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The Impact of Increased Use of Hydrogen on Petroleum Consumption and Carbon Dioxide Emissions

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Energy Information Administration
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Office of Coal, Nuclear, Electric and Alternate Fuels
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Preface and Contacts

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Executive Summary

This report responds to a request from Senator Byron L. Dorgan for an analysis of the impacts on U.S. energy import dependence and emission reductions resulting from the commercialization of advanced hydrogen and fuel cell technologies in the transportation and distributed generation markets.

Hydrogen is an energy carrier, not a primary energy source. Like electricity, another energy carrier, hydrogen can be produced from a variety of fossil fuels and other primary energy sources. Electricity can also be used to produce hydrogen via electrolysis, and hydrogen can, in turn, fuel electricity generation using either combustion technologies or fuel cells.

The production of hydrogen using primary energy sources or electricity necessarily engenders some loss of energy content. This situation is typical of all energy transformation processes, including the generation of electricity from fossil fuels, where the electricity produced contains only 33 to 55 percent of the energy content of the oil, natural gas, or coal input to generation. Despite these transformation losses, electricity has been the fastest-growing source of energy in end-use applications in both the United States and the world over the past 50 years, reflecting its highly desirable characteristics, which include flexibility, efficiency, and absence of pollution at the point of end use, as well as the availability of a wide range of alternative generation technologies. Hydrogen's future success as an energy carrier is likely to rely on its ability to demonstrate similar or superior attributes.

The development of a large market for hydrogen-powered light-duty fuel cell vehicles (FCVs) would likely require a major financial commitment by industry and government. The ultimate success of that market will depend on the ability to overcome significant technical and infrastructure challenges. Competition from other promising new vehicle technologies, such as plug-in hybrid electric vehicles (PHEVs) that could run on electricity from the grid for 50 to 80 percent of their travel, as well as continued improvement in more conventional technologies, make the prospect of widespread use of hydrogen FCVs an even greater challenge. Nonetheless, if the challenges can be met, FCVs powered with hydrogen can provide considerable reductions in light-duty vehicle (LDV) energy demand and carbon dioxide (CO_2) emissions by 2050.

Certain aspects of a hydrogen economy are already in place on an industrial scale. More than 1 quadrillion British thermal units (Btu) of hydrogen is produced annually in the United States, equivalent to more than 1 percent of the total U.S. primary energy consumption of approximately 100 quadrillion Btu. Petroleum refining and petrochemical industries producing methanol and ammonia currently account for more than 90 percent of hydrogen use. In a hydrogen economy, where hydrogen is used as a fuel or energy carrier rather than as an industrial chemical, substantially more hydrogen production capacity would have to be developed. There would also be a requirement to address transportation and distribution challenges that do not arise in current hydrogen markets, where hydrogen typically is consumed in large quantity at a small number of sites in close proximity to its production location.

Technologies for hydrogen production can be categorized on the basis of their primary fuel source and the distinction between "on-purpose"[1] and "byproduct" production. The technology options for fossil fuels include steam methane reforming (SMR) in "on-purpose" hydrogen production plants, and byproduct production of hydrogen in the petroleum refining process. Another option for hydrogen production is partial oxidation, which can include gasification of solid or liquid

[1]"On-purpose" production facilities are defined by the industry as those facilities where the primary purpose is the production of hydrogen gases or liquids.

feedstocks. Electrolysis processes using grid or dedicated energy sources could also be used to produce “on-purpose” hydrogen, and some production is currently available as a byproduct resulting from electrolysis processes used in the chlor-alkali industry. Other advanced electrolysis techniques—such as thermochemical processes using nuclear power as an energy source—may be available, but they have not yet been fully developed. From a cost perspective, it appears that production of hydrogen from electrolysis is generally a more expensive method of hydrogen production than gasification or SMR. The exception would be when hydrogen is produced as a byproduct of electrolysis used to produce chlorine.

Table ES1 summarizes the potential impacts of a hydrogen economy on petroleum use and CO_2 emissions in two scenarios where hydrogen serves as an energy carrier and light-duty FCVs achieve major market penetration. Both scenarios assume that the financial and infrastructure challenges to a widespread hydrogen economy that are discussed in this report can be overcome. Additionally, the range of potential impacts reflects a number of different assumptions related to vehicle market penetration, hydrogen production technologies (including the manner in which they are deployed from a distributed local level to centralized production), and hydrogen vehicle efficiencies.

Table ES1. Potential Impacts of Hydrogen-Powered FCVs on Petroleum Use and CO_2 Emissions from Light-Duty Vehicles in 2050 [a]

Case	Petroleum Reduction from Reference Case			CO_2 Reduction[b] from Reference Case	
	Percent	Quads [c]	MMBPD [d]	Percent	MMT [e]
Less Aggressive[f]	37.1	7.1	3.6	8.8	172
More Aggressive[g]	84.1	15.9	8.1	63.8	1,244

[a]Assumes fuel cell vehicle market penetration and development of centralized fueling infrastructure.
[b]In addition to the range of vehicle penetration rates and fuel economy improvement used, the less aggressive scenario assumes the most CO_2-intensive hydrogen production and the more aggressive scenario assumes the least CO_2-intensive hydrogen production.
[c]Quadrillion Btu.
[d]Million barrels per day.
[e]Million metric tons.
[f]Scenario with the lowest fuel cell vehicle penetration rate and lowest fuel economy.
[g]Scenario with the highest fuel cell vehicle penetration rate and highest fuel economy.

As shown in Figure ES1, under a more aggressive scenario,[2] U.S. CO_2 emissions from LDVs calculated on a full fuel cycle basis (often referred to as “wells to wheels”), could potentially be reduced to less than 54 percent of the emission level in 1990, reaching 704 million metric tons, compared to the 1990 level of 1,295 million metric tons. Under the less aggressive scenario,[3] there would be some reduction from the reference case,[4] but LDVs still would have higher CO_2 emissions and energy requirements than they do currently.

In the more aggressive scenario, petroleum consumption by U.S. LDVs would be reduced to a level of about 1.5 million barrels per day, 78 percent below the 1990 level of 6.9 million barrels per day. In the less aggressive scenario, LDV petroleum consumption in 2050 is 11 percent below its 1990 level.

Estimated impacts on overall energy demand for both scenarios can vary significantly depending on whether the focus is on the energy content of fuel directly consumed by LDVs or a “wells to wheels” concept of energy use that reflects the significant amount of energy used in the generation, transmission, and distribution of hydrogen that is not counted in LDV fuel use.

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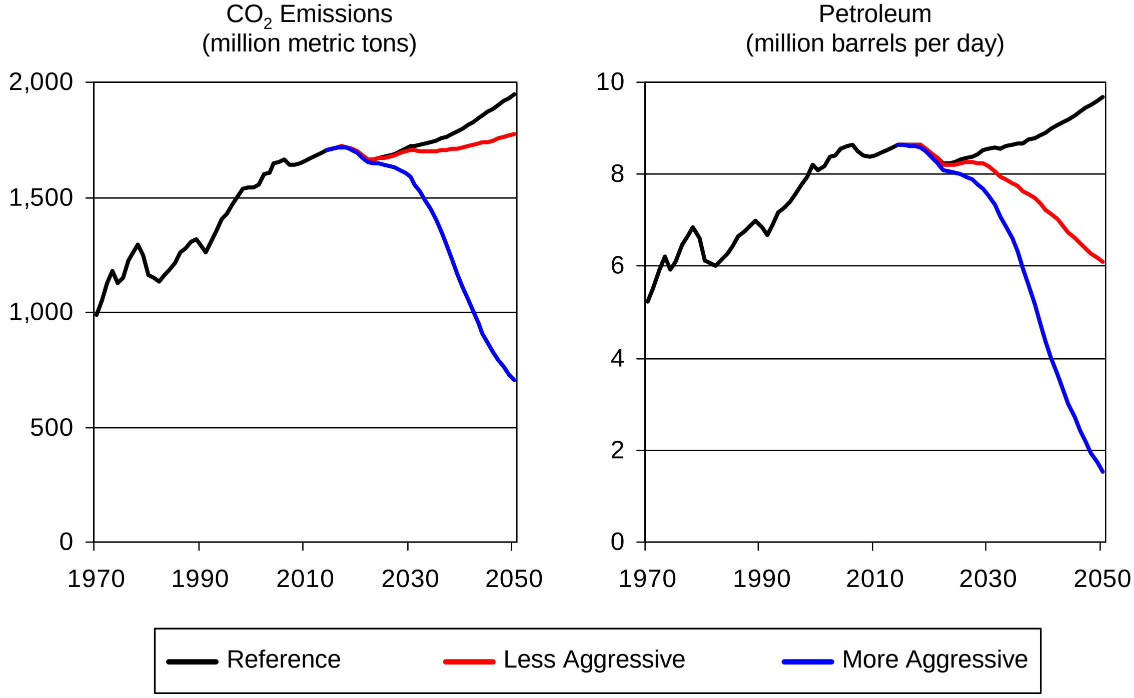
[2]Scenario with the highest fuel cell vehicle penetration rate and highest fuel economy.
[3]Scenario with the lowest fuel cell vehicle penetration rate and lowest fuel economy.
[4]The reference case referred to in this report is described more fully in Chapter 3.

Figure ES1. Historical Light-Duty Vehicle CO_2 Emissions and Petroleum Use, and Potential Impacts of a Hydrogen Economy, 1970-2050



The potential impacts depicted above are intended to illustrate the range of impacts that a hydrogen economy would have on LDV CO_2 emissions and petroleum consumption if all significant technical and other challenges, necessary for a large scale deployment of light-duty FCVs, are resolved. Most, if not all, of the following significant challenges will require successful resolution in order to make a hydrogen economy a reality, especially as characterized in the more aggressive scenario.

CO_2 Reduction. The main sources of hydrogen currently are hydrocarbon feedstocks, such as natural gas, coal, and petroleum, all of which also produce CO_2. Thus, in order for a hydrogen economy to produce overall CO_2 emissions reductions, any hydrogen production process must mitigate CO_2 emissions through carbon capture and sequestration (CCS) or similar technology; use non-emitting fuel sources such as nuclear, wind, or other renewable power; and/or offset CO_2 emissions with comparatively greater vehicle or generation efficiency. Because hydrocarbons currently are the cheapest feedstock, additional costs would be incurred.

Production and Distribution Costs. Fossil fuel feedstocks processed at large centralized facilities, with appropriate consideration of life-cycle emissions, are the least expensive source for a centralized hydrogen supply. Although a centralized distribution system is likely to provide the most economical means of production, such an infrastructure will have to overcome significant cost and structural challenges to become economically viable. If crude oil prices are sustained at about $90 per barrel in real 2006 dollars, the delivered (untaxed) cost of hydrogen, including production, transportation and distribution, must decline to between $2 and $3 per gallon gasoline equivalent in order to be economically viable.[5] Although future breakthroughs in other hydrogen production technologies, such as nuclear thermochemical processes, could substantially lower life-cycle

[5]The comparative estimate is based on EIA's *Annual Energy Outlook 2008* technology assumptions for the efficiencies of hydrogen FCVs and other highly efficient gasoline and diesel vehicle technologies that were affected by the CAFE provisions of the Energy Independence and Security Act of 2007, not the average fleet efficiency.

emissions, and presumably costs, they still need considerable research and development (R&D) before widespread adoption.

Hydrogen Storage. Efficient hydrogen storage is also among the most challenging issues facing the hydrogen economy, due to its low density as a gas and the costs of liquefaction. The largest hydrogen storage challenges relate to transportation applications in which FCV design constraints, such as weight, volume, and efficiency, limit the amount of hydrogen that can be stored onboard a vehicle. Hydrogen storage costs for fuel cells must fall to about $2 per kilowatthour, from the current estimate of about $8 per kilowatthour for a system with a pressure of 5,000 pounds per square inch.[6]

Hydrogen Vehicles. Perhaps the biggest impediments to a hydrogen economy require resolution of technical, economic, and safety challenges related to the FCVs themselves. Federal and State policies and incentives are likely to be needed to encourage fuel cell and vehicle manufacturers to invest in hydrogen FCVs. The cost of the fuel cells must fall to $30 per kilowatt,[7] compared with current cost estimates of $3,000 to $5,000 per kilowatt for production in small numbers. While projected fuel cell costs at a scale of 500,000 units per year would be considerably lower, in the neighborhood of $100 per kilowatt according to one recent study,[8] accomplishing a reduction in fuel cell costs to $30 per kilowatt over a period consistent with the time frames associated with any of the vehicle penetration rates analyzed here would represent technological learning and progress at rates that would be unprecedented for consumer durables.

Bridge Technologies. There are some “bridge” technologies that might provide some initial penetration that could lead to more experience with hydrogen as a fuel and greater public acceptance. For example, deployment of LDVs with hydrogen internal combustion engines (HICEs), which currently have a significantly lower incremental cost than FCVs, may represent an option for developing hydrogen production and fueling infrastructure; however, they still may be cost prohibitive for the average consumer. Unless there are CO_2 emission constraints or government incentives, HICE vehicles are not likely to penetrate the market significantly in the short term.

Similarly, the use of fuel cells in stationary applications could provide a path for continued development of fuel cell technology. Stationary fuel cells can be economically attractive at costs significantly above $30 per kilowatt of capacity. In addition, natural gas can be used with an on-site reformer to generate hydrogen for many stationary applications of fuel cells, allowing for deployment in advance of the availability of a hydrogen distribution infrastructure.

In sum, although R&D eventually could succeed in solving all the technical and economic challenges that are faced in making hydrogen FCVs a cost-effective reality, several concurrent successes and investments would be required within the next 25 years to permit early FCV penetration and the concomitant development of a fueling infrastructure. Other promising technologies, such as PHEVs with an extended driving range on electricity from the grid, also offer opportunities for major reductions in petroleum use and CO_2 emissions from LDVs. Competition from PHEVs presents further challenges to the prospect of a large future market for hydrogen FCVs.

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[6]U.S. Department of Energy, *Analysis of the Transition to a Hydrogen Economy and the Potential Energy Infrastructure Requirements* (Draft v.5-11-07)” (Washington, DC, May 2007), p. 4. The current costs assume compressed storage tanks operating at 5,000 psi.

[7]*Ibid.*, p. 4; and D.L. Greene, P.N. Leiby, and D. Bowman, *Integrated Analysis of Market Transformation Scenarios with HyTrans*, ORNL/TM-2007/094 (Oak Ridge, TN: Oak Ridge National Laboratory, June 2007).

[8]National Research Council, Committee on Assessment of Resource Needs for Fuel Cell and Hydrogen Technologies, *Transitions to Alternative Transportation Technologies—A Focus on Hydrogen* (Washington, DC, July 2008).

1. Introduction

Background

This report responds to a request from Senator Byron L. Dorgan for an analysis of the impacts on U.S. energy import dependence and emission reductions that could result from the commercialization of advanced hydrogen and fuel cell technologies in the transportation and distributed generation markets. As described in Senator Dorgan's request, substantial industry and Federal investments in research, development, and demonstration (RD&D) to enable a hydrogen economy have been, and continue to be, made since the completion of a 2004 National Academy of Sciences study.[9] The requested service report includes a group of detailed scenarios that highlight key issues affecting U.S. energy import dependence and CO_2 emissions. A copy of the service report request letter is provided in Appendix A.

The time horizon and the modeling framework employed to produce quantitative results for this report are beyond the scope of the National Energy Modeling System (NEMS). Industry and government researchers generally (but not universally) concur that significant market penetration of fuel cells and FCVs may begin by 2020 but would not achieve significant impacts until after 2030. EIA agrees with that conclusion; consequently, hydrogen is not modeled within NEMS, which currently has a time horizon through 2030.[10] Instead, EIA used a separate model, VISION,[11] for this analysis. The VISION model, described in Chapter 3, allows for a focus on issues directly associated with the hydrogen economy through 2050.

EIA's long-term projections typically are based on consideration of energy data and recent market trends; however, the availability and quality of hydrogen data are considerably more uncertain than those for other primary fuels or energy carriers. The Census Bureau's Industrial Gases Survey was discontinued in 2005,[12] and EIA currently surveys only a portion of the overall U.S. hydrogen capacity at oil refineries. Also, much of the published information on the hydrogen sector is incomplete, inconsistent, and outdated. A variety of reported measuring units (e.g., tons versus tonnes, standard cubic feet versus kilograms) and non-standard terminology further confound any analysis. Estimates of U.S. hydrogen capacity, even when published by the same organizations, have varied widely as a result of unit conversion errors. In compiling this report, EIA researched a wide variety of source materials, resolved the inconsistencies where possible, and provided its best estimate in those cases where definitive data were not available. Standard metric units are used to report the data and analysis results.

Report Organization

Chapter 2 of this report systematically reviews the components of existing industrial hydrogen production, capacity, and use, as well as those elements associated with the contemplated future hydrogen economy. The review proceeds from sources of supply and production technologies through distribution and storage issues, and then to dispensing and end uses. End-use issues are related to HICEs and FCVs as well as stationary applications of hydrogen fuel cells.

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[9] The National Academies, Board on Energy and Environmental Systems, *The Hydrogen Economy: Opportunity, Costs, Barriers, and R&D Needs* (Washington, DC, February 2004), web site www.nap.edu/catalog/10922.html.

[10] For an overview of NEMS refer to Energy Information Administration (EIA), *The National Energy Modeling System: An Overview 2003*, DOE/EIA-0581(2003) (Washington, DC, March 2003), web site www.eia.doe.gov/oiaf/aeo/overview/ index.html.

[11] Developed by Argonne National Laboratory. See web site www.transportation.anl.gov/ modeling_simulation/VISION.

[12] Census Bureau, U.S. Department of Commerce, *Current Industrial Reports: Industrial Gases, 2004* (Washington, DC, September 2005), web site www.census.gov/industry/1/mq325c045.pdf.

Chapter 3 provides quantitative estimates of energy and CO_2 emission impacts of FCVs, based on different market penetration scenarios, hydrogen production technologies (including the manner in which they are deployed from distributed to centralized production), and hydrogen vehicle efficiency (fuel economy). The results are compared with results for an alternative technology, PHEVs. The analysis provides some observations and insights into the potential impacts of the large-scale introduction of hydrogen vehicles.

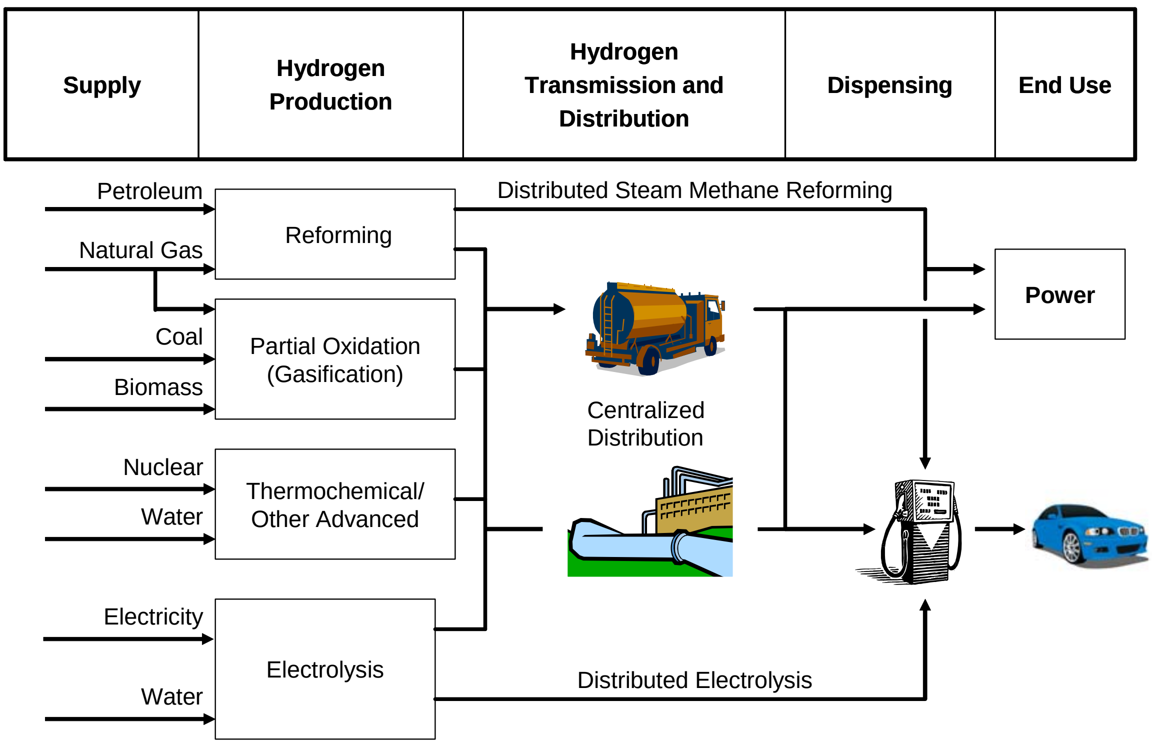
Chapter 4 addresses the challenges of making an expanded hydrogen economy a reality. Although EIA cannot project whether or when one or more of the technical breakthroughs required will be achieved, an appreciation of the magnitude of the challenges provides insight into the potential long-term path toward a hydrogen economy.

2. Hydrogen Economy Systems and Technology Review

This chapter reviews the hydrogen economy as currently envisioned by a variety of researchers and developers, using a systematic approach from supply through end use. Key production and end-use technologies are reviewed, including an assessment of current industry practice and challenges or opportunities within each of those elements.

A simplified system overview of the current and potential hydrogen economy is shown in Figure 2.1. The essential system elements include supply, production, distribution, dispensing, and end use. Although this overview includes a number of potential hydrogen supply and end-use scenarios, some elements may be condensed or abbreviated, depending on the particular application. For example, an early-stage implementation of hydrogen supply for hydrogen-fueled vehicles is through SMR of natural gas at the dispensing station. In that case, natural gas is delivered straight to the retail outlet from the point of supply, and the corresponding hydrogen transportation from the point of production is no more than a short pipe run.

Figure 2.1. Simplified Overview of the Hydrogen Economy



Source: Energy Information Administration.

The number of potential feedstock and production process pathways is greater than depicted in Figure 2.1. For example, electricity used in electrolysis could be grid-sourced or provided through a dedicated electric source at the point of production (i.e., wind, solar, biomass, etc.). Some potential feedstocks, such as ethanol, are themselves derived from other feedstocks and can be categorized generally with the primary feedstock source. Finally, hydrogen is also produced as a byproduct of other manufacturing processes, which could provide a hydrogen supply in addition to the hydrogen production technologies shown in Figure 2.1. This chapter considers each system element in turn, with particular emphasis on existing and future considerations with regard to production and end-use applications.

Hydrogen Supply

Hydrogen is the most abundant element in the universe. Yet, there is effectively no natural hydrogen gas resource on Earth. Hydrogen gas is the smallest and lightest of all molecules. When released, it quickly rises to the upper atmosphere and dissipates, leaving virtually no hydrogen gas on the Earth's surface. Because hydrogen gas must be manufactured from feedstocks that contain hydrogen compounds, it is considered to be an energy carrier, like electricity, rather than a primary energy resource.

Currently, the main sources of hydrogen are hydrocarbon feedstocks such as natural gas, coal, and petroleum; however, some of those feedstocks also produce CO_2. Thus, to provide overall emission savings, greenhouse gas (GHG) emissions must be mitigated during hydrogen production through CCS or similar technology, during end use through comparatively greater vehicle efficiency, or at other stages in the life cycle of the hydrogen fuel source.

In terms of fossil fuel supply, the estimated technically recoverable resource base for crude oil, natural gas, and coal in the United States in 2006 was 166 billion barrels,[13] 1,365 trillion cubic feet,[14] and 264 billion short tons,[15] respectively. Those resource levels amount to 33, 74, and 280 years of supply, respectively, at U.S. production levels in 2006.[16] It is generally recognized, however, that demand is not static and the accessibility of resources may be problematic. Also, the costs for addressing CO_2 and other GHG emissions may increase, which could deter the full utilization of fossil fuels as a primary energy source for a hydrogen economy unless suitable mitigation measures are employed.

Hydrogen can also be produced from cellulosic biomass, through a process much like coal gasification, to produce synthesis gas that is a mixture of hydrogen and carbon monoxide, from which the hydrogen can be removed and purified. EIA's estimate of biomass supply is as much as 10 quadrillion Btu per year in 2030. This estimate was derived in early 2007 using an integrated land and crop competition model known as POLYSYS.[17] Demand for cellulosic biomass is expected to increase as a result of the renewable fuel provisions in the Energy Independence and Security Act of 2007 (EISA2007), including increased production of cellulosic ethanol and other biomass-to-liquid (BTL) fuels.[18]

Another source for hydrogen production is electrolysis of water. For decades, the National Aeronautics and Space Administration (NASA) has used this process in hydrogen fuel cells to produce both power and water for its astronauts in space. However, hydrogen production from conventional grid-based electricity is an expensive process, as discussed below, and at present it is the least carbon-neutral method for hydrogen production, given that more than 49 percent of U.S. electricity generation in 2007 was from coal-fired power plants. Reducing costs and emission impacts may be achievable through the application of CO_2 mitigation measures for existing electricity generation technologies or through breakthroughs in advanced electrolysis technologies.

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[13]EIA, *Assumptions to the Annual Energy Outlook 2008*, DOE/EIA-0554(2008) (Washington, DC, June 2008).
[14]*Ibid.*
[15]EIA, "Coal Reserves Current and Back Issues," web site www.eia.doe.gov/cneaf/coal/reserves/reserves.html.
[16]In 2006, U.S. crude oil production was 5.1 million barrels per day and natural gas production was 18.5 trillion cubic feet. See EIA, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008).
[17]Dr. Daniel de la Torre Ugarte, University of Tennessee, provided the initial supply curves for cellulosic biomass inApril 2007, using the agricultural model POLYSIS. The curves were used initially to study the combined economic and energy impacts of a 25-percent renewable fuel standard and 25-percent electricity renewable portfolio standard, using EIA's *AEO2007* world oil price assumptions. See EIA, *Energy and Economic Impacts of Implementing Both a 25-Percent Renewable Portfolio Standard and a 25-Percent Renewable Fuel Standard by 2025*, SR/OIAF/2007-05 (Washington, DC, August 2007).
[18]EIA, *Annual Energy Outlook 2008*, DOE/EIA-0383(2008) (Washington, DC, June 2008).

Options for mitigating the CO_2 emissions produced when grid-based electricity is used for electrolysis include building new renewable generators (e.g., wind or biomass) and purchasing off-peak (surplus) power, presumably at low wholesale prices, from renewable generators and nuclear power plants to generate hydrogen. Each of these alternatives creates a new set of questions and challenges.

The construction of new renewable generation capacity for the exclusive purpose of producing hydrogen from electrolysis is unlikely to be desirable from an investment perspective if, in order to make the resulting hydrogen competitive, the cost of the electricity is required to be less than the wholesale price at which that electricity could be sold to the grid. The price would include any other tax credits and any Renewable Portfolio Standard (RPS) credits that might accrue if the electricity were sold to the grid. Because the value of wind-generated electricity is likely to be much higher when it is sold to the grid, investments in standalone wind systems to produce hydrogen appear to be unlikely economically. The use of biomass-generated electricity exclusively for hydrogen production would be even less attractive than wind because of higher capital costs and, unlike wind, significant feedstock costs. On the other hand, direct biomass gasification would have much better economic prospects for producing hydrogen than either wind or biomass generation if the engineering challenges of raising the maximum capacity utilization to at least 80 percent were overcome.[19]

Under a CO_2-constrained scenario, large amounts of existing coal-fired capacity are likely to be retired, and new nuclear and renewable generators are likely to be added, to meet the CO_2 emissions target. Because a CO_2-constrained scenario is defined by policies that achieve a targeted level of CO_2 emission reductions, any grid-based power production would already have those target CO_2 emission levels factored into prices, with wind, biomass, and other power sources having been rewarded for their contributions, and higher CO_2-emitting technologies having been penalized, as appropriate.

Hydrogen Production

Hydrogen production processes can be classified generally as those using fossil or renewable (biomass) feedstocks and electricity. The technology options for fossil fuels include reforming, primarily of natural gas in “on-purpose” hydrogen production plants,[20] and production of hydrogen as a byproduct in the petroleum refining process. Partial oxidation technologies, which can include gasification of solid or liquid feedstocks, are another option for hydrogen production. Electrolysis processes using grid or dedicated energy sources, including some advanced techniques that have not yet been proven, also can be used. Among those advanced techniques are thermochemical processes, including nuclear as an energy source. In addition, hydrogen is produced as a byproduct of some other existing industrial processes.

Significant amounts of hydrogen are produced and consumed in the United States and worldwide, using a number of commercially-proven technologies. For example, EIA estimates that the United States produced about 17 percent of the 53 million metric tons of hydrogen consumed in 2004

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[19]The current maximum capacity factor for biomass gasification is less than 60 percent, because biomass shredders tend to jam and must be taken offline to be cleared.

[20]“On-purpose” production facilities are defined by the industry as those facilities where the primary purpose is the production of hydrogen gases or liquids.

throughout the world.[21] One way to appreciate the scale of the existing hydrogen economy is to consider that the 10.7 million metric tons of U.S. hydrogen production capacity would produce 1.4 quadrillion Btu at full utilization, which is equivalent to 660 thousand barrels of crude oil[22] or 1.4 trillion cubic feet of natural gas per day. Appendix C provides an overview of existing hydrogen production capacity in the United States.

On-Purpose Hydrogen Production Technologies

The on-purpose hydrogen production technologies are reforming, partial oxidation (including gasification), and electrolysis. Each process has its own advantages and disadvantages with respect to capital costs, efficiency, life-cycle emissions, and technological progress.

Reforming of hydrocarbon feedstocks can be done using technologies such as the SMR process, which is the most commonly used method to supply large centralized quantities of hydrogen gas to oil refineries, ammonia plants, and methanol plants. The SMR process is popular because its natural gas feedstock has high hydrogen content (four hydrogen atoms per carbon atom) and because a distribution network for the natural gas feedstock already exists.

One benefit of SMR technology is its high degree of scalability. SMR production costs are highly dependent on the scale of production. Large, modern SMR hydrogen plants have been constructed with hydrogen generation capacities exceeding 480,000 kilograms of hydrogen per day, or about 200 million standard cubic feet per day. These large hydrogen plants typically are co-located with the end users in order to reduce hydrogen gas transportation and storage costs. In addition, SMR technology is also scalable to smaller end-use applications. This has the potential advantage, during the early phases of a hydrogen transportation economy, of having hydrogen production located at the dispensing stations, so that the existing natural gas distribution system can be used to have feedstocks delivered close to the point of production and end use. The distributed SMR approach reduces or eliminates the need for a dedicated hydrogen transmission, storage and distribution infrastructure.

Partial oxidation of a hydrogen-rich feedstock (such as natural gas, coal, petroleum coke, or biomass) is another pathway for hydrogen production. With natural gas as a feedstock, the partial oxidation process typically produces hydrogen at a faster rate than SMR, but it produces less hydrogen from the same quantity of feedstock. Moreover, as a result of increasing natural gas prices, the further development of natural gas partial oxidation technology has slowed. The use of solid fuels is also possible, through gasification, to produce a synthetic gas (syngas) that can then be used in a partial oxidation process to obtain a hydrogen product.

Electrolysis, or water splitting, uses energy to split water molecules into their basic constituents of hydrogen and oxygen. The energy for the electrolysis reaction can be supplied in the form of either heat or electricity. Large-scale electrolysis of brine (saltwater) has been commercialized for chemical applications. Some small-scale electrolysis systems also supply hydrogen for high-purity chemical applications, although for most medium- and small-scale applications of hydrogen fuels, electrolysis is cost-prohibitive.

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[21]U.S. hydrogen production and utilization has been estimated by various sources to have been 9 million metric tons in 2004. See U.S. Climate Change Technology Program, web site www.climatetechnology.gov/library/2005/tech-options/tor2005-223.pdf. World hydrogen production has been estimated at 52 million metric tons for the captive hydrogen sector and 2.5 million metric tons for the merchant sector by Venki Raman, "Hydrogen Production and Supply Infrastructure for Transportation - Discussion Paper," in Pew Center on Global Climate Change and National Commission on Energy Policy, *10-50 Workshop Proceedings: The 10-50 Solution: Technologies and Policies for a Low-Carbon Future, March 25-26, 2004*, web site www.pewclimate.org/global-warming-in-depth/workshops_and_conferences/tenfifty/proceedings.cfm.
[22]On a higher heating value basis of 0.135 million Btu per kilogram (Appendix B) and assuming 5.8 million Btu per barrel for crude oil.

One drawback with all hydrogen production processes is that there is a net energy loss associated with hydrogen production, with the losses from electrolysis technologies being among the largest. The laws of energy conservation dictate that the total amount of energy recovered from the recombination of hydrogen and oxygen must always be less than the amount of energy required to split the original water molecule. For natural gas SMR, the efficiency at which the feedstock is converted into hydrogen ranges from 67 percent to 73 percent. Despite the energy loss resulting from the conversion of natural gas to hydrogen in the SMR process, the fuel costs per mile for compressed natural gas (CNG) vehicles and FCVs are comparable. In fact, assuming current commercial natural gas prices and the current fuel economies of existing FCV and CNG vehicles, operating fuel costs for FCVs are less than those for CNG vehicles. With projected fuel efficiency improvements in both vehicles, however, the comparative operating fuel cost advantage could reverse, making CNG vehicles more competitive with FCVs, if SMR conversion efficiencies do not improve. It should be noted, however, that taking into account the incremental capital costs of these vehicles would result in a much higher cost associated with FCVs, unless there were also dramatic decreases in fuel cell and other production costs.

For electrolysis, the efficiency of converting electricity to hydrogen is 60 to 63 percent.[23] To the extent that electricity production itself involves large transformation losses, however, the efficiency of hydrogen production through electrolysis relative to the primary energy content of the fuel input to generation would be significantly lower. In certain cases, it may be economical to use off-peak electricity if it is priced well below the average electricity price for the day; however, such market applications would have to be balanced with other potential electricity supplies, the cost versus benefits of appropriate metering and rate design, and the implied reduction in utilization of the electrolysis unit, as described above. The development of such an application could also support other technologies, such as PHEVs.

Advanced technologies for hydrogen production are also being explored.[24] They include thermochemical reactions, such as those using nuclear fission, photosynthesis, fermentation, landfill gas recovery, and municipal waste reformation. However, the likelihood of the technological and economic success of these advanced technologies is not guaranteed.

Economics of Hydrogen Production Technologies

The economics of hydrogen production depend on the underlying efficiency of the technology employed, the current state of its development (i.e., early stage, developmental, mature, etc.), the scale of the plant, its annual utilization, and the cost of its feedstock. From a systems perspective, as shown in Figure 2.1, other considerations include the physical distance and availability of potential feedstocks from potential end-use markets for hydrogen gas, and whether to use centralized production in order to take advantage of economies of scale in production and incorporate hydrogen transmission and distribution systems from the plant gate, or rely on distributed hydrogen production, where the feedstocks are transported over a greater distances and the hydrogen gas transmission and distribution infrastructure is minimized.

A summary of the economics of select hydrogen production technologies, based on U.S. annual average prices during 2007, is provided in Table 2.1. The values in Table 2.1 are based on a review of existing literature, and many aspects of technology costs and performance have not been independently verified, but some trends in production cost economics can be observed. For example,

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[23]U.S. Department of Energy, Hydrogen Analysis Resource Center, "Hydrogen Production Energy Conversion Efficiencies" (Excel file), web site http://hydrogen.pnl.gov/cocoon/morf/hydrogen/article/706. The estimate excludes non-feedstock inputs and the energy losses to generate, transmit, and distribute the electricity.

[24]For example, M.W. Kanan, and D.G. Nocera, "In Situ Formation of an Oxygen-Evolving Catalyst in Neutral Water Containing Phosphate and Co^{2+}," *Science* (July 31, 2008).

large SMR plants using natural gas as a feedstock have a clear operating cost advantage over the smaller SMR units designed for distributed hydrogen production applications, mainly as a result of economies of scale and utilization.

Table 2.1. Estimated Hydrogen Production Costs

Technology and Fuel	Capacity MGPD	Overnight Capital Cost		Capacity Factor (Percent)	Hydrogen Production Cost (Dollars per Kilogram)			
		Million Dollars	Dollars per MGPD		Capital[a]	Feed-stock	O&M	Total
Central SMR of Natural Gas[b]	379,387	$181	$477	90	$0.18	$1.15	$0.14	**$1.47**
Distributed SMR of Natural Gas[c]	1,500	$1.14	$760	70	$0.40	$1.72	$0.51	**$2.63**
Central Coal Gasification w/ CCS[d]	307,673	$691	$2,246	90	$0.83	$0.56	$0.43	**$1.82**
Central Coal Gasification w/o CCS[d]	283,830	$436	$1,536	90	$0.57	$0.56	$0.09	**$1.21**
Biomass Gasification[e]	155,236	$155	$998	90	$0.37	$0.52	$0.55	**$1.44**
Distributed Electrolysis[f]	1,500	$2.74	$1,827	70	$0.96	$5.06	$0.73	**$6.75**
Central Wind (Electrolysis)[g]	124,474	$500	$4,017	90	$1.48	$1.69	$0.65	**$3.82**
Distributed Wind (Electrolysis)[h]	480	$2.75	$5,729	70	$3.00	$3.51	$0.74	**$7.26**
Central Nuclear Thermochemical[i]	1,200,000	$2,468	$2,057	90	$0.76	$0.20	$0.43	**$1.39**

SMR = Steam Methane Reforming; CCS = Carbon Capture and Sequestration; MGPD = thousand kilograms per day; O&M = Operations and Maintenance.

Note: Table excludes transportation and delivery costs and efficiency losses associated with compression or transportation.

[a]For all cases a 12-percent discount rate is used. Economic life of 20 years assumed for distributed technologies and 40 years for all other technologies. Average United States prices for 2007 are used where practicable.

[b]Assumes industrial natural gas price of $7.4 per million Btu and industrial electric price of 6.4 cents per kilowatthour.

[c]Assumes commercial natural gas price of $11 per million Btu and commercial electric price of 9.5 cents per kilowatthour.

[d]Assumes coal price of $2.5 per million Btu.

[e]Assumes biomass price of $2.2 per million Btu ($37.8 per ton).

[f]Assumes commercial electric price of 9.5 cents per kilowatthour.

[g]Excludes opportunity cost of wind power produced.

[h]Assumes grid supplies 70 percent of power at 9.5 cents per kilowatthour and remainder at zero cost.

[i]Includes estimated nuclear fuel cost and co-product credit as net feedstock cost, decommissioning costs included in O&M.

Sources: The National Academies, Board on Energy and Environmental Systems, *The Hydrogen Economy: Opportunity, Costs, Barriers, and R&D Needs* (Washington, DC, February 2004), web site www.nap.edu/catalog/10922.html; and U.S. Department of Energy, Hydrogen Program, *DOE H2A Analysis*, web site www.hydrogen.energy.gov/h2a_analysis.html.

For most of the production technologies shown in Table 2.1, plant capital costs are a relatively large portion of the production costs. The capital costs for the distributed wind (electrolysis) and central nuclear thermochemical technologies were obtained from a 2004 study by the National Academies of Sciences, while the other production costs were estimated by the National Renewable Energy Laboratory in 2005, with the exception of central coal gasification with CCS, whose costs were updated this year.[25]

The degree of sensitivity of total production costs to capital costs will depend on the production method. In the case of a centralized SMR plant, for example, the 2005 overnight capital cost was $181 million. Using the Chemical Engineering Plant Cost Index (CEPCI), the 2008 capital cost is computed to be $209 million (2008 nominal dollars), which would result in an increase in the

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[25]The National Academies, Board on Energy and Environmental Systems, *The Hydrogen Economy: Opportunity, Costs, Barriers, and R&D Needs* (Washington, DC, February 2004), web site www.nap.edu/catalog/10922.html; and U.S. Department of Energy, Hydrogen Program, *DOE H2A Analysis*, web site www.hydrogen.energy.gov/h2a_analysis.html.

product cost of $0.21 per kilogram of hydrogen, or 15 percent. If the operating and maintenance costs and feedstock costs are not adjusted, the increase in capital costs results in only a 3-percent increase in the total production cost. Much more important for the centralized SMR production cost is the price of natural gas, which has varied from about $6 per million Btu in 2005 to more than $13 per million Btu in 2008. Similarly, in the case of distributed electrolysis, the capital cost has increased to $1.11 per kilogram of hydrogen in 2008, based on the CEPCI, representing a 2-percent increase in the overall cost due to the relatively high cost of the electricity input.

At the other extreme, the total cost of hydrogen production from the central nuclear thermochemical method is most sensitive to capital costs, which account for 55 percent of the total hydrogen production cost. Using the CEPCI escalator, the capital cost component would have increased to $0.88 per kilogram of hydrogen in 2008, translating to a 9-percent increase in total production cost.

In addition to capital cost disadvantages because of their size, smaller plants tend to have higher feedstock and utility costs, lower conversion efficiencies, and higher per-unit costs for labor and other operations and maintenance costs. In addition, smaller distributed units are likely to have a lower capacity factor over which capital and fixed costs can be amortized, as indicated in Table 2.1. Including consideration of these factors, the distributed SMR production cost of $2.63 per kilogram is 79 percent higher than the central SMR production cost.

The substantially lower feedstock cost for coal drives the relatively lower overall production cost for coal gasification, both with and without CCS. However, coal gasification on this scale is limited,[26] and the application of CCS is at an early evaluation and testing stage.[27] The large scale of the plant drives unit capital costs down, but at costs approaching or exceeding $600 million, investment risk may be a concern.

Biomass gasification offers some of the same promise and concerns as coal gasification. On the positive side, life-cycle CO_2 emissions may be substantially less, with the possibility that CCS combined with biomass gasification might reduce GHG emissions. The energy density of the biomass feedstock is substantially less than that of coal, however, and it may not be practical to build a biomass gasification unit with a hydrogen production capacity of 155,000 kilograms and supply sufficient quantities of biomass to the plant site at a delivered price of $38 per ton.[28]

Electrolysis technologies suffer from a combination of higher capital costs, lower conversion efficiency, and a generally higher feedstock cost when the required electricity input is considered. A distributed electrolysis unit using grid-supplied electricity is estimated to have a production cost of $6.77 per kilogram of hydrogen when the assumed 70-percent capacity factor is considered. A central electrolysis unit operating at 90-percent capacity factor, with 30 percent of the power requirements coming from wind and 70 percent from the grid, is estimated to have a production cost roughly 15 percent higher than that of a distributed SMR plant.

Advanced nuclear-fueled thermochemical processes are unproven, but they may provide low per-unit production costs in the future, as indicated by the $1.39 per kilogram production cost. The estimated $2.5 billion investment required for a facility with a capacity of 1.2 million kilograms per

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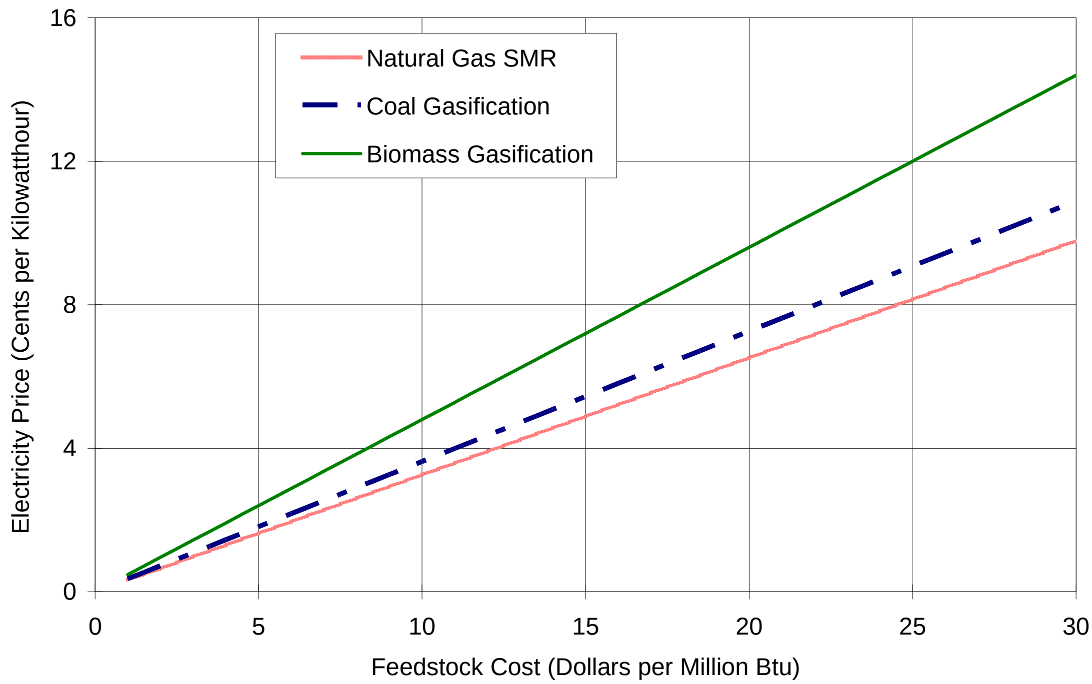
[26]The Tennessee Eastman Kodak and Great Plains Gasification facilities are two examples of large-scale commercial applications of coal gasification technology.
[27]One example is the sale of CO_2 produced at the Great Plains Synfuels Plant in Montana to PanCanadian Petroleum Limited for use in enhanced oil recovery and to test CO_2 sequestration at oil fields in Saskatchewan, Canada. See web site www.canadiangeographic.ca/magazine/JF08/feature_carbon.asp.
[28]For example, the 155,000 kilogram per day hydrogen biomass gasification plant would require about 720,000 metric tons of biomass per year, which is 167 percent more feedstock than required for a nominal 80-megawatt biomass power plant operating at 83 percent capacity.

day leads to capital charges of $0.76 per kilogram. The lower feedstock cost includes the cost of nuclear fuel, net of any co-product benefits from oxygen sales that may be available. Operating and maintenance costs include decommissioning costs in addition to the usual labor, taxes, security, and other costs.

Because feedstock and electricity prices can be expected to vary considerably over time, it is useful to change the assumed values for those prices used in Table 2.1 from point estimates to variables and plot the resulting "breakeven curves," as shown in Figure 2.2. The figure shows, for a given feedstock price in dollars per million Btu, what the electricity price would be for the cost of hydrogen production to be the same. For electricity prices above each line, the fossil or biomass feedstock in question would be less expensive than electrolysis, with the reverse being true for electricity prices below the line.

Figure 2.2. Breakeven Cost Curves for Hydrogen Production Between Carbonaceous Feedstocks and Electrolysis, Feedstock Cost Only

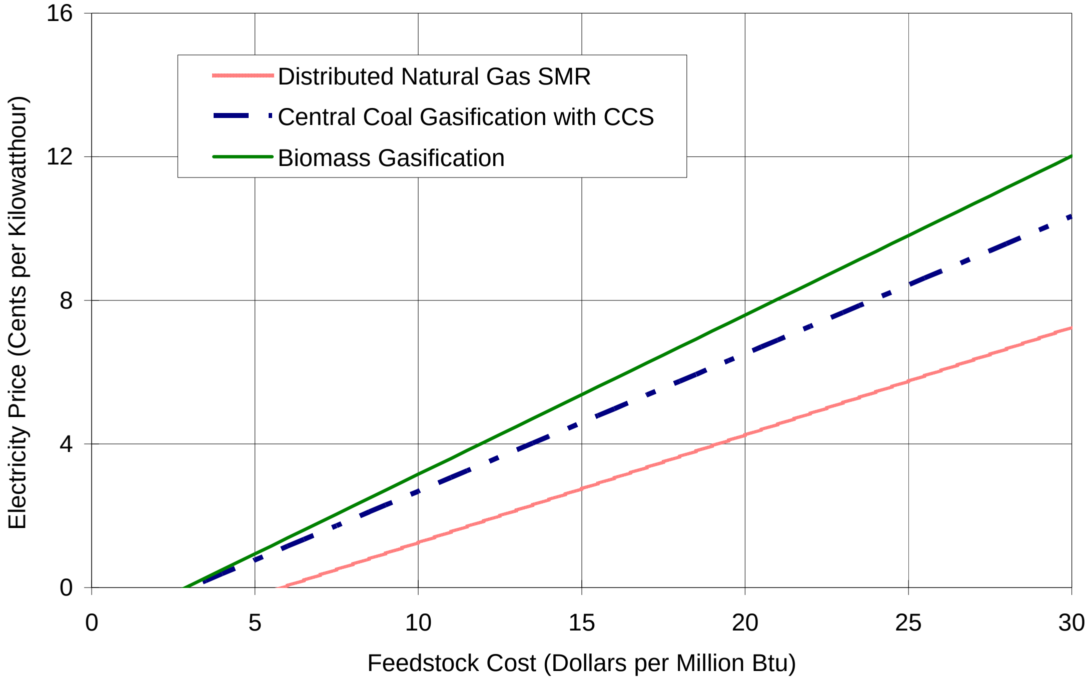


Sources: The National Academies, Board on Energy and Environmental Systems, *The Hydrogen Economy: Opportunity, Costs, Barriers, and R&D Needs* (Washington, DC, February 2004), web site www.nap.edu/catalog/10922.html; U.S. Department of Energy, Hydrogen Program, *DOE H2A Analysis*, web site www.hydrogen.energy.gov/h2a_analysis.html; and EIA.

Figure 2.2 considers only the carbonaceous feedstock versus the price of electricity used for electrolysis. Other costs, such as capital and operating and maintenance, could be applied to both electrolysis and other processes, with the differential of those costs applied to the lines as shown in Figure 2.3. Because electrolysis technologies generally have higher capital and operating and maintenance costs, the implied price for electricity would have to be lower to achieve cost parity with a fossil or biomass feedstock.

The "breakeven curves" shown in Figures 2.2 and 2.3 illustrate the cost advantage of using fossil or biomass-based feedstocks in comparison with current electrolysis technologies. With coal and biomass prices in the range of $2 to $3 per million Btu, those technologies can be seen to have a significant cost advantage over electrolysis. Even at delivered natural gas prices of $15 per million Btu, delivered electricity prices would have to be no more than 4.9 cents per kilowatthour on a feedstock basis only, as shown in Figure 2.2, or no more than 2.8 cents per kilowatthour when capital and other costs are also considered, as shown in Figure 2.3.

Figure 2.3. Breakeven Cost Curves for Hydrogen Production Between Carbonaceous Feedstocks and Electrolysis, All Costs



Sources: National Research Council and National Academy of Engineering, *The Hydrogen Economy: Opportunities, Costs, Barriers, and R&D Needs*, 2004, DOE Hydrogen Analysis Group, *DOE H2A Analysis*, web site www.hydrogen.energy.gov/h2a_analysis.html, and EIA.

Hydrogen Transmission and Distribution

Centrally produced hydrogen must be transported to markets. The development of a large hydrogen transmission and distribution infrastructure is a key challenge to be faced if the United States is to move toward a hydrogen economy. A variety of hydrogen transmission and distribution methods are likely to be used. Currently, small and mid-sized hydrogen consumers use truck, rail, and barge transportation modes for hydrogen in either liquid or gaseous form. Larger industrial users rely on pipelines and compressors to move the hydrogen gas. In theory, a blend of up to 20 percent hydrogen in natural gas can be transported without modifying the current 180,000-mile natural gas pipeline infrastructure.[29] Some States, including Pennsylvania and California, already are examining this option. However, pipelines that carry pure hydrogen will require special construction and materials in order to avoid issues of steel embrittlement and leakage. This analysis provides only a basic overview of hydrogen distribution issues.

A network for the commercial transmission and distribution of hydrogen gas has been developed and used successfully by the industrial gas industry. There are slightly over 1,200 miles of hydrogen gas pipelines today, compared with about 295,000 miles of natural gas transmission lines and approximately 1.9 million miles of natural gas distribution lines to deliver some 23 trillion cubic feet

[29] F. Oney, T.N. Veziroglu, and Z. Dulger, "Evaluation of Pipeline Transportation of Hydrogen and Natural Gas Mixtures," *International Journal of Hydrogen Energy*, Vol. 19, No. 10 (1994), pp. 813-822.

of natural gas per year.[30] Delivery methods for hydrogen are determined chiefly by the production volume and the delivery distance. For example, compressed gas pipelines are used to transport large volumes of hydrogen over short distances to industrial users, such as oil refineries and ammonia plants. Cryogenic, over-the-road tank trucks, railcars, and barges are used to transport mid-sized quantities of liquid hydrogen over longer distances.[31] Very small quantities of gaseous and liquid hydrogen currently are distributed via high-pressure cylinders and tube trailers. For transportation over longer distances, all the distribution options are relatively expensive, and typically they can more than double the delivered cost of the hydrogen.

Because hydrogen is highly volatile, safety is also a necessary enabling requirement for the current and potential future hydrogen economy. Safety issues are not, however, addressed in this report.

Hydrogen Pipeline Systems

Currently, more than 99 percent of all the hydrogen gas transported in the United States is transported by pipeline as a compressed gas. Pipeline transmission of hydrogen dates back to the late 1930s.[32] The pipelines that carry hydrogen generally have operated at pressures less than 1,000 pounds per square inch (psi), with a good safety record. As of 2006, the U.S. hydrogen pipeline network totaled over 1,200 miles in length, excluding on-site and in-plant hydrogen piping (Table 2.2). More than 93 percent of the U.S. hydrogen pipeline infrastructure is located in just two States, Texas and Louisiana, where large chemical users of hydrogen, such as refineries and ammonia and methanol plants, are concentrated.

Table 2.2. Miles of Hydrogen Pipeline in the United States

State	Miles of Hydrogen Pipeline	State	Miles of Hydrogen Pipeline
Alabama	30.9	New York	0.7
California	12.9	Ohio	1.8
Delaware	0.6	Texas	847.6
Indiana	15.0	West Virginia	6.7
Louisiana	290.0		
Michigan	6.5	**Total**	**1,212.7**

Source: U.S. Pipeline and Hazards Material Safety Administration (2006).

The natural gas supply system provides an interesting example of how a hydrogen supply system might ultimately evolve to support a hydrogen economy. Each day, close to 70 million customers in the United States depend on the natural gas distribution network to deliver fuel to their homes or places of business. Overall, the U.S. network comprises more than 302,000 miles of interstate and intrastate transmission pipelines for natural gas, more than 1,400 compressor stations that maintain pressure on the pipeline network and assure continuous forward movement of supplies, and more

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[30]U.S. Department of Transportation, Office of Pipeline Safety, web site http://primis.phmsa.dot.gov/comm/PipelineBasics.htm (2007).
[31]J. Ogden, "Hydrogen as an Energy Carrier: Outlook for 2010, 2030 and 2050," in Pew Center on Global Climate Change and National Commission on Energy Policy, *10-50 Workshop Proceedings: The 10-50 Solution: Technologies and Policies for a Low-Carbon Future, March 25-26, 2004*, web site www.pewclimate.org/global-warming-in-depth/workshops_and_conferences/tenfifty/proceedings.cfm.
[32]M. Altmann and F. Richert, "Hydrogen Production at Offshore Wind Farms," presented at the Offshore Wind Energy Special Topic Conference (Brussels, Belgium, December 10-12, 2001).

than 11,000 delivery points, 5,000 receipt points, and 1,400 interconnection points. Another 29 natural gas hubs or market centers provide additional interconnections, along with 399 underground natural gas storage facilities and 49 locations where natural gas can be imported and exported via pipeline.

In comparison, the existing U.S. hydrogen pipeline network is only one-third of 1 percent of the natural gas network in length and has less than 200 delivery points. Also, because of concerns over potential leakage, the hydrogen pipes tend to be much smaller in diameter and have fewer interconnections. Special positive displacement compressors are also required to move hydrogen through the pipelines. The length of hydrogen gas piping tends to be short, because it is usually less expensive to transport the hydrogen feedstock, such as natural gas, through the existing pipeline network than to move the hydrogen itself through new piping systems. Historically, welded hydrogen pipelines have been relatively expensive to construct (approximately $1.2 million per transmission mile and $0.3 million per distribution mile).[33] Consequently, the pipelines have required a high utilization rate to justify their initial capital costs.[34] More recently, polyethylene sleeves and tubing systems have emerged as a possible low-cost alternative solution for new hydrogen distribution systems, with total capital investments for transmission piping potentially dropping to just under $0.5 million per mile (in 2005 dollars) by 2017 and with commensurately lower costs for distribution lines.[35]

How a centralized hydrogen transmission and distribution system will evolve is unknown, and therefore the costs cannot be estimated with a high degree of confidence. The costs will depend on where the pipelines are sited, rights-of-way, pipeline diameter, quality and nature of the pipeline materials required to address the special properties of hydrogen, operating pressures, contractual arrangements with hydrogen distributors, financing and loan guarantees, the locations of dispensing stations relative to distributors, and how applicable environmental and safety issues in the production, transmission, distribution, and dispensing of hydrogen are addressed. Because all hydrogen gas has to be manufactured, hydrogen production facilities may be located in ways that minimize overall production and delivery costs.

Liquid Hydrogen (Cryogenic) Transport

Hydrogen can be cooled and liquefied in order to increase its storage density and lower its delivery cost. There are currently four liquid hydrogen suppliers and seven production plants in the United States with a total production capacity of about 76,495 metric tons per day. Those facilities support about 10,000 to 20,000 bulk shipments of liquid hydrogen per year to more than 300 locations.[36] Most long-distance transfers of hydrogen use large cryogenic barges, tanker trucks, and railcars to transport the liquid hydrogen.[37] NASA is the largest consumer of liquid hydrogen. The chief constraints to widespread use of this hydrogen transportation mode relate to the energy losses associated with liquefying hydrogen and the storage losses associated with boil-off.

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[33]See U.S. Department of Energy, Energy Efficiency and Renewable Energy, *Hydrogen, Fuel Cells & Infrastructure Technologies Program: Multi-Year Research, Development and Demonstration Plan*, Table 3.2.2 (Washington, DC, October 2007), web site www1.eere.energy.gov/hydrogenandfuelcells/mypp.
[34]*Ibid.*
[35]B. Smith, B. Frame, L. Anovitz, and T. Armstrong, "Composite Technology for Hydrogen Pipelines," in U.S. Department of Energy, Hydrogen Program, *2008 Annual Merit Review Proceedings*, web site www.hydrogen.energy.gov/annual_review08_proceedings.html.
[36]See Northeast Advanced Vehicle Consortium, "Fuel Cell Buses: Where Does Hydrogen Come From?" web site www.navc.org/wheredoes1.html.
[37]See OCEES International, Inc., "Hydrogen: The Fuel of the Future," web site www.ocees.com/textpages/txthydrogen.html.

Compressed Hydrogen Gas Cylinders

Hydrogen is also distributed in high-pressure compressed gas "tube trailer" trucks and cylinder bottles. This delivery method is relatively expensive, and typically it is limited to small quantities and distances of less than 200 miles.

Alternative Chemical Carriers

Hydrogen also can be transported using hydrogen-rich carrier compounds, such as ethanol, methanol, gasoline, and ammonia. Such carriers offer lower transportation costs, because they are liquids at room temperature and usually are easier to handle than cryogenic hydrogen; however, they also require an extra transformation step, with costs that must be weighed against the cost savings associated with transporting low-pressure liquids. Hydrogen carriers such as methanol and ammonia may also present some additional safety and handling challenges.

Hydrogen Fuel Distribution

The most economical methods for distributing hydrogen depend on the quantities and distances involved. For distribution of large volumes of hydrogen at high utilization rates, pipeline delivery is almost always cheaper than other methods—except in the case of long-distance transportation, e.g., over an ocean, in which case liquid hydrogen transport is cheaper. Laying a hydrogen distribution system in large, high-density cities can also be very expensive, approaching the cost of transmission systems, because existing roads must be dug up and repaired following practices to minimize disruptions to other co-located systems, such as electricity, natural gas, communication cables, etc.

For smaller quantities of hydrogen, pipeline delivery methods are not as competitive as liquid hydrogen delivery or compressed gas delivery via tube trailer or cylinders. The tube trailers have lower power requirements and slightly lower capital costs, although many more tube trailers may be required to deliver the same quantity of hydrogen. Distance is the chief deciding factor between liquid and gaseous hydrogen. At long distances, costs for the number of trucks needed to deliver a given quantity of compressed hydrogen will be greater than the energy costs associated with liquefaction and fewer trucks.

Hydrogen Storage

Because hydrogen gas has such a low density, and because the energy requirements for hydrogen liquefaction are high, efficient hydrogen storage generally is considered to be among the most challenging issues facing the hydrogen economy. For current chemical applications, storage issues are not so critical, because the large producers of hydrogen both generate and consume the gas simultaneously on site, thereby reducing storage and distribution requirements significantly.

Stationary Storage Systems

There are no official statistics on the locations, designs, and capacities of U.S. hydrogen chemical storage facilities. Some privately published data exist, from which the following estimates were derived:

- **Intermediate-Scale Compressed Gas Storage Tanks.** About 600 large high-pressure gaseous storage facilities currently exist in the United States.[38]

- **Intermediate-Scale Liquid Hydrogen Storage Tanks.** About 459 large liquid hydrogen storage sites exist in 41 States.[39] In addition, 4 States (California, Illinois, Michigan, and Nevada) and Washington, DC, currently operate hydrogen vehicle refueling stations that use liquid hydrogen as the storage medium.

- **Large-Scale Gaseous Storage in Caverns and Salt Domes.** Very large quantities of hydrogen can be stored as a compressed gas in geological formations such as salt caverns or deep saline aquifers. There are two existing underground hydrogen storage sites in the United States.

In addition, the co-storage of hydrogen with natural gas has been proposed. There are 417 locations in the United States where natural gas is currently stored in rock caverns, salt domes, aquifers, abandoned mines, and oil/gas fields, with a total storage capacity exceeding 3,600,000 million cubic feet. Hydrogen stored in salt caverns has the best injection and withdrawal properties.

Small-Scale and Mobile Storage Systems

The largest challenges for hydrogen storage are related to transportation applications, in which constraints on hydrogen vehicle design, weight, volume, and efficiency, limit the amount of the gas that can be stored onboard a vehicle. Currently, about 4 to 10 kilograms of hydrogen are required to power an LDV for 300 miles, which is the driving range that most consumers expect. Neighborhood hydrogen refueling stations also are expected to require small- to medium-scale storage systems compatible with the small footprint of existing gasoline stations. Several small-scale storage options are currently under development, but each has some limitation:

- **Compressed Gas Storage Tanks.** Compressed gas is currently the preferred method for onboard vehicular storage; however, very high gaseous storage pressures, on the order of 5,000 to 10,000 psi (350 to 700 bar), are required to contain a sufficient driving range of fuel. They are relatively expensive, and the high operating pressures give rise to safety concerns in the event of an accident. In addition, there is significant use of energy to compress the gas. Nevertheless, more than 95 percent of all current hydrogen vehicles use compressed gas storage systems, and driving ranges of 200 to 300 miles are being achieved in the latest U.S. vehicle designs. With production at 500,000 units per year, high-pressure storage tanks for hydrogen (5,000 to 10,000 psi) are estimated to range in cost from about $8 per kilowatthour to $17 per kilowatthour,[40] depending on the pressure capability. Assuming that the full 5-kilogram and 10-kilogram hydrogen storage capabilities of the 5,000 psi and 10,000 psi rated storage tanks can be utilized, the hydrogen storage costs would range from $1,340 to $1,420 per vehicle at production volumes, which would constitute slightly more than an order of magnitude reduction from current costs.

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[38]T. Joseph, "Distribution, Storage, and Dispensing of Hydrogen at Vehicle Refueling Stations," presented at the ASME International Pipeline Conference, Calgary, Alberta, Canada (October 5, 2004), web site www.fitness4service.com/news/pdf_downloads/h2forum_pdfs/Joseph-APCI.pdf.

[39]*Ibid.*

[40]A.R. Abele, "Quantum Hydrogen Storage Systems," presented at the ARB ZEV Technology Symposium, Sacramento, CA, September 25-27, 2006, web site www.arb.ca.gov/msprog/zevprog/symposium/presentations/abele1_storage.pdf. The higher pressures attempt to increase the acceptability of the range of the vehicle to consumers. The costs quoted assume a production volume of 500,000 160-liter MPa tanks with optimized carbon fiber and health system.

- **Liquid Hydrogen Storage Tanks.** Liquid hydrogen has the highest energy storage density and lowest vehicular weight of any current method, but it also requires an expensive, insulated storage container (dewar) and an energy-intensive liquefaction process. Several concept vehicles have been developed and placed in service in the United States and Europe with liquid hydrogen storage. The cost of such a storage system is a concern, and if the storage system does not have an active refrigeration unit, approximately 2 percent of the hydrogen will need to be vented every day as it evaporates. The volume capacity required for liquid hydrogen will vary significantly, depending on whether the fuel is used in an HICE vehicle or an FCV. Because liquid hydrogen on a volume basis has approximately 26 percent the energy of a gallon of gasoline, the liquid hydrogen tank must have a capacity 3.8 times that of a gasoline tank to hold the same amount of energy. For conventional internal combustion engine (ICE) vehicles with an efficiency of 30 miles per gallon, a 15-gallon gasoline tank provides approximately the same range as a 60-gallon liquid hydrogen tank. For FCVs with an efficiency equivalent of 62 miles per gallon, a 28-gallon tank containing about 7.3 kilograms of liquid hydrogen will be required.

- **Advanced Storage Methods.** Other advanced storage methods include metallic and chemical hydrides, amides, alanate storage systems, and carbon nanotubes. Solid metal and chemical systems offer some unique storage solutions for hydrogen, with the main challenges at the current time being their weight and their slow response time during refueling. The interstitial storage of hydrogen in carbon nanotubes is another concept with potential for very lightweight hydrogen storage, but the R&D is still preliminary. In addition, several other storage systems and mechanisms may be promising, including the use of sponge iron and glass microspheres.

Hydrogen Dispensing

Currently, only a small number of States and the District of Columbia have announced plans to construct "Hydrogen Highways" with the refueling and maintenance stations needed to support hydrogen LDVs.[41] California has progressed furthest, with 31 installed hydrogen refueling stations (about one-half of the U.S. total) and a few private maintenance facilities.

More recently, an "East Coast Hydrogen Highway" has been proposed by a consortium of automobile manufacturers and hydrogen suppliers.[42] Initial hydrogen refueling stations have been constructed for public access in Washington, DC, and New York. Also, there is a military hydrogen refueling station in Virginia.

As of 2007, there were a total of 63 hydrogen demonstration refueling stations in the United States (Table 2.3). Two-thirds of the existing refueling stations are capable of self-producing hydrogen, and the remaining one-third are stationary or mobile refueling stations that rely on deliveries of liquid or gaseous hydrogen for their operation. Currently, there are no home refueling stations except those located at manufacturers' research facilities. California hosts the Nation's only hydrogen refueling station that is connected to a hydrogen pipeline and a centralized production plant.

Compression costs must be included in any discussion of the operating costs for hydrogen dispensing stations. For example, if hydrogen is produced via distributed SMR, the SMR typically produces hydrogen gas at a pressure of 150 to 200 psi, which then must be compressed to at least 6,000 psi in a storage tank, to be delivered to a vehicle's 5,000 psi fuel tank. Typically, the energy

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[41] California, Florida, Illinois, Michigan, New York, South Carolina, and Washington, DC.
[42] Johnson Matthey, "'Hydrogen Highway' Comes to the East Coast," *Platinum Today*, web site www.platinum.matthey.com/media_room/1141398005.html.

required for this compression is roughly 3 kilowatthours per kilogram of hydrogen,[43] which, at today's commercial electricity prices (approximately $0.09 per kilowatthour), translates into a compression cost of $0.27 per kilogram.

Table 2.3. Hydrogen Refueling Stations in the United States, 2007

State	Number of Self-Producing Hydrogen Refueling Stations	Number of Merchant-Supplied Hydrogen Refueling Stations	Total Number of Hydrogen Refueling Stations
Arizona	1	1	**2**
California	25	6	**31**
Connecticut	2	–	**2**
District of Columbia	1	–	**1**
Florida	2	–	**2**
Hawaii	1	1	**2**
Illinois	1	1	**2**
Indiana	1	–	**1**
Michigan	2	6	**8**
Missouri	–	1	**1**
Nebraska	1	–	**1**
Nevada	2	–	**2**
New York	2	1	**3**
North Carolina	1	–	**1**
Ohio	–	1	**1**
Pennsylvania	1	–	**1**
Vermont	1	–	**1**
Virginia	–	1	**1**
Total	**44**	**19**	**63**

Sources: EIA research, California Fuel Cell Partnership, the National Hydrogen Association, Fuel Cells 2000, DOE *Transportation Energy Data Book*: Edition 26-2007; and U.S. Department of Energy, Alternative Fuels Data Center.

Hydrogen End Use Applications

A multi-billion-dollar hydrogen industry currently exists in the United States, serving a myriad of hydrogen end-use applications; however, about 99 percent of that hydrogen currently is used in chemical and petrochemical applications. Of the end uses, the largest consumers are oil refineries, ammonia plants, chlor-akali plants, and methanol plants. Some specific examples of hydrogen end use include:

- **Petroleum refining**—to remove sulfur from crude oil as well as to convert heavy crude oil to lighter products
- **Chemical processing**—to manufacture ammonia, methanol, chlorine, caustic soda, and hydrogenated non-edible oils for soaps, insulation, plastics, ointments, and other chemicals
- **Pharmaceuticals**—to produce sorbitol, which is used in cosmetics, adhesives, surfactants, and vitamins
- **Metal production and fabrication**—to create a protective atmosphere in high-temperature operations, such as stainless steel manufacturing
- **Food processing**—to hydrogenate oils, such as soybean, fish, cottonseed, and corn oil

[43] Communication with Tom Harrison, Praxair (July 10, 2008).

- **Laboratory research**—to conduct research and experimentation
- **Electronics**—to create a special atmosphere for the production of semiconductor circuits
- **Glass manufacturing**—to create a protective atmosphere for float glass production
- **Power generation**—to cool turbo-generators and to protect piping in nuclear reactors.

The transportation sector and stationary power applications are widely viewed as the two critical sectors where there may be an opportunity to expand greatly the future use of hydrogen. These two sectors are the focus of the rest of this section.

Transportation End Uses

A wide variety of transportation end uses have been demonstrated in recent years, including hydrogen-fueled transit buses, ships, submarines, aircraft, bicycles, motorcycles, and scooters. Most of the hydrogen vehicles still are in the conceptual stage, and accurate statistics are difficult to locate.

LDVs are the largest segment of the U.S. vehicle market, the largest consumers of petroleum products, and a large source of GHG emissions in the transportation sector. As a result, fuel switching to hydrogen in LDVs may offer significant potential for oil savings and emissions reductions. Two main types of hydrogen vehicles have been proposed, HICE vehicles, an extension of current vehicle technology, and FCVs. Many analyses of the hydrogen economy consider only FCVs.

Although the discussion below focuses on the future role of hydrogen-powered LDVs, a small number of FCVs and HICE vehicles, including both LDVs and transit buses, already are operational. Appendix D provides a discussion of hydrogen vehicles currently in operation.

HICE Vehicles

Because HICE vehicles typically start from a mass-produced vehicle design and involve relatively low-cost modifications, they could be considered a near-term bridge to the hydrogen economy. In theory, the HICE vehicles can be deployed sooner and in much larger numbers than fuel cell vehicles due to their lower cost. The rapid deployment of HICE vehicles could encourage the construction of hydrogen refueling stations, maintenance facilities, and the development of hydrogen safety codes and standards.

HICE Vehicle Cost

One advantage of HICE vehicles is that their overall cost is only a small fraction of the current cost of an FCV. For example, many conventional vehicles can be converted to run on a mixture of hydrogen and gasoline by adding a small on-board electrolyzer for as little as $1,000. Full HICE vehicle designs that rely on onboard gaseous or liquid hydrogen storage systems to deliver pure hydrogen to the engine require more expensive modifications.

Among the automakers, Ford has demonstrated HICE vehicles and gained insight into current and projected costs versus performance. At production volumes, a vehicle can be designed to optimize the combustion of hydrogen fuel at approximately $5 per kilowatt additional engine cost[44] to achieve a 12- to 25-percent tank-to-wheels efficiency gain relative to a gasoline LDV, with an engine that is 68 to 83 percent more fuel-efficient being developed at a projected additional incremental cost of $5 per kilowatt.[45] At an average of 223 horsepower for the 2007 model year

[44]Typically, hydrogen engines and storage systems are described in terms of electrical units. One horsepower equates to 0.746 kilowatts.
[45]Personal communication with Robert Natkin, H2 ICE Technical Leader, Ford P/T Research (June 30, 2008).

LDV, which had an adjusted fuel economy rating of 20.2 miles per gallon,[46] the additional HICE cost would be $830 to $1,660 per vehicle. At an $830 incremental engine cost, the fuel efficiency would be approximately 22.6 to 25.2 miles per kilogram of hydrogen. The $1,660 incremental engine cost would have lead to a projected fuel efficiency of 34 to 37 miles per kilogram of hydrogen.

Adding storage tanks and safety systems[47] would bring the estimated incremental cost of an HICE LDV in large-scale production to between $2,370 and $3,280 above a comparable average conventional LDV. The range of the incremental costs depends on determining the appropriate tradeoffs among cost, efficiency, and range—while considering consumer preferences—that results in achieving production-level volumes.

Electric Vehicles (EVs) and PHEVs

The chief alternative to today's ICE vehicle is an electric motor vehicle. The major automakers consider EVs to be the ultimate, emission-free at point-of-use replacement for gasoline and diesel vehicles. The key challenge for EVs has been the development of sufficient onboard electricity supply capacity to satisfy customers' expectations for vehicle range.[48] Advanced battery designs and ultra-capacitors are considered to be potential solutions to this challenge. In these vehicle designs, the consumer would plug the vehicle into an electrical outlet, charge the battery or ultra-capacitor, drive the vehicle, and then recharge the battery or capacitor as necessary. Although advanced lithium-ion batteries and ultra-capacitors have been successfully demonstrated, their costs are high, and current storage capacities still are too low.

To create a vehicle with batteries far smaller than required for a full-range electric-only vehicle while retaining an extended driving range, a more modest battery may be supplemented with an on-board liquid-fueled generator to create a PHEV. Given typical driving patterns, a PHEV with a 40-mile range on grid-supplied electricity (PHEV-40) could achieve a 65- to 75-percent reduction in vehicle petroleum consumption compared to a conventional ICE vehicle.[49] This estimated reduction in petroleum use reflects petroleum savings in charge-depleting operation, when the onboard generator is not running, and in charge-sustaining operation, as in today's current HEVs, where the onboard generator operates with higher efficiency than a conventional ICE. Compared to an EV with a 220-mile range on grid power (EV-220), a PHEV-40 would reduce initial battery size and cost by a factor of three.[50] This technology is nearing commercialization and is expected to be offered to consumers in late 2010.[51] Generally speaking, the larger the onboard battery, the less the choice of fuel used for onboard power generation will affect the overall amount of LDV petroleum use and emissions produced.

The relatively small proportion of total travel fueled by power generated onboard a PHEV-40 suggests a large reduction in total petroleum use even if the onboard generator is powered by a

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[46]U.S. Environmental Protection Agency, *Light-Duty Automotive Technology and Fuel Economy Trends: 1975 Through 2007*, EPA420-R-07-008 (Washington, DC, September 2007).

[47]Personal communication with Robert Natkin, H2 ICE Technical Leader, Ford P/T Research (June 30, 2008). Current safety systems cost approximately $4,000 per vehicle in limited quantities and could drop to $100 to $200 per vehicle in production quantities.

[48]A typical consumer expects a vehicle range of at least 200 to 300 miles between successive refuelings.

[49]T. Markel and A. Simpson, "Plug-in Hybrid Electric Vehicle Energy Storage System Design," presentation at the Advanced Automotive Battery Conference (May 17-19, 2006), web site www.nrel.gov/docs/fy06osti/40237.pdf.

[50]Comparing the Tesla Roadster at 53 kilowatthours to the proposed Chevy Volt at 16 kilowatthours, which depending on how often the batteries are replaced during vehicle life may be more or less than a factor of 3. See G. Berdichevsky et al., "The Tesla Roadster Battery System" (August 2006, updated December 2007); and B. Stewart, "GM Testing Volt's Battery, iPhone-like Dash on Track to 2010," *Popular Mechanics* (April 4, 2008).

[51]P. Nunn, "Imagine the 2010 Toyota Prius," *Edmunds Inside Line* (May 7, 2008).

petroleum fuel. Generally speaking, the larger the onboard battery, the less the choice of fuel used for onboard power generation will affect the overall amount of LDV petroleum use and emissions produced.

FCVs

Several major automobile manufactures have begun R&D programs to develop hydrogen fuel cells as an onboard electricity generation system, serving as an alternative to a conventional onboard generator in substituting for or supplementing an onboard electricity storage system (see text box on page 21). Hydrogen fuel cells produce electricity from a chemical reaction much like a battery does. The key difference is that the fuel cell can be recharged continuously with fresh hydrogen from an on-board storage tank, whereas the battery system must be recharged from an electrical outlet. Also, the on-board hydrogen storage tank can be recharged more quickly than batteries.

Much of the industry's fuel cell R&D information remains proprietary. As of 2005, two major auto manufacturers, GM and Daimler Chrysler, acknowledged expenditures of more than $1 billion in FCV development.[52] GM has begun market testing of 100 Chevrolet Equinox fuel cell sport utility vehicles.[53] Daimler has announced plans to start serial production of its Mercedes Benz B-Class FCV in 2010.[54] Honda began commercial leasing of its FCX Clarity in 2008.[55] Other automobile manufacturers, including Toyota, Ford, and Volkswagen, also have developed FCV concept cars.

All FCV concepts currently under development use electric motors to power the wheels, typically accomplished through the combination of an electric battery storage system and an on-board hydrogen fuel cell. Depending on the degree of hybridization, the battery may provide pure "plug-in" electricity to drive the vehicle some distance. The battery system would be complemented by a hydrogen storage system and a fuel cell, with the goal of extending the driving range to 300 miles.

The primary impediments to the deployment of hydrogen FCVs include cost, fuel cell durability, and expanding the operational temperature range of the cell. The costs of current FCVs are prohibitive as a result of high component costs and the fact that the vehicles are either custom-built or produced in limited series. Also of concern is achieving the necessary minimum range for consumer acceptance.

The primary cost component of the FCV is the fuel cell itself, which has a life expectancy about one-half that of an internal combustion engine. Thus, consumers would have to replace the fuel cell twice in order to achieve a vehicle operating lifetime equivalent to that of a traditional engine. Other features of electric/fuel cell vehicles are reasonably well understood at this time and have been commercialized to some extent in the current generation of hybrid vehicles.

Stationary Power Systems

A near-term area of demand for fuel cells includes stationary power applications, such as backup power units, power for remote locations, and distributed generation for hospitals, industrial buildings, and small towns. Stationary fuel cell power systems already are commercially viable in settings where the consumer is willing to pay a small price premium for reliable energy, and in

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[52]J. Fahey, "Hydrogen Gas," *Forbes* (May 9, 2005).
[53]See web site www.chevrolet.com/fuelcell.
[54]S. Abuelsamid, "Some Details on Mercedes 2010 Fuel Cell Production Plans," AutoBlogGreen.com (September 17, 2007).
[55]See web site http://automobiles.honda.com/fcx-clarity.

remote areas where fossil fuel transportation costs are prohibitive. To date, approximately 600 stationary power systems, each with 10 kilowatts or more capacity, have been built worldwide; and

Hydrogen Fuel Cell Technologies

A fuel cell is an energy conversion technology that allows the energy stored in hydrogen to be converted back into electrical energy for end use. Although fuel cells can use a variety of fuels including gasoline, hydrogen is usually preferred because of the ease with which it can be converted to electricity and its ability to combine with oxygen to emit only water and heat. Fuel cells look and function very similar to batteries. A fuel cell continues to convert chemical energy to electricity as long as fresh hydrogen fuel is fed into it.

Aside from being pollution-free at their point of use, fuel cells are quiet because they are non-mechanical. In addition, through concerted R&D efforts, fuel cell efficiencies continue to grow. Fuel cells manufactured today have achieved a conversion efficiency of more than 50 percent of the energy in hydrogen to electricity, depending on the type of fuel cell. For stationary fuel cells, the conversion efficiency is approximately 40 percent; but when combined with the use of byproduct heat, the overall efficiency can approach 90 percent. Size, flexibility, and their corresponding electrical output make fuel cells ideal for a wide variety of applications, from a few kilowatts to power a laptop computer to several megawatts at a central power generation facility. For automotive applications, 70- to 120-kilowatt systems are typically required. Fuel cells are classified by their electrolyte and operational characteristics:

- The Polymer Electrolyte Membrane (PEM) fuel cell is lightweight and has a low operating temperature. PEM fuel cells operate on hydrogen and oxygen from air. Other fuels can be used, but must they must be reformed onsite, which can reduce fueling cost but also drives up the purchase price and maintenance costs and results in CO_2 emissions. PEM systems are typically designed to serve in 70- to 120-kilowatt transportation applications and may be useable as uninterruptible power supplies (UPS) in special commercial applications. Current PEM stack life is typically around 1,350 hours, as used in automotive applications.

- Alkaline fuel cells (AFCs) are one of the most mature fuel cell technologies. AFCs have a combined electricity and heat efficiency of 60 percent efficient and have been used for the production of electrical power and heated water on the Gemini and Apollo spacecrafts. However, their short operating time renders them less than cost effective in commercial applications. Their susceptibility to poisoning by even a small amount of CO_2 in the air also requires purification of the hydrogen feed.

- A newer cell technology is the Direct Methanol Fuel Cell (DMFC). The DMFC uses pure methanol mixed with steam. Liquid methanol has a higher energy density than hydrogen, and the existing infrastructure for transport and supply can be utilized. Research and development of DMFCs are about 3 to 4 years behind other fuel cell technologies.

- For stationary power applications, Phosphoric Acid Fuel Cells (PAFCs) are commercially available today. Over 200 PAFCs have been placed into operation. PAFCs are less efficient than other fuel cell designs, and they tend to be large, heavy and expensive. Nevertheless, they have been used in emergency power and remote power applications.

- Molten Carbonate Fuel Cells (MCFCs) and Solid Oxide Fuel Cells (SOFC) are high temperature designs that promise higher operating efficiencies. The newest fuel cell technology is the Unitized Regenerative Fuel Cell (URFC) that can produce electricity from hydrogen and oxygen while generating heat and water. The URFC is lighter than a separate electrolyzer and generator, making it desirable for weight-sensitive applications.

more than 1,000 smaller stationary fuel cells, less than 10 kilowatts, have been installed in homes and as backup power systems.[56]

Comprehensive data on U.S. stationary fuel cell installations are not available, but the following types of stationary fuel cell applications are under development:

- Large cogeneration (combined heat and power) systems are being manufactured for large commercial buildings or industrial sites that require significant amounts of electricity, water heating, space heating, and/or process heat. Fuel cells combined with a heat recovery system can meet some or all of these needs, as well as providing a source of purified water.
- Small, standalone cogeneration systems currently are viable in some areas where the large cost of transmitting power justifies the added cost of a fuel cell. Currently, U.S. companies (such as Plug Power) manufacture small fuel cell systems that are able to produce up to 5 kilowatts of electricity and 9 kilowatts of thermal energy. The excess heat can be used for water or space heating to further reduce the site's electrical energy use.
- Uninterruptible power supply (UPS) systems, in which fuel cells are used as backup power supplies if the primary power system fails, are one of the fastest growth areas for stationary fuel cell technologies. UPS systems often are used in important services, such as telecommunications, banking, hospitals, and military applications. Battery systems have been used for many years to provide backup power to essential services; however, the battery output time is relatively short. In contrast, fuel cells with refillable fuel storage systems can provide power for as long as required during a blackout.
- Home energy stations are another variant of small, standalone cogeneration systems. They use either reformers or electrolyzers to produce hydrogen fuel for personal vehicles, and they also incorporate a hydrogen fuel cell that can provide heat and electricity for the home. One advantage of the stations is that they offer enhanced utilization of the hydrogen gas, i.e., higher capacity factors for the hydrogen production unit, and therefore help to defray some of the overall cost of the hydrogen refueling station. Appliance-sized home energy stations are undergoing development by several automobile manufacturers as a potential alternative to commercial refueling stations.

Market Potential for Hydrogen in Distributed Generation

The market for distributed generation could be significant if selected goals of the U.S. Department of Energy (DOE) hydrogen program are met. The appropriate match between a fuel cell technology and the intended application depends on the magnitude and duration of the power needed, the cost, performance, and durability of the fuel cells, and the operating temperature range.

All fuel cells produce some byproduct heat, but the temperature of the byproduct heat can vary dramatically, from about 180 degrees Fahrenheit for PEM fuels to more than 1,200 degrees for molten carbonate fuel cells. Fuel cells that produce high-temperature byproduct heat with over 250 kilowatts of capacity are suitable for combined heat and power applications in industrial and large commercial settings; those that produce low-temperature byproduct heat are suitable for both mobile uses (e.g., LDVs and forklifts, 80 to 130 kilowatts) and residential applications (e.g., providing electricity, space, and water heating, up to 10 kilowatts). Most fuel cell designs, including PEM and molten carbonate technologies, use different electrolytes, stack designs, and balance of plant.

[56]U.S. Department of Energy, Energy Efficiency and Renewable Energy, "Distributed/Stationary Fuel Cell Systems," web site www1.eere.energy.gov/hydrogenandfuelcells/fuelcells/systems.html.

Consequently, technology learning achieved for one of the technologies is not entirely transferable to other fuel cell technologies, with a few exceptions.[57]

The installed capital cost of phosphoric acid fuel cells in the commercial sector varies according to size. For 200-kilowatt systems, the cost quoted by United Technologies Corporation (UTC) for the PureCell 200 ranges from $6,000 to $7,750 per kilowatt, and for the PureCell 400 system the installed cost ranges from $3,625 to $4,500 per kilowatt in 2008.[58] The first generation of commercial molten carbonate fuel cells in 2010 is estimated to cost about $6,200.[59] Molten carbonate fuel cells use the high operating temperatures of the fuel cell to reform methane and steam to produce hydrogen. The CO_2 produced is recycled to restore the molten chemical used to generate electricity. Efficiencies to produce only electricity can approach 50 percent, and overall efficiencies (electricity plus byproduct heat) are approximately 70 percent when both products are fully used. A U.S. DOE program supports R&D to develop and implement a molten carbonate fuel cell design that uses some of the lost heat to mechanically turn a turbine to increase generation efficiency by another 10 percent.

If the R&D succeeds in lowering the installed capital costs of molten carbonate fuel cells below $2,500 per kilowatt, the technology could satisfy a significant percentage of new demand for combined heat and power in the industrial and commercial markets. The resulting market penetration, once the cost reductions are achieved, may be slow due to the fact that industrial and commercial boilers are long-lived. According to a 2005 study by Energy and Environmental Analysis, Inc. (EEA),[60] at least 47 percent of all boilers were at least 40 years old. Because boiler equipment rarely is replaced before it fails, the fuel cell technology is unlikely to replace existing boilers or existing cogeneration equipment before it fails. Also, because energy-intensive industries are in decline in the United States, the market potential for molten carbonate fuel cells in the industrial sector is limited, unless significant economic benefits could be realized by replacing current equipment. For example, in the *Annual Energy Outlook 2008* (*AEO2008*) reference case, demand for boiler steam (heat) applications in the industrial sector[61] is projected to decline by 360 trillion Btu, or 9.5 percent, while the demand for electricity[62] is projected to increase by 170 trillion Btu, or 4.3 percent, between 2010 and 2030.

The market potential in the commercial sector is better but does not promise rapid growth. Commercial electricity and heat demands are expected to grow more quickly than in the industrial sector, including space and water heating by 358 trillion Btu (16 percent) and purchased electricity by 1,896 trillion Btu (40 percent). Nevertheless, it appears unlikely that the capital costs and performance of molten carbonate fuel cells will improve to the levels needed for substantial

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[57]Discovery Insights, LLC, *Commercial and Industrial CHP Technology Cost and Performance Data Analysis for EIA's NEMS* (February 2006), p. 18. If it is assumed that "learning" spilled over from other fuel cell technologies to PEM, the potential cost reductions that might be expected from learning theory would be much smaller than those illustrated earlier, because the starting capacity would have been much larger, exponentially increasing the future capacity additions needed to achieve the same cost reductions.

[58]For the PureCell 200, the production cost is $950,000 and the delivery and installation cost varies from $250,000 to $600,000 and translates to an installed cost of $6,000 to $7,750 per kilowatt. The PureCell 400 system is quoted with a production cost of $1.2 million and the same range for the delivery and installation costs and translates to an installed cost of $3,625 to $4,500 per kilowatt.

[59]EIA, *Assumptions to the Annual Energy Outlook 2008*, DOE/EIA-0554(2008) (Washington, DC, June 2008). Note that the first-of-a-kind commercial costs are almost always underestimated for any new technology, often by as much as 50 percent.

[60]EEA, *Characterization of the U.S. Industrial Commercial Boiler Population* (Arlington, VA, May 2005), Section ES-6, web site www.cibo.org/pubs/industrialboilerpopulationanalysis.pdf.

[61]Excluding refinery demand for steam.

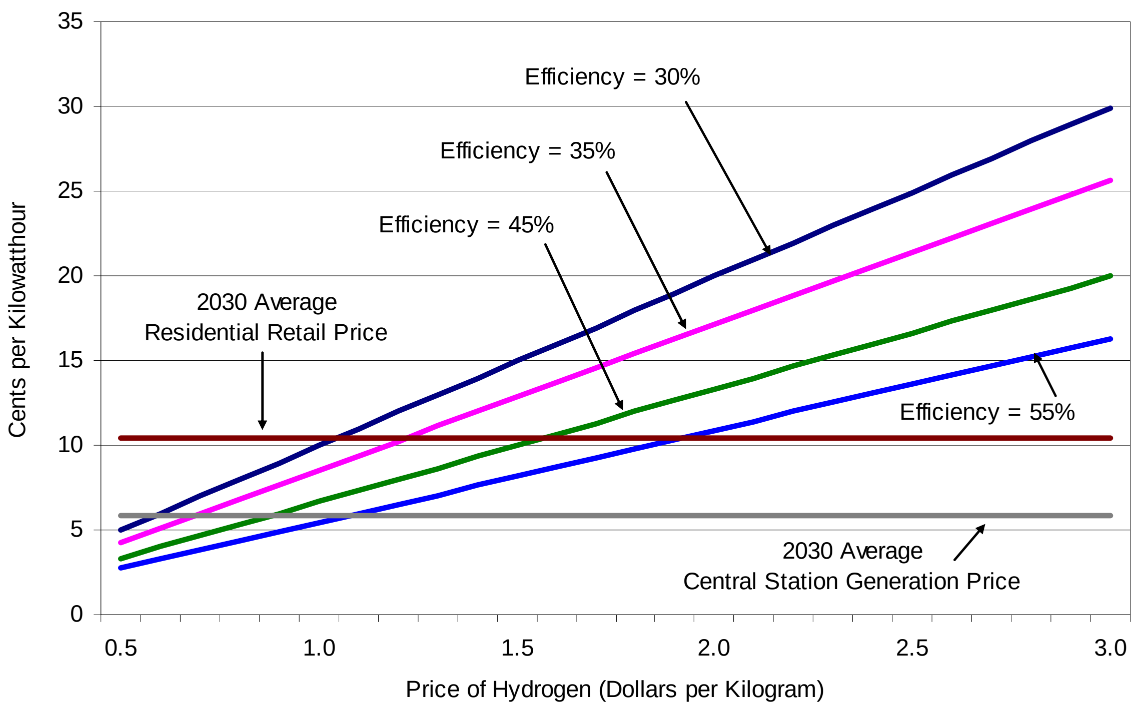
[62]Purchased electricity plus generation on site, excluding refinery demand.

penetration of the new market. Any technology learning from PEM fuel cell successes may not be readily transferable to molten carbonate fuel cell production due to the difference in technologies.

With only about 1,350 hours between stack and catalyst replacement, the PEM fuel cell currently is not sufficiently durable to penetrate most markets in large numbers. The electricity generation efficiency of a PEM fuel cell is projected to rise to 36 percent by 2030, while the combined efficiency for electricity and byproduct heat is expected to range between 50 percent and 65 percent if all of the electricity and heat are used. At a delivered hydrogen cost of $2 to $3 per kilogram ($17.54 to $26.32 per million Btu), the fuel component of the cost of electricity generation is expected to range between 14 cents and 21 cents per kilowatthour, which would not be competitive with projected central station delivered electricity prices of 10.5 cents per kilowatthour in 2030. Because the construction costs for hydrogen pipelines to all homes would be extremely expensive, a more likely option might use the existing natural gas infrastructure and on-site natural gas steam reforming. The cost of that option is currently too high, at up to $40 per million Btu according to DOE's Office of Fossil Energy, and additional R&D on small-scale SMR will be required to bring the delivered fuel cost under $2 per kilogram of hydrogen.

Figure 2.4 illustrates the fuel-related costs of electricity generation as a function of the cost of hydrogen, excluding the capital plus operating costs of the PEM units. The ability to also satisfy space and water heating demand allows the range to increase, depending on how well the end-use demands match the PEM supply and whether backup space and water heating equipment has to be purchased to satisfy any unmet heating demand.

Figure 2.4. Fuel-Related Electricity Cost of PEM



Note: Only the fuel input costs and efficiency of electricity conversion are considered in the illustration.
Source: Energy Information Administration.

3. Energy and CO_2 Emissions Impacts of Fuel Cell Vehicles

This chapter examines the potential impacts of FCVs on energy demand and full fuel cycle CO_2 emissions under a variety of scenarios for: (1) new vehicle market penetration, (2) vehicle fuel economy improvement, (3) sources of hydrogen supply, and (4) transition from distributed to centralized production. The analysis and results presented in this chapter reflect the assumptions made to illustrate the impacts of scenarios where the challenges facing a hydrogen economy are overcome. They are not intended to endorse, support, or imply plausibility or likelihood. This analysis serves to demonstrate the relative time frame and significance of energy and CO_2 impacts, given assumptions regarding FCV market penetration, FCV fuel economy, hydrogen feedstocks, and hydrogen production methods.

The VISION model was selected to examine the various fuel cell cases, because the time frame necessary to observe impacts extends beyond the NEMS time frame.[63] In addition, use of NEMS would have required the development of very specific assumptions about the timing and success of FCV research and development, hydrogen production and infrastructure development, and the companion Federal and State policies that are likely to be needed to ensure the successful development of hydrogen-powered FCVs within the next 10 to 20 years. To generate the reference case used in this analysis, the VISION 2007 AEO Base Case Expanded Model was updated to reflect the projections of LDV sales, stocks, travel, and fuel economy in the *AEO2008* reference case.

Fuel Cell Vehicle Market Penetration Scenarios

Three FCV market penetration scenarios were examined, based on studies completed by DOE, Oak Ridge National Laboratory (ORNL), and the National Research Council (NRC). The market penetration scenarios represent shares of new vehicle sales through 2050 and are taken from studies and reports that have assumed different levels of success in meeting FCV research, development, and cost goals, as well as capital investments needed to produce the vehicles and provide the necessary hydrogen fueling infrastructure. Those reports have determined that a successful transition to hydrogen-powered light-duty FCVs is likely to require some type of policy incentive to stimulate initial investments in the technology, as well as Federal and/or State financial incentives or mandates that significantly reduce the financial risk of investments in vehicle production and infrastructure development.

The first, and least aggressive, market penetration scenario examined in this report is derived from DOE's Office of Energy Efficiency and Renewable Energy (EERE) fiscal year 2008 budget (Figure 3.1).[64] In this scenario, FCV penetration of the market for new LDVs begins in 2015 and increases slowly through 2020 to 1 percent, after which it increases rapidly to 22 percent in 2030 and approximately 50 percent in 2045. Although not specified, EERE assumed that Federal and State policies would be in place in the early stages of FCV development to foster vehicle production and sales as well as the development of a companion hydrogen infrastructure.[65]

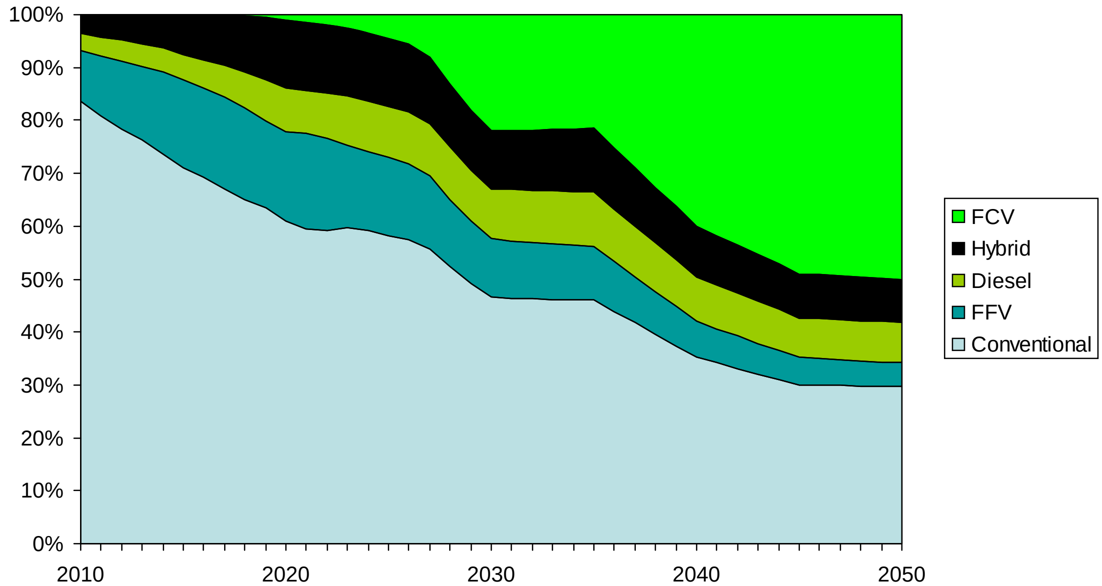
The second market penetration scenario represents a more aggressive sales path, where initial sales volumes are relatively low but cost reductions realized from learning and economies of scale coupled with Federal incentives foster a rapid expansion of FCV production and hydrogen infrastructure development that is sustained throughout the projection period (Figure 3.2). This

[63] Argonne National Laboratory, "The VISION Model," web site www.transportation.anl.gov/modeling_simulation/VISION.

[64] EIA projections, derived using travel projections from the Office of Energy Efficiency and Renewable Energy.

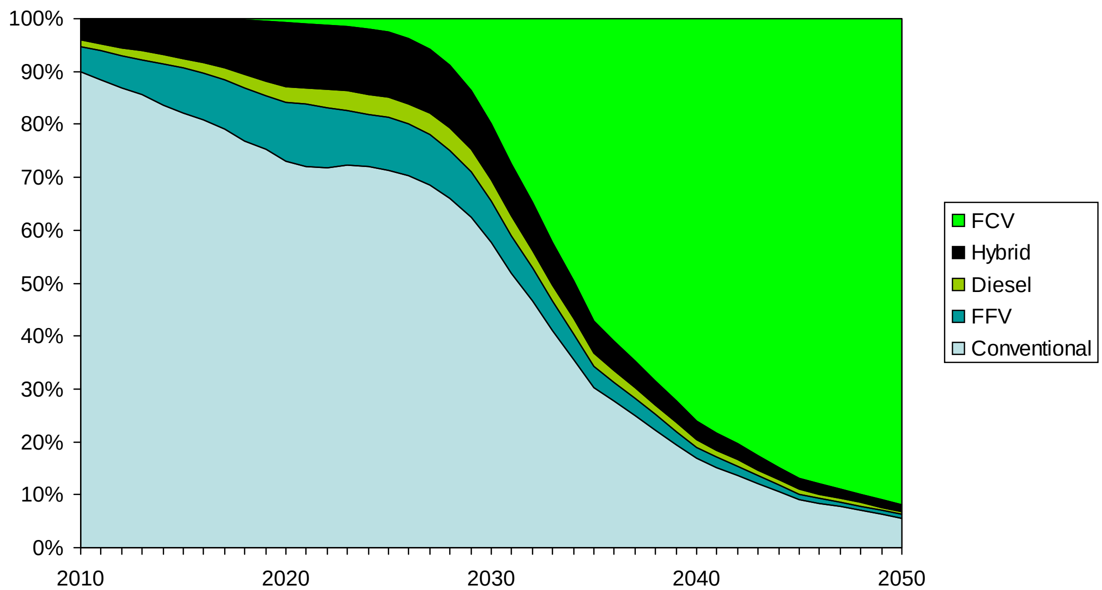
[65] Conversation with Philip Patterson, Office of Energy Efficiency and Renewable Energy.

Figure 3.1. Fuel Cell Vehicle Market Penetration Scenario 1 (S1)
(Percent of New Light-Duty Vehicle Sales)



Note: FCV = Fuel Cell Vehicle; FFV = Flex-Fuel Vehicle.
Sources: U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy; and Energy Information Administration.

Figure 3.2. Fuel Cell Vehicle Market Penetration Scenario 2 (S2)
(Percent of New Light-Duty Vehicle Sales)



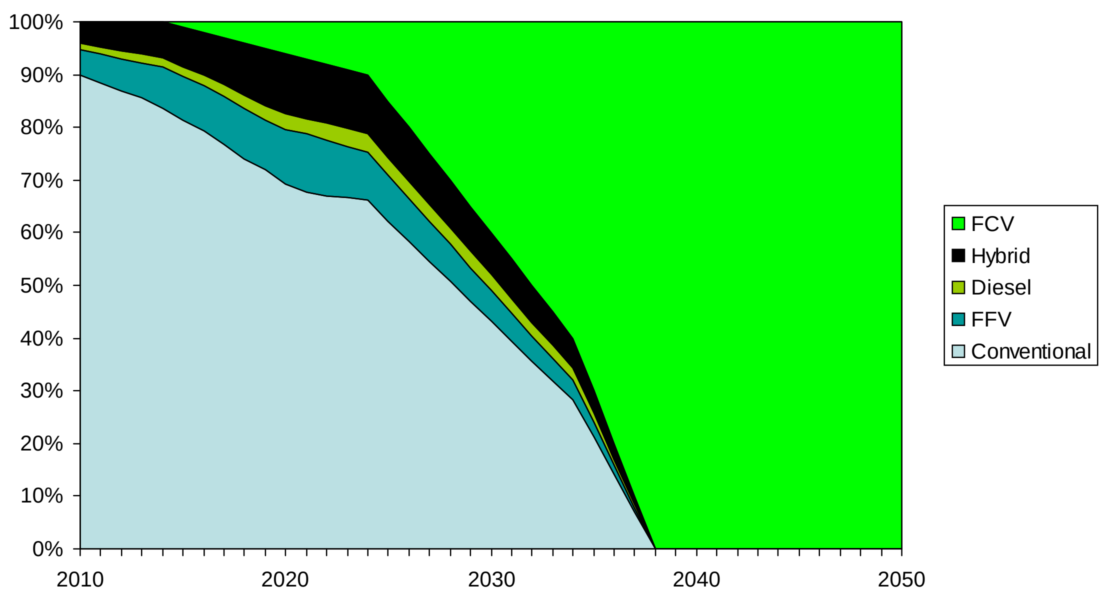
Note: FCV = Fuel Cell Vehicle; FFV = Flex-Fuel Vehicle.
Source: Oak Ridge National Laboratory.

market penetration scenario, developed by ORNL, reflects the results of an analysis that examines the impacts of cost reductions associated with vehicle sales volumes and infrastructure development and discusses combinations of monetary policy and their impacts on reducing industry financial risk.[66] For this scenario, market penetration begins in 2018 and increases slowly, to 2.5 percent in 2025. After 2025, FCV market share continues to grow rapidly through 2050, when approximately 90.0 percent of new vehicles sold are hydrogen FCVs.

The third and most aggressive market penetration scenario examined was taken from a scenario put forth by the NRC in an examination of the potential impacts of a rapidly developed hydrogen economy (Figure 3.3).[67] This scenario assumes that all hydrogen FCV technology and cost goals are met, that the infrastructure is developed in tandem, and that there are no impediments to success. This is the most aggressive market penetration scenario, with market penetration beginning in 2015 and growing by 1 percentage point a year to 10 percent in 2024. After 2024, the rate of market penetration increases to 5 percentage points per year through 2034, when FCVs make up 60 percent of new vehicle sales. In 2038, FCVs account for 100 percent of new LDV sales.

For each of the three FCV market penetration scenarios, projected market shares for other advanced technology and alternative fuel vehicles reflect the projections in the *AEO2008* reference case. In each of the scenarios, it is assumed that, as FCV market share increases, the market shares for other vehicle types are reduced in proportion to their *AEO2008* reference case market shares in that year.

Figure 3.3. Fuel Cell Vehicle Market Penetration Scenario 3 (S3)
(Percent of New Light-Duty Vehicle Sales)



Note: FCV = Fuel Cell Vehicle; FFV = Flex-Fuel Vehicle.
Source: National Research Council.

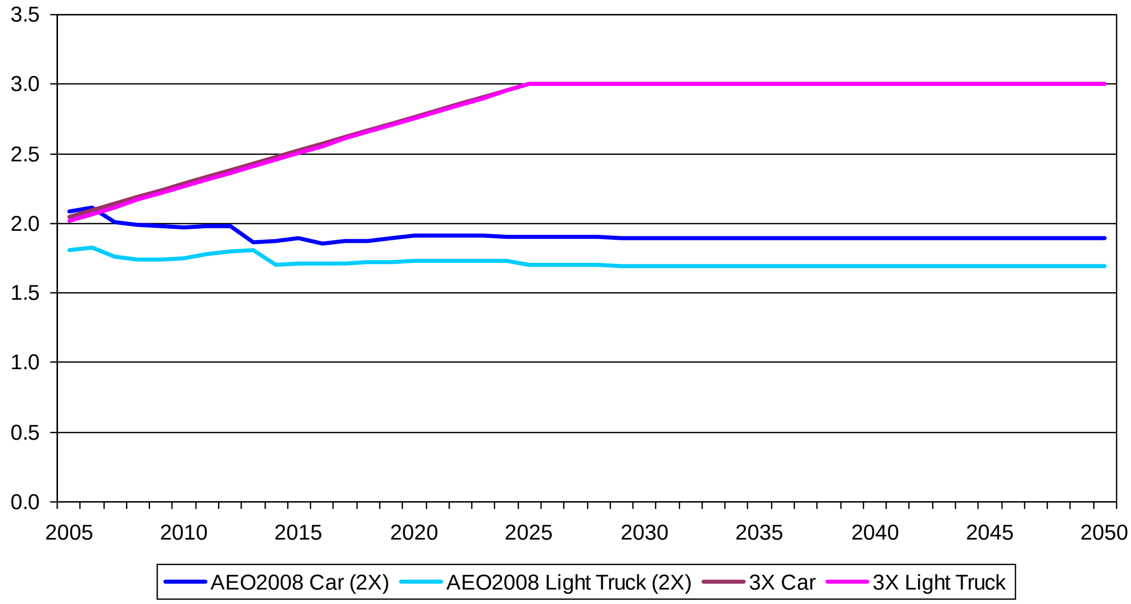
[66]D.L. Greene, P.N. Leiby, and D. Bowman, *Integrated Analysis of Market Transformation Scenarios with HyTrans,* ORNL/TM-2007/094 (Oak Ridge, TN: Oak Ridge National Laboratory, June 2007), Figure 16.

[67]The National Academies, Board on Energy and Environmental Systems, *The Hydrogen Economy: Opportunity, Costs, Barriers, and R&D Needs* (Washington, DC, February 2004), Figure 3-1, web site www.nap.edu/catalog/10922.html.

Fuel Cell Vehicle Fuel Economy Scenarios

Two FCV fuel economy scenarios are examined, based on projected improvement relative to a 2005 base year conventional gasoline vehicle.[68] The first scenario assumes that FCV fuel economy improvements mirror those projected in *AEO2008* through 2030 and remain constant at 2030 levels through 2050 (Figure 3.4). In this scenario, the fuel economy of FCV cars is approximately twice that of conventional gasoline cars in 2005. After 2005, the FCV fuel economy ratio for cars decreases, as power output in conventional gasoline vehicles changes over time.[69]

Figure 3.4. Fuel Cell Vehicle Fuel Economy Improvement Ratio



It is assumed that FCVs are introduced in the large car size class in 2013, which further reduces the average FCV fuel economy ratio to approximately 1.8, where it remains relatively constant for the remainder of the projection. For FCV light trucks, the fuel economy ratio varies in response to power output in conventional gasoline vehicles between 2005 and 2013, when it peaks at an improvement ratio of 1.8. The FCV fuel economy ratio decreases to 1.7 in 2014, when it is assumed that fuel cells are introduced into the large light truck classes, and remains relatively constant through the remainder of the projection. Scenarios using this assumption are designated as “2X.”

The second scenario assumes that FCV efficiency improves from twice the fuel economy of the 2005 base year vehicle in 2005 to three times the fuel economy of the base year vehicle in 2025 (Figure 3.4). The fuel economy improvements are assumed to be linear, although it is highly unlikely that improvement would occur in such a uniform fashion. After 2025, FCV fuel economy is assumed to remain constant. Scenarios using this assumption are designated “3X.”

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[68]The NEMS model uses model year 2005 LDVs as the base year vehicles. Adoption of technology and the corresponding changes to vehicle attributes are estimated as incremental changes relative to the base year vehicle.

[69]In the NEMS model, projections of fuel cell power requirements are increased or decreased to match equivalent conventional gasoline vehicle performance, in order to meet projected consumer preferences for that vehicle attribute. Performance is measured as the ratio of vehicle horsepower to vehicle weight.

Hydrogen Feedstock and Production Scenarios

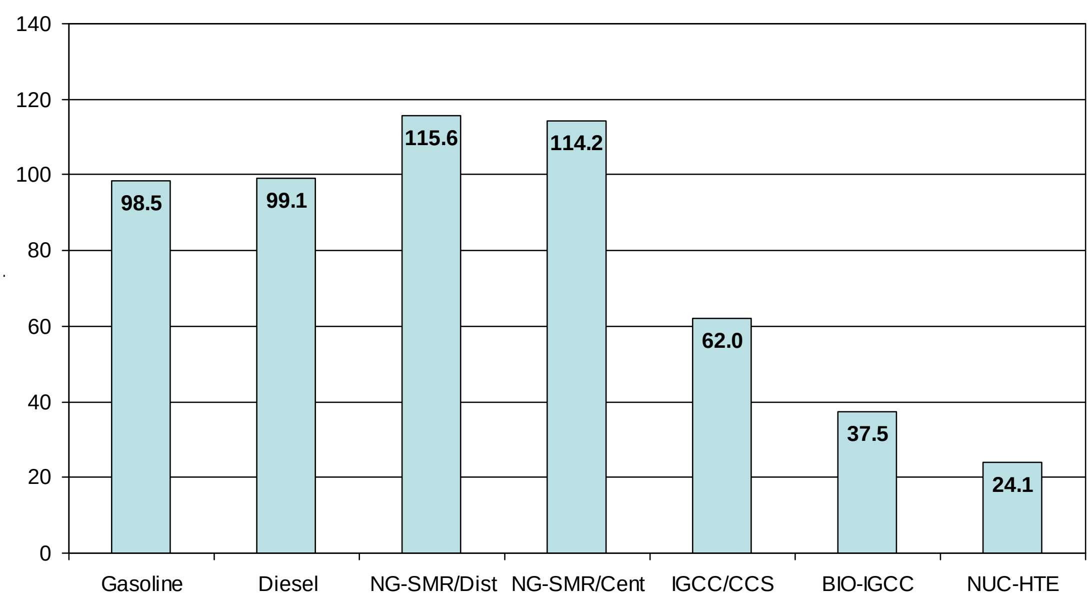
To examine the potential impacts on full fuel cycle CO_2 emissions associated with the market transition to hydrogen FCVs, five sources of hydrogen production were considered: (1) distributed natural gas SMR, (2) centralized natural gas SMR, (3) centralized coal gasification with CCS, (4) centralized biomass gasification, and (5) centralized nuclear power high-temperature electrolysis (HTE) of water. Table 3.1 provides the scenario descriptors and definitions used in the analysis.

Table 3.1. Hydrogen Feedstock and Production Scenarios

Scenario Descriptor	Scenario Definition
NG-SMR/Dist	Natural gas steam methane reformation (distributed)
NG-SMR/Cent	Natural gas steam methane reformation (central)
IGCC/CCS	Integrated coal gasification with carbon sequestration
BIO-IGCC	Biomass IGCC
NUC-HTE	Nuclear power high-temperature electrolysis of water

To examine the relative CO_2 impacts of moving from distributed natural gas SMR to one of the other four centralized production methods, the production sources were combined into four production pathways. The hydrogen production methods chosen are not intended to provide an exhaustive list of possibilities but were selected to demonstrate a range of outcomes, given current expectations of CO_2 emissions for the fuel delivered to the vehicle. The "wells to tank" CO_2 emissions associated with each of the sources of production are provided in Figure 3.5.[70]

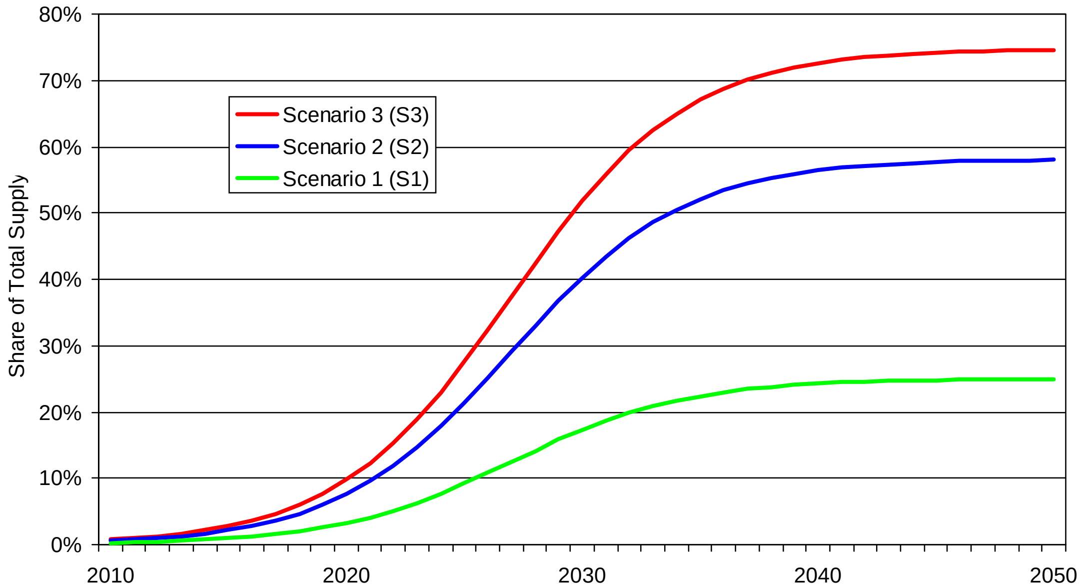
Figure 3.5. Full Fuel Cycle CO_2 Emissions by Hydrogen Production Source
(Million Metric Tons CO_2 Equivalent per Quadrillion Btu)



[70]Carbon coefficients are taken from the VISION model and reflect estimates developed using the GREET model per a conversation with Margaret Singh of Argonne National Laboratory. For a description of the GREET model, see web site www.transportation.anl.gov/software/GREET/index.html.

For each of the FCV market penetration scenarios, a companion hydrogen production transition scenario was developed to examine the range of potential full fuel cycle CO_2 emission impacts. It is difficult to say with any certainty how and when the transition from distributed to central hydrogen production for vehicle refueling will occur and what actions will spur those developments. The scenarios envisioned for this analysis were constructed to reflect infrastructure development commitments that are correlated with the FCV market penetration scenarios. Figure 3.6 illustrates the share of total centralized hydrogen production for each of the FCV market penetration scenarios.

Figure 3.6. Transition to Central Hydrogen Production by Fuel Cell Vehicle Market Penetration Scenario



The hydrogen production pathways examined for this analysis illustrate the potential CO_2 emissions associated with each production scenario when transitioning from distributed natural gas SMR to one of the other central production methods (i.e., coal gasification with CCS or nuclear power HTE of water). In all likelihood, hydrogen feedstock and production methods will vary by region to optimize production economically, based on available resources, infrastructure availability or limitations, and levels of demand.

Impacts on Light-Duty Vehicle Direct Energy Use

Projections of LDV energy demand are made for each of the FCV market penetration scenarios using the FCV fuel economy projections reflected in the *AEO2008* reference case and the assumed 3X FCV fuel economy improvement. Projections of LDV energy demand are presented for 2030 and 2050 to demonstrate the relative energy impacts across market penetration scenarios and assumed levels of FCV fuel economy. There are two issues to consider when interpreting these results: (1) The energy consumption numbers reported in this analysis are at the point of use—i.e., at the LDV fleet level—and do not reflect primary energy use, which includes energy losses associated with the production, compression, and transportation of hydrogen. (2) The FCV market penetration rate will affect the total LDV stock.

Primary Energy Use Considerations

In discussing the energy use impacts of hydrogen consumed by LDVs, it must be noted that direct energy use is not the same as primary energy use. For impacts on primary energy use, it is important to consider the differences among fuel and technology combinations with regard to the efficiency of conversion from feedstock to product and the delivery of the product in a suitable form to the vehicle's tank. For example, gasoline in an LDV contains 91 percent of the total primary energy used to supply the finished fuel. For hydrogen, the fuel load in the LDV may represent between 70 and 73 percent of the primary energy if natural gas was the primary feedstock but only 48 to 63 percent if another feedstock and production technology was used, as described in Chapter 2. Adding compression or liquefaction of the hydrogen, if required, and other transportation losses would decrease the primary energy content of the hydrogen fuel delivered to the LDV. For assessing petroleum impacts, however, because the production, transport, distribution, and dispensing of hydrogen use little if any petroleum, the changes in petroleum use described below are reasonably representative of the economy-wide changes in petroleum use.

FCV Market Penetration Considerations

By 2030, the rate of FCV market penetration in each of the three scenarios examined does not reach a level significant enough to have a large impact on LDV energy demand. This is due to the amount of time it takes to turn over the vehicle stock. Currently, the median lifetime of an LDV is approximately 16 years.[71] As a result of slow stock turnover, as market penetration increases for newly introduced technologies or alternative-fuel vehicles, the impact of those vehicles will not be fully realized for well over a decade, when stock accumulations account for a larger percentage of total vehicles in use. For this reason alone, the investments needed to transition from a gasoline-centric market to a hydrogen-fueled market will initially present great economic risk for both industry participants and consumers.

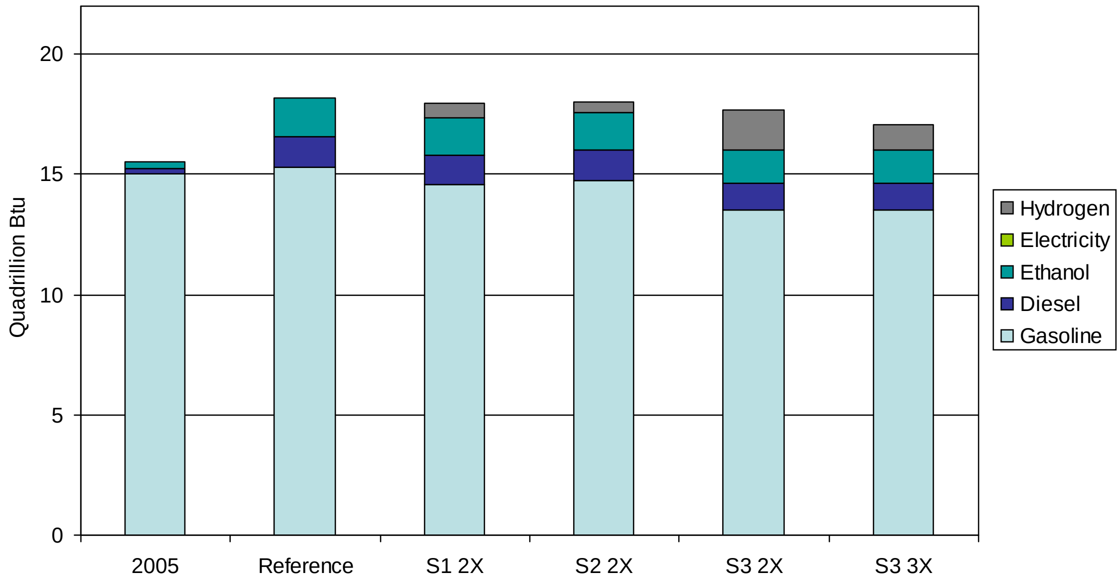
LDV Direct Energy Use Impacts

As indicated in Figure 3.7, 2030 LDV energy use in the 2X FCV fuel economy scenarios is reduced by between 0.15 and 0.52 quadrillion Btu (between 0.8 and 2.9 percent) relative to the reference case, depending on the market penetration and fuel economy scenario chosen. The energy demands associated with the most optimistic FCV scenario, market penetration scenario 3 with the 3X FCV, are also shown in Figure 3.7. In this scenario, LDV energy demand in 2030 is reduced by 1.1 quadrillion Btu (6.1 percent) in comparison with the reference case. The reduction in LDV demand for petroleum products, which unlike the change in LDV demand for all energy would be representative of changes at the economy-wide level, is more dramatic. Across the three FCV market penetration scenarios, demand for gasoline and diesel is reduced by a range of 0.58 to 1.97 quadrillion Btu (3.5 to 11.9 percent) relative to the reference case, indicating a significant level of substitution of hydrogen for petroleum-based fuels.

LDV energy demand is noticeably reduced by 2050 in each of the FCV market penetration scenarios under both assumptions for FCV fuel economy. In comparison with the reference case, LDV energy demand in 2050 is reduced by 1.6 to 3.7 quadrillion Btu (8.0 to 18.1 percent), and petroleum consumption is reduced by 7.0 to 15.8 quadrillion Btu (37.1 to 84.1 percent) across the 2X FCV cases, depending on the market penetration scenario (Figure 3.8). In both scenario 2 and scenario 3,

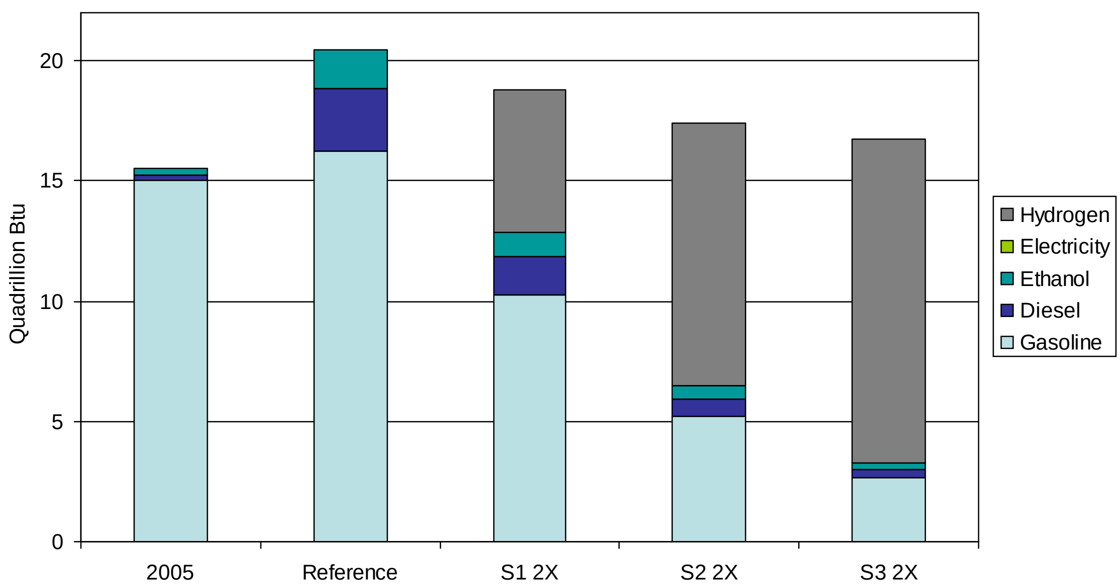
[71] S.C. Davis and S.W. Diegel, *Transportation Energy Data Book: Edition 26,* ORNL-6978 (2007), Tables 3.8 and 3.9.

Figure 3.7. Light-Duty Vehicle Energy Demand, 2030



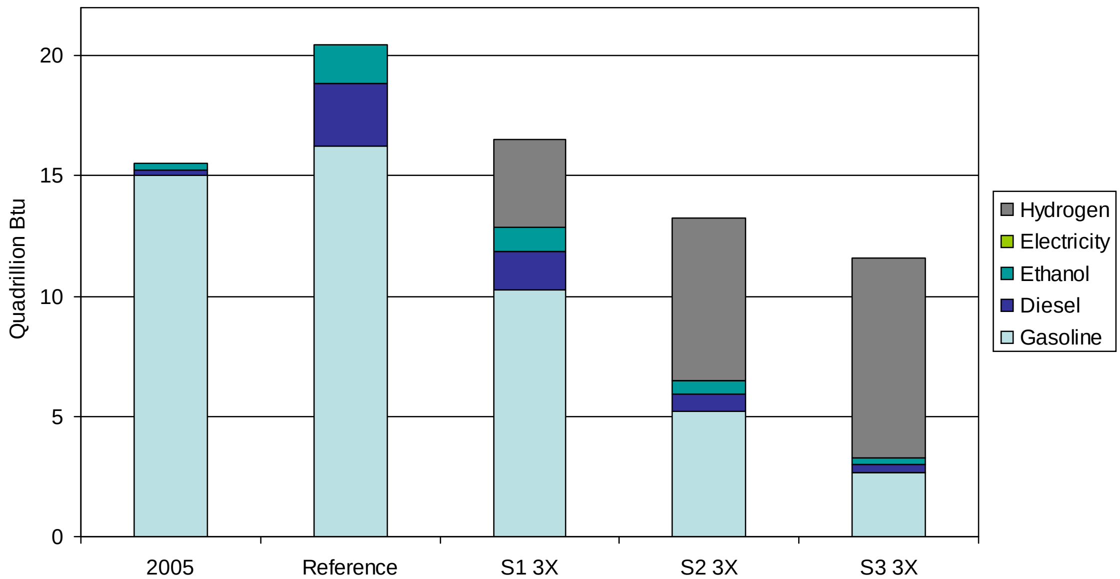
hydrogen becomes the primary fuel for LDVs, accounting for 62.8 percent and 80.4 percent of total demand, respectively. For the reasons outlined above, the change in petroleum use is likely to represent an economy-wide impact, but the change in total energy demand by LDVs does not reflect the increase in primary energy use in other sectors to produce, transport, distribute, and dispense hydrogen.

Figure 3.8. Light-Duty Vehicle Energy Demand, Assuming 2X FCV Fuel Economy, 2030



Assuming that FCVs achieve 3X fuel economy, energy use by LDVs in 2050 is reduced by 3.9 to 8.8 quadrillion Btu, or between 19.1 and 43.3 percent (Figure 3.9). Because FCVs are operating on an alternative fuel and the rate of conventional vehicle displacement determines the amount of petroleum reduction achieved across the market penetration scenarios, petroleum displacement realized across the FCV market penetration scenarios in the 2X FCV and the 3X FCV fuel economy scenarios are the same. However, relative to the 2X FCV scenarios, total hydrogen demand is lower under the 3X FCV fuel economy scenarios. In the 3X FCV scenarios, total demand for hydrogen in 2050 is between 2.2 quadrillion Btu and 5.1 quadrillion Btu lower, reducing total hydrogen demand by 38 percent across the scenarios relative to the 2X FCV scenarios.

Figure 3.9. Light-Duty Vehicle Energy Demand, Assuming 3X FCV Fuel Economy, 2050



If the assumptions in scenarios 2 and 3 were realized, energy use by LDVs in 2050 would decrease below the demand level realized in 2005 and in scenario 3 would approach a level of LDV energy use last realized in 1980. Again, these estimates of energy use by LDVs do not reflect the increase in primary energy use in other sectors to produce, transport, distribute, and dispense hydrogen.

Similar to the energy impacts realized in 2030 across the scenarios, the full fuel cycle CO_2 emission reductions in 2030 are minimal. From the most conservative to the most aggressive scenario analyzed, reductions in CO_2 emissions are estimated to be between 0.4 percent and 7.8 percent (Figure 3.10). Again, because FCVs do not account for a significant percentage of the operating vehicle stock in 2030, their impact on overall LDV CO_2 emissions is minimal. In addition, the full transition to central hydrogen production has not occurred by 2030. In scenario 1 and scenario 2, hydrogen demand is met primarily by distributed natural gas SMR (82.7 percent and 59.7 percent, respectively), which is the highest CO_2 emitter of the hydrogen production methods analyzed. As hydrogen production transitions to the lower CO_2 emitting central production methods over the projection period, greater emissions reductions are realized.

As shown in Figure 3.11, CO_2 emission reductions are achieved in all FCV scenarios relative to the reference case in 2050. The projections show CO_2 emission reductions in 2050 varying from 2.0 percent (in scenario 1 with 2X fuel economy and hydrogen production transitioning to centralized SMR) to 63.8 percent (in scenario 3 with 3X fuel economy and hydrogen production transitioning to centralized nuclear HTE of water). Appendix C provides a description of each of the hydrogen FCV scenarios examined and graphical projections of CO_2 emissions through 2050.

Figure 3.10. Light-Duty Vehicle Full Fuel Cycle CO_2 Emissions, 2030
(Million Metric Tons CO_2 Equivalent)

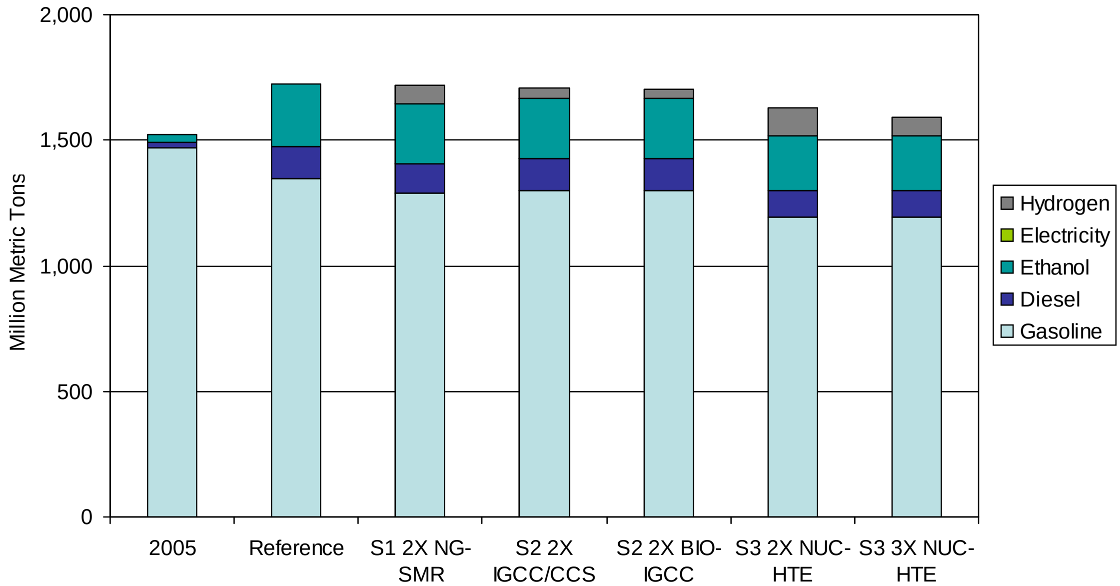
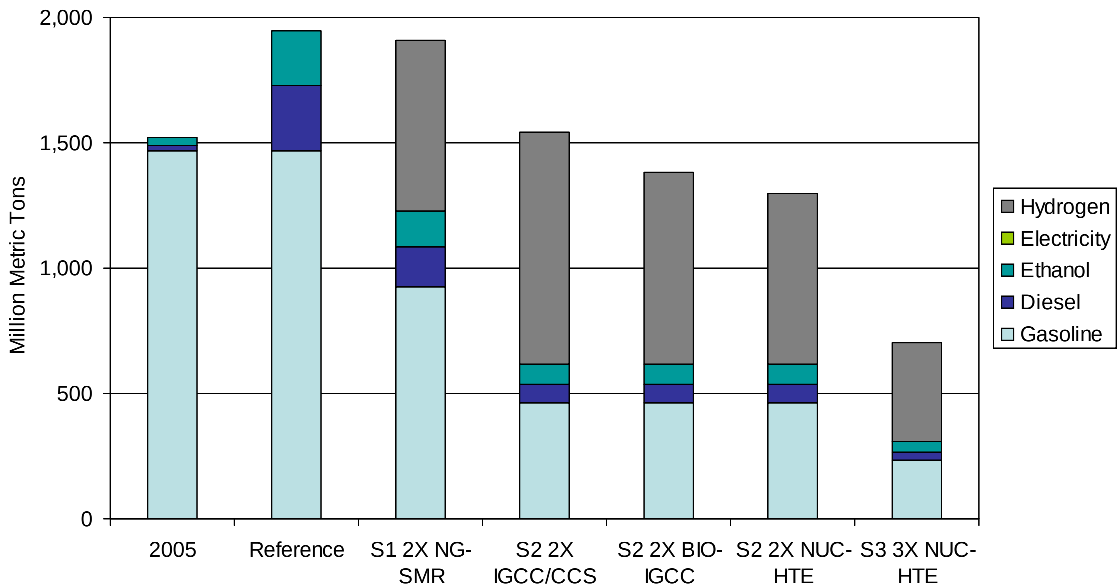


Figure 3.11. Light-Duty Vehicle Full Fuel Cycle CO_2 Emissions, 2050
(Million Metric Tons CO_2 Equivalent)



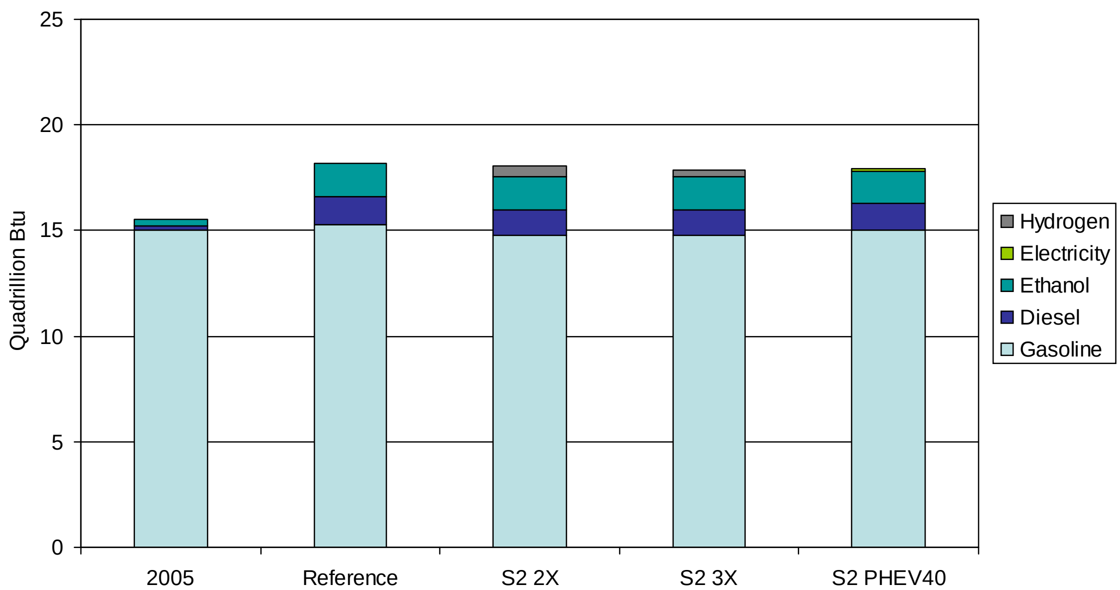
Plug-in Hybrid Electric Vehicle Comparison Scenario

To provide a comparative reference of the potential energy and CO_2 emission impacts of a similar advanced technology to those of the hydrogen FCV, an alternative case was developed to examine the successful development of a PHEV with a 40-mile range. For purposes of evaluation, PHEVs were assumed to penetrate under market penetration scenario 2. As in the FCV scenarios, the success of PHEVs will require that all technology and cost issues be successfully resolved, that the necessary infrastructure be developed, and that policies be enacted to ensure a successful market transition. This scenario is not offered as an endorsement of PHEVs over FCVs but only as a demonstration of their relative impacts on energy demand and CO_2 emissions in 2030 and 2050.

For the PHEV scenario, it is assumed that the PHEV would operate on gasoline and achieve approximately 50 miles per gallon in hybrid mode of operation and approximately 130 miles per gallon of gasoline equivalent in all-electric mode. It is also assumed that approximately 50 percent of annual PHEV travel will be provided by the all-electric mode of operation. Comparatively, the FCV achieves approximately 50 miles per gallon of gasoline equivalent in the *AEO2008* reference scenario and 90 miles per gallon of gasoline equivalent in the 3X fuel economy scenario.

Figure 3.12 shows the 2030 LDV energy use under market penetration scenario 2 for the reference case, the FCV with *AEO2008* reference case fuel economy, the FCV with 3X fuel economy, and the PHEV-40. As discussed previously, vehicle penetration is not at a level aggressive enough to stimulate significant energy impacts across the different scenarios, with total reductions from the reference case projected to be between 0.5 percent and 1.8 percent.

Figure 3.12. Scenario 2 Light-Duty Vehicle Energy Demand, 2030

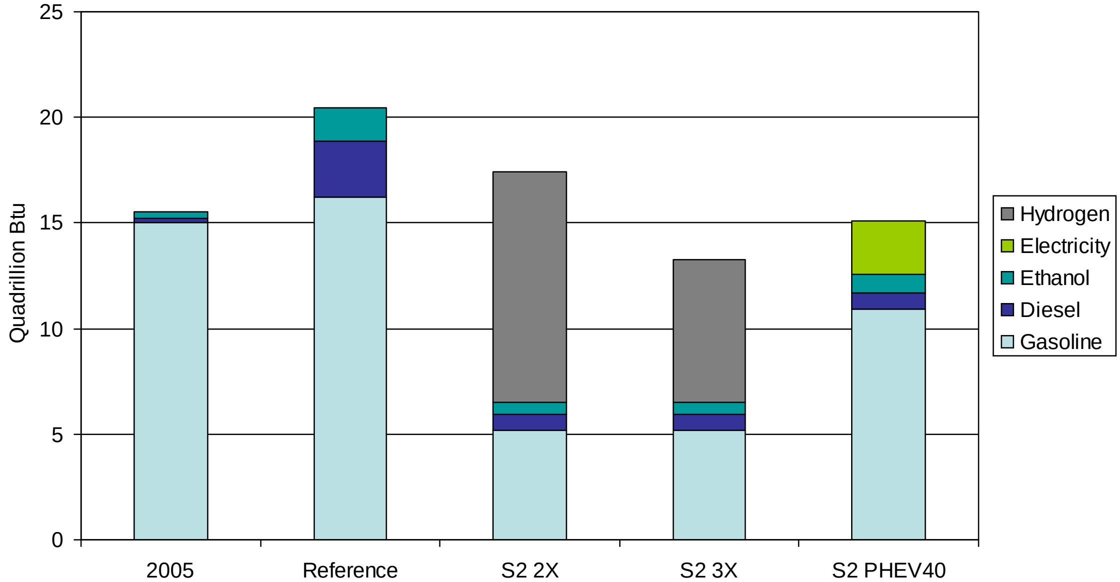


As shown in Figure 3.13, projections of LDV energy use in 2050 indicate that PHEVs could provide energy reductions commensurate with those projected under similar FCV scenarios. In the PHEV scenario, total LDV energy demand is reduced by 5.4 quadrillion Btu (26.3 percent), as compared with 3.0 quadrillion Btu (14.8 percent) in the fuel cell with *AEO2008* reference fuel economy scenario and 7.2 quadrillion Btu (35.3 percent) in the fuel cell with 3X fuel economy scenario. Although reductions in petroleum demand are projected across the scenarios, the PHEV scenario reduces petroleum demand by 38.0 percent (7.1 quadrillion Btu) relative to the reference case, while a 68.5-percent reduction (12.9 quadrillion Btu) is projected in the FCV scenarios.[72] In the PHEV scenario, electricity demand in 2050 is increased by 2.5 quadrillion Btu compared to the reference case. Although the VISION model does not make projections of total electricity demand for all sectors, the *AEO2008* reference case projects total electricity demand in 2030 at 49.2 quadrillion

[72]The petroleum reductions discussed account only for LDV energy demand and do not include petroleum products used in the generation of electricity.

Btu. Assuming that total electricity demand remained constant between 2030 and 2050, PHEVs would increase that demand by 5.1 percent.

Figure 3.13. Scenario 2 Light-Duty Vehicle Energy Demand, 2050



Comparisons of projected CO_2 emissions were also examined for the scenarios. For the PHEVs, two CO_2 emission scenarios were developed, based on projected electricity generation mix—one based on the generation sources projected in the *AEO2008* reference case, the other on generation sources projected in an analysis of S.2191, the Lieberman-Warner Climate Security Act of 2007, where costs for CCS and nuclear and biomass plants are 50 percent more than in the *AEO2008* reference case.[73,74] Figure 3.14 illustrates the shares of electricity production by fuel type in both cases.[75]

The impacts of the PHEV utility mix scenarios on full fuel cycle CO_2 emissions from electric power generation are provided in Figure 3.15. In the *AEO2008* reference case, CO_2 emissions from electricity generation increase by 7.1 percent over the projection period, due to the greater percentage of total generation coming from coal. In the S.2191 high cost case, electric power full fuel cycle CO_2 emissions decline significantly over the projection period, by 72.4 percent from 2010 to 2050, as the generation sector transitions to low-CO_2 generation to meet the policy-imposed CO_2 emission constraints.

Relative to the FCV scenarios that assume *AEO2008* reference case fuel economy improvement, the PHEV scenarios project full fuel cycle CO_2 emission reductions in 2050 that are similar to those achieved in the hydrogen production scenarios considered. In the PHEV scenario with *AEO2008* reference case generation mix, total CO_2 emissions are reduced by 165 million metric tons CO_2 equivalent (8.5 percent) in comparison with the reference case in 2050, as shown in Figure 3.16. In comparison, the reductions projected in the FCV scenarios that assume the transition of hydrogen production to centralized natural gas SMR or coal with CCS, where CO_2 emissions are 3.9 percent and 20.9 percent, respectively. If the generation mix projected in the S.2191 high cost scenario were

[73] EIA, *Annual Energy Outlook 2008*, DOE/EIA-0383(2008) (Washington, DC, June 2008).
[74] EIA, *Energy Market and Economic Impacts of S.2191, the Lieberman-Warner Climate Security Act of 2007*, SR/OIAF/2008-01 (Washington, DC, April 2008); National Energy Modeling System, run S2191HC.D031708A.
[75] Projections provided for 2050 are derived from trend extrapolations determined by the VISION model.

achieved, CO_2 emissions from PHEVs would be reduced by 30.9 percent (601 million metric tons CO_2 equivalent) relative to the reference case in 2050, comparable to the reductions projected in the most optimistic fuel cell scenarios with 2X fuel economy improvement.

Figure 3.14. Share of Total Electricity Production by Fuel Type in Two Cases

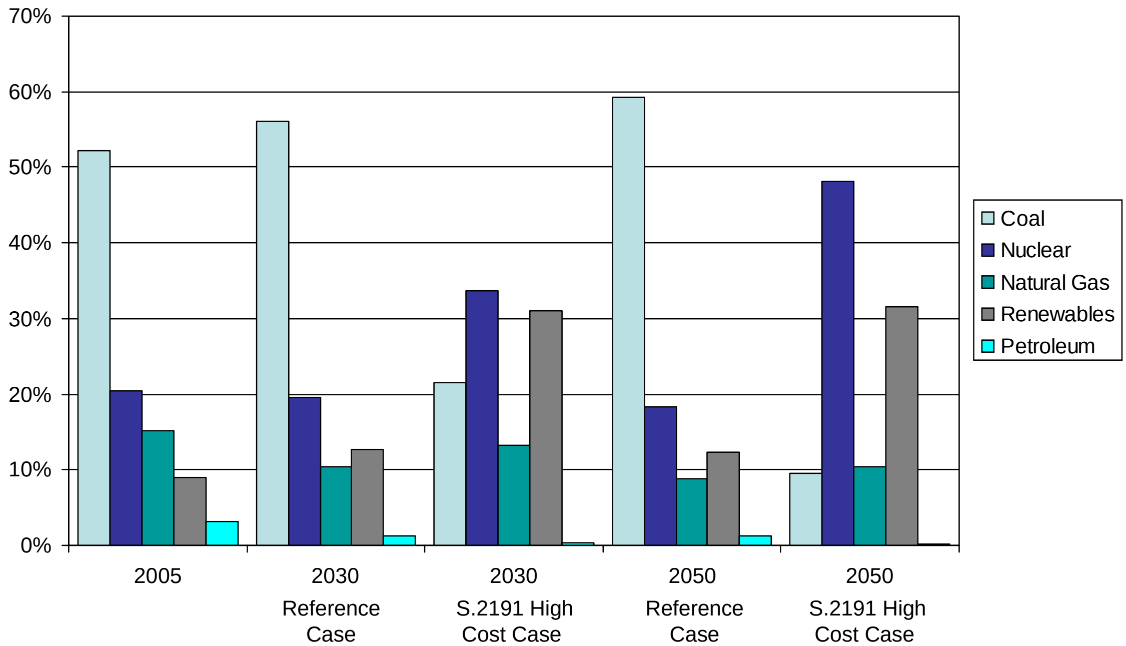


Figure 3.15. Full Fuel Cycle CO_2 Emissions from Electricity Generation, 2010-2050
(Million Metric Tons CO_2 Equivalent per Quadrillion Btu)

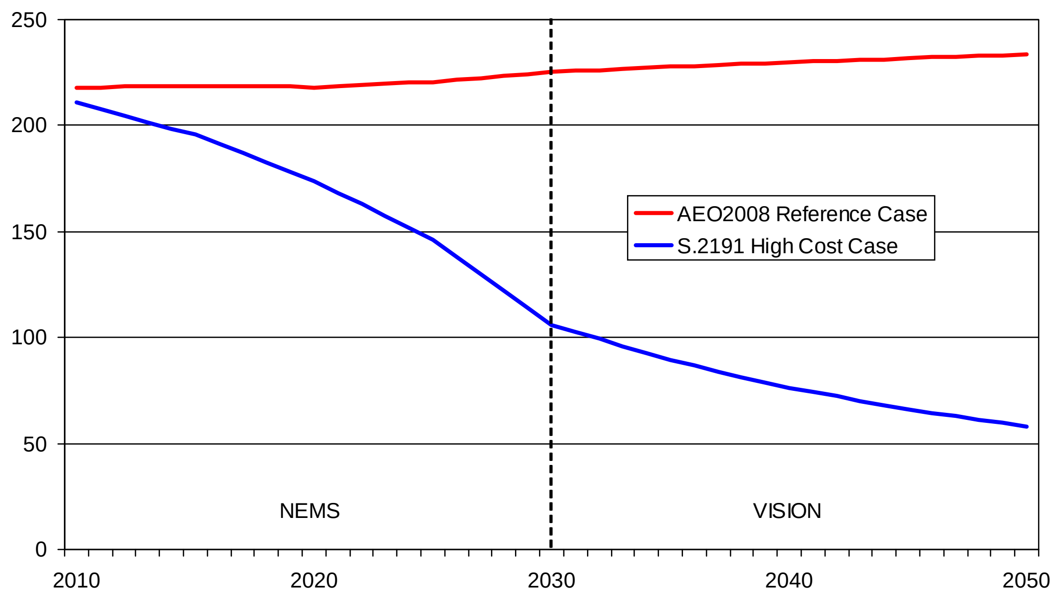
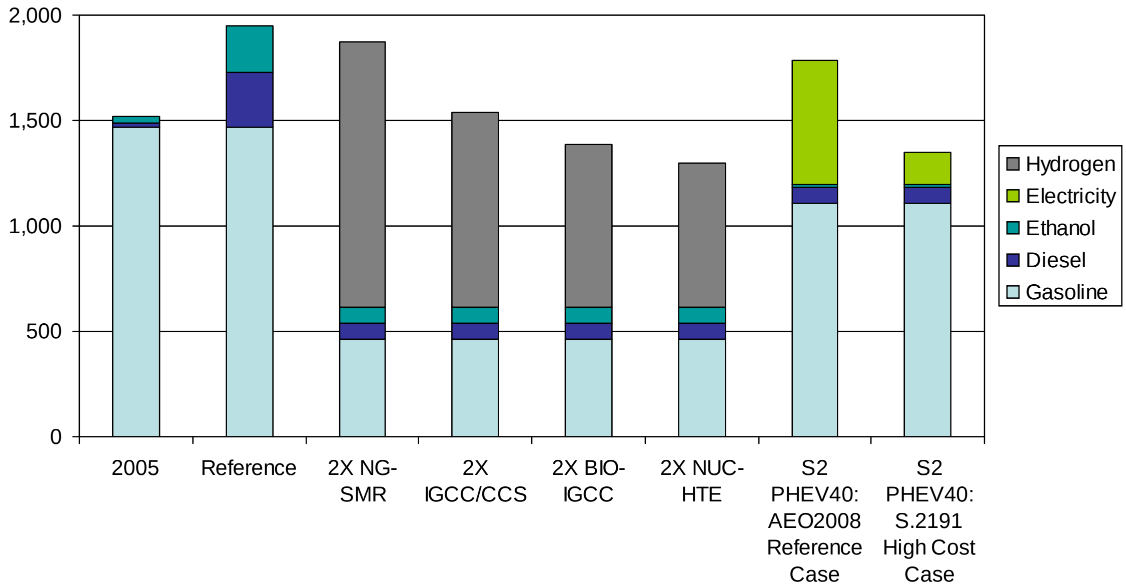
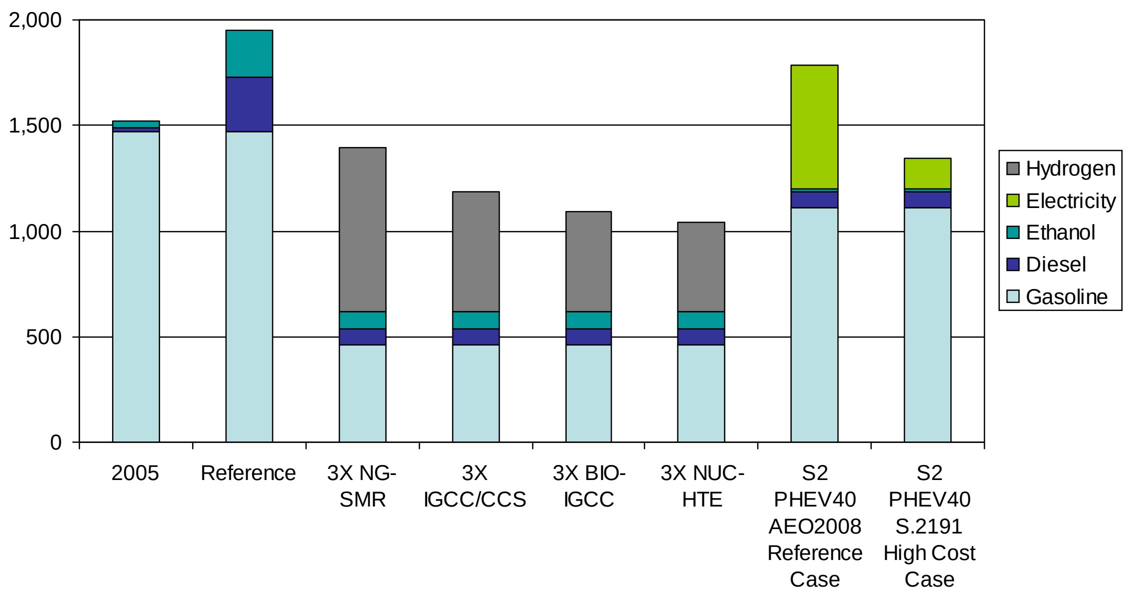


Figure 3.16. Light-Duty Vehicle Full Fuel Cycle CO_2 Emissions, 2X Fuel Cell Vehicle Economy, Scenario 2, 2050
(Million Metric Tons CO_2 Equivalent)



If fuel cell vehicles achieve 3X fuel economy improvement, as shown in Figure 3.17, then projected full fuel cycle CO_2 emission reductions for all the hydrogen production scenarios exceed those projected in the PHEV scenario with the *AEO2008* reference case utility mix. The projected emissions reductions for the PHEV scenario with the S.2191 high cost scenario utility mix exceed the reductions projected for the natural gas SMR FCV scenario.

Figure 3.17. Scenario 2 Light-Duty Vehicle Full Fuel Cycle CO_2 Emissions, 3X Fuel Cell Vehicle Fuel Economy, 2050
(Million Metric Tons CO_2 Equivalent)



Conclusion

Considerable reductions in LDV energy demand and full fuel cycle CO_2 emissions could be achieved if the assumptions for FCVs and hydrogen infrastructure development were to come to fruition. The development of a large market for hydrogen-powered LDVs probably will require a massive financial commitment by industry and government and, ultimately, will hinge on success in fuel cell R&D as described in previous sections of this report. Competition from other promising technologies represents a further market challenge to hydrogen-powered LDVs.

The following are key findings from this analysis:

- It is highly unlikely that hydrogen FCVs will have significant impacts on LDV energy use and CO_2 emissions by 2030.
- Depending on fuel economy improvement and rate of market penetration, hydrogen FCVs could reduce petroleum demand in 2050 by 37.1 to 84.1 percent.
- Depending on the method of hydrogen production, full fuel cycle CO_2 emissions in 2050 could be reduced by 2.0 to 63.8 percent, depending on the market penetration scenario.
- Under similar market penetration assumptions, successful development of a PHEV-40 could provide significant reductions in petroleum use; however, the maximum reductions in petroleum use would be less than those projected in the most aggressive FCV scenarios. PHEVs can also achieve significant reductions in CO_2 emissions, but the full fuel cycle emissions reductions fall short of those projected in some of the hydrogen FCV scenarios. The fuel economy of FCVs and the electricity generation mix are the key determinants of relative emissions outcomes.

4. Technological and Economic Challenges

While engineering research and other R&D eventually could succeed in solving all the technical and economic challenges of making hydrogen-powered light-duty FCVs a cost-effective reality by 2030, the number of necessary successes and investments required over the next 25 years is large by many measures. Large-scale penetration of FCVs or HICE vehicles in the United States is unlikely without significant long-term Federal and State policies that promote FCV and HICE vehicle adoption and hydrogen infrastructure development. This chapter focuses on some of the challenges faced in achieving widespread penetration of FCV vehicles. All but one of the challenges—economical fuel cells—are the same for widespread HICE vehicle penetration.

Challenges to Deployment of a Hydrogen Economy

The most difficult technical challenge for large-scale adoption of FCVs appears to be the high capital cost of the PEM fuel cell, which would need to drop to about $30 per kilowatt. Complicating the potential for success in achieving this target is the cost of the platinum catalyst, which has been affected by a recent dramatic increase in platinum prices.

Widespread use of hydrogen fuel cells in LDVs will require significant R&D breakthroughs, including: (1) the development and widespread deployment of economical hydrogen production technologies or processes; (2) the development and production of economical, high-density, on-board hydrogen storage that can be drawn on quickly as needed;[76] (3) the widespread development and deployment of an economical hydrogen transportation, distribution, and dispensing network; and (4) the development and large-scale deployment of economical PEM fuel cells and their seamless integration into LDV motors. Moreover, in addition to the economic and technological challenges, public safety concerns about hydrogen in LDVs must be addressed at the consumer, State, and Federal levels, as they have been for compressed natural gas (CNG) vehicles.[77]

Competition in the Light-Duty Vehicle Market and Technological Progress

While considerable Federal R&D is focused on the development of FCVs and advanced battery technologies, large amounts of industry R&D are also focused on improving the performance of more conventional automotive technologies. Previous studies of investments in R&D indicate that that Federal R&D represents roughly 10 percent of the total R&D spending. However, industry's R&D typically is focused on the next 5 years. Consequently, technological progress on conventional power trains and advanced hybrids is likely to advance, especially with the challenges faced by the automobile industry in meeting the Corporate Average Fuel Economy (CAFE) standards set by provisions of EISA2007, which raise average new LDV fuel efficiency to 35 miles per gallon in 2020. To comply with the law, average new car efficiency is projected to rise to about 42 miles per gallon and new light truck efficiency to about 31 miles per gallon in 2020.

FCVs are also likely to face stiff competition from all-electric vehicles and PHEVs. Only one major challenge remains for those vehicles to be commercialized: the development of a durable, safe,

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[76]The hydrogen storage and delivery medium must function well under a wide range of temperatures, provide a range of at least 300 miles between fill-ups, allow rapid fill-ups, and last for at least 3 to 5 years without the need for replacement of the storage medium.

[77]Hydrogen-based vehicles may be restricted from traveling over bridges and through tunnels until rigorous safety tests by independent experts certify that vehicle accidents in bridges and tunnels will be at least as safe as accidents of comparable conventional vehicles. Virtually all bridge and tunnel authorities in the United States require special treatment of vehicles containing potentially explosive chemicals.

reliable, and relatively light-weight set of batteries that do not produce too much heat and can safely power the LDV for about 40 miles under normal driving conditions.

Successful R&D and commercialization of an advanced battery technology that achieves acceptable safety, performance, durability, and costs could support all three advanced automotive technologies—for all-electric PHEVs, all-electric FCVs, and hybrid FCVs. Because about 80 percent of all LDV round trips in the United States are less than 40 miles, early development of either the all-electric car or the PHEV could provide an attractive alternative to FCVs for significantly reducing oil imports, even if PHEVs continued to consume some petroleum and other liquid fuels on long-distance trips. There still are unresolved issues of safety and overheating with the current lithium-ion configuration, however, and how those challenges are addressed will weigh heavily on the ultimate success and market acceptance of the technology. Successful battery development could be an important option, or part of a portfolio of options, if a policy to reduce CO_2 emissions were adopted.

General Motors has suggested that the delivered price at which hydrogen is competitive with gasoline is the price of gasoline, excluding taxes, times the average efficiency advantage that the FCV has over a new conventional vehicle, all else being equal.[78] If FCVs had a 50-percent efficiency advantage over the best new conventional and hybrid vehicle alternatives (Table 4.1), then, all else being equal, hydrogen priced between $2 and $3 per kilogram would be competitive with gasoline priced between $3 and $4.50 per gallon.

Table 4.1. New Car Efficiency in the *AEO2008* Reference Case
(Miles per Gallon)

Vehicle Type[a]	2006	2015	2020	2030
Conventional Gasoline ICE	30.8	34.1	40.4	40.3
Conventional Diesel ICE	42.8	44.7	51.4	51.0
Gasoline-Electric Hybrid	45.2	46.8	53.9	53.7
Diesel-Electric Hybrid	–	51.5	57.5	57.4
Plug-in Gasoline Hybrid	–	67.6	73.2	72.9
DOE Target Hydrogen FCV	62[b]	95	95	95[b]

[a]*AEO2008* assumes that the technologies listed are used in cars of almost all sizes, and in the reference case average vehicle weight increases through 2030.

[b]The weight/size classes and performance characteristics for FCVs were not stated in the documents reviewed. The ultimate target for the FCV efficiency is 95 miles per gallon gasoline equivalent, but the achieved date is also unclear. Intermediate goals were not specified.

Source: AEO2008 National Energy Modeling System, run AEO2008.D030208F (reference case).

While further R&D on fuel cells targets improving electricity generation for FCVs,[79] R&D is also likely to improve the performance of more conventional automotive technologies and the development of enhanced battery technology for PHEVs. As shown in Table 4.1, the technological progress projected for gasoline and diesel hybrids in *AEO2008* is expected to result in average fuel

[78]B. Gross, I. Sutherland, and H. Mooiweer, "Hydrogen Fueling Infrastructure Assessment," RD-11,065 (General Motors Research and Development Center, Detroit, MI, December 2007).
[79]As rated by the U.S. Environmental Protection Agency, the Honda FCV hybrid, Clarity, has a fuel efficiency of 72 to 74 miles per gallon. Source: Stephen Ellis, Honda Motors.

efficiencies of more than 50 miles per gallon by 2015 and nearly 60 miles per gallon by 2030, narrowing the efficiency advantage of FCVs over conventional hybrids.

DOE's Key Targets and Goals for Hydrogen and Fuel Cell Vehicles

According to EERE,[80] the following hydrogen-related goals must be achieved if FCVs are to attain large-scale dominance in the LDV market:

- The delivered, untaxed, cost of hydrogen, including production, transportation, and distribution, must decline to between $2 and $3 per gallon gasoline equivalent, or approximately $2 to $3 per kilogram of hydrogen, because 1 kilogram of hydrogen contains about the same energy as a gallon of gasoline, and $1 per kilogram is about $8.77 per million Btu,[81] if crude oil prices are sustained at about $90 per barrel in real 2006 dollars. Higher crude oil prices would allow higher-cost hydrogen to pass the economic test.

- Federal and State policies must be instituted to facilitate the construction of all phases of a hydrogen production, transmission, distribution, and dispensing infrastructure. The policies may have to include financial incentives and guarantees that currently are unspecified, as well as safety regulations for the transportation of hydrogen through tunnels and on bridges.

- Fuel cell and vehicle manufacturers must be convinced that the Federal and State governments will provide a stable and supportive set of policies that encourage their investments in hydrogen FCVs for at least 10 years, according to an ORNL report.[82]

- Hydrogen storage costs for fuel cells must fall to about $2 per kilowatt from their currently estimated price of about $8 per kilowatt for the 5,000 psi system.[83]

- The total cost of all the fuel cell components, including fuel stacks, catalyst, and balance of system, must fall to $30 per kilowatt,[84] as compared with current cost estimates of $3,625 to $4,500 per kilowatt for production in small numbers.

- Ideally, the first FCV markets must be developed in areas with high population densities that already have excess capacity at hydrogen production facilities, in order to encourage early adoption, provide consumer familiarity, and accelerate fuel cell cost reductions based on learning by the automobile manufactures.

Each of these major goals and associated challenges are discussed below. Additional technical and economic feasibility items may also require resolution.

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[80]U.S. Department of Energy, web sites www1.eere.energy.gov/hydrogenandfuelcells/ presidents_initiative.html (April 2008), and www1.eere.energy.gov/hydrogenandfuelcells/news_cost_goal.html (July 2005).

[81]$1 per kilogram / 114,000 Btu per kilogram hydrogen. The Lower Heat Value(LHV) is about $8.77 per million Btu. One gallon of gasoline contains approximately 120,000 Btu and weighs about 6.2 pounds (see web site www.santacruzpl.org/ readyref/files/g-l/gasoline.shtml); however, the energy content of 1 gallon of liquid hydrogen is about 26 percent that of gasoline.

[82]D.L. Greene, P.N. Leiby, and D. Bowman, *Integrated Analysis of Market Transformation Scenarios with HyTrans,* ORNL/TM-2007/094 (Oak Ridge, TN: Oak Ridge National Laboratory, June 2007).

[83]U.S. Department of Energy, *Analysis of the Transition to a Hydrogen Economy and the Potential Energy Infrastructure Requirements* (Draft v.5-11-07)" (Washington, DC, May 2007), p. 4. The current costs assume compressed storage tanks operating at 5,000 psi.

[84]*Ibid.* According to the ORNL report, if the PEM fuel cell costs fell to only $60 per kilowatt, the expected market penetration of FCVs could be significantly diminished.

Hydrogen Production

Hydrogen can be produced from any number of well-known processes, as described in Chapter 2. As shown in Table 2.1, hydrogen production from a large-scale SMR plant is less than $1.50 per kilogram, whereas the cost of production from small-scale decentralized plants is much higher—roughly, $2.60 to $7.00 per kilogram using today's technologies, depending on the production method and source.

DOE has noted that there are not enough dispensing stations with sufficient land to construct on-site natural gas steam reformers to achieve a market penetration of between 2 million and 10 million FCVs.[85] Additional R&D breakthroughs or significant subsidies will be required to reduce the delivered cost of hydrogen at the dispensing stations.

In regard to the supply of biomass for hydrogen production, enactment of either a stringent cap-and-trade program for GHG emissions or an RPS for electricity generation, in addition to recently enacted EISA2007 provisions, could cause biomass prices to rise significantly and make the production of hydrogen from biomass much more costly.[86] Other researchers have also highlighted the implied scale-up of biomass production from current levels that must be achieved as a significant uncertainty in evaluating the feasibility of using biomass resources on a large scale.[87]

Hydrogen Storage

Any vehicle that provides a substantially lower range and less convenience than those of conventional gasoline and diesel vehicles (currently, about 300 miles per fill-up) is unlikely to achieve dominance in the LDV market, because consumer expectations for vehicle range have been set by conventional gasoline and diesel vehicles and, more recently, hybrids. The three prevalent on-board hydrogen storage methods being considered, as discussed previously, are high-pressure tanks, liquid storage in refrigerated or insulated containers, and storage in a yet-to-be developed metal hydride.

The ultimate goals of the hydrogen storage R&D program are to develop a low-cost storage medium that would: (1) safely trap and store sufficient volumes of hydrogen to provide a range of at least 300 miles per fill-up; (2) provide stable "on-demand" hydrogen storage under a wide range of temperatures; (3) quickly and controllably release the stored hydrogen "on demand" to the fuel cell or HICE to provide acceptable vehicle acceleration and torque; (4) safely provide numerous recyclings, or fill-ups, that are comparable in number and frequency to those for a conventional LDV over a 3- to 5-year period; and (5) reduce hydrogen storage costs for FCVs to about $2 per kilowatthour, as compared with current estimated costs of at least $8 per kilowatthour.[88]

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[85]U.S. Department of Energy, *Analysis of the Transition to a Hydrogen Economy and the Potential Energy Infrastructure Requirements* (Draft v.5-11-07)" (Washington, DC, May 2007), p. 19.
[86]See, for example, EIA, *Energy Market and Economic Impacts of S. 2191, the Lieberman-Warner Climate Security Act of 2007*, SR/OIAF/2008-01, and *Energy and Economic Impacts of Implementing a 25-Percent Renewable Portfolio Standard and Renewable Fuel Standard by 2025*, SR/OIAF/2007-05.
[87]For example, M. Toman, J. Griffin and R. J. Lempert, *Impacts on United States Energy Expenditures and Greenhouse-Gas Emissions of Increasing Renewable-Energy Use* (RAND, Santa Monica, CA, June, 2008).
[88]U.S. Department of Energy, *Analysis of the Transition to a Hydrogen Economy and the Potential Energy Infrastructure Requirements (Draft v.5-11-07)* (May 2007), p. 4. The current costs are based on a 5,000 psi storage tank.

High-pressure tanks (5,000 to 10,000 psi) made of carbon fiber that can be used for hydrogen storage range in cost from $8 per kilowatthour to $17 per kilowatthour,[89] depending on the pressure capability. Doubling the tank pressure from 5,000 to 10,000 psi increases the hydrogen storage capacity by 70 percent for the same volume, based on the physical properties of hydrogen, thus increasing the range of the vehicle by 70 percent. More than 65 percent of the estimated storage cost is the cost of the carbon-fiber tank.[90] Used in vehicle conversions, these tanks take up most of the trunk space in LDVs, provide a range of more than 250 miles in FCVs and less than 100 miles in HICE engines, require a relatively long time to refill (2 minutes per kilogram or gasoline gallon equivalent,[91] are significantly more expensive than gasoline or diesel vehicles, and face perceived safety concerns in the event of accidents. These characteristics, while generally undesirable for LDVs, are likely to be surmountable.

Hydrogen could also be stored in liquid form, at about -423 degrees Fahrenheit, in refrigerated or insulated units, thereby significantly increasing its volumetric energy density but still containing only about 26 percent of the energy of a gallon of gasoline. Furthermore, the evaporative losses of at least 1.7 percent per day and the energy consumption needed to convert the hydrogen gas to liquid form (the equivalent of at least one-third of the original tank of liquid hydrogen), add to the energy transformation losses associated with hydrogen production and increase the cost of hydrogen-fueled vehicles using liquid hydrogen considerably. The major drawback for liquefied hydrogen storage, besides the hydrogen production and liquefaction cost, is the volume of trunk space required—roughly four times the volume of gasoline for the same energy content.

Considerable research is being directed by DOE into the development of storage systems, including: metal hydride storage media, carbon nanotube systems, and other novel storage systems, as discussed above. There are no economical advanced storage media that currently satisfy all the requirements, and it is uncertain whether or when the needed successes will occur. It would appear that considerable R&D success would be required to make them commercial.

Development and Deployment of a Hydrogen Infrastructure

Through 2030, the two approaches being considered to develop a hydrogen transmission and distribution infrastructure are the development of a complete pipeline transmission and distribution system, similar in some ways to the current system for natural gas, and the development and implementation of a series of local hydrogen production facilities using natural gas as the feedstock. The goal of the current program is to start with the local system and then transition to the larger central system as the hydrogen market grows.

The economic challenges are different for each option and difficult to overcome without government intervention. A full-scale hydrogen pipeline and distribution system resembling today's natural gas network would provide more options for hydrogen production and generally lower costs than the decentralized option, provided that the hydrogen pipeline and distribution system has a high utilization rate. Initially, however, utilization rates are likely to be low, and the investments needed are unlikely to be made without significant Federal incentives. The local SMR option would avoid high initial investment costs and the need for high overall utilization rates, but the efficiency of the technology would have to be improved, and production costs would have to be reduced

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[89]A.R. Abele, "Quantum Hydrogen Storage Systems," presented at the ARB ZEV Technology Symposium, Sacramento, CA, September 25-27, 2006, web site www.arb.ca.gov/msprog/zevprog/symposium/presentations/abele1_storage.pdf. The higher pressures attempt to increase the acceptability of the range of the vehicle to consumers. The costs quoted assume a production volume of 500,000 160 liter MPa tanks with optimized carbon fiber and health system.
[90]*Ibid.*
[91]*Ibid.*

significantly. In addition, the feedstock fuel usually is limited to natural gas, which is subject to significant price volatility and could become more expensive when natural gas is used on a large scale for hydrogen production.

For centralized hydrogen production and distribution, the cost of a hydrogen transmission system will depend on a number of factors that are specific to the site, operating conditions, and pipeline. Hydrogen pipelines are likely to have a smaller diameter than natural gas pipelines, which would reduce the cost; however, they also are likely to require more expensive steel alloys to avoid embrittlement and other issues, unless alternatives are developed.

Distribution and dispensing costs for hydrogen depend heavily on the mode of transportation (pipeline, truck, or rail) and the form of the hydrogen (pressurized gas, container, or liquefied) delivered to distribution and dispensing centers. The costs can vary widely. Shell, a partner in a recent hydrogen infrastructure study, noted that it expected a limited role for distributed SMR in the initial development of the hydrogen economy, because SMR requires significant progress in the development of small reformer technology before it becomes economical.[92]

The current analytic approach is to initially target locations with high population densities, such as Southern California and the New York City metropolitan area, with decentralized hydrogen production facilities to avoid the costs of constructing a transmission and distribution system. Those areas would be later be expanded to include the Boston and Washington, DC, areas. This approach minimizes many of the initial large-scale investment cost difficulties of the centralized hydrogen production, transmission, and distribution system, but it could create other new challenges in terms of potential natural gas delivery bottlenecks and price volatility.

Production of Fuel Cells for Light-Duty Vehicles

Fuel cells have been used for more than 40 years in niche markets, including the U.S. space program. Capital costs initially exceeded $30,000 per kilowatt. PEM fuel cells, a more recent development, have been built and used in some LDVs. More than 4,000 new transportation vehicle applications of PEM-like fuel cells have been made worldwide between 2000 and 2006,[93, 94] amounting to more than 250 megawatts of capacity for transportation applications. Honda Motor Company will introduce 200 fuel cell hybrid cars, the FCX Clarity, late in 2008 or early in 2009 for 3-year leases. The Clarity, which uses a 100-kilowatt hydrogen fuel cell system, will be leased at $600 per month for 3-year leases in the Los Angeles metropolitan area. Honda has stated that the lease rate does not fully cover the cost of the vehicle.

Reduction of Automotive PEM Fuel Cell Costs to $30 per Kilowatt

The PEM units to be used in LDVs produce low-level heat and are estimated to have initial costs between $3,000 and $5,000 per kilowatt, depending on the application (e.g., LDVs or forklifts). Costs are already projected to be considerably lower for production on a large scale, with one recent study citing estimates in the neighborhood of $100 per kilowatt[95] but are still well above the DOE

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[92]B. Gross, I. Sutherland, and H. Mooiweer, "Hydrogen Fueling Infrastructure Assessment," RD-11,065 (General Motors Research and Development Center, Detroit, MI, December 2007).
[93]K.-A. Adamson, *2006 Light Duty Vehicle Survey* (Fuel Cell Today, March 2006), web site www.fuelcelltoday.com/media/pdf/surveys/2006-Light-Duty-Vehicle.pdf.
[94]K.-A. Adamson, *2007 Niche Transport (2)* (Fuel Cell Today, September 2007), web site www.fuelcelltoday.com/media/pdf/surveys/2007-Niche-Transport%202.pdf.
[95]National Research Council, Committee on Assessment of Resource Needs for Fuel Cell and Hydrogen Technologies, *Transitions to Alternative Transportation Technologies—A Focus on Hydrogen* (Washington, DC, July 2008).

goal to reduce the "first purchase" cost of the PEM fuel cell to about $30 per kilowatt by 2015. In addition, catalyst use is targeted for reduction from 1.7 ounces to 0.56 ounces of platinum per 80-kilowatt fuel cell system.[96] If the program goals are achieved, the incremental cost of the fuel cell drive system would be approximately offset by the elimination of the internal combustion engine.

Although the target cost of PEM fuel cells may be achievable with successful R&D and numerous breakthroughs, the timing and occurrence of those breakthroughs are far from certain. The fuel cell cost reductions, if achieved through normal technological learning and progress, would be unprecedented for consumer durables. Appendix F provides a further discussion of learning in the context of experience in other markets for durable goods.

Catalyst Cost Challenge

Using DOE's catalyst cost of $1,000 per ounce,[97] and assuming that platinum usage is 1.7 ounces per FCV, the cost of the catalyst in a PEM fuel cell is about $21 per kilowatt. Reducing the platinum requirement to 0.56 ounces by 2015 would reduce the per-kilowatt incremental cost of the catalyst to $7 per kilowatt.

Recent developments in the worldwide platinum market suggest the possibility that platinum prices could rise to more than $1,000 per ounce. Platinum is a rare metal—more than 30 times more rare than gold and much more difficult and costly to mine. The commodity prices of platinum, while showing some variability, have been trending steadily upward since January 2003, reflecting rising demand for platinum in all markets. Worldwide platinum production in 2007 was about 225 tons, and the average price was about $1,200 per ounce.[98] In early 2008, the spot price for platinum continued rising to more $1,500 per ounce, and it hovered between $1,700 and $2,200 per ounce from April through July 2008. According to the largest platinum distributor in the world (the United Kingdom's Johnson Matthey), in 2007 the total world demand for platinum was 241 tons, of which roughly 27 percent was used for industrial purposes, 23 percent for jewelry, 3 percent for investment purposes, and the remaining 47 percent for catalytic converters. Appendix G provides a further discussion of the implications of platinum market conditions for the cost of PEM fuel cells using platinum.

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[96]DOE's PEM platinum use as of 2007 is stated as 0.6 grams per kilowatt, and the goal for 2015 is 0.2 grams per kilowatt. See web site www.hydrogen.energy.gov/pdfs/review08/6_fuel_cells_nancy_garland.pdf. Further development and validation of platinum usage and recycling are the subject of continued research.

[97]*Ibid*.

[98]See D. Jollie, *Platinum 2008* (Johnson Matthey, May 2008). It should be noted that the demand of platinum for the autocatalyst market continues to be partially mitigated by the growing catalytic converter recycling industry. Although the fraction of platinum being recovered so far has not kept up with the accelerating demand growth, this may change in the future as regions such as Europe and eventually Asia develop mature recycling industries similar to that in the United States.

Appendix A. Analysis Request Letter

BYRON L. DORGAN
NORTH DAKOTA
[illegible]

COMMITTEES:
APPROPRIATIONS
COMMERCE, SCIENCE & TRANSPORTATION
ENERGY & NATURAL RESOURCES
CHAIRMAN, INDIAN AFFAIRS

CHAIRMAN, DEMOCRATIC POLICY COMMITTEE

United States Senate

WASHINGTON, DC 20510-3405

October 22, 2007

STATE OFFICES

312 FEDERAL BUILDING
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FARGO, ND 58106
[illegible]

The Honorable Guy F. Caruso
Administrator
Energy Information Administration
Forrestal Building
1000 Independence Avenue, S.W.
Washington, DC 20585

Dear Mr. Caruso:

The Energy Information Administration (EIA) has often provided the Congress with important analyses of future energy policy options. Increasing concern about energy security, trade deficits, economic growth, air quality and climate change will engage us for many years, and these reviews make key contributions to the course of policy debate.

I am writing to request that you conduct a quantitative analysis of the pollutant emissions reductions (including greenhouse gases) and oil savings that would result from commercializing advanced hydrogen and fuel cell technologies, both in transportation and distributed electricity generation. Several different sizes of a hydrogen economy have been evaluated since 2004's landmark study done by the National Academy of Sciences, including work from the Department of Energy's (DOE's) Energy Efficiency and Renewable Energy program, the International Energy Agency, the European Commission and several National Laboratories. They have shown that a wide range of energy alternatives will be needed to fully ensure a steadily cleaner and more efficient energy economy.

Substantial industry, federal, and state investment in research, development and demonstration has moved our technical knowledge forward since 2004 -- a succinct systems examination of the emissions, energy efficiency and oil savings benefits of a hydrogen economy, however, has yet to be done. When Congress passed the Energy Policy Act of 2005, we intended to accelerate the development of technology toward commercialization, and gave the Secretary of Energy more authority and resources to accelerate this initiative. Title VII, *Vehicles and Fuels*, and Title VIII, *Hydrogen*, clearly set goals and methods for how federal resources need to be focused, in partnership with industry. The potential for dramatic improvement in emissions, efficiency and oil use is very real. The stakes are high, and better analysis can usefully guide our oversight and funding of these programs.

I request that the EIA undertake a broad review of the expected impacts of a group of detailed scenarios, highlighting those key differences that could

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significantly reduce America's dependence on imported energy, while dramatically reducing emissions. The key drivers are the pace of technological change, the magnitude and focus of private and public investment, the success of these partnerships, the role of tax incentives and careful design of regulatory policy.

I appreciate your guidance and assistance. The EIA has often made key contributions to debate and understanding, and I appreciate the contributions your energy analysis has made on policy debates in Congress. I expect that the analysis I have described here will greatly help us in our pursuit of future initiatives. Please contact Franz Wuerfmannsdobler or John Rockey of my staff at (202) 224-2551 with any questions.

Sincerely,

Byron L. Dorgan
United States Senator

Appendix B. Heat Content and Useful Conversions

Table B.1. Heating Values

Material	Energy Content	Source
H_2 (HHV)	0.135 million Btu per kg	P.L. Smith and M.K. Mann, *Life Cycle Assessment of Hydrogen Production via Natural Gas Steam Reforming* (National Renewable Energy Laboratory, February 2001).
H_2 (LHV)	0.114 million Btu per kg	
Motor gasoline (HHV)	0.125 million Btu per gallon	Bureau of Transportation Statistics, *National Household Travel Survey (NHTS) 2001*, Appendix N, Table 9 (January 2004).[a]
Motor gasoline (LHV)	0.1154 million Btu per gallon	
Dry natural gas (HHV)	1,029 million Btu per cubic foot	EIA, *Annual Energy Review 2006*, Table A4.[b,c]

[a]Web site www.bts.gov/publications/National_household_travel_survey_2001_cd/html/appendix_n/table_9.html.

[b]See also, for both LHV and HHV for natural gas, GREET *Transportation Fuel Cycle Analysis Model*, GREET 1.8a, developed by Argonne National Laboratory, Argonne, IL, released August 30, 2007, web site http://www.transportation.anl.gov/software/GREET/index.html.

[c]The HHV for natural gas presented here (1,089 Btu / ft^3) is equal to the *AER* value of 1,029 Btu / ft^3 when the differences in temperature are taken into account.

Notes: The lower heating values and the higher heating values are the amounts of heat released when a substance is combusted at an initial temperature of 25°C. For the lower heating value (LHV), the products are returned only to a temperature of 150°C, and thus the latent heat of vaporization in the water is not released. In contrast, higher heating value (HHV) measurements assume that the products are cooled back down to 25°C, and so the heat from the water is released upon condensation. For stationary combustion (such as in power plants) the HHV measure is more appropriate, because the heat of the product exhaust gases can be harnessed before being discharged. The LHV is more appropriate for combustion processes in transportation, because no useful work is extracted from the exhaust gases. In this analysis, the LHV measure is used in accounting for hydrogen production costs.

Appendix C. Existing Hydrogen Production Capacity

An estimate of U.S. hydrogen production capacity in 2003 and 2006 is provided in Table C.1. U.S. hydrogen production capacity is subdivided into "on-purpose" and "byproduct" production capacity, with the on-purpose capacity further classified as "captive" and "merchant" production capacity.

Table C.1. Estimated United States Hydrogen Production Capacity, 2003 and 2006

Capacity Type	Production Capacity (Thousand Metric Tons per Year)	
	2003	2006
On-Purpose Captive[a]		
Oil Refinery	2,870	2,723
Ammonia	2,592	2,271
Methanol	393	189
Other	18	19
On-Purpose Merchant[a]		
Off-Site Refinery	976	1,264
Non-Refinery Compressed Gas (Cylinder and Bulk)	2	2
Compressed Gas (Pipeline)	201	313
Liquid Hydrogen	43	58
Small Reformers and Electrolyzers	<1	<1
Total On-Purpose[a]	**7,095**	**6,839**
Byproduct		
Catalytic Reforming at Oil Refineries	2,977	2,977
Other Off-Gas Recovery[b]	462	478
Chlor-Alkali Processes	NA	389
Total Byproduct	**3,439**	**3,844**
Total Hydrogen Production Capacity	**10,534**	**10,683**

[a]"On-purpose" are those units where hydrogen is the main product, as opposed to "byproduct" units where hydrogen is produced as a result of processes dedicated to producing other products.

[b]From membrane, cryogenic and pressure swing adsorption (PSA) units at refineries and other process plants.

Sources: The EIA-820 Refinery Survey, The Census Bureau MA28C and MQ325C Industrial Gas Surveys, SRI Consulting, The Innovation Group, Air Products and Chemicals, Bilge Yildiz and Argonne National Laboratory (Report # ANL 05/30, July 2005), and EIA analysis.

Refinery activities are estimated to account for 65 percent of hydrogen production capacity. Adding the hydrogen production capacity at ammonia and methanol production plants to the hydrogen production capacity associated with oil refineries brings the share of hydrogen production capacity related to petroleum refining and petrochemical production up to 92 percent. Indeed, the share of petrochemical production capacity has declined as higher natural gas prices have led to a 35-percent reduction in ammonia production capacity and a 44-percent reduction in ammonia production between 1999 and 2006.[99, 100] Over the same time period, methanol production capacity has also

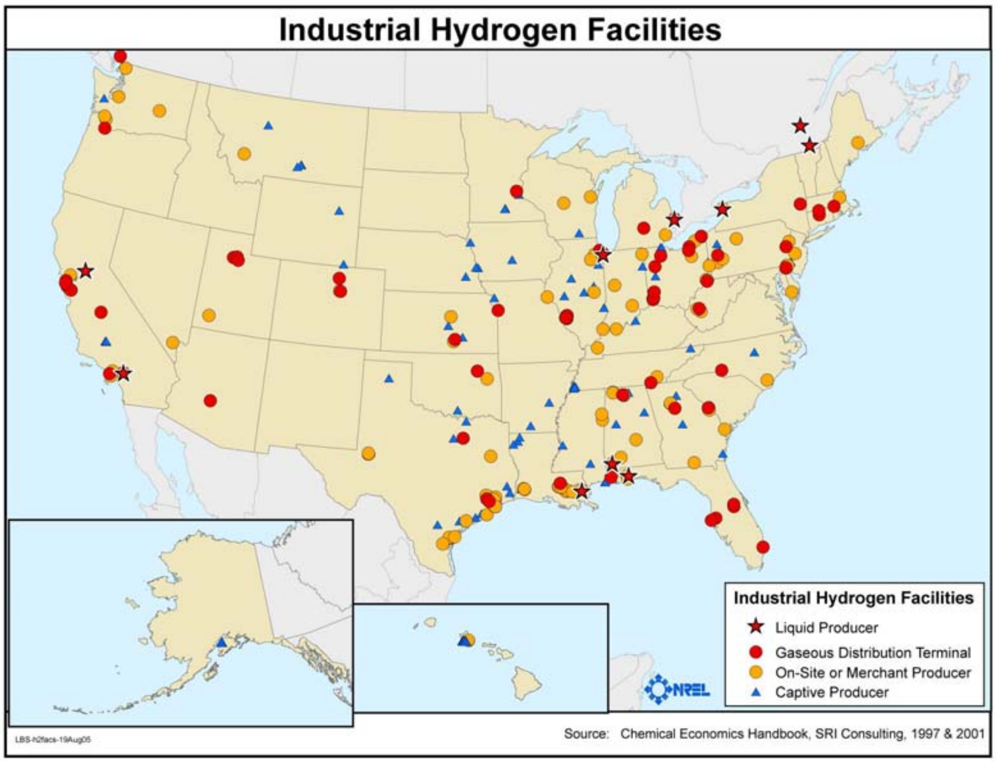
[99]W. Huang, *Impact of Rising Gas Prices on United States Ammonia Supply*, Report WRS-0702 (Washington, DC: U.S. Department of Agriculture, August 2007).

[100]Pacific Environmental Services, Inc., *Background Report: AP-42 Section 5.2, Synthetic Ammonia* (Research Triangle Park, NC, January 1996), web site www.epa.gov/ttn/chief/ap42/ch08/bgdocs/b08s01.pdf.

declined, by 86 percent, with only four facilities remaining in operation in 2006.[101] Two of those facilities were removed from service during the first half of 2007.

As indicated in Table C.1, existing hydrogen production capacity is from either technology dedicated to producing hydrogen “on-purpose” or as a byproduct from processes dedicated to producing some other product. Of the on-purpose hydrogen production technologies, the three major processes are reforming, partial oxidation and electrolysis. Byproduct production of hydrogen occurs in catalytic reforming of crude oil and other refinery processes and in chlor-alkali processes for chlorine and alkali production. As shown in Figure C.1, hydrogen production capacity exists across the United States.

Figure C.1. Map of United States Industrial Hydrogen Production Facilities



Source: National Renewable Energy Laboratory (2006).

Chlor-Alkali By-Product Production Capacity

The byproduct production of hydrogen gas is of interest because the estimated 389 thousand metric tons of hydrogen annually produced from chlor-alkali processes alone are equivalent to the annual fuel consumption of 1.9 million light-duty hydrogen vehicles. The process itself involves the electrolysis of salt water which, in combination with other process steps, splits salt (NaCl) in solution into sodium hydroxide (NaOH), chlorine gas and hydrogen gas. In this process, hydrogen is a byproduct. In some facilities, approximately 10 percent of the hydrogen produced is used on site to produce hydrochloric acid (HCl), while larger portions are either sold to third-party marketers of

[101]B. Yildiz, M. C. Petri, G. Conzelmann, and C. W. Forsberg, *Configuration and Technology Implications of Potential Nuclear Hydrogen System Applications*, ANL-05/30 (Chicago, IL: Argonne National Laboratory, July 2005).

hydrogen gas for further purification and distribution. Some facilities also combust hydrogen on site to meet steam and power production needs. Some chlorine producers may produce excess hydrogen gas that is either vented[102] or flared and thus could be a source of supply, potentially at a low cost for nearby consumers such as hydrogen dispensing stations. Additionally, the fraction of hydrogen byproduct that is currently used as process heat at some facilities (perhaps up to 40 or 50 percent of the total) could be available as an additional source of supply. The minimum cost related to that potential additional supply would likely be the substitute fuel that would be used for process heat. In most cases that substitute fuel would be natural gas. Thus, for this portion of the hydrogen byproduct, the minimum value would be $1.49 per kilogram at a delivered natural gas price of $11 per million Btu (excluding purification and distribution).[103] The portion of hydrogen that is sold to marketers would have a different, and likely higher, opportunity cost associated with its pricing.

Approximately 70 percent of the United States chlor-alkali production capacity is in the Gulf Coast region.[104] There are plants located throughout the United States, but a major shift of capacity away from the chemical industry hub in the Gulf Coast would likely to be costly and occur slowly.

Oil Refinery Hydrogen Production Capacity

Currently, the largest sources of hydrogen production capacity in the United States are associated with the nation's 145 operating oil refineries and 4 idle refineries. The refineries consist of a complex system of chemical processes such as hydrocracking, reforming, hydrotreating, and other processes in which crude oil and hydrocarbon compounds are distilled, processed and blended into a wide array of products. There are four primary sources of hydrogen at refineries: catalytic reforming, on-site hydrogen production, purchases from merchant plants, and byproduct production from other refinery processes.

Many refineries augment their catalytic reformer system's capacity to produce hydrogen with a separate, on-site hydrogen plant. EIA's 2007 Refinery Capacity Report, EIA-820, shows 89 refiners, or about 61 percent, having on-site hydrogen production capacity. This capacity amounts to 3,100 million standard cubic feet (SCF) of hydrogen per day or the equivalent of 2.723 million metric tons of hydrogen per year.

Some refineries purchase hydrogen from merchant suppliers. The merchant suppliers may operate a hydrogen plant adjacent to the refinery and supply the gas "through-the-fence". In other cases, the refinery is connected to a large hydrogen supply pipeline that the merchant operates. EIA estimates that the merchant-supplied hydrogen production capacity related to refineries was about 1,264 thousand metric tons per year in 2006 as shown in Table C.1.

As illustrated in Figure C.2, the refinery demand for hydrogen is increasing in order to satisfy the growing demand for hydrocarbon transportation fuels and the tightening environmental restrictions on vehicle exhaust emissions. Since 1982, there has been a 59-percent expansion of onsite refinery-owned hydrogen plant capacity—an average growth rate of about 1.2 percent per year. Prior to 2006 the United States hydrogen industry had been growing at a rate of about 7 to 10 percent per year[105]

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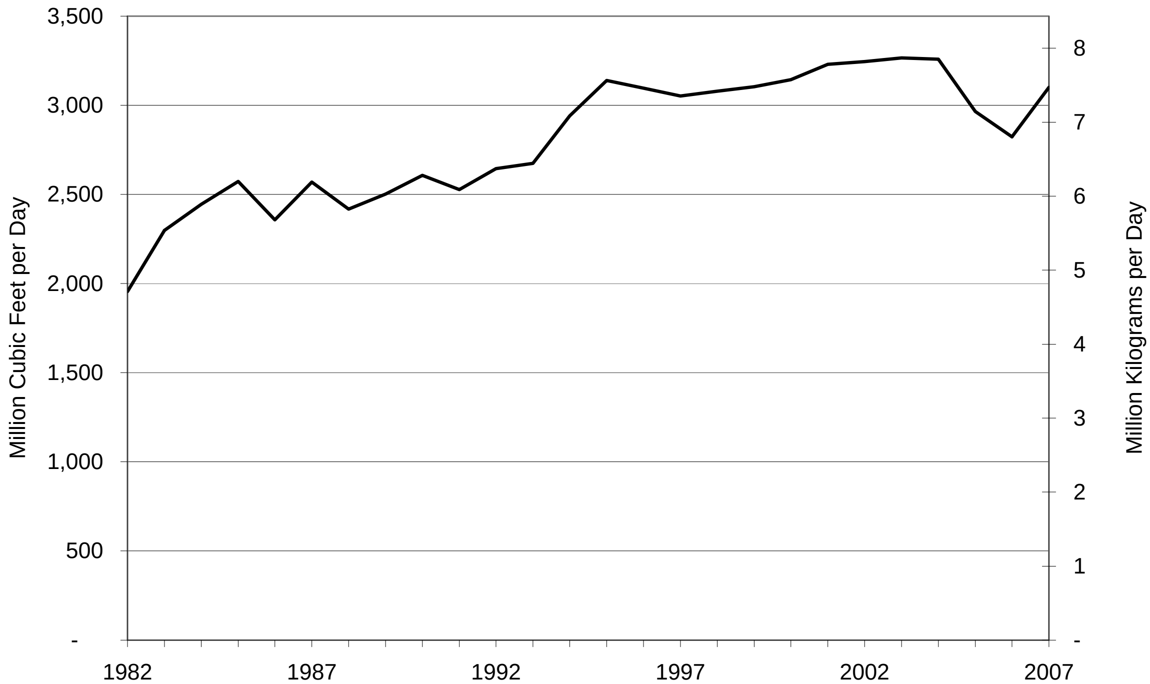
[102]Personal communication with Hassan Arabghani, VP Business Development & Strategy of Olin Chlor Alkali Products (May 20, 2008).
[103]Calculated as 0.135 million Btu per kilogram of hydrogen (HHV) times $11 per million Btu. Any hydrogen gas recovered from flaring would represent a zero opportunity cost.
[104]J. Thornton, *Pandora's Poison: Chlorine, Health, and a New Environmental Strategy* (Cambridge, MA: MIT Press, 2000).
[105]S. Ritchey, "Existing Growth Opportunities for Hydrogen Transportation in California" (March 2006), web site http://hydrogen.its.ucdavis.edu/publications/pubpres/2006presentations/pre06others/ritchey07.

and is projected to grow another 40 percent over the next five years.[106] Within the refinery sector, the near-term average annual growth rate of hydrogen consumption is projected to be about 4 percent per year.[107] The merchant share of hydrogen to refineries is estimated to grow at an annual rate of about 8 to 17 percent per year.[108, 109]

Figure C.2. United States Refinery On-Site Hydrogen Production Capacity



Source: Energy Information Administration, Form EIA-820.

Other Hydrogen Production Capacity

Other producers and consumers of hydrogen include ammonia plants, methanol production facilities, brine electrolysis facilities that produce chlorine, hydrogen and bleach, and other smaller facilities. Ammonia and methanol facilities have experienced steady closures or declining production since 2000 because of steadily increasing natural gas prices.[110, 111]

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[106] B. Suresh, M. Yoneyama, and S. Schlag, "Hydrogen," in *Chemical Economics Handbook* (SRI Consulting, October 2007), web site www.sriconsulting.com/CEH/Public/Reports/743.5000.
[107] P. Dufor and J. Glen, "Analyst, Investor, and Journalist Site Visit Houston" (Air Liquide, December 18-20, 2005), web site www.airliquide.com/file/otherelement/pj/pdf-corporate/2005-12-19_houston_hydrogen_today59319.pdf.
[108] *Ibid.*
[109] R. Cassidy, Air Liquide Canada, "Hydrogen: Current Reality and Future Perspective from a Major Producer" (February 13, 2006).
[110] Methanol Institute, "Methanol Supply and Demand in the United States" (November, 2007).
[111] W. Huang, *Impact of Rising Gas Prices on United States Ammonia Supply*, Report WRS-0702 (Washington, DC: U.S. Department of Agriculture, August 2007).

Appendix D. Operational Hydrogen FCVs

The first United States hydrogen FCV, a GM Electrovan, was introduced in 1966. Since that time, more than 150 different models and well over 300 total hydrogen-fueled LDVs have been demonstrated on United States roads. Most of these early vehicles were concept cars, and many have since been removed from service. However, as of May 2008, there are 93 FCVs currently operating in the Department of Energy demonstration programs and about 100 additional FCVs have been placed into private service.[112] The auto manufacturers also have an undisclosed number of unreleased FCVs at their R&D facilities. California leads the Nation in terms of hydrogen vehicle demonstrations with 224 different vehicle deployments as of 2006 (Table D.1).

Table D.1. California Hydrogen Vehicles
(Estimated Numbers of Hydrogen Vehicles Placed into Use Each Year)

Vehicle Type	Pre-2001	2001	2002	2003	2004	2005	2006	Cumulative Total
Fuel Cell Light-Duty	1	16	3	36	32	39	32	**159**
Fuel Cell Heavy-Duty (Buses)	1	1	2			4	3	**11**
Fuel Cell Special Vehicles and Boats	2	4	1		2			**9**
HICE/HCNG Light-Duty		1	1				36	**38**
HICE/HCNG/HHICE Heavy-Duty (Buses)		3		1	1		1	**6**
HICE/HCNG Special Vehicles and Boats					1			**1**
Total	**4**	**25**	**7**	**37**	**36**	**43**	**72**	**224**

Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternative Fuels.

Hydrogen Transit Buses

Transit vehicles currently make up less than two percent of the total number of vehicles in the Nation. Nevertheless, they have several characteristics that make them well suited for early hydrogen adoption:

- They typically operate in heavily populated areas where pollution is a problem.
- They are centrally located, maintained and fueled.
- They are usually government-subsidized and professionally operated and maintained.
- They operate on well-known routes and fixed schedules.
- They have high public visibility.
- They can accommodate the added weight and volume of hydrogen storage tanks.

[112] Private communications with GM, Honda, Toyota, and Daimler at the DOE/EERE Annual Hydrogram Program Review (May 2008).

As a result, some of the earliest hydrogen vehicle demonstrations have involved transit buses. In 1994, for example, the Georgetown Fuel Cell Bus Program demonstrated the Nation's first 30-foot fuel cell transit bus.[113] This was followed by three additional hydrogen fuel cell buses in Chicago in 1997. Later, in 2000, the Department of Transportation began testing a fuel cell bus in California, and DOE's National Renewable Energy Laboratory also began a program involving 12 fuel cell bus evaluations. The past transit bus evaluations can be seen in Table D.2.

Table D.2. DOE/National Renewable Energy Laboratory Heavy Vehicle Fuel Cell/Hydrogen Evaluations

Fleet	Vehicle/Technology	Number	Evaluation Status
U.S Air Force/Hickam Air Force Base (Honolulu, HI)	Shuttle Bus: Hydrogenics and Enova, battery-dominant fuel cell hybrid	1	Shuttle bus in operation; data collection started
	Delivery van: Hydrogenics and Enova, fuel; cell hybrid	1	Van in operation: data collection started
Alameda-Contra Costa Transit District (Oakland, CA)	Van Hool/UTC Power fuel cell hybrid transit bus integrated by ISE Corp.	3	In process; preliminary results reported Mar. 2007
SunLine Transit Agency (Thousand Palms, CA)	New Flyer/ISE Corp. hydrogen internal combustion engine transit bus	1	In process; preliminary results reported Feb. 2007
	Van Hool/UTC Power fuel cell hybrid transit bus integrated by ISE Corp.	1	In process; preliminary results reported Feb. 2007
Connecticut Transit (Hartford, CT)	Van Hool/UTC Power fuel cell hybrid transit bus integrated by ISE Corp.	1	Bus in operation; data collection started
Santa Clara Valley Transportation Authority (VTA), (San Jose, CA) and San Mateo County Transit District (Sam Tran) (San Carlos, CA)	Gillig/Ballard fuel cell transit bus	3	Complete and reported in 2006
SunLine Transit Agency (Thousand Palms, CA)	ISE Corp./ UTC Power ThunderPower hybrid fuel cell transit bus	1	Complete and reported in 2003

Source: Eudy, Leslie, National Renewable Energy Laboratory. "Fuel Cell Bus Evaluation Results". NREL/PR-560-42665. Presented at the *Transportation Research Board (TRB) 87th Annual Meeting* held January 13-17, 2008, Washington, D.C.

Not all hydrogen transit buses have been based on fuel cells. In 2002, the world's first commercial transit bus using a Hybrid Hydrogen Internal Combustion Engine (HHICE) was introduced, and four additional transit buses were later tested in California using a mixture of hydrogen and methane fuel, i.e., hythane. To date, a total of 20 HICE and hydrogen fuel cell buses have been demonstrated in the United States. Ten of them are currently in service. An additional 15 hydrogen buses are in the planning and development stages for deployment over the next 4 years.[114]

At the current stage of the technology, a fuel cell bus is still an order of magnitude more costly than a standard diesel bus (Table D.3). California's last seven fuel cell buses have ranged in cost from

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[113] L. Eudy, K. Chandler, and C. Gikakis, *Fuel Cell Buses in U.S. Transit Fleets: Summary of Experiences and Current Status*, NREL/TP-560-41967 (Golden, CO: National Renewable Energy Laboratory, September 2007), web site www.nrel.gov/hydrogen/pdfs/41967.pdf.
[114] *Ibid.*

$3.1 to $3.5 million per vehicle. The HHICE buses offer a lower cost, but a lower-efficiency pathway to low emissions than fuel cell buses, but are still 46 percent more fuel efficient than a conventional bus using compressed natural gas.[115] A HICE bus cost is currently about 2 to 3 times that of a conventional transit bus, but United States transit operators are usually eligible to receive a Federal subsidy of up to 90 percent of the cost difference. Whereas FCV transit buses are currently limited by their high costs, the chief constraint to wide scale deployment of HICE buses appears to be the lack of refueling and maintenance facility infrastructure, coupled with unresolved issues at the local and State level over safety codes and standards.

Table D.3. Typical United States Transit Bus Costs

Vehicle	Vehicle Cost	Annual Fuel Cost[a]
Diesel Transit Bus[b]	$350,000	$14,000-$28,000
Thor/ISE Fuel Cell Bus[c]	$1.7 Million	$20,000
CUTE Fuel Cell Bus	$2.5 Million	$100,000
ISE Hybrid Fuel Cell Bus[d]	$2.5 Million	$30,000
Hydrogen Hybrid ICE Bus[e]	$600,000 (in production)	$36,000

[a]Assuming 50,000 miles per year of service.

[b]Assumes 3.5 miles per gallon.

[c]Assumes 5,000 kilogram x $4 per kilogram.

[d]Assumes 7 miles per kilogram.

[e]Assumes 5.5 miles per kilogram.

Source: Bartley, Tom, “Hybrid Electric HICE and Fuel Cell Buses: Comparing the Hydrogen Bus Technologies,” ISE Presentation to *Third International Hydrail Conference*, August 13-14, 2007.

[115]K. Chandler and L. Eudy, *SunLine Transit Agency Hydrogen-Powered Transit Buses: Preliminary Evaluation Results*, NREL/TP-560-41001 (Golden, CO: National Renewable Energy Laboratory, February 2007), web site www.nrel.gov/docs/fy07osti/41001.pdf.

Appendix E. Carbon Dioxide Emissions Scenarios

Figure E.1. Scenario 1 Light-Duty Vehicle Full Fuel Cycle CO_2 Emissions 2X Case Fuel Cell Vehicle Fuel Economy, 2050
(Million Metric Tons CO_2 Equivalent)

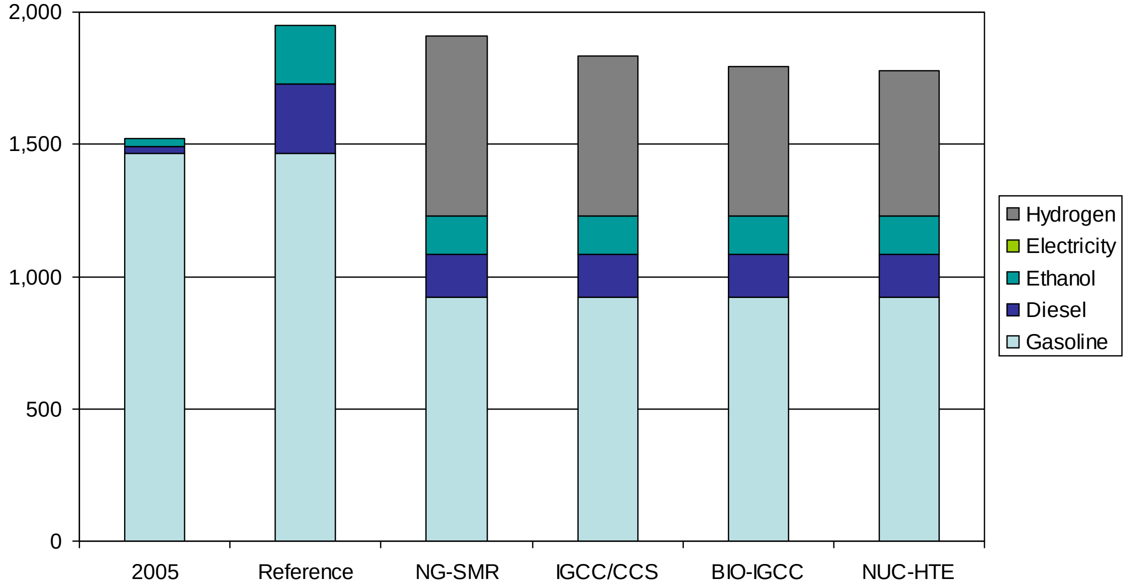


Figure E.2. Scenario 1 Light-Duty Vehicle Full Fuel Cycle CO_2 Emissions 3X Case Fuel Cell Vehicle Fuel Economy, 2050
(Million Metric Tons CO_2 Equivalent)

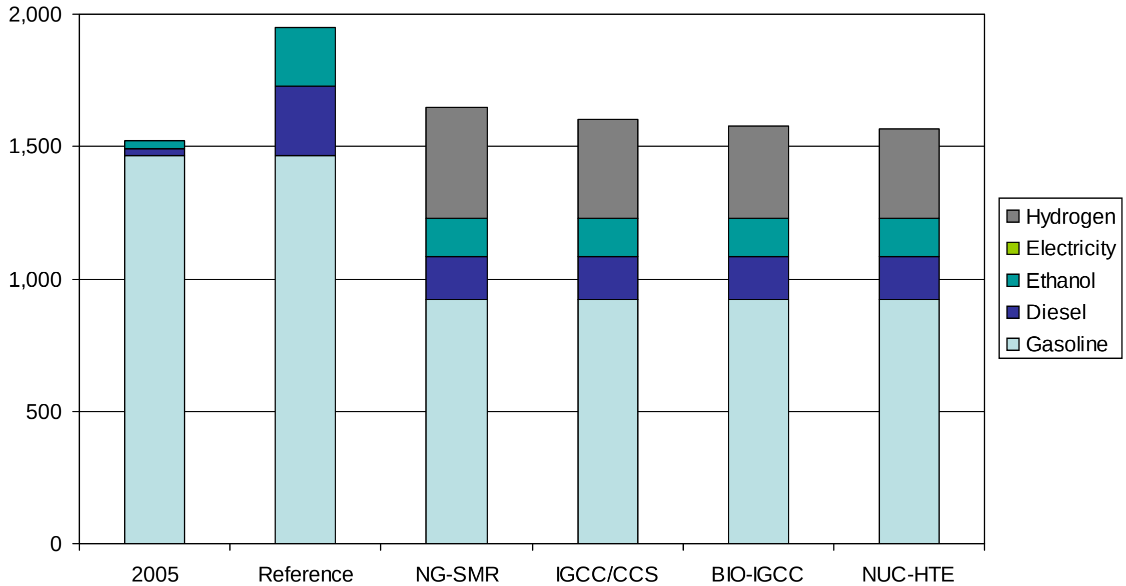


Figure E.3. Scenario 2 Light-Duty Vehicle Full Fuel Cycle CO_2 Emissions 2X Case Fuel Cell Vehicle Fuel Economy, 2050
(Million Metric Tons CO_2 Equivalent)

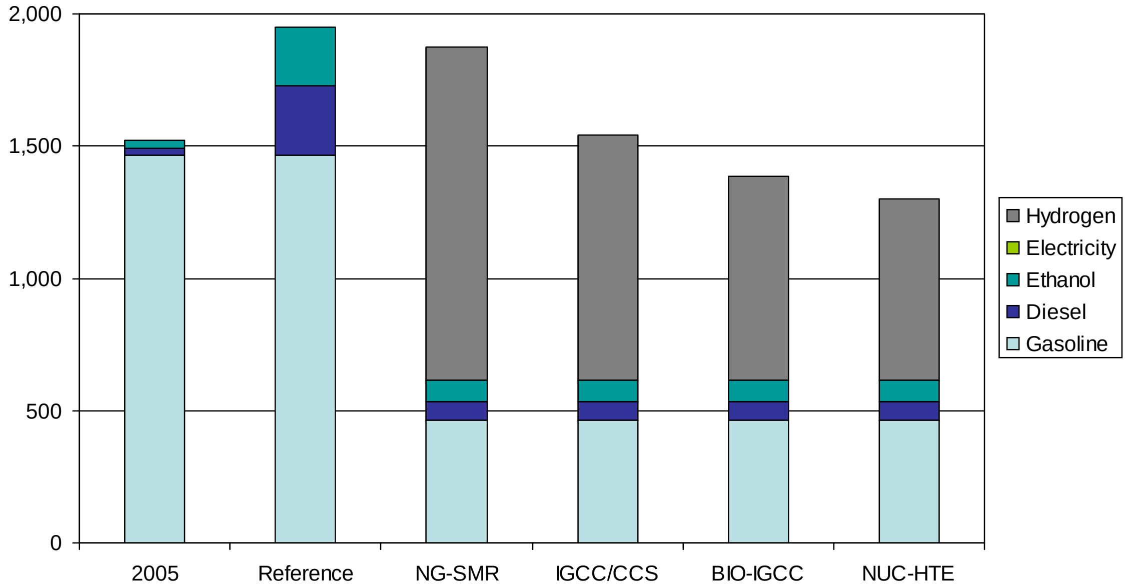


Figure E.4. Scenario 2 Light-Duty Vehicle Full Fuel Cycle CO_2 Emissions 3X Case Fuel Cell Vehicle Fuel Economy, 2050
(Million Metric Tons CO_2 Equivalent)

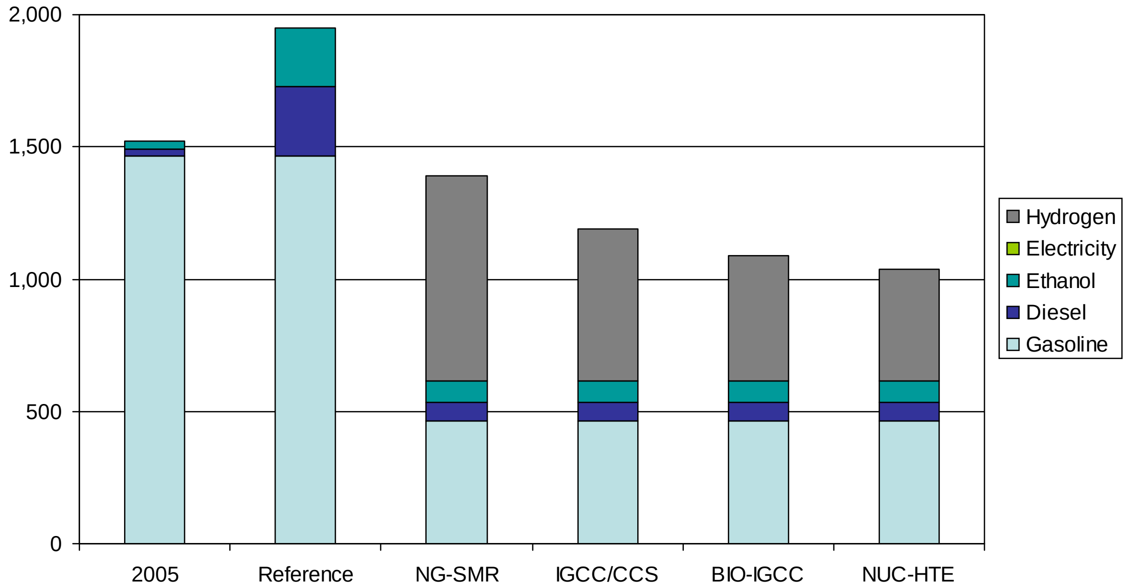


Figure E.5. Scenario 3 Light-Duty Vehicle Full Fuel Cycle CO_2 Emissions 2X Case Fuel Cell Vehicle Fuel Economy, 2050
(Million Metric Tons CO_2 Equivalent)

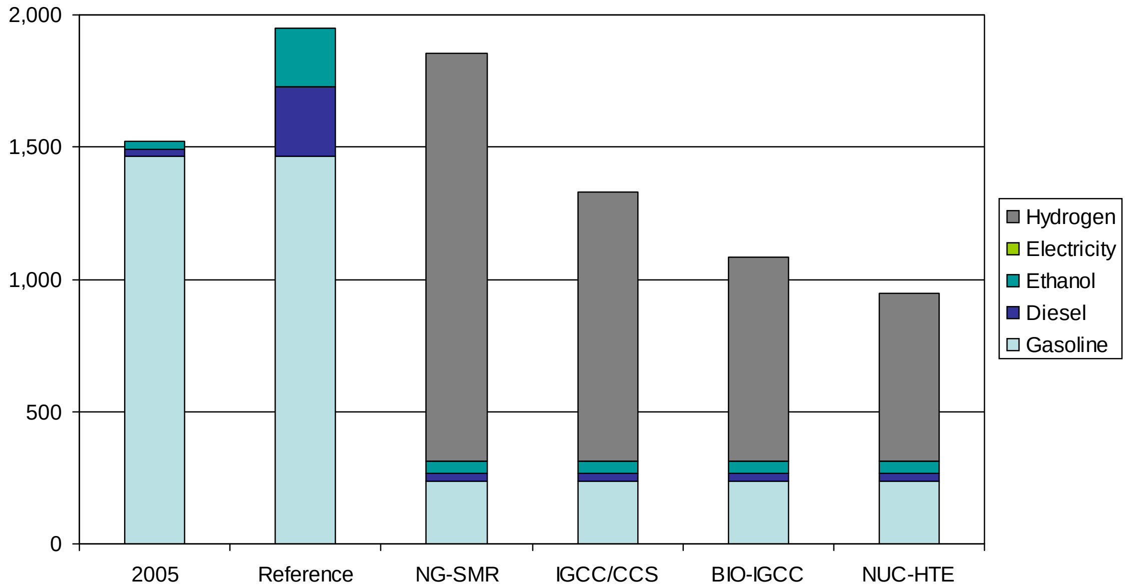
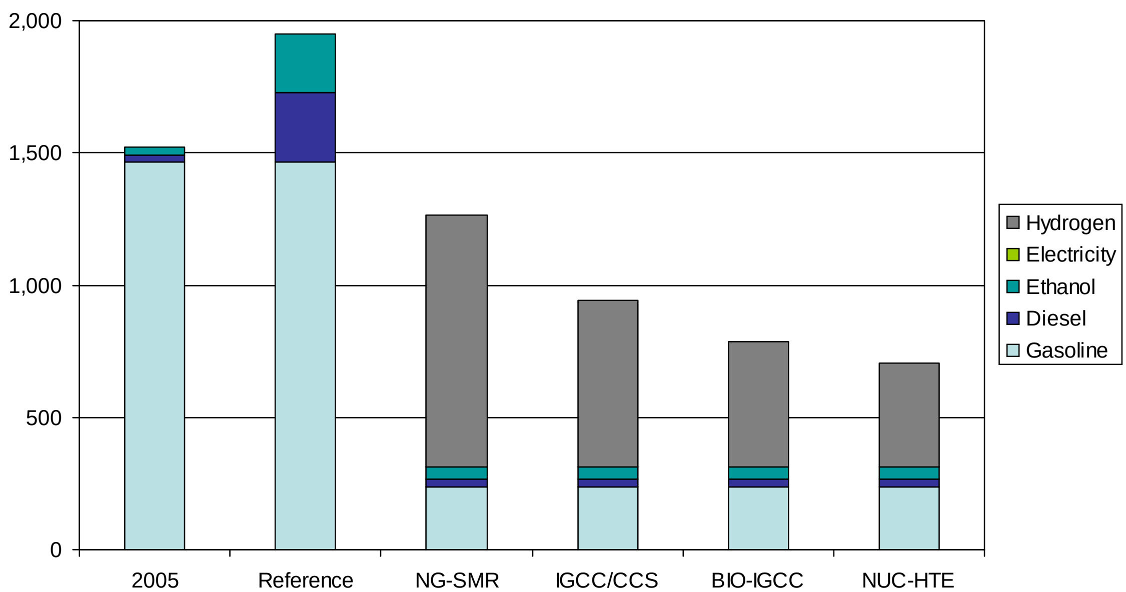


Figure E.6. Scenario 3 Light-Duty Vehicle Full Fuel Cycle CO_2 Emissions 3X Case Fuel Cell Vehicle Fuel Economy, 2050
(Million Metric Tons CO_2 Equivalent)



Appendix F. Technology Learning and Market Penetration

Every commercialized technology has shown a propensity to reduce costs with cumulative manufacturing experience. Cost reduction and performance improvements can occur for a wide variety of reasons, including R&D, economies of scale, technology spill-over, economy-wide advances in science and technology, and process improvement resulting from manufacturing learning. Most of these factors are virtually impossible to separate from each other because of the lack of data and the high correlation among many of the factors.

This appendix explores the implications of technological progress induced by "learning-by-doing" to assess the challenge presented by the cost reduction target of PEM fuel cells. To apply the theory of learning to a particular technology, it is necessary to establish initial unit overnight capital costs and the cumulative quantities/capacity of the PEM fuel cell technology already built at a point in time. Cumulative capacity built is a surrogate for cumulative learning in the formulation. The learning rate must be assumed, i.e., the percent cost reduction for every doubling of cumulative capacity due to experience.

Cumulative PEM Capacity and Initial Capital Cost

As noted above, according to *Fuel Cell Today* (March 2006), 550 FCVs were built world-wide between 2000 and 2005 and at least another 70 units of 70 to 80 kilowatts each are estimated to have been built in each of 2006 and 2007.[116] Honda will add another 200 FCVs by 2009 and more are reasonably expected in 2010. An additional 3,000 fuel cells, similar or identical to the PEM systems used in FCVs, have been built and used for niche transport markets such as marine and auxiliary power applications, light rail, and fork lifts through year 2006,[117] with sizes varying from 65 kilowatt to 130 kilowatt. For this illustration of the potential impacts that "learning" might have on cost reduction, the starting point for technology learning of PEM fuel cells in 2010 was assumed to be at least 250 megawatt and at costs of between $3,000 and $5,000 per kilowatt in the learning process.[118] A cost of $3,000 per kilowatt in 2010 is assumed for this example.

PEM Technology Learning Rate

The rate of technology learning for the PEM fuel cell is critical to the success of the hydrogen FCV. To achieve PEM capital cost of $30 per kilowatt and achieve a dominant share of FCVs in the LDV market, the learning rate for both the fuel stacks and the balance of plant (BOP)[119] must be at least a 30 percent for every doubling of cumulative capacity built. Such a learning rate has never been

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[116]K.-A. Adamson, *2006 Light Duty Vehicle Survey* (Fuel Cell Today, March 2006), web site www.fuelcelltoday.com/media/pdf/surveys/2006-Light-Duty-Vehicle.pdf.
[117]K.-A. Adamson, *2007 Niche Transport (2)* (Fuel Cell Today, September 2007), web site www.fuelcelltoday.com/media/pdf/surveys/2007-Niche-Transport%202.pdf.
[118]The $5,000 per kilowatt cost is ascribed to fork lift units and light- to medium-duty trucks.
[119]The fuel cell unit usually is divided for convenience into two parts: (1) the fuel stack usually contains the newest portion of the technology and its catalyst that converts hydrogen to electricity and water; and (2) the balance of plant contains the electronics and hardware that connects and integrates the fuel cell to the electricity-demanding devices.

realized for any durable good product throughout the production life of that product.[120] Portions from the McDonald and Schrattenholzer article are provided in Table F.1. For estimated learning rates with R^2 of over 80 percent, learning rates vary by region and time period and generally range between 8 and 26 percent per doubling of cumulative capacity. Most researchers use a learning rate of about 20 percent for newly-commercialized technologies in their projections for the initial phase of cost reductions.

Table F.1. Estimated Learning Rates

Technology	Country/Region	Data Time Period	Estimated Learning[a] (Percent)	R2[b]
DC Converters	United States	1984-1997	37	0.35
Gas turbines	World	1958-1963	22	–
Gas Turbines	World	1963-1980	9.9	–
Gas Turbines	World	1958-1980	13	0.94
Nuclear Power Plants	OECD	1975-1993	5.8	0.95
Coal Plants	OECD	1975-1993	8.6	0.90
GTCC Power Plants[c]	World	1981-1991	-11	0.41
GTCC Power Plants	World	1991-1997	26	0.90
Wind Power Plants	OECD	1981-1995	17	0.94
Wind Turbines	Germany	1990-1998	8	0.89
Solar PV Modules	World	1968-1998	20	0.99
Solar PV Panels	United States	1959-1974	22	0.94
Ethanol[d]	Brazil	1979-1995	20	0.89

[a]Learning is defined as the percent capital cost reduction per doubling of cumulative capacity built.

[b]R^2 expresses the quality of the fit between the data and the estimated learning curve. R^2 values between different lines should not be compared because the number of data points are different and will influence the value of the measure.

[c]The estimations here were based on price, not costs and the distortion may be due to oligopolistic behavior, according to the authors.

[d]Ethanol production was included in this set of technologies to demonstrate that the general range of 10 to 30 percent learning applies even to non-generation technologies, and thus lends support to the use of a 20 percent long-term learning rate, at least in the early mass production phase.

Source: Alan McDonald and Leo Schrattenholzer, "Learning rates for energy technologies," *Energy Policy*, 29(4):255-261, 2001. Fuel cells were not listed in their paper. Source: Bartley, Tom, "Hybrid Electric HICE and Fuel Cell Buses: Comparing the Hydrogen Bus Technologies," ISE Presentation to *Third International Hydrail Conference*, August 13-14, 2007.

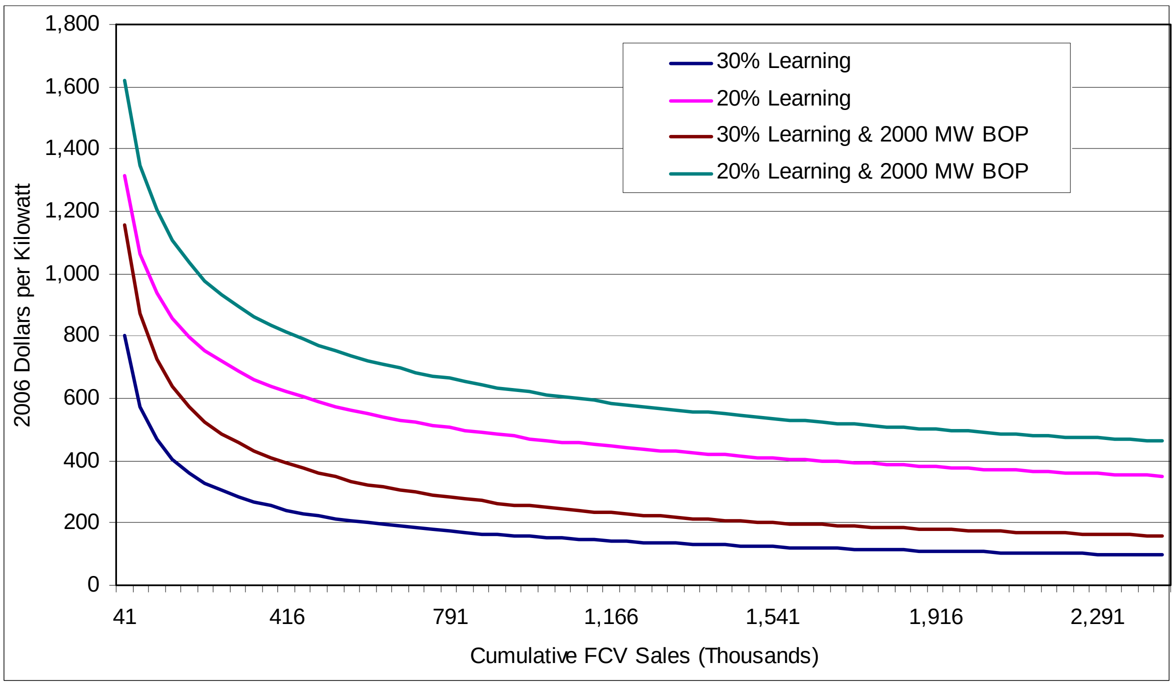
Lipman and Sperlman (2000) at the University of California at Davis discussed the PEM technology in its infant stage and warned against assuming that high early learning rates will continue indefinitely: "For products such as PEM fuel cells that may reach high levels of accumulated production, we suggest methods [*be developed*] for bounding [*cost*] forecasts in order to guard

[120]A. McDonald and L. Schrattenholzer, "Learning Rates for Energy Technologies," *Energy Policy*, Vol. 29, No. 4, pp. 255-261 (2001). McDonald and Schrattenholzer provide empirically derived learning rates for a number of technologies throughout the world (Table 1 of the article). In the empirical data, learning rates vary over time and location. Learning rates of 30 percent are rarely if ever achieved for durable goods for extended periods after the technology has been commercialized. The learning rate for gas turbines has varied between 7 and 20 percent despite the experience it has derived from airplane turbine manufacturing experience. Learning for wind systems has actually decreased on a cost per kilowatt basis. However, since the wind turbine design has increased the maximum utilization rate, the actual cost per kilowatthour has declined, although not at rates exceeding 15 to 20 percent per doubling of capacity.

against eventually forecasting unrealistically low costs."[121] The table by McDonald and Scharattenholzer and the learning rates for the gas turbine anecdotally support the warning. While gas turbine costs declined worldwide by 22 percent for every doubling of production capacity between 1958 and 1963, the learning rate declined to about 10 percent between 1963 and 1980.

Figure F.1 illustrates the sensitivity of capital costs to the learning rate assumption and the experience, or cumulative capacity, at any point in time.[122] Learning rates are assumed to vary between 20 and 30 percent in the examples of Figure F.1. Cumulative experience for balance of plant[123] was assumed to range between 250 MW and 2,000 MW while the core fuel cell component assembly was assumed to have 250 MW of cumulative capacity (experience).

Figure F.1. Illustrations of Technology Learning by PEM Fuel Cells



Note: The graph assumes that the current cost of a PEM fuel cell is $3,000 per kilowatt.
BOP = Balance of Plant.

As seen by these curves and their extension, PEM fuel cell costs would not fall enough under any of these assumptions to meet the $30 per kilowatt capital cost target by the time two million FCVs are sold. In most instances, the target fuel cell cost including the catalyst could not be achieved if 10 million FCVs were sold. Assuming a 30-percent learning rate for the complete fuel cell, the PEM

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[121]T. Lipman and D. Sperlman, "Forecasting the Cost of Automotive PEM Fuel Cell Systems—Using Bounded Manufacturing Progress Functions," in C.O. Wene, A. Voss, and T. Fried (editors), *Experience Curves for Policy Making-The Case For Energy Technologies* (April 2000), Proceedings of the IEA Workshop, Stuttgart, Germany, May 10-11, 1999.

[122]Overnight Cost (C) is a function of cumulative capacity (Q): $C(Q) = a * Q^{-b}$. Parameter a is determined from initial conditions, and b is related to the learning rate.

[123]The balance of plant component of fuel cells typically is composed of electronics that regulate fuel input and control voltage and otherwise control the quality of the power sent to the electric motor. Most of these components are not as new as the PEM fuel stacks and represent a more mature technology. Consequently, the cumulative experience associated with balance of plant is much higher than the cumulative experience associated with the PEM fuel stacks. The use of 2,000 megawatts for the balance of plant component is more indicative of the starting point for "technological progress" in the projection.

fuel cell cost, i.e., $47 per kilowatt, would nearly reach the DOE target costs when 10 million vehicles are sold. Learning rates of 20 percent would yield fuel cell costs of $223 per kilowatt and would not achieve the target DOE fuel cell costs.

While R&D and engineering research could eventually succeed in solving all of the challenges that are faced in making fuel cell LDVs a cost-effective reality, the number of necessary simultaneous R&D successes that are required within the next 22 years makes large scale penetration of FCVs largely improbable in the United States without significant long-term Federal and State policies that promote FCV adoption over a 10-to-20 year period.

Learning by Doing

“Learning by doing” is the process by which the market gains operational and manufacturing experience that result in cost decreases, efficiency improvements or quality improvements. The process has been documented since the 1930s. Wright (1936) showed that direct labor costs of manufacturing an airframe fell by 20 percent with every doubling of cumulative output.[a] Subsequent authors broadened the analysis of learning to other costs and showed similar cost declines with experience. In 1998, Hatch and Mowery showed that cumulative learning for electronic chip manufacturing, which is not a durable good, was a combination of cumulative learning in the production process plus the cumulative engineering resources applied to bringing an innovation from the R&D laboratory to the manufacturing production line.[b]

[a]T.P. Wright (1936), “Factors Affecting the Costs of Airplanes,” *Journal of Aeronautical Sciences* 3, 122.
[b]N.W. Hatch and D.C. Mowery, “Process Innovation and Learning by Doing in Semiconductor Manufacturing,” *Management Science*, Vol. 44, No. 11 (November 1998).

Appendix G. FCVs and the Market for Platinum

Projected Demand for Platinum by FCVs

As noted in Chapter 4, as of 2007, 80-kilowatt fuel cell systems use 1.7 ounces of platinum, which is equivalent to 0.6 grams per kilowatt, and the DOE R&D goal is to reduce the platinum needed in PEM fuel cells to 0.56 ounces by 2015, which is equivalent to 0.2 grams per kilowatt. To achieve FCV sales volumes of 500,000 units per year using a platinum catalyst, an additional 8 tons will have to be produced for the new units assuming the 2015 goal is met,[124] and assuming that the 0.56 ounces will work well enough in an 80 kilowatt system.[125] If the 2015 goal cannot be met, then 25.6 tons of additional platinum will be needed, assuming the current platinum requirement of 0.6 grams per kW. Additionally, unless the platinum catalysts can be economically recycled to the purity needed, additional platinum will have to be mined to replace the platinum in the refurbished fuel cells in the existing fleet.

If PEM-based new vehicle sales took a 50-percent share of the United States new LDV market, about 10 million new vehicles in 2025, the incremental demand for platinum by the new FCVs would be between about 160 tons and 513 tons above the entire word-wide platinum production in 2007, or 71 and 228 percent respectively depending on whether each 80 kilowatt fuel cell unit used 0.56 or 1.7 ounces (Figure G.1). Given the scarcity of platinum, which has one thirtieth the availability of gold, such penetration is likely to create large platinum spot price increases that are well above current prices of about $1,700 per ounce, making achievement of the economic fuel cells even more challenging. A breakthrough in the development of a much more plentiful and low-cost catalyst will be required to achieve a 50-percent FCV market share of LDVs if the remaining challenges are overcome.

It should be noted that both public and private research is making strides in reducing platinum requirements. Nissan, for example, recently claimed to have reduced its catalytic platinum use by 50 percent.[126] Current estimates for FCV platinum use are around 100 grams per car;[127] thus, Nissan's breakthrough could be significant. As with all advances, it is reasonable to assume that further testing for fuel cell performance and durability outside the laboratory will need to be performed before commercialization. However, there is no doubt that Nissan's progress is yet another example of how technological advances will continue to reduce platinum usage in fuel cells just as they have done in catalytic converters.

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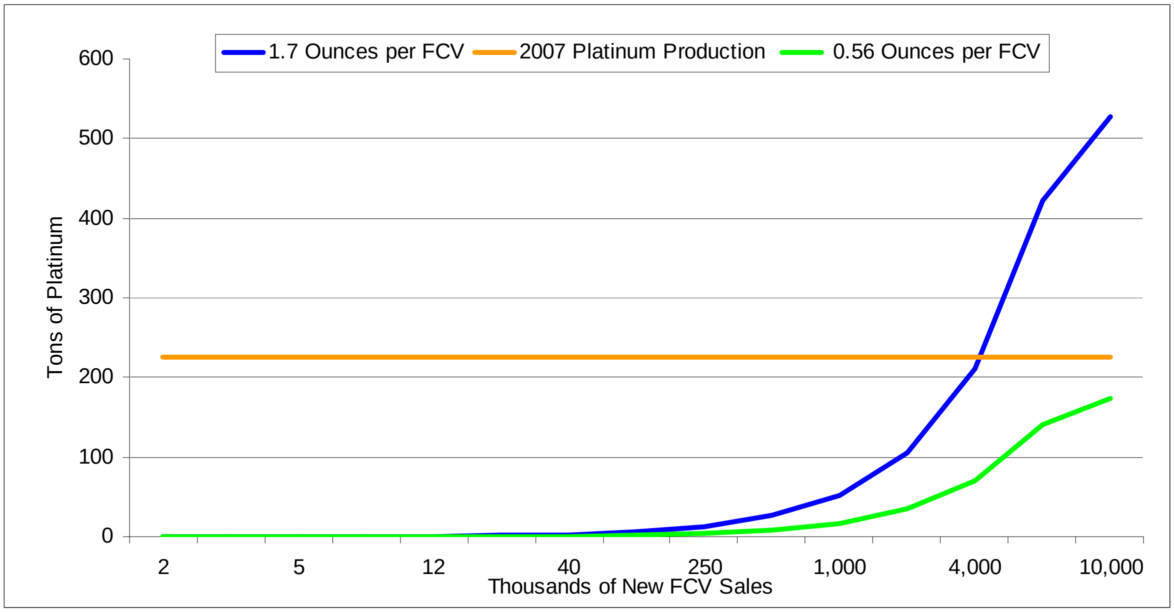
[124] At current platinum levels in fuel cells, 500,000 new FCVs per year require 25.6 tons of platinum if 1.7 ounces is used per 80-kilowatt system (0.6 g per kW) and it is also assumed that each new FCV displaces a conventional vehicle's catalytic converter (containing about 1.5 grams per vehicle). [(80x0.6 – 1.5)x500,000/(28.35x16))/2,000]. If the R&D goal for 2015 is achieved (0.2 g per kW), 8.0 tons of platinum (computed under the same assumptions) will be required to power the 80-kilowatt systems. R&D success is far from assured.

[125] Mr. Stephen Ellis of American Honda Corporation noted on July 10, 2008, that 200 FCX Clarity vehicles will be leased for 3 years beginning in 2008 in California, and that the Clarity is a hybrid fuel cell vehicle using a 100-kilowatt fuel cell electric motor as the principle drive and the electric battery with the usual regenerative braking to produce the supplemental drive; the hybrid gets an EPA-estimated 72 to 74 mile per gallon equivalent vehicle. Honda produces the entire system. No specific information was provided on the fuel cell costs, amounts of catalyst used per 100-kilowatt system, or the production cost of the vehicle. Mr. Ellis said that while the $1 million or so price may be appropriate for production numbers of about 200 Clarity vehicles per year, he was confident that the production cost would decline with larger production volumes, to perhaps the price of a luxury vehicle.

[126] See web site www.worldcarfans.com/9080806.004/nissan-breakthrough-doubles-fuel-cell-power-density.

[127] See web site http://africa.reuters.com/metals/news/usnSP243749.html.

Figure G.1. Incremental Platinum Demand for New FCV Sales



Note: 1 ton = 2,000 pounds.

Additional Issues to Platinum Pricing and Availability

This discussion has focused entirely on the incremental demand for platinum used in fuel cell LDVs in the United States. Since platinum is used in catalytic converters in the United States and the rest of the world, the reduction of platinum use in catalytic converters would marginally reduce platinum demand for the pollution control market and act to reduce the upward price pressure from increased platinum use in FCVs. In addition, further research may lead to breakthroughs that result in further reductions in the need for platinum or the development of alternative catalysts to replace the use of platinum. These successes cannot be predicted with any confidence. However, other factors are likely to drive the worldwide platinum demand higher:

- Increased use of catalytic converters in automobiles in rapidly developing countries like China and India to control severe pollution will significantly increase platinum demand.
- Rapid industrial growth in developing countries like China and India are likely to increase the demand for platinum, a crucial catalyst in some processes.
- Successful FCV penetration in the United States could lead to FCV adoption in the rest of the word, increasing platinum demand further.
- The demand for jewelry made from platinum has been growing, most rapidly in Japan, and continued growth in the use of platinum for jewelry could further exacerbate the upward price pressures on platinum.

Implications of Successful PEM Diffusion into the U.S. Transportation Market

When the 11 millionth FCV is sold, almost 900,000 megawatts of PEM generation capacity, approximately equal to the total electricity generation capacity of the United States in 2005, will have been built to power transportation fuel cell vehicles. The implication of continued penetration to 50 percent of new LDV sales is that more than 900 gigawatts of PEM generation capacity will be added every year thereafter for at least 10 years.[128] If FCVs are assumed to represent about half of the LDV fleet, about 148 million vehicles in 2030, the total PEM generation capacity in FCVs would be over 12 times larger than the total electricity generation capacity in the United States in 2005. Unless R&D breakthroughs occur to dramatically reduce the need for the platinum catalyst or to develop a much cheaper and effective catalyst to replace it, about 160 tons of platinum will be required for the first 10 million FCV vehicles, assuming the DOE goal of 0.56 ounces per FCV is achieved. The cumulative platinum demand to ultimately gain a 50-percent LDV market share for FCVs is roughly 2,400 tons, about 10 times the 2007 demand for platinum. Such platinum demand increases could result in a significant rise in the price of platinum.

[128]This statement assumes that, for the most part, the platinum would be recycled some time after FCVs have accounted for 50 percent of new vehicle purchases for 10 consecutive years.