp)	$2.26-3.14/kg ($15.9-22.1/GJ) *(6% DR)* $3.12-4.59/kg ($22.0-32.3/GJ) *(12% DR)*	Future projection Southwest U.S. Demonstration Scale	Ogden and Nitsch, 1993
PV Electrolysis	n.s. (750 MWp)	$2.50-3.38/kg ($17.6-23.8/GJ) *(6% DR)* $3.32-4.77/kg ($23.4-33.6/GJ) *(12% DR)*	Future projection Southwest U.S. City supply scale	Ogden and Nitsch, 1993
PV Electrolysis	2,400 kg/day	$28.19/kg ($198.81/GJ) *Current* $6.18/kg ($43.58/GJ) *Future*	Distributed production Stand-Alone	NRC, 2004
PV Electrolysis	480 kg/day	$9.71/kg ($68.48/GJ) *Current* $4.37/kg ($30.82/GJ) *Future*	Distributed production Grid-Tied	NRC, 2004
Biomass				
Battelle/FERCO Gasifier	22,737 kg/day	$1.59/kg ($11.22/GJ) *$2.90/kg ($20.40/GJ)* *With 15% after tax IRR*	Central production Pipeline delivery (10 miles)[a]	Spath et al, 2000

Battelle/FERCO Gasifier	75,790 kg/day	$1.50/kg ($10.59/GJ) *$2.44/kg ($17.17/GJ)* *With 15% after tax IRR*	Central production Pipeline delivery (10 miles)[a]	Spath et al, 2000
Battelle/FERCO Gasifier	113,685 kg/day	$1.41/kg ($9.94/GJ) *$2.25/kg ($15.82/GJ)* *With 15% after tax IRR*	Central production Pipeline delivery (10 miles)[a]	Spath et al, 2000
IGT Gasifier	22,737 kg/day	$1.66/kg ($11.72/GJ) *$3.40/kg ($23.96/GJ)* *With 15% after tax IRR*	Central production Pipeline delivery (10 miles)[a]	Spath et al, 2000
IGT Gasifier	75,790 kg/day	$1.52/kg ($10.73/GJ) *$2.75/kg ($19.39/GJ)* *With 15% after tax IRR*	Central production Pipeline delivery (10 miles)[a]	Spath et al, 2000
IGT Gasifier	113,685 kg/day	$1.42/kg ($10.01/GJ) *$2.51/kg ($17.69/GJ)* *With 15% after tax IRR*	Central production Pipeline delivery (10 miles)[a]	Spath et al, 2000
Pyrolysis	22,737 kg/day	$1.40/kg ($9.89/GJ) *$1.93/kg ($13.56/GJ)* *With 15% after tax IRR*	Central production Pipeline delivery (10 miles)[a]	Spath et al, 2000
Pyrolysis	75,790 kg/day	$1.01/kg ($7.08/GJ) *$1.49/kg ($10.47/GJ)* *With 15% after tax IRR*	Central production Pipeline delivery (10 miles)[a]	Spath et al, 2000
Gasification	150,000 kg/day	$4.98/kg ($35.07/GJ)	Central production Liquid H_2 delivery	Simbeck and Chang, 2002
Gasification	150,000 kg/day	$6.29/kg ($44.30/GJ)	Central production Pipeline delivery	Simbeck and Chang, 2002
Gasification	150,000 kg/day	$5.77/kg ($40.63/GJ)	Central production Tube trailer delivery	Simbeck and Chang, 2002
Gasification	24,000 kg/day	$7.04/kg ($49.65/GJ) *Current* $3.62/kg ($25.53/GJ) *Future*	Central production Tanker truck delivery (liquid H_2)	NRC, 2004
Gasification	24,000 kg/day	$7.50/kg ($52.89/GJ) *Current* $3.89/kg ($27.43/GJ) *Future*	Central production Tanker truck delivery (liquid H_2) CO_2 sequestered	NRC, 2004
Grid Power				
Electrolysis	480 kg/day	$6.58/kg ($46.41/GJ) *Current* $3.93/kg ($27.72/GJ) *Future*	Distributed production	NRC, 2004
Electrolysis	24,000 kg/day	$7.12/kg ($50.21/GJ) *Current* $3.71/kg ($26.17/GJ) *Future*	Central production Tanker truck delivery (liquid H_2)	NRC, 2004

Note: Delivered hydrogen costs are on HHV basis unless otherwise specified.

[a] See report for additional storage and transport methods, including 100-mile pipeline, 1,000-mile pipeline, onsite consumption, and “gas station” delivery.