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HYDROGEN ENERGY SYSTEMS STUDIES

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Abstract

In this progress report (covering the period May 1997-May 1998), we summarize results from ongoing technical and economic assessments of hydrogen energy systems. Generally, the goal of our research is to illuminate possible pathways leading from present hydrogen markets and technologies toward wide scale use of hydrogen as an energy carrier, highlighting important technologies for RD&D. This work is being carried out as part of the systems analysis activity of the US Department of Energy Hydrogen R&D Program.

Over the past year we worked on three projects.

From May 1997-November 1997, we completed an assessment of hydrogen as a fuel for fuel cell vehicles, as compared to methanol and gasoline. (This study began in July 1996 and finished in November 1997).

Two other studies were begun in November 1997 and are scheduled for completion in September 1998.

* We are carrying out an assessment of potential supplies and demands for hydrogen energy in the New York City/New Jersey area. The goal of this study is to provide useful data and suggest possible implementation strategies for the New York City/New Jersey area, as the Hydrogen Program plans demonstrations of hydrogen vehicles and refueling infrastructure.

* We are assessing the implications of CO_2 sequestration for hydrogen energy systems. The goals of this work are a) to understand the implications of CO_2 sequestration for hydrogen energy system design; b) to understand the conditions under which CO_2 sequestration might become economically viable; and c) to understand design issues for future low-CO_2 emitting hydrogen energy systems based on fossil fuels.

Introduction

Summary of Approach/Rationale

Since 1986, researchers at Princeton University's Center for Energy and Environmental Studies have carried out technical and economic assessments of hydrogen energy systems. Our approach has been to assess the entire hydrogen energy system from production through end-use from several perspectives (fuel producer, consumer, society) considering technical performance, economics (e.g. capital cost, delivered hydrogen cost, cost of energy services), infrastructure, environmental and resource issues. The goal of our work is to illuminate possible pathways leading from present hydrogen markets and technologies toward wide scale use of hydrogen as an energy carrier, highlighting important technologies for RD&D. This work has been part of the systems analysis activity of the DOE Hydrogen Program since 1991.

Past Results

In the late 1980s and early 1990s we focussed on the long term potential of hydrogen derived from renewables (solar, wind, biomass). These studies suggested that renewable hydrogen used in energy efficient end-use devices (e.g. fuel cells) could become economically competitive, beginning in the next century. More recently we have explored how a transition to large scale use of hydrogen energy might begin, starting with the use of hydrogen from natural gas.

Over the past few years our focus has been on strategies for producing, distributing and using hydrogen as a fuel for zero emission vehicles. We have looked in detail at various near term options available for providing hydrogen transportation fuel to vehicles (production of hydrogen from natural gas or off-peak power). We have also considered longer term options such as gasification of biomass or MSW and hydrogen from wind or solar. In FY '95 and FY '96 we assessed the potential impact of advances in small scale hydrogen production technologies (steam reforming of natural gas, electrolysis using off-peak power) on the cost of hydrogen transportation fuel. In particular, we assessed the possibilities for low cost, small scale hydrogen production from natural gas. During FY'96 (July 1995-July 1996), we completed a case study of developing a hydrogen refueling infrastructure in Southern California.

In FY'97 and FY'98 (July 1996-November 1997), we studied the prospects for using hydrogen as a fuel for fuel cell vehicles, compared to vehicles witrh onboard reformation of methanol or gasoline. Vehicle performance and cost and refueling infrastructure issues were considered.

In FY'98 (November 1997-present), two new projects were begun:

* an assessment of potential supplies and demands for hydrogen transportation fuel in the New York City/New Jersey area and

* an assessment of the implications of CO2 sequestration for the design of hydrogen energy systems.

Table 1 and the attached bibliography summarize Princeton CEES work related to hydrogen and fuel cells. Studies supported by the USDOE Hydrogen R&D Program are indicated with a star "*".

Table 1. Hydrogen and Fuel Cell Related Research at the Center for Energy and Environmental Studies, Princeton University, 1986-Present (* = USDOE Supported Research) -- see attached Bibliography

YEAR	TOPIC	INVESTIGATORS	REF.S
*1985-1991	Design and economics of solar PV/ electrolytic hydrogen systems	J. Ogden, R. Williams	[1-4]
*1991-1993	Renewable hydrogen energy systems studies	J.Ogden	[4-5]
*1991-present	Assessments of hydrogen fuel cell vehicles	M. Delucchi, M. Steinbugler, J. Ogden, T. Kreutz R. Williams, L. Iwan	[8-11,13-16, 24, 25, 31, 34]
1991-1993	Production of hydrogen and methanol from biomass	E.Larson, R. Katofsky, R. Williams	[6-8]
*1993-present	Production of hydrogen from municipal solid waste	E. Larson, J. Chen, E. Worrell, R. Williams	[14, 17, 29]
*1993-present	Role of natural gas in a transition to hydrogen	J. Ogden, J. Strohbehn, E.Dennis	[12,13,16]
*1993-present	Assessments of fuels for fuel cell vehicles	R. Williams, J. Ogden, E. Larson, R. Katofsky, J. Chen, M. Steinbugler	[14, 14a, 31]
*1993-1994	Assessment of using the existing natural gas transmission and distribution system w/H2	J. Ogden, J. Strohbehn	[12,16]
*1993-1994	Development of refueling infrastructure for hydrogen vehicles	J. Ogden, E. Dennis, K. Montemayor	[12,13,16, 30, 33]
*1993-1995	Assessment of PEM fuels cells for residential cogeneration	M. Steinbugler, J. Ogden, K. Kissock, R. Williams	[16]
*1994-1996	Assessment of small scale methane reformer technologies	J.Ogden	[22, 26]
*1995- present	Studies of CO2 sequestration	R. Williams, J. Ogden, R. Socolow	[28, 36, 37]
*1995-1996	Case study of developing refueling infrastructure for fuel cell vehicles in So. California	J. Ogden, A. Cox, J. White	[21,22,23,27, 30]
*1996-present	Comparison of hydrogen, methanol and gasoline as fuels for fuel cell vehicles	J. Ogden, T. Kreutz, M. Steinbugler	[24, 25, 31, 38]
*1996-present	Models of onboard fuel processors for fuel cell vehicles	T. Kreutz, J. Ogden, S. Kartha	[25, 31, 32]
*1997-present	Case study refueling infrastructure for H2 vehicles in the New York/New Jersey area	J. Ogden	

Notes for Table 1: Bibliography of Hydrogen and Fuel Cell Related Work at Princeton Center for Energy and Environmental Studies

1. J.M. Ogden and R.H. Williams, Solar Hydrogen : Moving Beyond Fossil Fuels, World Resources Institute, Washington DC, October 1989.

2. J.M. Ogden and R.H. Williams, "Electrolytic Hydrogen from Thin Film Solar Cells," International Journal of Hydrogen Energy, v. 15, 1990, p.155.

3. J.M. Ogden, "Cost and Performance Sensitivity Studies for Solar Photovoltaic/Electrolytic Hydrogen Systems," Solar Cells, v. 30, No. 1-4, May 1991, p. 515.

4 J.M. Ogden and J. Nitsch, "Solar Hydrogen," Chapter 22 in T. Johansson, H. Kelly, A.K.N. Reddy and R.H. Williams, Renewable Energy: Fuels and Electricity from Renewable Sources, Island Press, Washington, DC, 1993.

5. J.M. Ogden, Renewable Hydrogen Energy Systems Studies, final report for NREL Contract No. XR-2-11265-1, June 24, 1993.

6. E.D. Larson and R.E. Katofsky, "Production of Methanol and Hydrogen from Biomass," Princeton University, Center for Energy and Environmental Studies Report No. 271 July 1992.

7. Katofsky, R.E., "Production of Fluid Fuels from Biomass," Princeton University, Center for Energy and Environmental Studies Report No. 279, June 1993.

8. M.A. DeLuchi, E.D. Larson and R.H. Williams, "Hydrogen and Methanol from Biomass and its Use in Fuel Cell and Internal Combustion Engine Vehicles," Princeton University, Center for Energy and Environmental Studies Report No. 250, August 1991.

9. J.M. Ogden and M.A. DeLuchi, "Solar Hydrogen Transportation Fuels," Chapter 8, in D. Greene and D. Santini, eds., Proceedings of the Conference on Transportation and Global Climate Change, American Council for an Energy Efficient Economy, Washington, DC, 1993.

9a. Delucchi, M.A. 1992. "Hydrogen Fuel Cell Vehicles," UCD-ITS-RR-92-14, Institute of Transportation Studies, University of California, Davis.

10. M.A. DeLuchi and J.M. Ogden, "Solar Hydrogen Fuel Cell Vehicles," Transportation Research-A, Vol. 27A, No. 3, pp. 255-275.

11. J.M. Ogden, E.D. Larson and M.A. Delucchi, "An Assessment of Renewable Transportation Fuels and Technologies," report to the US Congress Office of Technology Assessment, May 27, 1994.

12. J.M. Ogden, J.W. Strohbehn and E. Dennis, "Hydrogen Energy Systems Studies," Proceedings of the USDOE Hydrogen Program Review Meeting, April 19, 1994.

13. J.M. Ogden, E. Dennis and J.W. Strohbehn, "A Technical and Economic Assessment of the Role of Natural Gas in a Transition to Hydrogen Transportatio Fuel," presented at the 10th World Hydrogen Energy Conference, Cocoa Beach, FL, June 21-24, 1994.

14. J.M. Ogden, E.D. Larson, R.H. Williams, R. Katofsky, J. Chen, and M. Steinbugler,"Fuels for Fuel Cell Vehicles," presented at the Vice President's Meeting on Fuel Cell Vehicles, Partnership for a New Generation of Vehicles, Washington DC, July 27, 1994.

14a. R.H. Williams, "Fuel Cells, Their Fuels and the US Automobile," First Annual World Car Conference," University of California at Riverside, Riverside, CA, June 20-24, 1993.

15. M. Steinbugler, and J.M. Ogden, "Design Considerations for Fuel Cell Vehicles," presented at the Fuel Cell Seminar, November 28-December 1, 1994.

16. J.M. Ogden, E. Dennis, M. Steinbugler, and J. Strohbehn, "Hydrogen Energy Systems Studies," Final Report to NREL for Contract No. XR-11265-2, January 18, 1995.

17. J.S. Chen, "The Production of Methanol and Hydrogen from Municipal Solid Waste," Princeton University, Center for Energy and Environmental Studies Report No. 289, March 1995.

18.J.M. Ogden, E. Dennis and K. Montemayor, "Development of Refueling Infrastructure for Hydrogen Vehicles," Proceedings of the 6th National Hydrogen Association Meeting, March 7-9, 1995.

19. J.M. Ogden, E.D. Larson and M.A. Delucchi, "Assessment of Renewable Transportation Fuels and Technologies," Proceedings of the American Solar Energy Society Meeting, Minneapolis, MN, July 17-20, 1995.

20. J.M. Ogden, "Refueling Infrastructure Needs for Fuel Cell Vehicles," presented at the Society of Automotive Engineers Topical Technical Conference on Fuel Cells for Transportation, Alexandria, VA April 1, 1996.

21. J.M. Ogden, "Options for Refueling Hydrogen Vehicles: A Southern California Case Study", presented at the 7th National Hydrogen Association Meeting, Alexandria, VA, April 3, 1996.

22. J.M. Ogden, T.G. Kreutz, M. Steinbugler, A Cox, J. White, "Hydrogen Energy Systems Studies," USDOE Hydrogen R&D Program Review Meeting, Miami, FL, April 29-May 2, 1996.

23. J.M. Ogden, "Development of Refueling Infrastructure for Hydrogen Vehicles," Proceedings of the 11th World Hydrogen Energy Conference, Stuttgart, Germany, June 2 23-28, 1996.

24. M. Steinbugler and J. Ogden, "Fuel Economy and Range Estimates for Fuel Cell Vehicles," '96 Fuel Cell Seminar, Orlando, FL, Nov 17-20, 1996.

25. T. Kreutz, M. Steinbugler and J. Ogden, "Onboard Fuel Reformers for Fuel Cell Vehicles: Equilibrium, Kinetic and System Modelling," 96 Fuel Cell Seminar, Orlando, FL, Nov 17-20, 1996.

26. J. Ogden, T Kreutz, S. Kartha and L. Iwan, " Assessment of Technologies for Producing Hydrogen from Natural Gas at Small Scale," Princeton University Center for Energy and Environmental Studies Draft Report, November 26, 1996.

27. J. Ogden, A Cox and J. White, " Case Study of Developing Hydrogen Refueling Infrastructure in Southern California," Princeton University Center for Energy and Environmental Studies Draft Report, December 9, 1996.

28. R. Williams, "Fuel Decarbonization for Fuel Cell Applications and Sequestration of the Separated CO2," Princeton Center for Energy and Environmental Studies Report No. 295, January 1996.

29. E. Larson, E. Worrell and J. Chen, "Clean Fuels from Municipal Solid Waste for Fuel Cell Buses in Metropolitan Areas," Resources, Conservation and Recycling, v. 17, p. 273-298, 1996.

30. J.M. Ogden, "Infrastructure for Hydrogen Fuel Cell Vehicles: A Southern California Case Study," Proceedings of the '97 World Car Conference, Riverside, CA, January 19-22, 1997.

31. J. Ogden, M. Steinbugler and T. Kreutz, "Hydrogen as a Fuel for Fuel Cell Vehicles," Proceedings of the 8th National Hydrogen Association Meeting, Alexandria, VA, March 11-13, 1997.

32. S. Kartha, S. Fischer and T. Kreutz, "Analysis of Onboard Fuel Procesing Designs for PEM Fuel Cell Vehicles," 96 Fuel Cell Seminar, Orlando, FL, Nov 17-20, 1996.

33. J.M. Ogden, M. Steinbugler, E. Dennis, S. Kartha, L. Iwan, A. Jones, J. Strohbehn, "Hydrogen Energy System Studies," Proceedings of the 1995 US DOE Hydrogen Program Review, vol. 1, April 18-21, 1995, Coral Gables, FL, NREL/CP-430-20036, United States Department of Energy, National Renewable Energy Laboratory, Golden, CO, September 1995.

34. M. Steinbugler, "How Far, How Fast, How Much Fuel: Evaluating Fuel Cell Vehicle Configurations," presented at the Commercializing Fuel Cell Vehicles

Conference, Intertech Conferences, Hyatt Regency O'Hare, Chicago, September 17-19, 1996.

35. J. Ogden, "Prospects for Non-carbon Fuels," presentation to the ASPEN Energy Forum, Aspen Institute, Aspen, CO, July 1997.

36. J. Ogden, "Hydrogen Systems and CO2 Sequestration," DOE Workshop on Fuels Decarbonization and CO2 Sequestration, July 28-30, 1997, Washington, DC.

37. J. Ogden, "Hydrogen Systems and CO2 Sequestration, " 9th National Hydrogen Association Meeting, Arlington, VA, March 3-5, 1998.

38. J. Ogden, "Refueling Infrastructure," invited panel presentation to the SAE TOPTEC on Fuel Cell Vehicles, March 17-19, 1998, Cambridge, MA.

Table 2. Industrial, Government and Academic Contacts

INDUSTRY	GOVERNMENT
Industrial Gas Suppliers Air Products and Chemicals, Praxair BOC Gases MG Gases **Reformer Manufacturers** Howe-Baker Engineering Hydrochem Haldor-Topsoe KTI Hydrogen Burner Technology **Electric and Gas Utilities** Public Service Gas &Elec.,Jersey Central Power &Light, Atlantic Electric Company, Rockland Electric, New Jersey Natural Gas, South Jersey Gas, and Elizabethtown Gas, Consolidated Edison, New York Power Authority, Brooklyn Union Gas, Lilco **Fuel Cell Developers** Ballard Power Systems International Fuel Cells Energy Partners H-Power **Oil Companies** Exxon Mobil **Electrolysis Manufacturers** Electrolyser, Inc. Teledyne **Automotive Companies** Ford GM Chrysler Daimler-Benz Toyota Mazda **Engineering/Research Co.** Directed Technologies, Inc. Arthur D. Little Xerox/Clean Air Now Project Gas Research Institute Glyn Short (consultant)	**National Laboratories** National Renewable Energy Laboratory Lawrence Livermore National Laboratories Los Alamos National Laboratories Argonne National Laboratories Sandia National Laboratories Oak Ridge National Laboratories **US Department of Energy** **South Coast Air Quality Management District** **California Air Resources Board** **Los Angeles Metropolitan Transit Authority** **New Jersey Department of Environmental Protection** **New Jersey Department of Transportation** **New Jersey Board of Public Utilities, Energy Department** **New Jersey Transit** **NYSERDA** **Northeast Alternative Vebicle Consortium** **Federal Highway Administration** **ACADEMIC INSTITUTIONS** University of California at Davis University of California at Riverside University of Michigan TexasA&M Humboldt State University Georgetown University

Papers on our USDOE sponsored work on hydrogen infrastructure and fuel cell vehicle modeling have been presented to a variety of audiences including invited talks at the Society of Automotive Engineers Topical Technical Conferences on Fuel Cell Vehicles (in April 1996 and March 1998), the 11th World Hydrogen Energy Conference (June 1996), two National Hydrogen Association Meetings (March 1997 and March 1998), the '97 World Car Conference (January 1997), and the Aspen Energy Forum (July 1997). We have presented papers on our work on Hydrogen Energy Systems and CO_2 Sequestration at the DOE Workshop on Fuels Decarbonization and Carbon Sequestration (July 1997), the 9th National Hydrogen Association Meeting (March 1998), and the 12th World Hydrogen Energy Conference (June 1998).

Current Year Results

Overview

Over the past year we worked on three projects, which are described below.

From May 1997-November 1997, we completed an assessment of hydrogen as a fuel for fuel cell vehicles. (This study began in July 1996 and finished in November 1997).

Two other studies were begun in November 1997 and are scheduled for completion in September 1998:

* an assessment of potential supplies and demands for hydrogen energy in the New York City/New Jersey area,

* an assessment of the implications of CO_2 sequestration for the design of hydrogen energy systems.

Cost And Performance Benchmarks For Hydrogen As A Fuel For Fuel Cell Vehicles (July 1996-November 1997)

Since the last DOE Hydrogen Program Review Meeting in May 1997, we completed our technical and economic comparisons of hydrogen, methanol and gasoline as fuels for fuel cell vehicles. A detailed description of the methodology and preliminary results of these studies were reported in the Proceedings of the May 1997 Hydrogen Program Review Meeting (Ogden, Steinbugler, and Kreutz 1997). In this report we summarize the final results of this study.

All fuel cells currently being developed for near term use in vehicles require hydrogen as a fuel. Hydrogen can be stored directly or produced onboard the vehicle by reforming methanol, ethanol or hydrocarbon fuels derived from crude oil (e.g. gasoline, Diesel, middle distillates). The vehicle design is simpler with direct hydrogen storage, but requires developing a more complex refueling infrastructure. Figure 1 shows three alternative configurations for fuel cell vehicles using direct hydrogen storage, onboard steam reforming of methanol and onboard partial oxidation of gasoline.

In this study, we concentrated on a set of related tasks aimed at assessing the potential for using hydrogen directly as a fuel for fuel cell vehicles, as compared to onboard reforming of methanol and gasoline. This work builds on our earlier studies of hydrogen infrastructure, and extends it to consider alternative fuel cell vehicle designs as well as the refueling system.

The following tasks were completed:

Task 1 . Evaluate the projected performance and cost characteristics of alternative fuel cell vehicles with:

* compressed gas hydrogen storage

* onboard reforming of methanol

* onboard partial oxidation of hydrocarbon fuels derived from crude oil

To estimate the performance of fuel cell vehicles, we employ fuel cell vehicle models developed at Princeton. We also draw on existing vehicle modelling work ongoing as part of the DOE/OTT (DOE/Office of Transportation Technologies) and PNGV (Partnership for a New Generation of Vehicles) programs on fuel cell vehicles, and related studies by other academic groups (UC Davis, U of Michigan, Georgetown U.). Although a considerable amount of modelling work has been done on hydrogen and methanol fuel cell vehicles, there is little published data on vehicles where hydrogen is produced onboard via partial oxidation of hydrocarbon fuels derived from crude oil. We have concentrated on understanding the issues for this alternative.

Task 2. Evaulate the refueling infrastructure requirements for each alternative. As part of this study we consider strategies for building a hydrogen infrastructure, e.g. examine how hydrogen might be introduced for centrally refueled buses and automotive fleets first, eventually moving to public use.

Task 3. Determine the delivered fuel cost for the various fuels including hydrogen from natural gas, coal, solar, wind, biomass or nuclear; methanol from natural gas, biomass or coal; and hydrocarbon fuels such as gasoline or Diesel from crude oil.

Task 4. Calculate the lifecycle cost of transportation for each alternative.

Task 5. Compare the design and economics of hydrogen refueling station options including using small scale onsite steam reforming of natural gas and methanol, POX processing of hydrocarbon fuels and electrolysis. The results of this task are a comparison of designs for hydrogen refueling stations, which might be appropriate for vehicle demonstrations. This builds on previous work at Princeton, as well as work published as part of the PNGV and DOE/OTT programs.

Summary of Results

Task 1: Evaluate the projected performance and cost characteristics of alternative fuel cell vehicles

* Equilibrium, kinetic and heat integrated system (ASPEN) models have been developed to estimate the performance of onboard steam reforming and POX fuel processors for fuel cell vehicles (Kreutz, Steinbugler and Ogden 1996, Ogden, Steinbugler and Kreutz 1997). These results have been incorporated into Princeton's fuel cell vehicle model (Steinbugler 1998, Ogden, Steinbugler and Kreutz 1997, Steinbugler and Ogden 1996, Steinbugler 1996), allowing us to

compare the vehicle performance, fuel economy, weight, and cost for various fuel storage choices and driving cycles. Each vehicle is designed to meet specified performance criteria. The model is described in detail in (Ogden, Steinbugler and Kreutz 1997).

* A range of technical and economic parameters were considered. (Our base case modeling assumptions are given in Table 3.) For the same vehicle performance, we find that hydrogen fuel cell vehicles are simpler in design, lighter weight, more energy efficient and lower cost than those with onboard fuel processors (Table 4).

* A fuel cell vehicle with onboard methanol steam reforming is 10% heavier than one with direct hydrogen storage. A gasoline/POX vehicle is about 20% heavier. The weight contributions of various components (fuel cell, fuel processor, fuel storage, peak battery, etc.) are shown in Figure 2.

* Vehicles with onboard steam reforming of methanol or partial oxidation of gasoline have roughly two thirds the fuel economy of direct hydrogen vehicles. The efficiency is lower because of the conversion losses in the fuel processor (losses in making hydrogen from another fuel), reduced fuel cell performance on reformate, added weight of fuel processor components, and effects of fuel processor response time.

* For mid-size automobiles with PNGV type characteristics (base vehicle weight of 800 kg -- e.g. weight without the power train and fuel storage, aerodynamic drag of 0.20, and rolling resistance of 0.007), fuel economies (on the combined FUDS/FHDS drving cycle) are projected to be about 106 mpeg for hydrogen fuel cell vehicles, 69 mpeg for fuel cell vehicles with onboard methanol steam reforming, and 71 mpeg for onboard gasoline partial oxidation.

* Based on projections for mass produced fuel cell vehicles developed as part of the PNGV program (see Table 5), methanol fuel cell automobiles are projected to cost about $500-600 more than comparable hydrogen fuel cell vehicles. Gasoline/POX fuel cell automobiles are projected to cost $800-1200 more than hydrogen fuel cell vehicles (Figure 3).

Task 2: Evaluate the refueling infrastructure requirements for each alternative

* The cost of developing hydrogen refueling infrastructure based on near term technologies was estimated for various scenarios. We consider the following hydrogen supply options (see Figure 4):

    * hydrogen produced from natural gas in a large, centralized steam reforming plant, and truck delivered as a liquid to refueling stations,

    * hydrogen produced in a large, centralized steam reforming plant, and delivered via small scale hydrogen gas pipeline to refueling stations,

    * hydrogen from chemical industry sources (e.g. excess capacity in ammonia plants, refineries which have recently upgraded their hydrogen production capacity, etc.), with pipeline delivery to a refuelingstation.

Table 3. Parameters Used in Fuel Cell Vehicle Modelling

Vehicle Parameters	
Glider Weight (= vehicle - power train)[a]	800 kg
Drag Coefficient[a]	0.20
Rolling Resistance[b]	0.007
Frontal Area[a]	2.0 m^2
Accessory Load[c]	0.4 kW
Structural Weight Compounding Factor[d]	15%
Fuel Cell System	
Operating pressure	3 atm
Cathode Stoichiometry	2
System weight (including air handling, thermal and water management)[e]	4.0 kg/kW
Fuel Processor Systems	
Methanol Steam Reformer	
Gross efficiency (HHV H2 consumed in fuel cell/HHV MeOH in)	62%
$V_{comp/exp}$	0.067 Volts
Hydrogen utilization[g]	80%
Voltage Penalty for reformate operation[h]	0.06 x current (amp/cm^2)
Weight of system[i]	32 kg+1.1 kg/kW
Response time	5 sec
Reformate Composition	70% H_2, 24% CO_2, 6% N_2
Gasoline POX	
Efficiency (HHV H2 consumed/HHV gasoline in)[j]	69.4%
Hydrogen utilization[g]	80%
Voltage Penalty for reformate operation[h]	0.128 x current (amp/cm^2)
Weight of system[i]	32 kg+1.1 kg/kW
Response time	1 sec
Reformate Composition	42% N_2, 38% H_2, 18% CO_2, 2% CH_4
Peak Power Battery	
Battery type	Spiral wound, thin film, lead-acid
System weight[k]	1.0 kg/kW
Maximum charge rate	30 amps
Nominal state of charge[k]	50%
Energy stored[k]	15 Wh/kg
Motor and Controller	
Overall efficiency[b]	77%
Overall weight[l]	2.0 kg/kW
Fuel Storage	
Hydrogen[d]	5000 psi compressed gas tank total weight 50 kg, 7.5% H2 by weight
Methanol, Gasoline	12 kg tank, 13 gallon capacity total weight 50 kg
Driving schedules	FUDS, FHDS
Regenerative braking recovered up to battery capabilities	

Notes for Table 3

a. Based on PNGV targets. (Source: CALSTART website. http://www.calstart.org/about/pngv/pngv_ta.html)

b. Energy and Environmental Analysis, "Analysis of Fuel Economy Boundary for 2010 and Comparison to Prototypes," p. 4-11, prepared for Martin Marietta Energy Systems, Contract No. 11X-SB0824, November 1990.

c. Ross, M. and W. Wu, "Fuel Economy Analysis for a Hybrid Concept Car Based on a Buffered Fuel-Engine Operating at a Single Point," SAE Paper No. 950958, presented at the SAE Interantional Exposition, Detroit, MI, Feb 27-March 2, 1995.

d. C.E. Thomas and R. Sims, "Overview of Onboard Liquid Fuel Storage and Reforming Systems," "Fueling Aspects of Hydrogen Fuel Cell Powered Vehicles," Society of Automotive Engineers, Proceedings, Fuel Cells for Transportation TOPTEC, April 1-2, 1996, Arlington, VA.

e. Based on a Ballard-type PEM fuel cell system with a stack power density of 1 kg/kW. Other weight is due to auxiliaries for heat and water management equipment and air compression.

f.Arthur D. Little 1994. "Multi-Fuel Reformers for Fuel Cells Used in Transportation, Multi-Fuel Reformers, Phase I Final Report," USDOE Office of Transportation Technologies, Contract No. DE-AC02-92-CE50343-2.

g. This estimate was verified with fuel cell developers.

h. The voltage penalty for operation on reformate is based on models by Shimson Gottesfeld at Los Alamos National Laboratory.

i. William Mitchell, Arthur D. Little, private communications, 1997.

j. Mitchell, W. April 2, 1996. "Development of a Partial Oxidation Reformer for Liquid Fuels," Society of Automotive Engineers, Proceedings, Fuel Cells for Transportation TOPTEC, Arlington, VA.

k. Keating, J., B. Schroeder and R. Nelson 1996. "Development of a Valve-Regulated, Lead/Acid Battery for Power-Assist Hybrid Electric Vehicle Use," Bolder Technologies Corporation, Wheat Ridge, CO.

l. Chang, L. "Recent Developments of Electric Vehicles and Their Propulsion Systems," Proceedings of the 28th Intersociety Engineering Conference, vol. 2, pp. 2.205-2.210, American Chemical Society, 1993.

Table 4.
Model Results:
Comparison of Alternative Fuel Cell Vehicle Designs

Fuel Storage/ H2 Generation System	Vehicle mass (kg)	Peak Power (kW) (FC/Battry)	FUDS mpeg	FHDS mpeg	Combined 55% FUDS 45% FHDS mpeg	range (mi)
Direct H2	1170	77.5 (34.4/43.1)	100	115	106	425
Methanol Steam Reformer	1287	83.7 (37.0/46.7)	62	79	69	460
Gasoline POX	1395	89.4 (39.4/50.0)	65	80	71	940

For the assumptions in Table 3.

Table 5. Cost Estimates for Mass Produced Fuel Cell Vehicle Components

Component	High estimate	Low estimate
Fuel cell system[a]	$100/kW	$50/kW
Fuel processor system [b]	$25/kW	$15/kW
Hydrogen storage cylinder rated at 5000 psia[c]	$1000	$500
Motor and controller[d]	$26/kW	$13/kW
Peak power battery[e]	$20/kW	$10/kW
Extra structural support	$1/kg	$1/kg
Cost of 12 kg gasoline or methanol tank	$100	$100

Notes for Table 5

a. Based on a range of estimates found in the literature. For example, GM/Allison projects a fuel cell "electrochemical engine" cost of $3899 for a 60 kW system including the fuel cell, fuel processor (methanol reformer), heat and water management. This is about $65/kW (at the rated power of 60 kW) or $46/kWpeak. About 45% of the cost per peak kW ($21/kW) is for the fuel cell stack, 28% ($13/kW) for the methanol reformer and the rest for auxiliaries. This cost assumes large scale mass production. (Allison Gas Turbine Division of General Motors December 16, 1992).

Mark Delucchi of Institute of Transportation Studies at UC Davis estimates a retail cost of $2954 for a mass produced 25 kW hydrogen/air PEM fuel cell system or about $120/kW. (The manufacturing cost is $59/kW, with a materials costs for the fuel cell stack plus auxiliaries estimated to be $41/kW, and the labor cost $18/kW.) (J. M. Ogden, E.D. Larson and M.A. Delucchi May 1994).

A study by Directed Technologies for the USDOE estimated a cost in mass production of $2712 for a hydrogen/air fuel cell plus auxiliaries with net output of 85 kW power (about $32/kW). Directed Technologies is now working with Ford Motor Company on fuel cell vehicles as part of the PNGV program. (Ref: B.D. James, G.N. Baum and I.F. Kuhn, Directed Technologies, Inc. "Technology Development Goals for Automotive Fuel Cell Power Systems," prepared for the Electrochemical Technology Division, Argonne National Laboratory, Contract No. W-31-109-Eng-28, February 1994.)

Chrysler estimates that even with current fuel cell manufacturing technology, mass produced costs would be $200/kW (Chris Boroni-Bird, private communications 1997).

b. W. Mitchell, J. Thijssen, J.M. Bentley, "Development of a Catalytic Partial Oxiidation Ethanol Reformer for Fuel Cell Applications," Society of Automotive Engineers, Paper No. 9527611, 1995.

c. C.E. Thomas and R. Sims, "Overview of Onboard Liquid Fuel Storage and Reforming Systems," "Fueling Aspects of Hydrogen Fuel Cell Powered Vehicles," Society of Automotive Engineers, Proceedings, Fuel Cells for Transportation TOPTEC, April 1-2, 1996, Arlington, VA.

d. Derived from estimates in B. James, G. Baum, I. Kuhn, "Development Goals for Automotive Fuel Cell Power Systems," ANL-94/44, August 1994.

e. Based on PNGV goals

* hydrogen produced at the refueling station via small scale steam reforming of natural gas, (in either a conventional steam reformer or an advanced steam reformer of the type developed as part of fuel cell cogeneration systems)

* hydrogen produced via small scale electrolysis at the refueling station.

* We find that the capital cost of hydrogen infrastructure would be about $400-800/car depending on the type of hydrogen supply. [Figure 5 and Tables 6a and 6b summarize the assumed infrastructure capital costs for two levels of infrastructure development: a) early development serving a total vehicle fleet of 17,800 fuel cell cars or 280 fuel cell buses, b) a large scale system serving 1.4 million fuel cell cars.]

* Options for methanol fuel delivery infrastructure are shown in Figure 7. Worldwide there is currently methanol production capacity of about 28 million metric tonnes per year (Table 7). If all the methanol were used for fuel cell cars, about 29 million vehicles could be fueled. Methanol production capacity is not fully utilized at present, suggesting that up to several million fuel cell vehicles could be served worldwide without building new production capacity. Initially, developing a methanol refueling infrastructure for vehicles should entail relatively modest costs per car. Retrofitting gasoline refueling stations and delivery trucks to handle methanol might cost only about $50/car, and the excess capacity in the existing industrial methanol supply system should be adequate to supply fuel to perhaps a few million fuel cell cars worldwide. Once fuel cell cars reached beyond this level, new methanol production capacity would be needed, which we estimate might cost $400-800/car (Tables 8 and 9, Figure 8). No extra costs are assumed for developing gasoline infrastructure.

* Defining "infrastructure" to mean all the equipment (both on and off the vehicle) required to bring hydrogen to the fuel cell, we find that the cost is comparable for hydrogen ($400-800/car for off-vehicle infrastructure), methanol ($500-600/car for onboard fuel processor, plus in the longer term $400-800/car for methanol production capacity) and gasoline POX fuel cell vehicles ($800-1200/car for onboard fuel processor). (See Figure 9.)

* It is likely that hydrogen fuel cells might be introduced first for transit buses, where centralized refueling is the norm, and the cost requirements are less stringent than for automobiles.

Task 3: Determine the delivered fuel cost

* Considering near term options, the delivered cost of hydrogen ftransportation fuel for Southern California conditions is found to be $14-40/GJ depending on the refueling station size and the technology. This is shown in Figure 6.

* The delivered costs of alternative transportation fuels for fuel cells (hydrogen, methanol and gasoline) are shown in Figure 10. We see that the delivered cost of hydrogen is higher on an energy basis than methanol or gasoline. However, because of the hydrogen fuel cell vehicle's higher fuel economy the fuel cost per km is about the same for hydrogen made from natural gas as for gasoline (Figure 11).

Table 6a. Capital Cost for Developing New Hydrogen Delivery and Refueling Station Infrastructure Serving a Total Fleet of 17,800 FCV Cars, Delivering 2 million scf H_2/day (assuming that existing production capacity is used)

	Centralized Production via Steam Reforming of Natural Gas w/LH2 Delivery	Centralized Production via Steam Reforming of Natural Gas w/Pipeline Delivery	Onsite Steam Reforming of Natural Gas: Convention Steam Methane Reformer	Onsite Steam Reforming of Natural Gas: Advanced Steam Methane Reformer	Onsite Advanced Electrolysis Using Off-Peak Power
Centralized Hydrogen Production	0 (assumed that existing capacity is used)	0 (assumed that existing capacity is used)			
Hydrogen Distribution	0 (assumed that existing trucks are used)	10 km pipeline = $6.2 million (at $1 million per mile)			
2 Refueling Stations each serving 654 cars/day	$1.4 million ($0.7 per station)	$3.4 million ($1.7 million per station)	$10.8 million ($5.4 million per station)	$6.8 million ($3.4 million per station)	$11.4 million ($5.7 million per station)
TOTAL	$1.4 million	$9.6 million	$10.8 million	$6.8 million	$11.4 million
infrastruct. cost per car	$79	$539	$607	$382	$640

Adapted from Ogden, Kreutz, Iwan and Kartha 1996.

Table 6b. Capital Cost for Developing New Hydrogen Production, Delivery and Refueling Station Infrastructure Serving a Total Fleet of 1.36 million Fuel Cell Cars, Delivering 153 million scf H_2/day

	Centralized Production via Steam Reforming of Natural Gas w/LH2 Delivery	Centralized Production via Steam Reforming of Natural Gas w/Pipeline Delivery	Onsite Steam Reforming of Natural Gas: Convention Steam Methane Reformer	Onsite Steam Reforming of Natural Gas: Advanced Steam Methane Reformer	Onsite Advanced Electrolysis Using Off-Peak Power
Centralized Hydrogen Production	$100 million for reformer + $ 200 million for liquefier + LH2 storage	$170 million for reformer + H_2 compressor			
Hydrogen Distribution	80 LH2 trucks each with a 3 tonne capacity, each making 2 local deliveries/day = $40 million	600 km pipeline = $380 million (at $1 million per mile)			
153 1 million scf H2/day Refueling Stations each serving 654 cars/day	$104 million ($0.7 million per station)	$260 million ($1.7 million per station)	$830 million ($5.4 million per station)	$516 million ($3.4 million per station)	$870 million $5.7 million per station)
TOTAL	$440 million	$810 million	$830 million	$516 million	$870 million
Infrastructur Cost per Car	$324	$596	$610	$379	$640

Adapted from Ogden, Kreutz, Iwan and Kartha 1996.

Table 7. Methanol Production Capacity 1995[a]

Region	1000 Metric Tonnes/y	EJ/yr (LHV)	Methanol FCV cars fueled (millions)[b]
North America	9550	0.19	9.8
Europe	7280	0.14	7.5
South America	3590	0.07	3.7
Far East and Asia	4680	0.09	4.8
Middle East and Africa	3460	0.07	3.6
WORLD	28,260	0.56	29.0

In 1995 total MeOH demand was 23.4 million metric tonnes or 83% of nameplate production capacity. This suggests that significant numbers (several million?) FCVs could be fueled without having to build new MeOH production capacity

a. CMAI 1995 World Methanol Analysis, p. 25.

b. It is assumed that methanol fuel cell cars have the fuel economy given in Table 4, and are driven 11,000 miles/year.

Table 8. Projected Capital Cost Of Methanol Refueling Infrastructure Development

Item	Cost
Convert Gasoline Refueling Station to Methanol	\$5000- 45,000/station[a] (for a station dispensing 1100 gallons MeOH/d)
Methanol Delivery truck	No cost (use existing gasoline trucks)[a] \$140,000 (per new 8500 gallon MeOH truck)[a]
Marine Terminal Bulk Storage Tank for Methanol (for a terminal with 1.3 million bbl storage = 20 days storage)	\$2.50/bbl (convert gasoline storage)[a] \$15/bbl (build new MeOH storage)[a]
Other terminal equipment	\$1/bbl[a]
Methanol Overseas Shipping Costs	No capital cost - use existing tankers; trans cost=3-5 cents/gallon[b,c]
Methanol Production Plant (from NG)	\$880-1540 million[c] (10,000 metric tonnes/day) \$330-570 million[c] (2500 mt/d)

a. DOE/PE-0095P, "Assessment of Costs and Benefits of Flexible and Alternative Fuel Use in the US Transportation Sector," USDOE, Policy, Planning and Analysis, Washington, DC, August 1990. This assumes that the storage capacity holds 20 days worth of fuel.

b. M. Lawrence and J. Kapler, "Natural Gas, Methanol and CNG: Projected Supplies and Costs," presented to "Transportation Fuels in the 1990s and Beyond, A Conference of the Transportation Research Board, Monterey, CA, July 1988.

c. A. Krupnik, M. Walls, M. Tolman, "The Cost Effectiveness and Energy Security Benefits of Methanol Vehicles," Resources for the Future, Discussion Paper QE90-25, September 1990.

Table 9. Capital Cost Of Methanol Infrastructure Per Car

Item	Capital Cost	#Cars Served	Capital Cost per car ($/car)	Capital Cost per car (1995$/car)
Refueling station conversion (1100 gallons/d) (1990$)	$45,000	1244	36	42
Marine Terminal Conversion (1990$)	@$18.5/bbl storage capacity 6500 barrels (minumum)	2.4 cars/bbl of storage capacity 15,400 cars (minimum)	8	9
Tanker Shipping Capacity	No cost (minimum delivery about 3-6 million bbl)	4-16 million cars (if 10-20 deliv/yr)	0	0
New Production Capacity (1988$)	$880-1540 million (10,000 metric tonnes/day) $330-570 million (2500 mt/d)	3.8 million cars 0.94 million cars	230-400 350-600	290-500 440-750

Task 4: Calculate the lifecycle cost of transportation

* The total lifecycle cost of transportation (cents/km) of fuel cell vehicles (counting vehicle capital costs, O&M and fuel) is slightly lower for hydrogen fueled vehicles (assuming the hydrogen is derived from natural gas) than for fuel cell vehicles using methanol or gasoline. This is true because the hydrogen fuel cell vehicles are likely to cost less to buy, and have roughly 50% higher fuel economy than methanol or gasoline fuel cell vehicles. (See Figure 12)

Task 5: Compare the design and economics of hydrogen refueling station options

* As part of our studies, a series of conceptual designs for hydrogen refueling stations were developed. These are summarized in Table 10.

Summary

* Hydrogen is the prefered fuel for fuel cell vehicles, for reasons of vehicle design, cost and efficiency, as well as potential energy supply and environmental benefits. The cost of developing hydrogen refueling infrastructure is comparable to the total cost (on and off the vehicle) for methanol or gasoline fuel cell vehicles. Like CNG or methanol, hydrogen faces the issue of reaching beyond centrally refueled fleet markets. Valuable experience can be gained in the near term by building the refueling systems for centrally refueled hydrogen fuel cell vehicle demonstrations, and investing now in technologies which could play a role in a future hydrogen infrastructure.

Data Sources

To estimate the infrastructure requirements for various fuels, we have used data developed as part of earlier studies of hydrogen refueling systems as well as data published as part of the PNGV and DOE/OTT programs. The emphasis is on studying infrastructure issues in Southern California, a likely site for hydrogen vehicle and refueling infrastructure demonstrations.

The work also involves estimating the cost and performance of alternative fuel cell vehicles. These estimates draw in part on existing published studies of fuel cell vehicle designs by Ford, GM, Chrysler and other PNGV participants. We also use the results of fuel cell vehicle component models developed at Princeton and at DTI. A large number of industry, government and academic sources have provided the data needed for our fuel cell vehicle calculations.

Carrying out conceptual designs of hydrogen energy systems requires a large data base on the performance and cost of hydrogen production, distribution and end-use equipment. A partial list of industrial, government, and academic sources used in the work is contained in Table 2.

Methods Of Analysis

As discussed above, where necessary, engineering models of fuel cell vehicles, fuel processors, and refueling station equipment have been developed.

Table 10. Cost Comparison of Alternative Designs for Gaseous Hydrogen Vehicle Refueling Stations

REFUELING STATION TYPE	STATION CAPACITY SCF H2/DAY (Cars Fueled Per Day)		
	100,000 (80 cars/day)	**366,000 (300 cars/day)**	**1,000,000 (800 cars/day)**
1) LH2 Truck Delivery	175,000	307,000	680,000
2) Pipeline H2 Delivery	200,500	620,500	1,681,500
3) Onsite Reforming (Conventional SMR)	1,769,900	3,054,740	5,379,500
4) Onsite reforming (FC SMR)	626,300	1,369,740	3,378,500
5) Onsite Electrolysis from Off-Peak Power: Current Electrolysis Technology	860,500	3,042,500	8,2455,500
6) Onsite Electrolysis from Off-Peak Power: Advanced Electrolysis Technology	608,500	2,132,500	5,745,500

Sources: Ogden et.al 1995, Ogden et.al. 1996)

The levelized cost of hydrogen production, delivered hydrogen cost and lifecycle costs of transportation are estimated using standard microeconomic techniques.

Interaction With Other Groups/Technology Transfer

In this research Princeton has coordinated with Directed Technologies, Inc. (DTI), Lawrence Livermore National Laboratory (LLNL) and other members of the Hydrogen Program Analysis Team to discuss cost and performance issues for hydrogen as a fuel for fuel cell vehicles. It has been particularly useful to compare our results with those from a recent infrastructure study undertaken by DTI for Ford and the Office of Transportation Technology.

This work has also involved interaction with fuel cell manufacturers and with automotive companies (including Ford, Chrysler and GM and their subcontractors) which are considering or planning fuel cell vehicle demonstrations as part of the DOE/OTT and PNGV programs. We have also interacted with groups at Los Alamos National Laboratory, and Argonne National Laboratory who are studying fuel cell vehicle systems, as well as other academic groups (UC Davis, U of Michigan, Georgetown U), fuel providers (Exxon, Mobil, ARCO), and other companies such as Arthur D. Little (ADL). A partial list of groups who have assisted us with useful data and discussions is given in Table 2.

Preliminary Results: Assessment of Potential Supplies and Demands for Hydrogen Energy in The New York City/New Jersey Area (November 1997-present)

The New York City/New Jersey metropolitan area is a possible candidate for "Clean Cluster" type demonstrations of hydrogen energy technologies. Like California, New York City and New Jersey have severe urban air quality problems and are considering the use of zero and low emission vehicles. Unlike California, relatively little analysis has been done looking into the possibilities for hydrogen and fuel cell vehicles.

As part of this year's research, we are carrying out a preliminary study of potential hydrogen demands and supplies in the New York City/New Jersey area, similar to our earlier work in Southern California. This study builds on our previous work on hydrogen infrastructure, and on preliminary studies at CEES on the potential for hydrogen production from muncipal solid waste (Larson, Chen and Worrell 1996.).

In particular, we are addressing the following questions:

Task 1.1. What are potential demands for hydrogen for transportation markets in the New York City/New Jersey area. We consider centrally refueled applications such as urban buses, vans and fleet autos, as well as public automobiles.

Task. 1.2. What are potential demands for hydrogen for transportation markets in the New York City/New Jersey area. considering:

* truck delivered or pipeline delivered merchant hydrogen,

* hydrogen byproduct from chemical plants and refineries,

* onsite hydrogen production from steam reforming of natural gas at small scale,

* electrolytic hydrogen from off-peak power,

* hydrogen from gasification of municipal solid waste.

Task 1.3 What is the production cost and delivered cost of hydrogen transportation fuel from these various sources.

Preliminary Results

Task 1.1: What are potential demands for hydrogen for transportation markets in the New York City/New Jersey area.

* There is a strong impetus to develop low polluting vehicles in the New York City/New Jersey area, which may present opportunities for hydrogen and fuel cell vehicles. Both the New York City metropolitan area and the state of New Jersey are currently non-attainment areas for ozone, carbon monoxide and particulates. New York state has a zero emission vehicle mandate, similar to the California ZEV regulations, and in August 1997 passed legislation offering tax credits for the incremental cost of alternative fueled vehicles and refueling stations, including hydrogen. New York City has undertaken a variety of efforts to introduce alternative vehicles. New York is probably second only to California in its commitment to alternative vehicles. New Jersey has a smaller but active program in alternative fueled vehicles, and a growing awareness of fuel cells and hydrogen, encouraged by the presence of several fuel cell companies, hydrogen suppliers and large scale hydrogen users such as refineries based in the state. New Jersey recently decided to develop a state climate change action plan, and has endorsed a National LEV standard.

* If siginficant numbers of vehicles in New York City or New Jersey were converted to hydrogen, a large hydrogen demand would develop.

    o The current light duty vehicle population in New Jersey is about 5.7 vehicles (including 1.0 million light trucks). The average annual mileage is 10,330 miles/yr, and the average fuel economy is 20.3 mpg. Vehicle miles are projected to increase from their 1995 level of 187 million miles/day to 209 million miles/day in 2010. We assume that the average fuel economy of light duty vehicles can be increased by a factor of four over present levels through a combination of lighter weight, more streamlined design (which could improve fuel economy by perhaps a factor of 1.5) and adoption of fuel cells rather than ICEs (which would increase fuel econony by another factor of 2.5). In this case, we find that the statewide average fuel economy would be 80 mpg equivlent. <u>The hydrogen needed would be about 1000 million scf/day to supply all NJ light duty vehicles in 2010.</u>

    o There are about 5300 buses in New Jersey including commercial and public fleets. Virtually all the buses are centrally refueled. The total energy use by buses in New Jersey in 1990 was estimated to be 5.9 Trillion BTU/yr of Diesel. Assuming that a fuel cell bus would acheive a 50% higher fuel economy than a Diesel, <u>the hydrogen needed to power New Jersey's fuel cell transit buses would be about 33 million H2/day.</u>

- o For New York City, the total vehicle miles are estimated to be 19 billion/year for light duty vehicles (or 52 million vehicle miles/day). The energy use is 127 million GJ/yr. Assuming that fuel cell vehicles could improve fuel economy from the current average of 20 mpg to 80 mpg, the corresponding hydrogen use for all NYC light duty vehicles would be about 250 million scf H2/day.

- o New York City's 3600 public transit buses log a total of about 90 million bus-miles, requiring perhaps 15 million scf/day of hydrogen, if fuel cell buses were used.

Task 1.2: What are potential hydrogen supplies in the New York City/New Jersey area.

* There are a variety of potential near term hydrogen supplies in the New York City/New Jersey area, which could be used to provide hydrogen transportation fuel. These include truck delivered merchant hydrogen, byproduct hydrogen from refineries and chemical plants, onsite hydrogen production via small scale steam reforming of natural gas, onsite hydrogen production via small scale water electrolysis. In the longer term hydrogen might be produced from large scale steam reforming of natural gas with pipeline distribution or gasification of municipal solid waste.

* Industrial gas companies in the NYC/NJ area generally meet hydrogen demands in the range needed for refueling stations (0.1-2.0 million scf H2/day) via truck delivery of either liquid hydrogen or compressed hydrogen gas. The hydrogen is originally produced at distant Chloralkali plants, and trucked into the area, rather than at nearby large steam methane reformers dedicated to merchant hydrogen production (as in Southern California). There are currently no hydrogen pipelines operating in the New York City/New Jersey area, except perhaps within refineries. The primary industrial gas companies (Air Products and Chemicals, Praxair, BOC Gases, Air Liquide, MG Gases) all serve this area.

* Excess byproduct hydrogen may be available from refineries and chemical plants located in New Jersey. Several large chemical/refinery complexes are found in New Jersey located in: 1) the Newark area, 2) the Philadelphia/Camden area, 3) the area near the Delaware Memorial Bridge at the NJ/DE border, which has both refineries and a Chloralkali plant. Details are still being gathered, but it appears likely that some hydrogen may be available from such sources, totalling perhaps a few million scf/day, enough for a few hundred buses.

* There is a significant amount of off-peak power available in New Jersey (total generation capacity is approximately 18,000 MW, and in theory about one third to half this capacity could be available for off-peak power generation), but the price of off-peak power is presently high, on the order of 7-8 cents/kWh . This may make it difficult for onsite electrolysis to compete as a source of hydrogen. Many analysts believe that the price of off-peak power should eventually go down with deregulation and utility restructuring, although the ultimate price is difficult to predict.

* Onsite production of hydrogen from natural gas in small steam refomers is another possibility. However, the cost of natural gas is moderately high in the

region, as New York and New Jersey are at the "end of the pipeline" bringing gas from the Gulf states. Moreover, there is little excess capacity in the existing natural gas interstate pipelines serving the New Jersey area. In the winter, gas delivery is limited by long distance pipeline capacity (rather than local distribution pipelines). Increasing natural gas supplies to the region (for example, to produce enough hydrogen to meet the demands for a large fleet of vehicles) could be costly if it entailed building new interstate natural gas pipeline capacity. Supplying enough natural gas to make hydrogen for all light vehicles in New Jersey (assuming fuel cell vehicles are used) would increase the natural gas flow into the state by perhaps 25%.

* Gasification of municipal solid waste is an intriguing longer term possibility for hydrogen production in the New York City/New Jersey area. (A system for hydrogen production from MSW gasification has not been commercialized although the component technologies are available) This would also help solve the problem of waste disposal, a serious issue in a region where landfill space is virtually exhausted. Preliminary calculations show that if all the non-recycleable waste streams in New York City were used to make hydrogen for fuel cell vehicles about 44% of New York City's estimated 19 billion light duty vehicle miles could served by this resource alone. Equivalently all of transit buses in New York City could be served by about 16% of the MSW. A similar fraction of LDVs in New Jersey could be served if all New Jersey's municipal solid waste were gasified for hydrogen production. The economics of this approach depend upon the scale of the plant (nominally a MSW to hydrogen plant might produce 25 million scf H2/day, enough for a fleet of perhaps 250,000 fuel cell cars, although smaller plants may be possible), and the tipping fee.

* Because the New York City/New Jersey region has higher energy prices than many regions of the US (electricity prices are among the highest in the nation, and natural gas prices above average), onsite small scale hydrogen production may be more expensive than in regions with lower energy costs.

* Figures 11 and 12 summarize the potential hydrogen supplies and demands in New Jersey. In the near term, refinery excess hydrogen and hydrogen from natural gas would be sufficient to get started. In the longer term gasification of MSW may be an interesting option.

Task 1.3: What is the production cost and delivered cost of hydrogen transportation fuel from these various sources.

* The economics of the various hydrogen supply options will be estimated in future work.

Data Sources

Data on vehicle energy use and alternative vehicles were obtained from the New Jersey Board of Public Utilities Energy Department (NJBPU), the New Jersey Department of Environmental Protection (NJDEP), the New Jersey Department of Transportation (NJDOT), and the NJ Office of Sustainability, the New York Power Authority, NYSERDA, the Northeast Alternative Vehicle Consortium and the Northeast Sustainable Energy Association.

For current energy prices in the area, we have contacted or are contacting the individual electric and gas utilities in the area (Public Service Gas and Electric, GPU/Jersey Central Power &Light, Atlantic Electric Company, Rockland Electric, New Jersey Natural Gas, South Jersey Gas, and Elizabethtown Gas, Consolidated Edison, New York Power Authority, Brooklyn Union Gas, Lilco), and using data from annual reports of the NJBPU.

For an understanding of current merchant hydrogen infrastructure in the area, we contacted Air Products, Praxair, and BOC Gases.

For data on hydrogen production in refineries and other chemical plants (Chloralkali, etc.), we collected data from the industrial gas companies, as well as from oil companies (Mobil and Exxon).

For data on the availability and content of municipal solid waste as a feedstock for hydrogen production, we contacted the New Jersey DEP, the New York Power Authority and the NY Department of Sanitation.

For data on fleet vehicles, and vehicle populations we consulted studies by the NJDOT, the NJBPU, Oak Ridge National Laboratory, the American Automobile Manufacturers' Association, and the Federal Highway Administration.

For estimates of hydrogen production, distribution and refueling systems, we utilized data collected in earlier studies of hydrogen infrastructure.

Methods Of Analysis

Where necessary, engineering models of hydrogen production, distribution and refueling station equipment are being developed or adapted from our earlier work on hydrogen infrastructure.

The levelized cost of hydrogen production, delivered hydrogen cost and lifecycle costs of transportation are estimated using standard microeconomic techniques.

Interaction With Other Groups/Technology Transfer

Understanding the potential demand for hydrogen vehicles in New York City and New Jersey involved interactions with the state and local governmental groups involved in alternative vehicles and energy, and with local gas and electric utilities.

These include the New Jersey Board of Public Utilities Energy Department, the New Jersey Department of Environmental Protection (NJDEP), which is rapidly developing an interest in hydrogen and fuel cells, and the New Jersey Department of Transportation (NJDOT), which is currently sponsoring H-Power's development of small scale fuel cells as battery replacements for highway warning signs. Governor Whitman of New Jersey has issued an order to develop a statewide "Climate Change Action Plan".

We have had several meetings with New Jersey officials involved in assessing the potential of new technologies to reduce greenhouse gas emissions in New Jersey. One of the most active interchanges thusfar has been with the NJ Department of Environmental Protection. We have given a number of briefings to this group, and to others in the newly created NJ Office of Sustainability and in the New Jersey Science and Technology Group on fuel cell vehicles, hydrogen and CO_2 sequestration. There is a growing interest in hydrogen and fuel cells in New Jersey, that may make it attractive as a potential site for hydrogen vehicle implementation.

Other valuable data were obtained from the New York Power Authority, NYSERDA and the Northeast Alternative Vehicle Consortium.

Preliminary Results: Implications Of CO_2 Sequestration For Hydrogen Energy Systems (November 1997-present)

Recently, it has been proposed that hydrogen could be produced at large scale via steam reforming of natural gas, or gasification of coal or biomass, with low cost separation of CO_2 and permanent sequestration underground, for example in depleted gas wells or in deep aquifers. The basic idea is sketched in Figure 15, showing hydrogen production from hydrocarbon feedstocks, with separation of CO_2 during the process. CO_2 is piped to a site for underground storage. The hydrogen is compressed and transmitted to distant users via high pressure hydrogen pipelines. A hydrogen energy system with sequestration would allow the continued large scale use of fossil fuel resources while greatly reducing CO_2 emissions into the atmosphere. The hydrogen would be separated out of hydrocarbon fuels and the CO_2 secured underground.

While CO_2 sequestration is an active research topic, under investigation by the USDOE (Socolow 1997) and internationally (Herzog 1997), there has been relatively little work done linking this idea to concepts of hydrogen energy systems. Indeed, CO_2 sequestration raises a host of interesting hydrogen systems questions, which we are addressing as part of our work for the Hydrogen R&D Program in FY'98. These include the following.

* What is the cost of hydrogen production with CO_2 sequestration compared to other hydrogen production methods? How does it compare to localized hydrogen production from natural gas and to fuel cycles with no net CO2 emissions (e.g. hydrogen from solar, wind or biomass)? How does the cost vary with demand? What are the potential impacts of new technologies for steam reforming and CO2 separation?

* When would it make sense to start sequestering CO2? In particular, at what scale of hydrogen production could you begin sequestering CO2? How large a demand must be in place before sequestering and long distance hydrogen transmission become attractive? Answering this question involves understanding the economies of scale of hydrogen production, CO2 separation and sequestration, and pipeline transmission.

* What are plausible scenarios for a transition toward a large scale hydrogen energy system with sequestration? Under what conditions will pipeline hydrogen (produced via large scale steam reforming and transmitted long distances via pipeline) compete with locally produced hydrogen (either at the city scale -- in a single city-sized refomer plant) or onsite (e.g. via small scale steam reforming at a hydrogen refueling station)?

To study these questions we are carrying out the following tasks:

Task 2.1: Understand scale economy issues for hydrogen energy systems with sequestration.

Task 2.1a. What are the scale economies of current and developing technologies for steam methane reforming and CO2 separation?

Task 2.1b. What are the scale economies of hydrogen pipeline transmission? Using pipeline transmission models developed at Princeton, we would estimate the cost of hydrogen pipeline transmission as a function of pipeline pressure, flow rate, and pipeline length.

Task 2.1c. What are the scale economies of pipeline transmission and sequestration of CO2? What determines the rate at which CO2 can be injected at the sequestration site?

Task 2.1d. How does the cost of hydrogen with sequestration vary with the energy demand and the distance of the hydrogen plant and sequestration site from the demand?

Task 2.1e. What is the cost of pipeline hydrogen with sequestration, compared to other hydrogen supply options (including "carbon-free" options such as renewable hydrogen), as a function of demand?

Task 2.2. Estimate the conditions under which pipeline hydrogen with sequestration will compete with other options. How large must the demand be? How close must the hydrogen production be to the demand? What are the potential impacts of new steam reforming technologies?

Task 2.3. Sketch possible scenarios for a transition toward a large scale hydrogen energy system employing CO2 sequestration.

Example: Understanding scale economy issues for natural gas-based hydrogen energy systems with CO_2 sequestration.

As an example, we consider a system with hydrogen production from natural gas and sequestration of CO_2. As shown in Figure 16 there are a number of options for delivering hydrogen to users, and for capturing CO_2. Key questions are

* "where do you make the hydrogen?" (hydrogen can be made at small scale at the user's site; at city scale with local distribution; or at large scale near the source of natural gas with long distance hydrogen pipeline transmission.)

and

* "where do you capture the CO_2?" (In theory CO_2 could be captured at small scale and collected, or captured at city scale and piped some distance to a sequestration site, or captured at a hydrogen production facility at the natural gas field and re-injected into gas wells).

The answers to these questions depend on scale economies in:

* hydrogen production,

* CO_2 separation,

* pipeline transmission of hydrogen, natural gas and CO_2,

* CO_2 injection at the sequestration site

To size the various components in the system, we first must understand the potential hydrogen demand and associated CO_2 production. Table 11 shows hydrogen flows needed to supply various end-use demands. Projected hydrogen demand varies over a wide range from 0.04 GJ/day for a single fuel cell car to 0.3 million GJ/day if all the cars in the Los Angeles Basin converted to hydrogen fuel cells to 3 million GJ/day to equal the energy in the current natural gas flow in the Southern Califormia Gas system.

The specific capital cost ($ per kW of hydrogen output) for various hydrogen production systems is shown as a function of plant size (in GJ/day) in Figure 17. Conventional steam methane reformer technology is shown, as well as advanced small scale reformers based on fuel cell reformer technology. Estimates for the mass produced capital cost of advanced small scale "fuel cell type" reformers are shown for various levels of cumulative production (1 unit up to 10,000 units), based on recent studies by Directed Technologies, Inc. (Thomas et.al. 1997). We see that the capital cost of small scale steam methane reformers could be significantly reduced with advanced technology.

However, the production cost of hydrogen would still be less for centralized production than for decentralized small scale production, because the feedstock cost will be less at a large central hydrogen plant. As shown in Figure 18, feedstock costs dominate the total cost of hydrogen production.

Of course, centrally produced hydrogen must be distributed to users, which adds distribution costs. The cost of small scale, local gaseous pipeline transmission is shown in Figure 19 as a function of pipeline length and number of fuel cell vehicles served. Costs are lowest for large flow rates and short pipelines (e.g. large, geographically concentrated hydrogen demands). The delivered cost of hydrogen transportation fuel is shown in Figure 20 including hydrogen production, local pipeline distribution (for centralized production) and refueling stations. We see that decentralized production with advanced reformers can compete with centralized pipeline production, because of pipeline distribution costs. As demand increases, the cost of pipeline transmission is reduced, and approaches that of decentralized production.

Let us now assume that we want to sequester CO_2. In this case centralized production will always be less costly because of the high cost of capturing and collecting CO_2 from many small dispersed sources. This is shown in Figure 21. But centralized production implies that a large demand has built up for hydrogen. Thus, sequestration may not be introduced until a large demand for hydrogen is in place.

Long distance pipeline transmission costs

Once hydrogen is produced and CO_2 separated, the CO_2 must be piped to a sequestration site. To understand the trade-offs in transmitting hydrogen and/or CO_2 long distances, we are developing engineering and economic models of pipeline transmission for hydrogen, methane and CO_2.

The cost of CO_2 transmission 250 km as a function of associated hydrogen production is shown in Table 12 and Figure 22. We see that for large scale energy systems, CO_2 pipeline costs add very little to the cost of producing hydrogen. At production scales of 0.2-8 million GJ of hydrogen/day, a CO_2 pipeline adds $0.27-0.04/GJ H2, as compared to hydrogen production costs of $5-8/GJ, depending on the production technology. (For reference, 0.2 million GJ H2/day would fuel half

Table 11. Hydrogen Demand: Scales Of Interest

DEMAND	H2 FLOW (GJ/day)
1 fuel cell car	0.038
1 fuel cell bus	2.7
10 fuel cell buses	27
100 fuel cell buses or 7000 fuel cell cars	270
1% of cars in LA Basin	3420
H2 Production at Large Refinery	36,200
10% of cars in LA Basin	34,200
100% of cars in LA Basin	342,000
Energy Flow = NG Flow in LA Basin	3,000,000

Table 12. Characteristics of 250 km CO_2 Pipelines

Pipeline Diameter (inches)	Flow Rate (million tonnes CO2/y)	Pipeline Capital Cost ($/m)	Trans Cost ($/tonne CO2)	Associated H2 Production (million GJ/d)	Added Cost to Hydrogen ($/GJ)
16	3	650	7.0	0.21	0.27
30	20	1300	2.1	1.4	0.08
40	35	1750	1.6	2.5	0.06
64	110	3300	1.0	7.7	0.04

Costs for CO_2 transmission include compression and pipeline capital and operating costs for a 250 km pipeline. The CO_2 is compressed to 110 bar for transmission as a supercritical fluid. The pressure at end of pipeline is 90 bar.

SOURCE: O. Skovholt, "CO2 Transportation System," Energy Conservation Management, Vol. 34, No. 9-11, pp. 1095-1103, (1993).

Associated hydrogen production is calculated assuming that hydrogen and CO_2 are produced by steam reforming natural gas. According to plant designs from Katofsky 1993, for each kg of hydrogen produced, 5.55 kg of CO_2 are recovered from the PSA. [39 kg of CO_2 are recovered from the PSA for each GJ of hydrogen produced (HHV basis).]

the cars in the Los Angeles Basin, if fuel cells were used, and 8 million GJ H2/day is twice the current total natural gas energy flow in Southern California.Gas Company's distribution system.)

More information on smaller CO_2 pipelines is needed to understand issues for smaller scale hydrogen production with CO_2 sequestration.

The cost of long distance pipeline transmission is shown for hydrogen and natural gas in Figures 23 and 24. Again, at large flow rates the cost contribution to the delivered fuel cost is small, perhaps 10-20% of the delivered hydrogen cost. Methane transmission is roughly 1/3 to 1/2 as costly as hydrogen transmission, for the same energy flow rate.

How do scale economies influence the design of energy systems with CO_2 sequestration?: preliminary insights

To justify putting a centralized hydrogen production plant and local hydrogen distribution pipeline system in place, a large, geographically concentrated hydrogen demand is needed. If you don't want to collect CO_2, and natural gas is plentiful, you may choose to make hydrogen onsite in advanced small scale reformers. If CO_2 sequestration is desired, the economics will always favor centralized hydrogen production, because of the high cost of separating and collecting CO_2 at small scale. The level of hydrogen demand required to implement a hydrogen energy system with CO_2 sequestration is probably something like 10-100% of cars in Los Angeles.

Large CO_2 flows are needed to make long distance transmission attractive. The associated hydrogen production is equal to that in 1 to 10 large refineries (in terms of chemical markets) or enough hydrogen about 10-100% of the cars in the Los Angeles Basin (in terms of energy markets).

Introduction of CO_2 sequestration requires a large hydrogen demand If PEM fuel cells are successfully commercialized for vehicles or combined heat and power, this could provide impetus toward such a market (Williams 1997). In the nearer term (before the build-up of large hydrogen energy markets), one could look for large scale point sources of CO_2 associated with hydrogen production from fossil fuels, which are currently vented, but could be captured at small additional cost and sequestered. Some possibilities are steam methane reformers in oil refineries ("reduced CO_2" gasoline?) or in ammonia manufacture. These may be about the right scale to consider CO_2 sequestration.

Summary of results to date

* Engineering/economic models are being developed of pipeline transmission for hydrogen, methane and CO_2, and hydrogen production with alternative methods of CO_2 separation.

* There are strong scale economies in gaseous pipeline transmission, hydrogen production, CO_2 separation and CO_2 injection which influence the design of a hydrogen energy system with CO_2 sequestration.

* If gases are piped long distances, a large flow rate is required to assure low transmission costs. Because of CO_2 pipeline scale economies, a large flow of CO_2 would be needed to reach low transmission costs, unless sequestration could be done near the site of hydrogen production. Large CO_2 flows imply a large geographically concentrated demand for the co-produced hydrogen would be required, before CO_2 sequestration could be done at low cost. The required

hydrogen energy demand would be equivalent to the fuel required for 10%-100% of the cars in the LA Basin (assuming hydrogen fuel cell cars were used), assuming the CO_2 must be piped 300-1000 km to a sequestration site.

* At large flows, the cost of hydrogen pipeline transmission is small, less than 10% (20%) of the cost of hydrogen production over a distance of 300 km (1000 km). The added cost of long distance CO2 transmission is less than 5% of the hydrogen production cost for very large flow rates (e.g. for an energy system which could serve half the cars in LA).

* It is not economically or technically attractive to collect CO_2 from many small dispersed sources. CO_2 sequestration favors large, centralized hydrogen production with local hydrogen pipeline distribution to users.

* Because of advances in small scale methane reformer technologies, it is likely that onsite production of hydrogen from natural gas (for example at refueling stations) will be economically preferable to centralized production with local hydrogen pipeline distribution until a large demand for hydrogen has developed. Once a large hydrogen demand is in place, pipeline distribution may become competitive.

* Initially, demand for hydrogen energy would probably be met by onsite production from natural gas. Once a large demand was present, CO_2 sequestration could be considered. When CO_2 sequestration was implented, a switch to centralized production with local hydrogen distribution would also take place.

* In the near term, large scale industrial production of hydrogen via steam methane reforming (e.g. in oil refineries or chemical plants) might produce enough byproduct CO_2, for CO_2 sequestration to be considered, if a sequestration site is near enough.

Data Sources

Data on CO_2 separation operations during hydrogen production were obtained via discussions with hydrogen producers and industrial gas companies.

Data on various aspects of CO_2 sequestration were also gathered at the USDOE workshop on Fuels Decarbonization and Carbon Sequestration held in Washington DC in July 1997.

Data on hydrogen pipeline systems were available from our earlier studies for the hydrogen program. Data on CO2 pipelines were obtained from the literature and from discussions with researchers at Argonne National Laboratory.

Methods Of Analysis

Engineering models of hydrogen production, CO_2 separation, hydrogen and CO_2 pipeline transmission and hydrogen refueling station equipment are being developed.

The levelized cost of hydrogen production, delivered hydrogen cost and lifecycle costs of transportation are estimated using standard microeconomic techniques.

Interaction With Other Groups/Technology Transfer

We have interacted with other researchers at MIT, Argonne National Laboratory, Air Products and Chemicals, and Mobil and benefitted from discussions with analysts at the USDOE, Directed Technologies Inc. and Energetics.

Plans for Future Work (beyond September 1998)

Assessment Of Hydrogen-Fueled Proton Exchange Membrane Fuel Cells For Distributed Generation And Cogeneration

Motivation And Background

Proton exchange membrane fuel cells (PEMFCs) are highly efficient power generators, achieving up to 50-60% conversion efficiency, even at very small sizes (down to the household level -- 3-5 kW). PEMFCs have zero pollutant emissions when fueled directly with hydrogen, and near zero emissions when coupled to reformers. These attributes make them potentially attractive for a variety of applications including electric vehicles and distributed generation and cogeneration of heat and power in buildings.

Over the past few years, there have been intense efforts worldwide to develop low-cost PEMFC systems. While the the primary focus has been on vehicle applications, an equally important application may be combined heat and power generation in commercial and residential buildings. The development of inexpensive PEMFC power systems for automotive applications may have powerful implications for the parallel development of analogous systems for residential-scale generation of distributed electric power and heat.

There are several reasons why PEMFCs might become competitive for buildings applications before they appear in vehicles:

1) The cost barrier is lower for PEMFC cogeneration systems than for automotive applications. To compete with internal combustion engines in automobiles, PEMFCs must achieve stringent cost goals of perhaps $50/kW. Recent studies indicate that significant cogeneration markets in commercial buildings could open for PEMFC stack costs of perhaps $300-500/kW (corresponding to complete system costs of $1000-1500/kW) (Arthur D. Little 1995). Residential markets might open at stack costs of $200-400/kW (O'Sullivan 1998).

2) The technical challenges are in many respects less severe for stationary power generation than for vehicles. (Start-up behavior and transient operation is likely to be less of a problem for power generation than for vehicles which are characterized by rapidly varying loads; heat and water management issues should be much easier; weight and volume constraints are less stringent; peak power devices will not be needed; control systems should be simpler; robustness and resistance to mechanical shocks during driving will not be an issue.) In one respect, technical requirements are more demanding for cogeneration applications: a longer operating lifetime (50,000-100,000 hours) would be needed for a stationary power system as compared to perhaps 5000 hours for vehicles.

Recently several initiatives have been launched to develop cogeneration systems based on PEM fuel cells. In 1997, GPU International (an international energy company) and Ballard Power Systems (a world leader in fuel cells) established a new company, Ballard

Generation Systems, to commercialize proton exchange membrane fuel cells for stationary power applications. Ballard's initial focus is on systems in the 250 kW range, a size appropriate for commercial buildings, where the economics of cogeneration can be favorable because of high electricity charges and significant heat loads.

If PEMFCs reach the cost goals set by the PNGV program for automotive fuel cells of $50/kW (PNGV 1997), it is likely that they would become competitive not only in commercial building markets, but for residential heat and power production, as well. In the past year two other companies, Plug Power (Chen 1998) and American Power in collaboration with EPRI (EPRI 1997) have begun development of small scale (e.g. 3-5 kWe) natural gas fueled PEM cogeneration systems, a size suitable for residential applications.

Much of the published work on residential scale PEMFC cogeneration systems has reported progress in building working prototypes which couple small scale methane reformers to PEM fuel cells (Ernst 1997, EPRI 1997). Relatively little analytical work has been done to identify promising PEMFC system configurations for residential cogeneration applications.

The potential role of hydrogen-fueled PEMFCs in future residential cogeneration markets has not been examined. As with vehicle applications, there is likely to be a trade-off between the fuel cell's superior efficiency, better performance, lower system cost and zero emissions on pure hydrogen, versus the convenience of using an existing fuel infrastructure (e.g. using a natural gas reformer close coupled to the fuel cell to provide hydrogen). As with vehicles, it is interesting to ask where the hydrogen should be made for PEMFC residential heat and power production (at the city, neighborhood, or household level).

Proposed Work:

Researchers at Princeton Center for Energy and Environmental Studies will carry out a series of detailed technical and economic assessments with the goal of understanding the prospects for hydrogen fueled PEM fuel cell cogeneration technology for residential applications. We concentrate on hydrogen derived from natural gas, a primary energy source which is widely available today, and is likely to give the lowest hydrogen cost in the near term.

We compare three types of PEM fuel cell cogeneration systems which could provide heat and power to residential users (see Figure 25).

Case 1) a centralized "neighborhood" scale (200-1000 kW) natural gas reformer/PEM fuel cell system which distributes heat (via district heating) and electricity (via wire) to 40-200 residential users. .

Case 2) a centralized "neighborhood" scale natural gas reformer, which produces hydrogen or a hydrogen rich gas for distribution to users. Each house has a small hydrogen fueled (5 kWe) PEM fuel cell providing electricity and heat.

Case 3) individual natural gas reformers coupled to 5 kW PEM fuel cells at each house.

For each case energy storage (in the form of hydrogen storage, hot water storage or electric batteries) could be used to meet time varying energy demands. Connections to the electric utility system could be made at the household or neighborhood level, allowing dispatch of power.

In the proposed work, engineering and economic models of PEM fuel cell based cogeneration systems will be developed. The potential advantages and disadvantages of each configuration will be investigated in terms of overall energy efficiency, performance, economics (capital cost, delivered cost of electricity and heat), and greenhouse gas emissions. PEMFC cogeneration systems will be compared to other alternatives for production of residential heat and power.

Several tasks are proposed:

Task 1. Develop engineering models of various types of PEM fuel cell cogeneration systems capable of supplying residential heat and power (see Cases 1-3 above). Our existing data base on performance and cost of system components such as PEMFC stacks, small natural gas reformers and power electronics will be updated and extended to include small systems (3-5 kW). Where appropriate engineering models of components such as fuel cell stacks and reformers will be developed, drawing on related work we have done as part of our PEMFC vehicle modeling research. Heat-integrated PEMFC cogeneration system models will be developed using ASPEN software to model steady state performance.

Task 2 Develop component sizing algorithms for various types of PEMFC cogeneration systems, based on the demand profile, energy prices and component performance. We will use typical US residential building heat and electricity demands, and a range of energy prices. Several questions will be addressed. How well can each system match building (or neighborhood) energy demands? How does the level of demand aggregation (neighborhood vs. single house) effect the sizing of the equipment and the need for energy storage? What are the most desirable utility connection strategies?

Task 3 Investigate design trade-offs. What type of reformer technology is prefered? How do scale economies in reformer technologies, energy storage and power conditioning equipment effect the economics of combined heat and power generation? What are the effects of fuel cell operating pressure and temperature on the system design? What are the heat integration opportunities on each system's performance and cost? (For example, in cases 1 and 3 the fuel cell anode exhaust can be utilized to provide heat for the steam reforming reaction to produce hydrogen more efficiently, in case 2, it can be used for extra heating.)

Task 4. Discuss the costs and trade-offs involved in distributing different forms of energy to houses (case 1: electricity and hot water, case 2: hydrogen rich gas, case 3: natural gas).

Task 5. Estimate the cost of electricity and heat from PEM fuel cells, as compared to other technologies available for cogeneration and distributed generation.

Task 6. Estimate the potential greenhouse gas emissions reductions possible with residential PEMFC fuel cells as compared to competing technologies.

Task 7. Discuss the role of distributed benefits and emissions benefits in the economic competitiveness of fuel cells. Discuss the required component cost and performance goals for small scale PEMFC cogeneration systems to compete economically with alternatives. (This task will be performed in coordination with researchers at Distributed Utilities Associates.)

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Figures

Figure 23,24 . Cost of long distance pipeline transmission for natural gas and hydrogen vs. energy flow rate and pipeline length.

Figure 25. Possible configurations for PEM fuel cell cogeneration in buildings

Figure 1: Possible Fuel Cell Vehicle Configurations

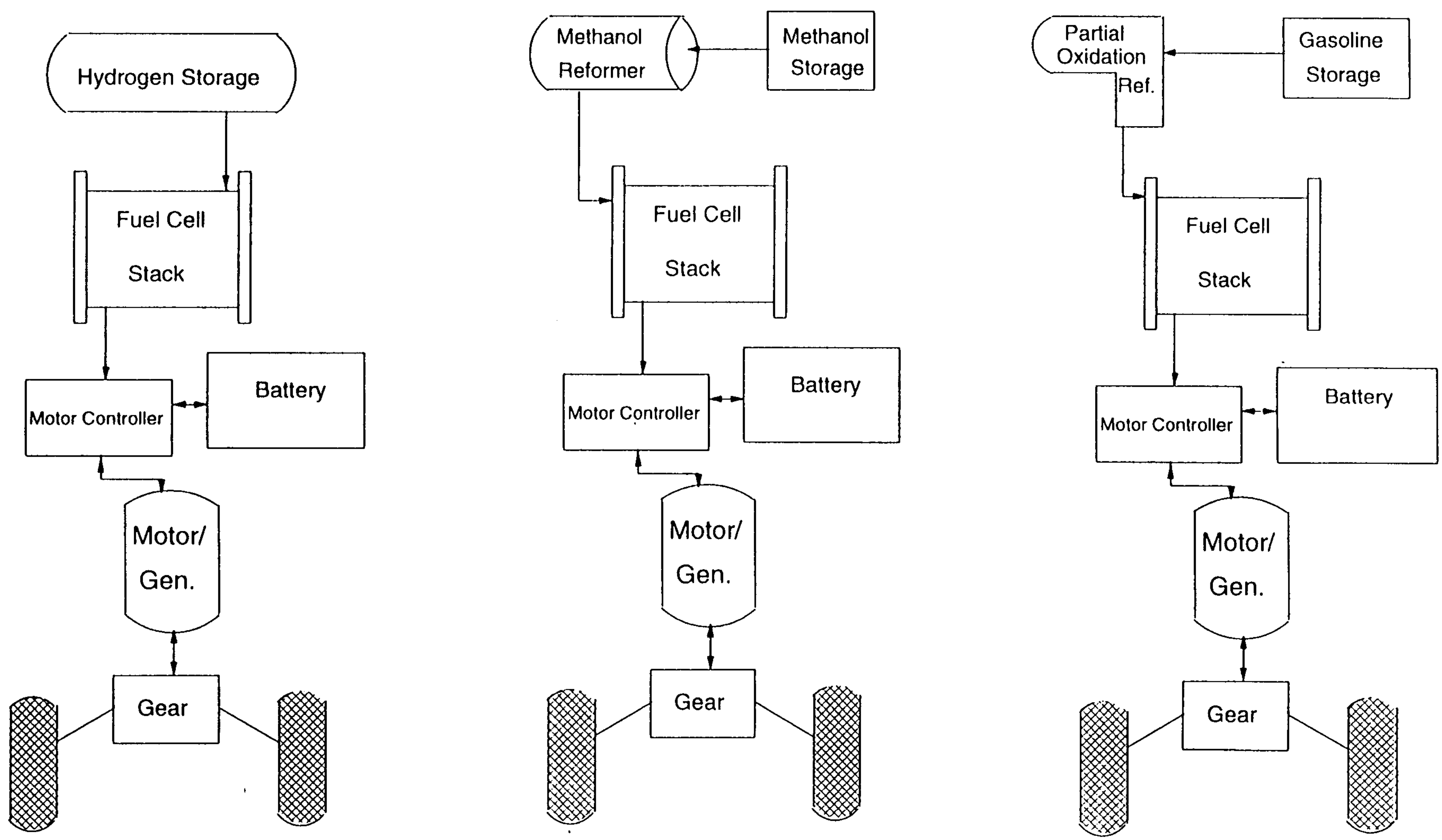


Figure 2. Contributions to Vehicle Weight

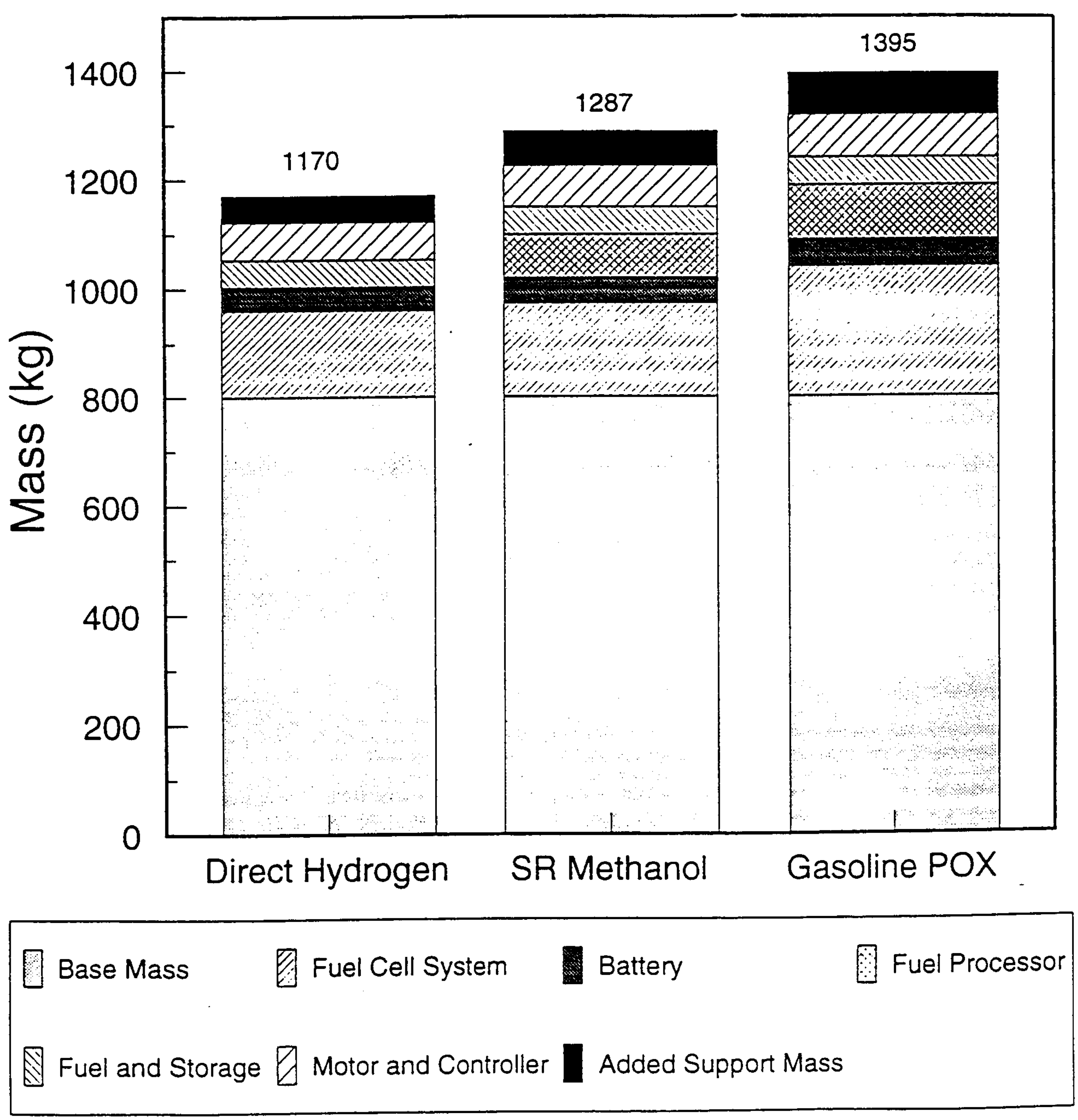
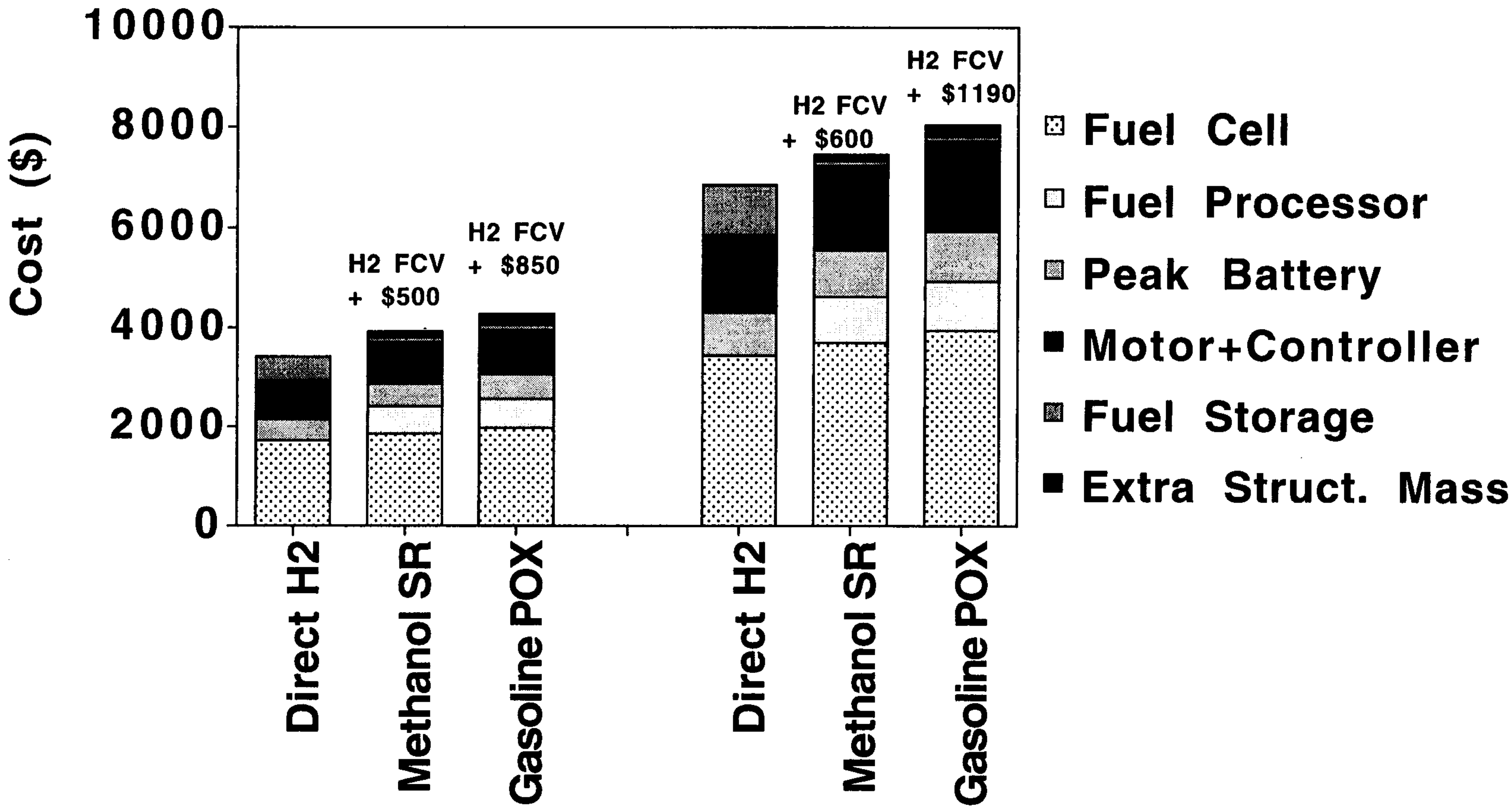


Figure 3. Capital Cost of Fuel Cell Vehicle Drive Train and Fuel Storage Components ($)



Fuel Cell = $50/kW	Fuel Cell = $100/kW
Fuel Processor=$15/kW	Fuel Processor = $25/kW
Peak Battery = $10/kW	Peak Battery = $20/kW
H2 Cylinder = $500	H2 Cylinder = $1000
Motor+Controller=$13/kW	Motor+Controller=$26/kW

Gasoline or Methanol Tank = $100
Extra Structural Mass = $1/kg

Figure 4. Near Term Gaseous H2 Supply Options

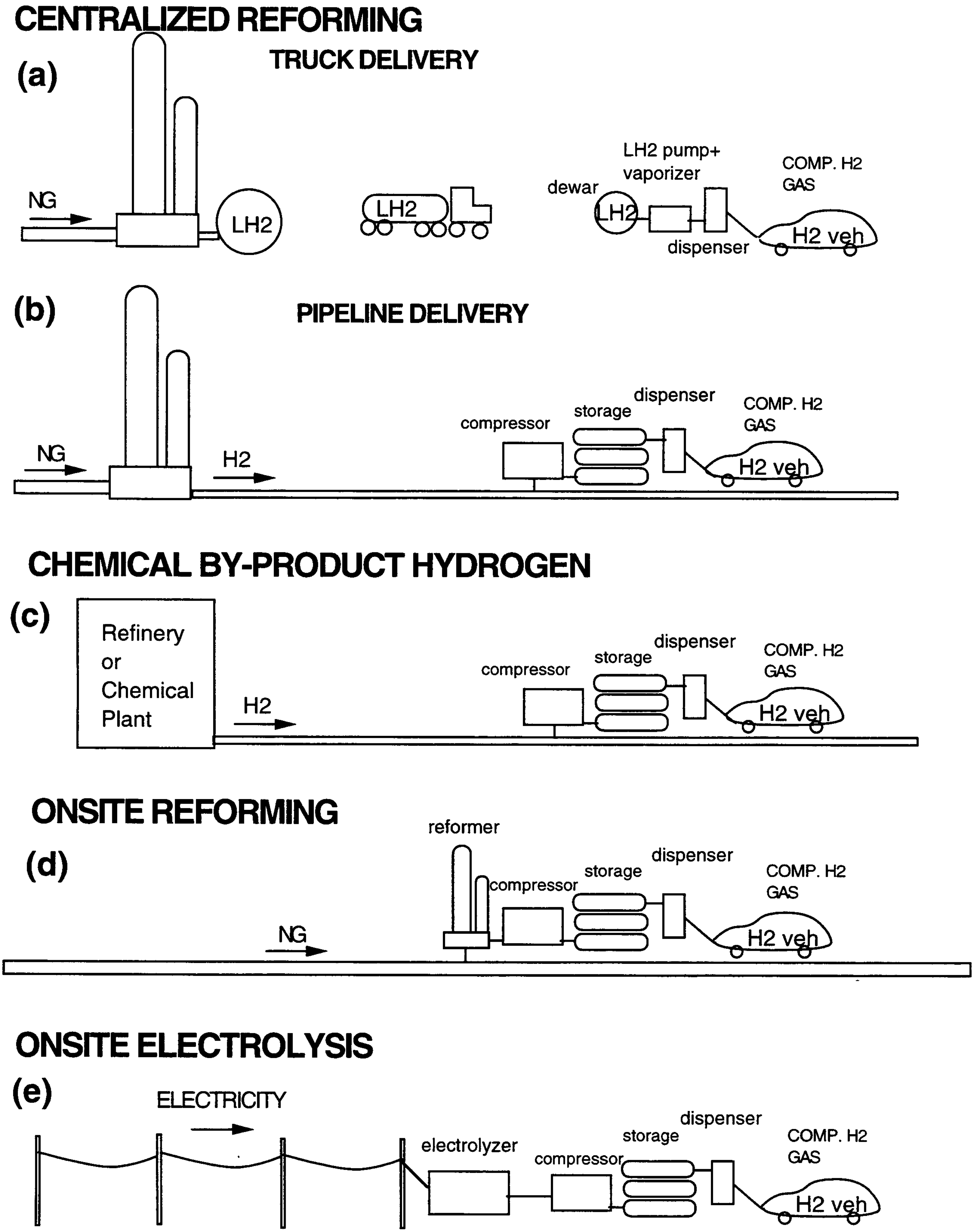
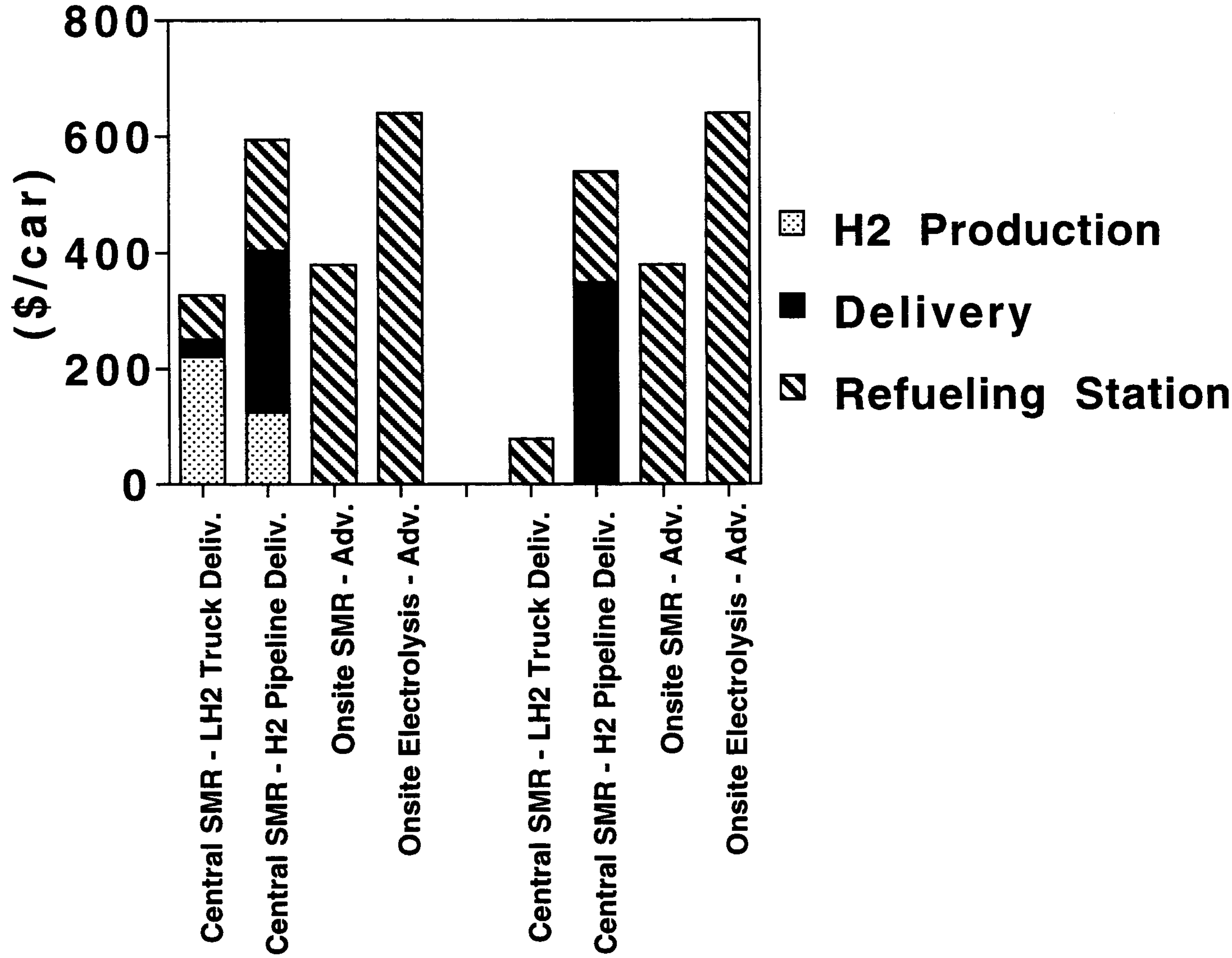


Figure 5. Capital Cost of H2 Refueling Infrastructure ($/car)



For a refueling system serving a fleet of 1.36 million H2 FCVs. Centralized options have new H2 production capacity

For a refueling system serving a fleet of 17,800 H2 FCV cars. Centralized options use existing H2 production capacity

Figure 6. Delivered Cost of Hydrogen Transportation Fuel ($/GJ)

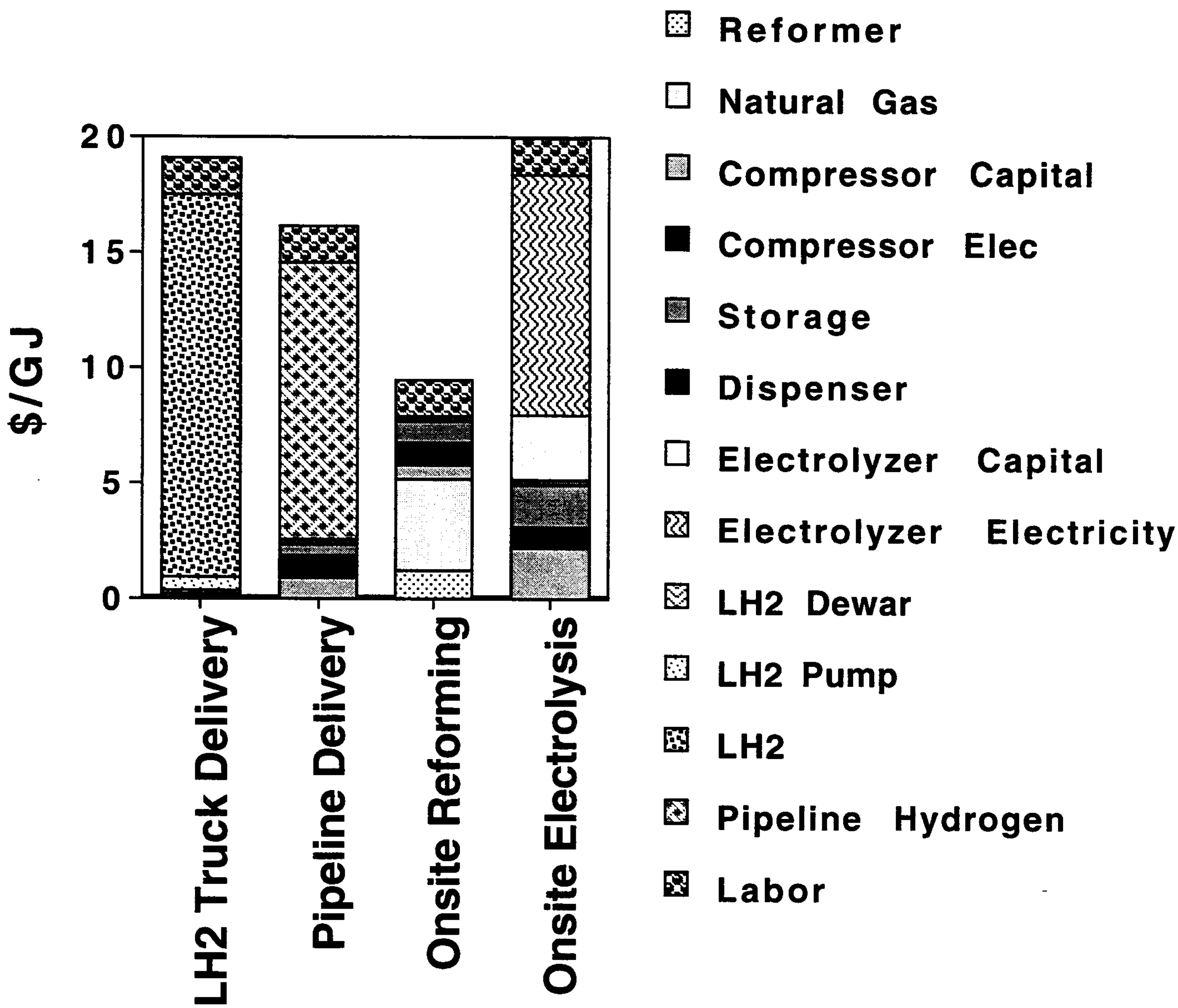
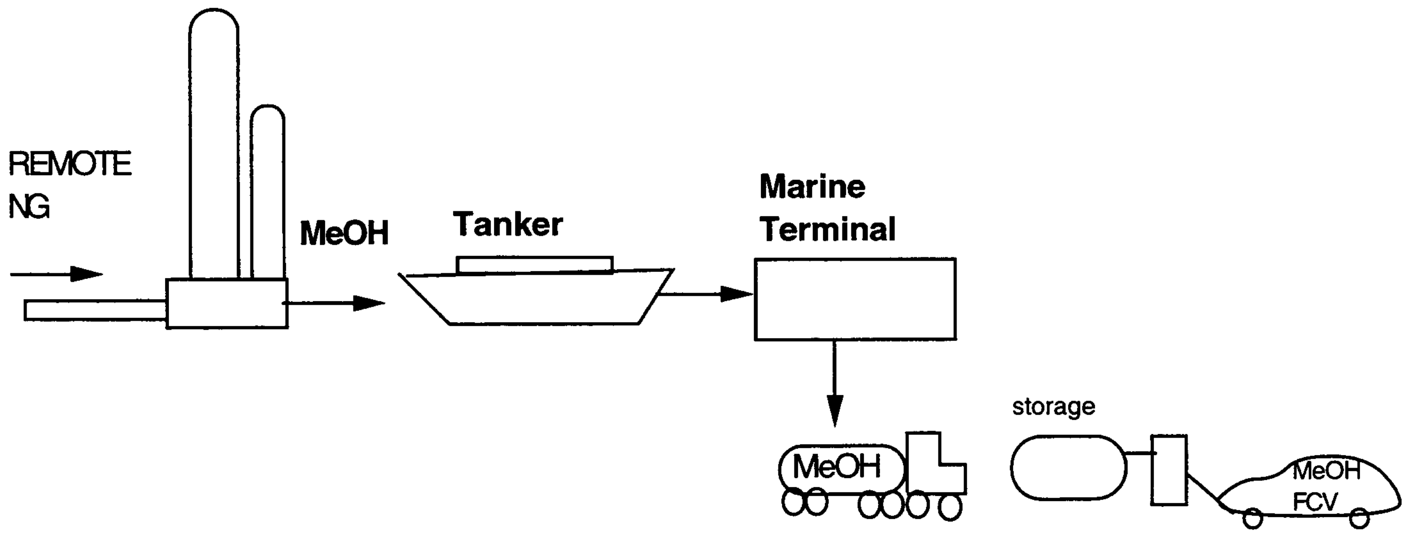


Figure 7. Methanol Supply Options

NATURAL GAS -> METHANOL



BIOMASS, COAL OR MSW -> METHANOL

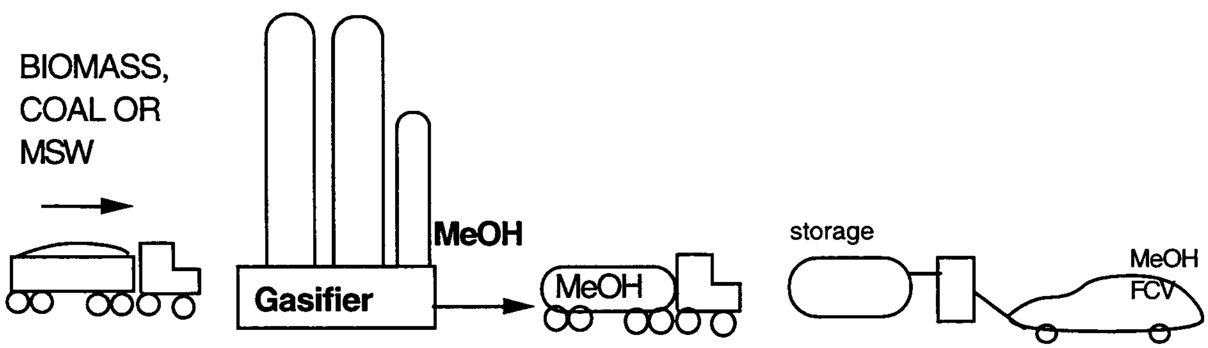


Figure 8. Capital Cost of Methanol Fuel Cell Vehicle Refueling Infrastructure ($/car)

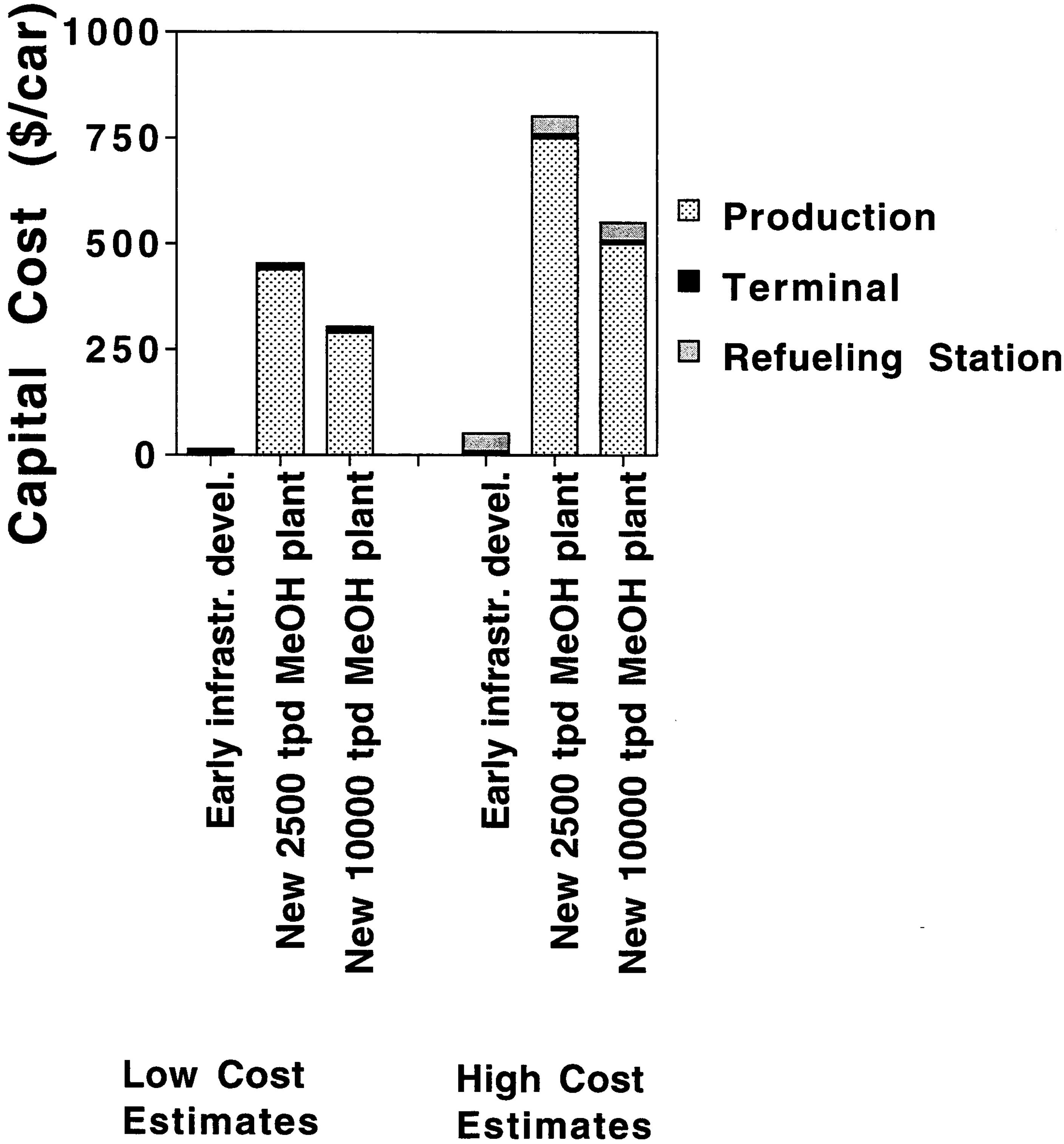
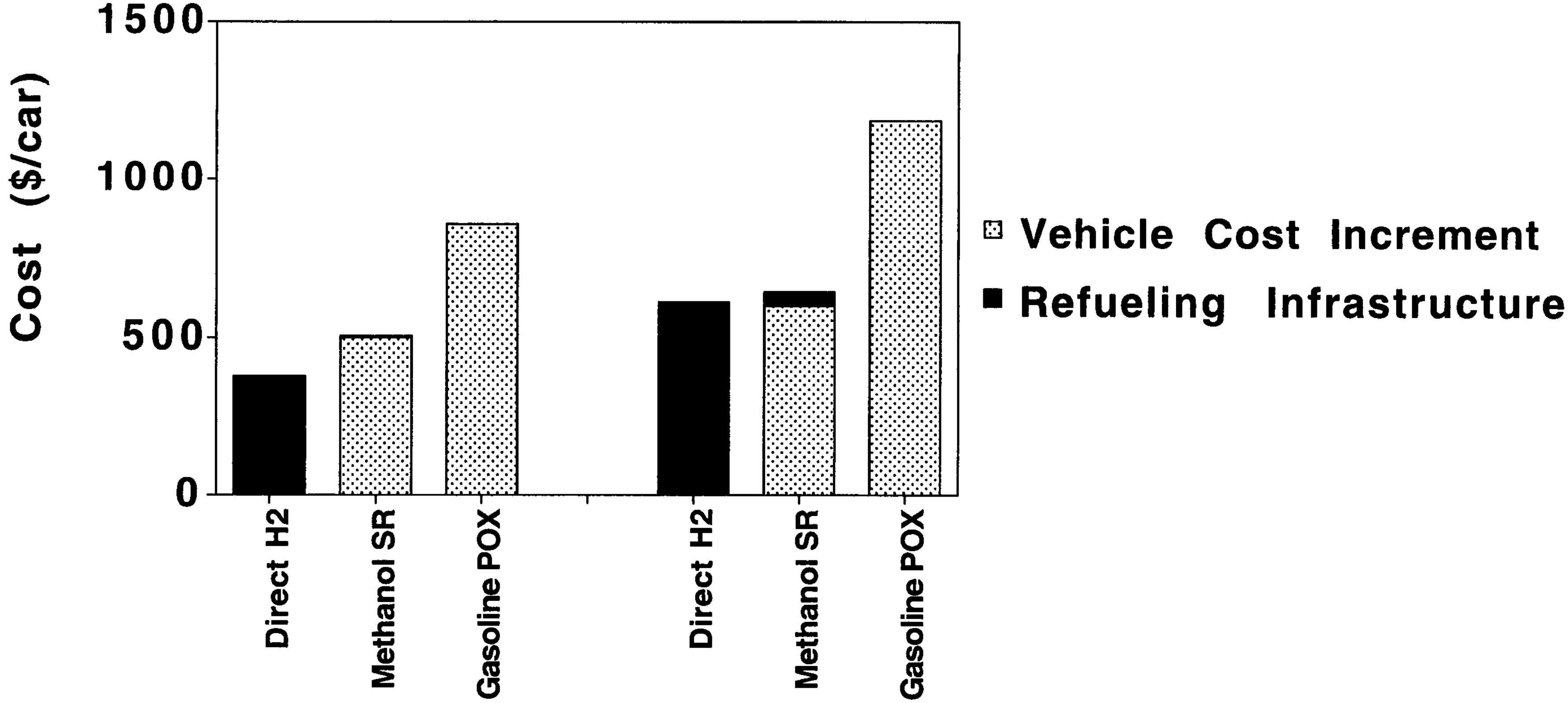


Figure 9. Comparison of Incremental Costs for Vehicles (Compared to H2 Fuel Cell Vehicle) and Refueling Infrastructure (Compared to Gasoline) ($/car)



Fuel Cell = $50/kW	Fuel Cell = $100/kW
Fuel Processor = $15/kW	Fuel Processor = $25/kW
Peak Battery = $10/kW	Peak Battery = $20/kW
H2 Cylinder = $500	H2 Cylinder = $1000
Motor+Controller=$13/kW	Motor+Controller=$26/kW
H2 Infrastructure = $380/car	H2 Infrastructure= $610/car
MeOH Infrastructure=$5/car	MeOH Infrastructure=$42/car

Gasoline or Methanol Tank = $100
Extra Structural Mass = $1/kg

Figure 10. Delivered Cost of Transporation Fuels ($/GJ)

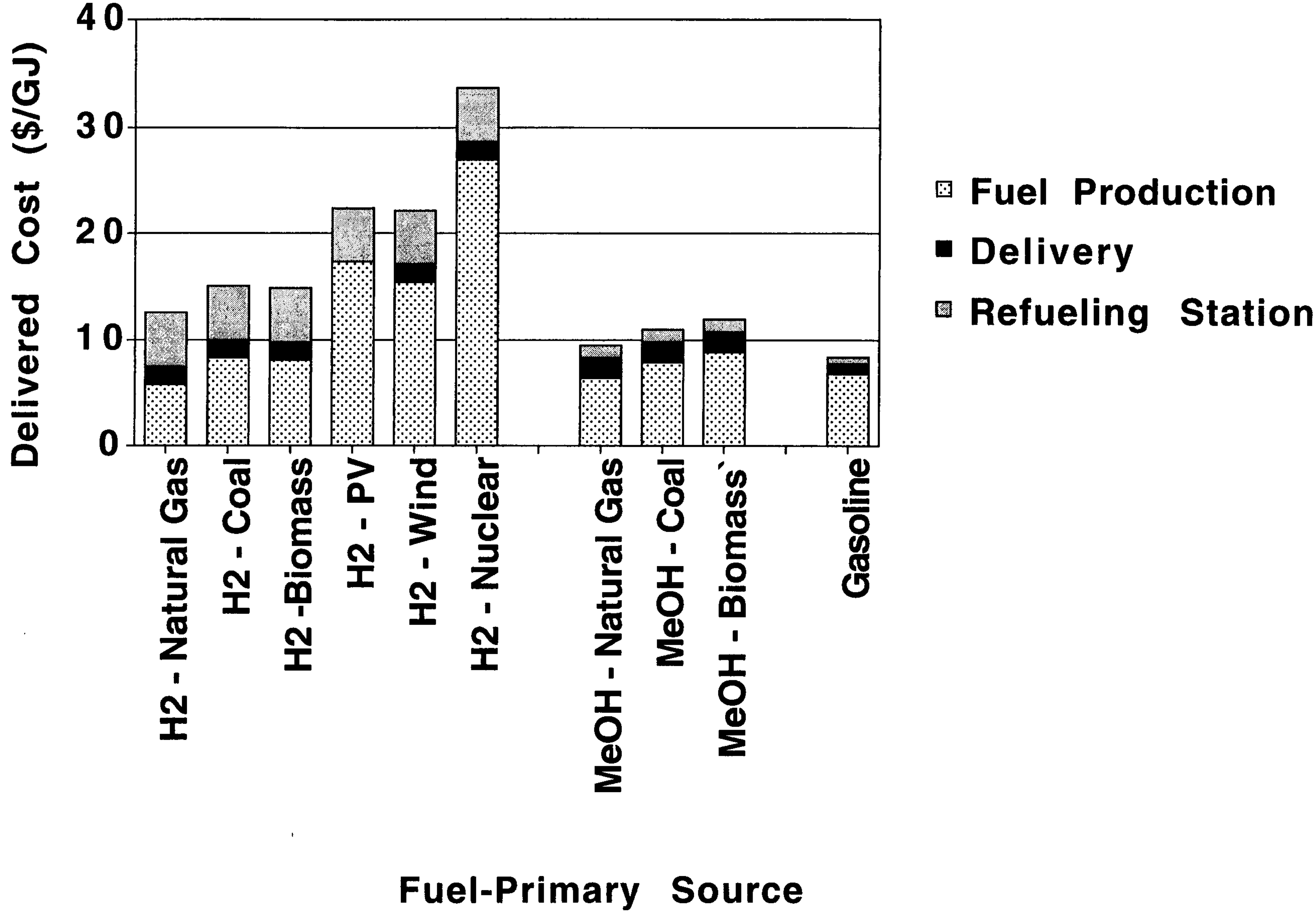


Figure 11. Fuel Cost Contribution to Fuel Cell Vehicle Lifecycle Cost ($/km)

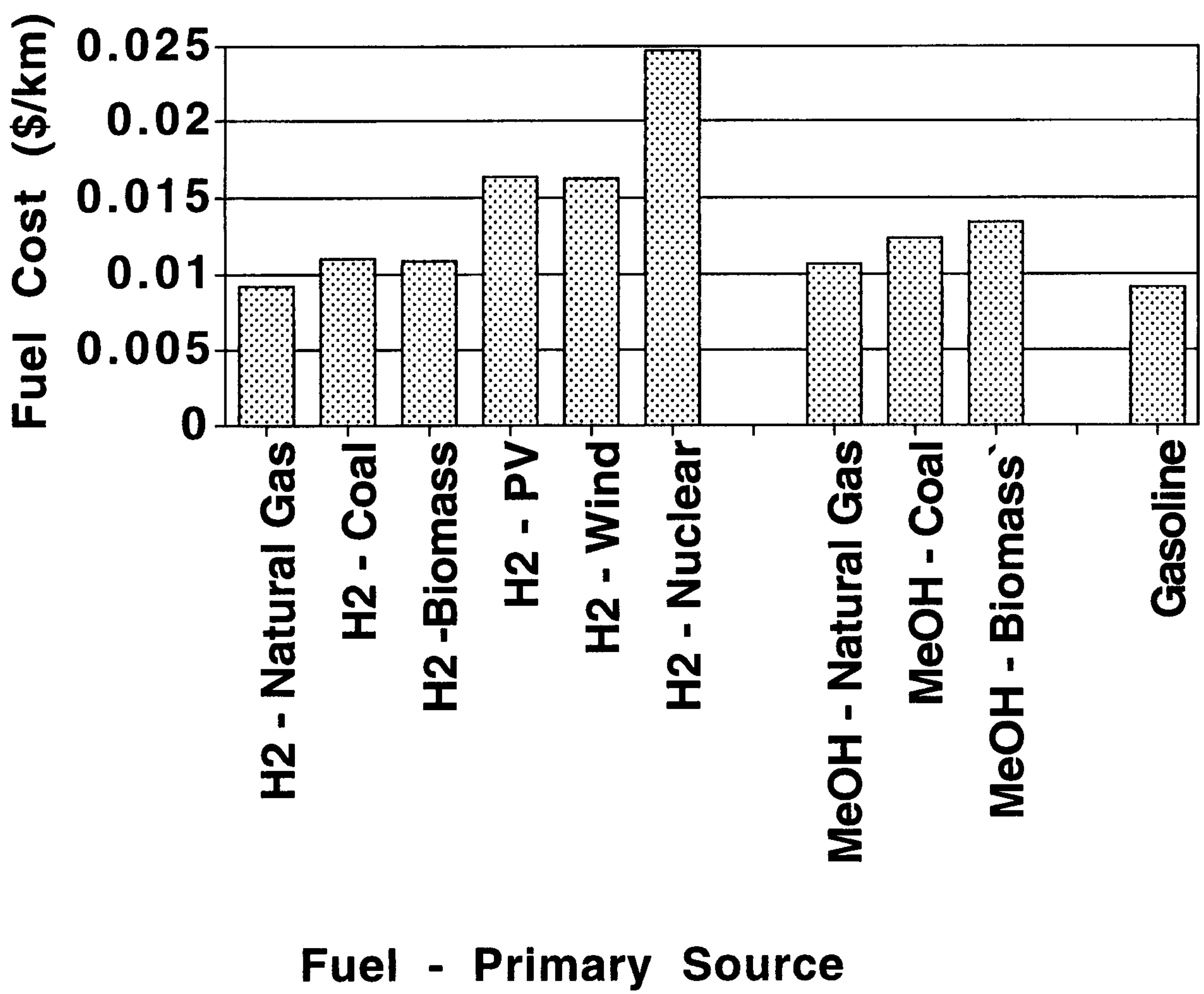


Figure 12. Lifecycle Cost of Transportation for Alternative Fuel Cell Vehicles and Primary Fuel Sources

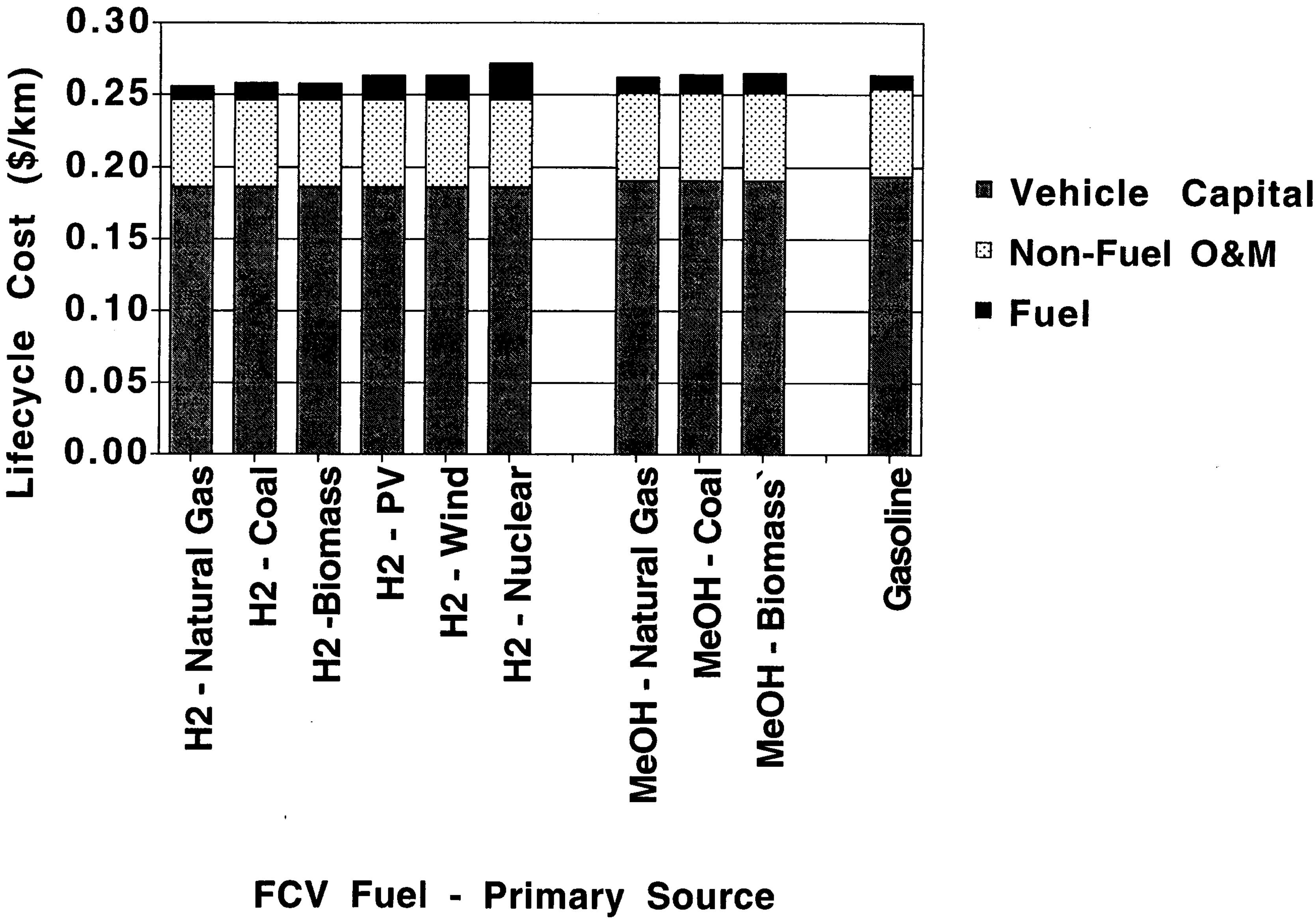


Figure 13. Potential Near Term Hydrogen Supplies and Demands in New Jersey

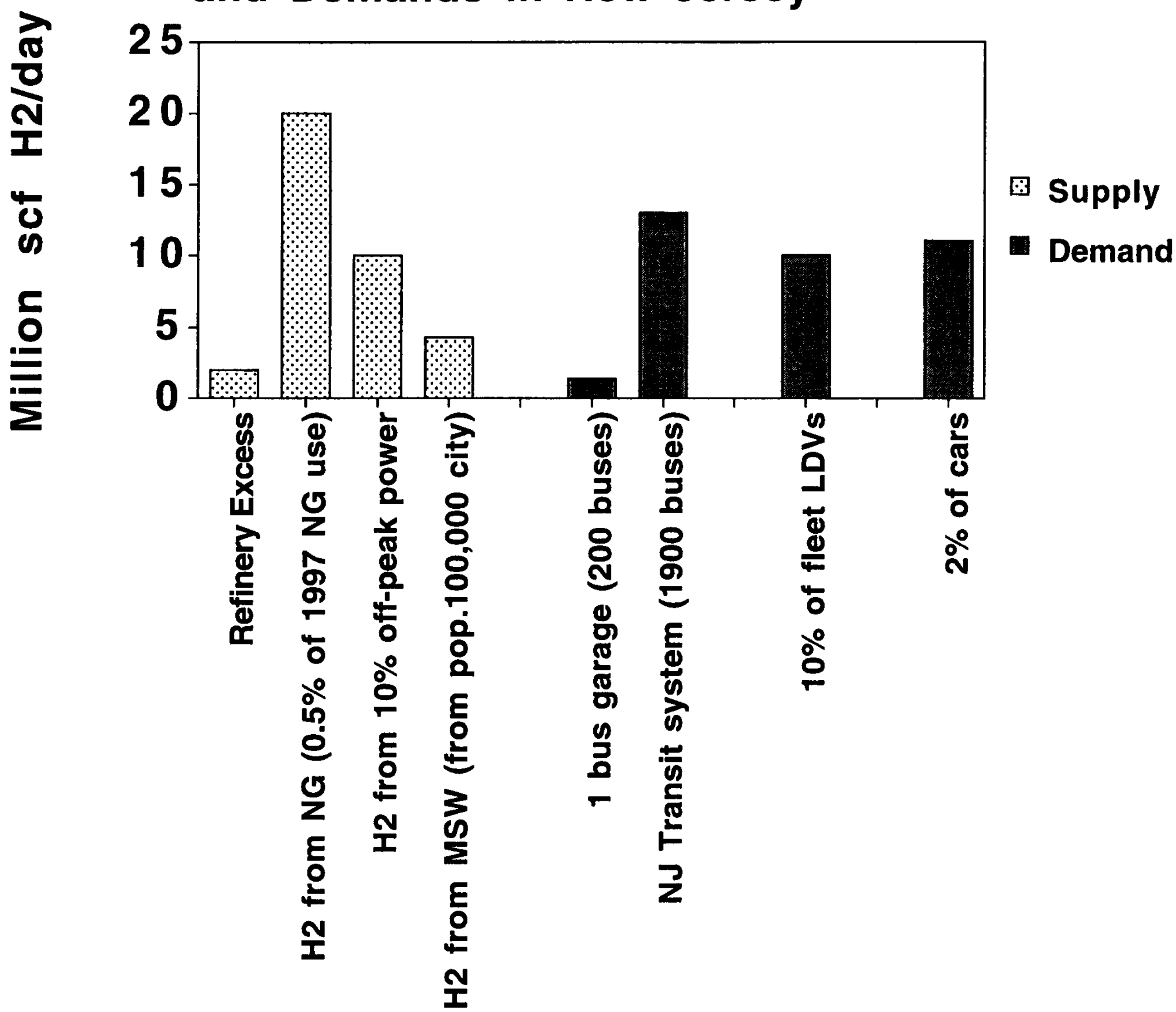


Figure 14. Potential Long Term Hydrogen Supplies and Demands in New Jersey

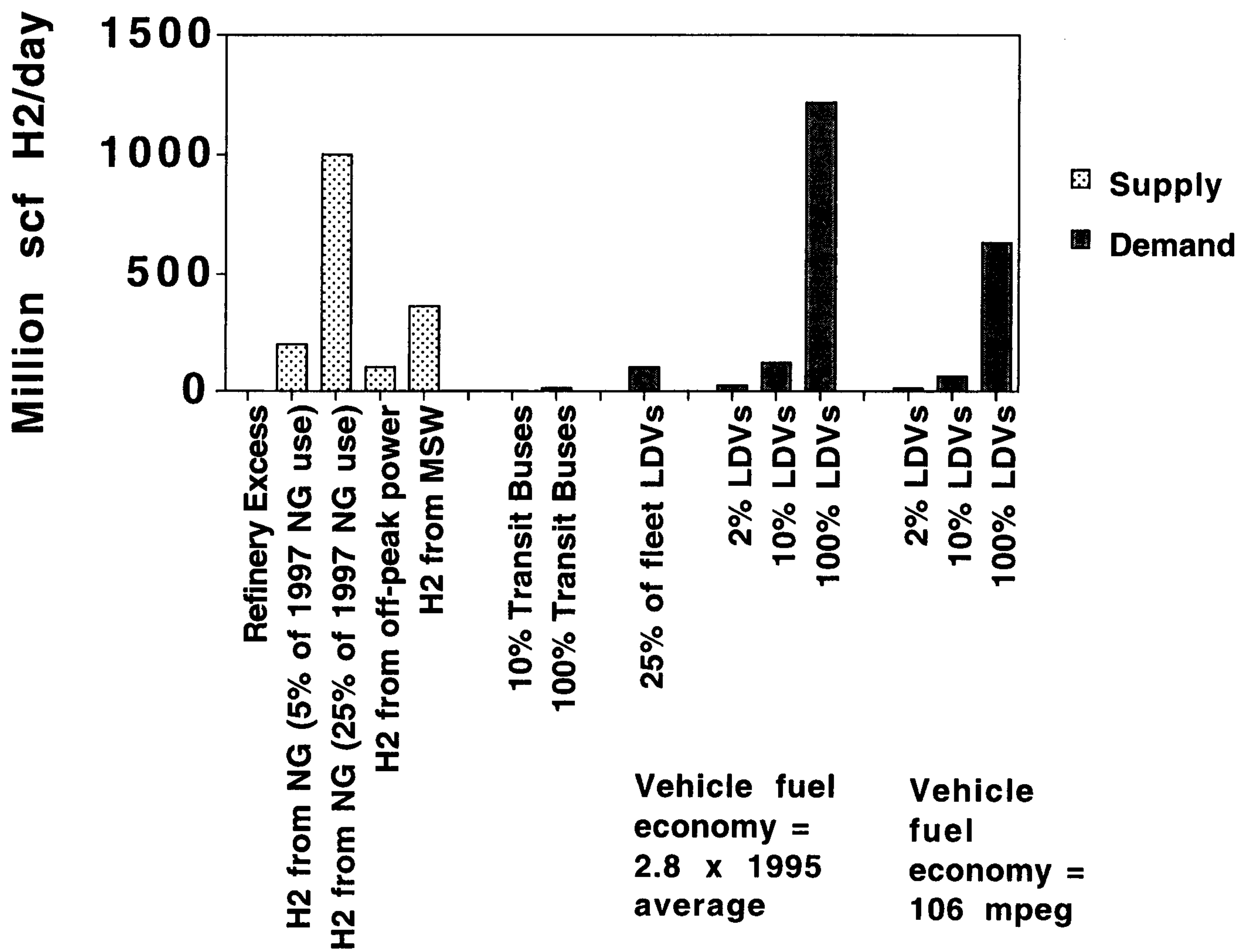


Figure. 15. Hydrogen Production from Hydrocarbons w/CO2 Sequestration

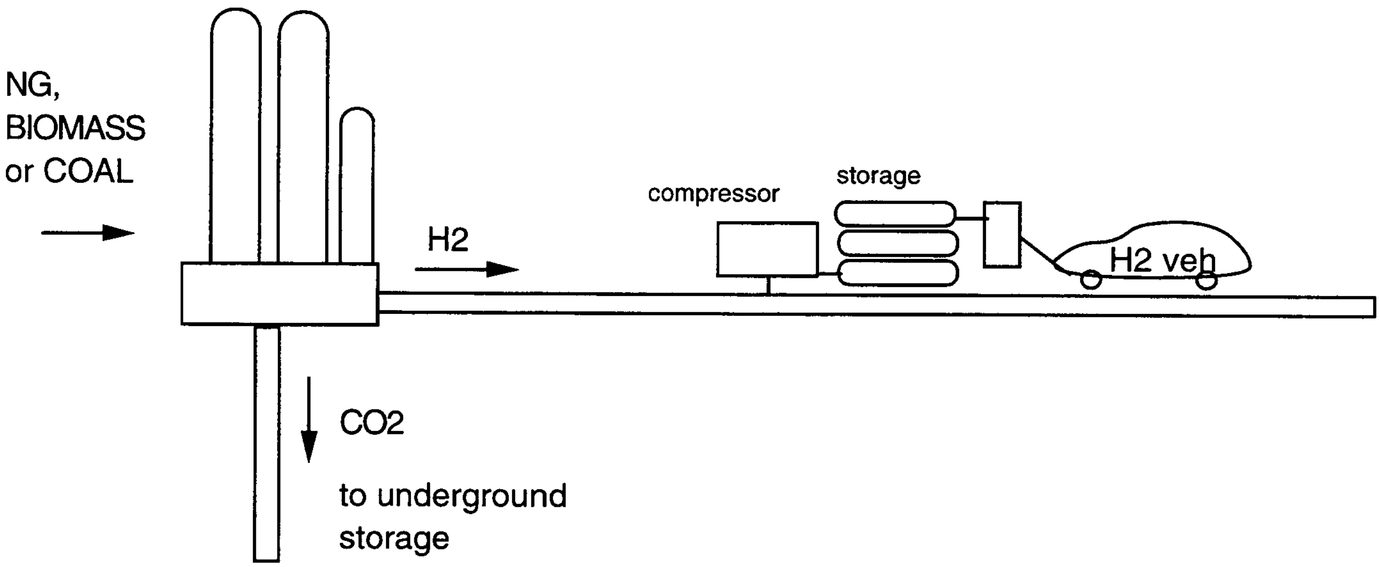


Figure 16. Example: H2 from Natural Gas

QUESTIONS:
Where do you make hydrogen?

When does it make sense to sequester CO2?

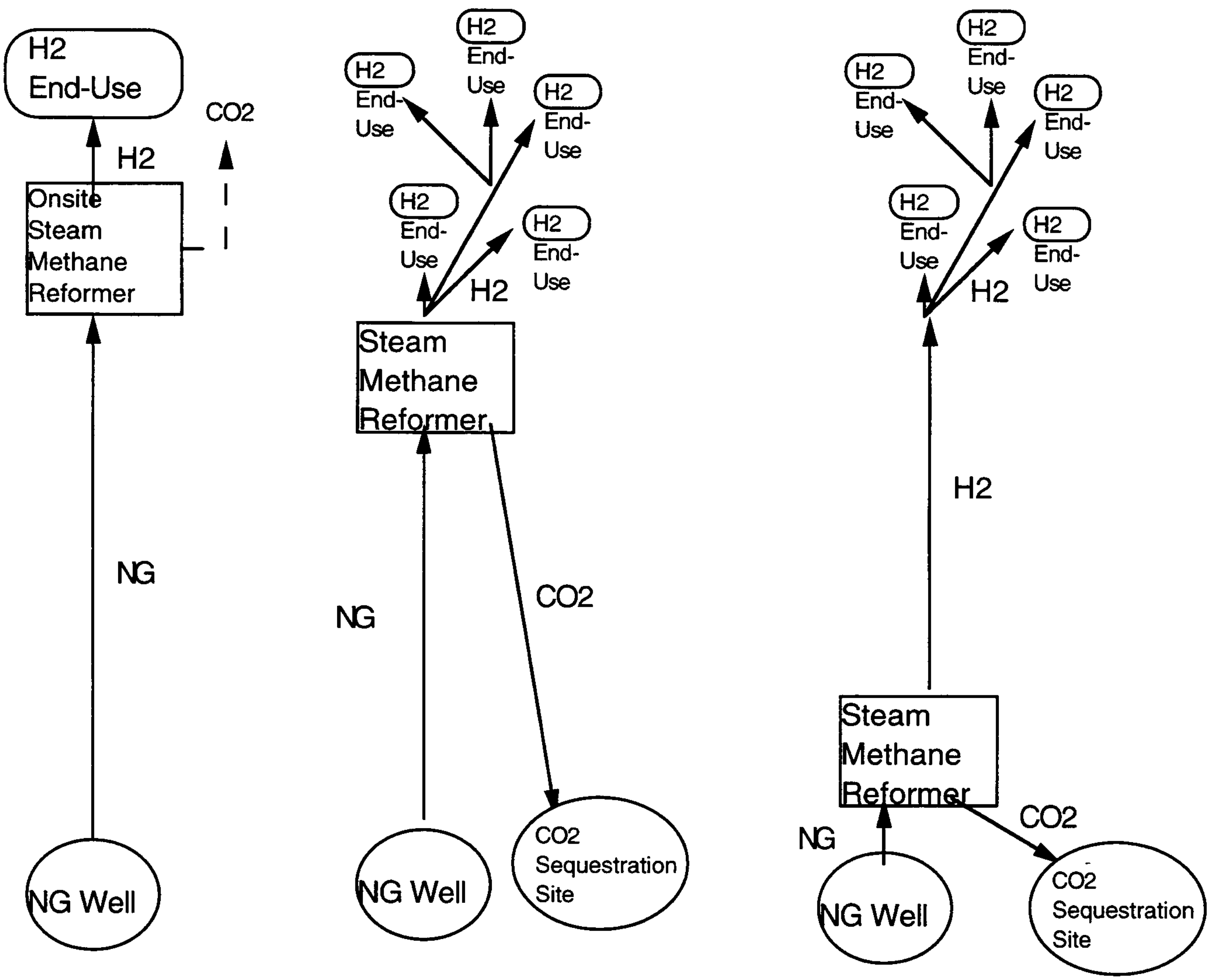
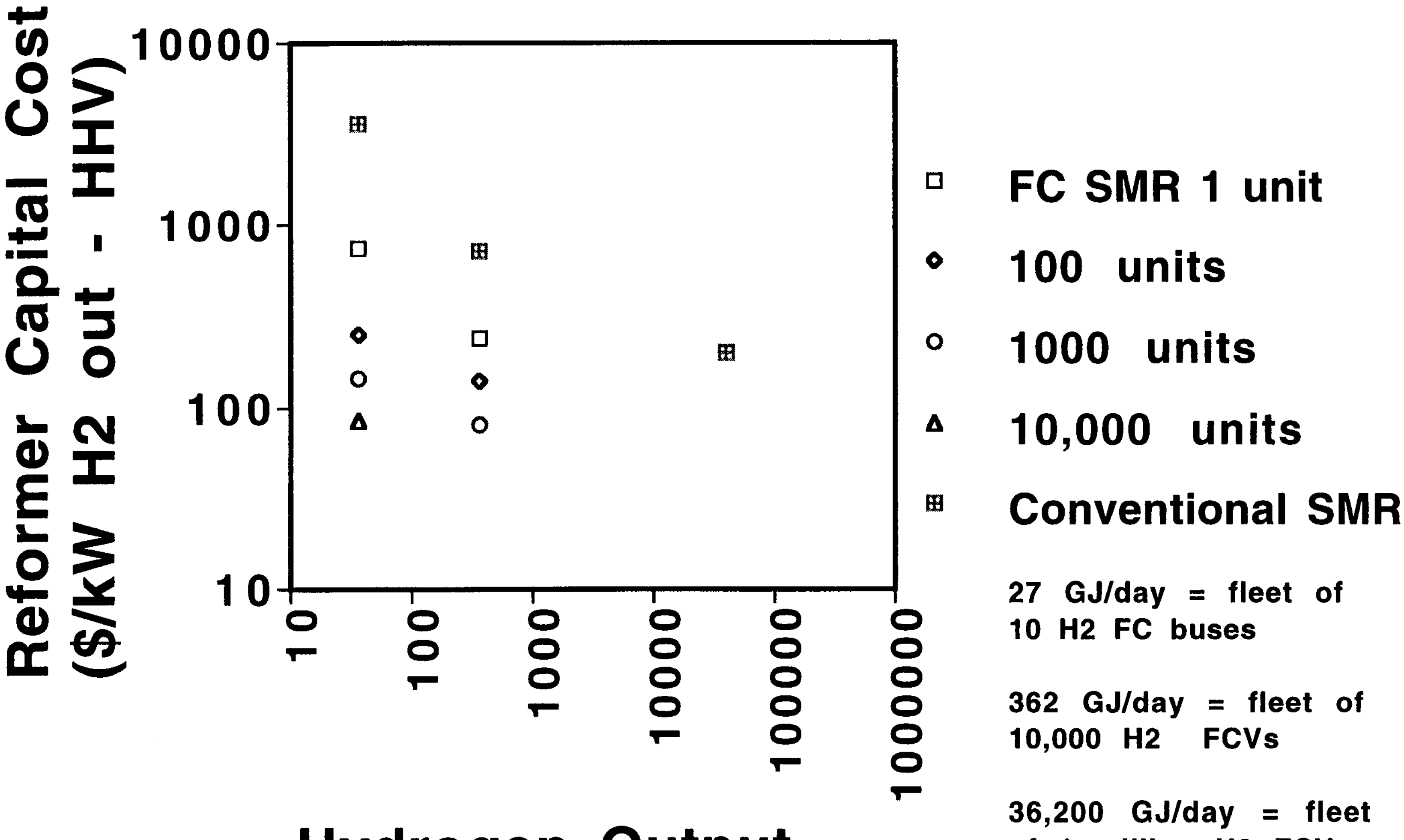


Figure 17. Capital Cost of Steam Methane Reformers vs. H2 Output Capacity



27 GJ/day = fleet of 10 H2 FC buses

362 GJ/day = fleet of 10,000 H2 FCVs

36,200 GJ/day = fleet of 1 million H2 FCVs = 10% of vehicles in LA Basin

Figure 18. Hydrogen Production Cost in Small vs. Large Steam Methane Reformers ($/GJ)

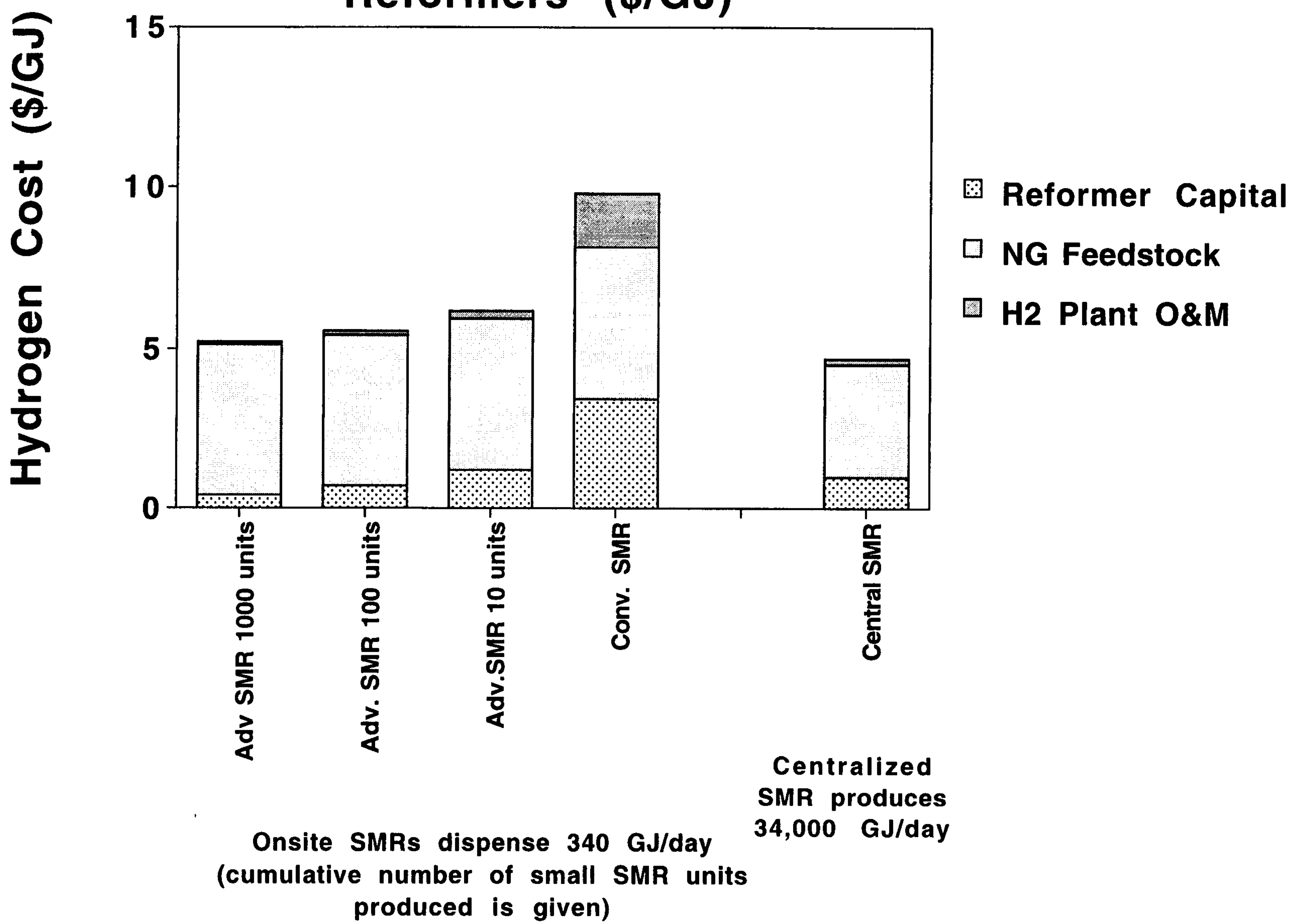
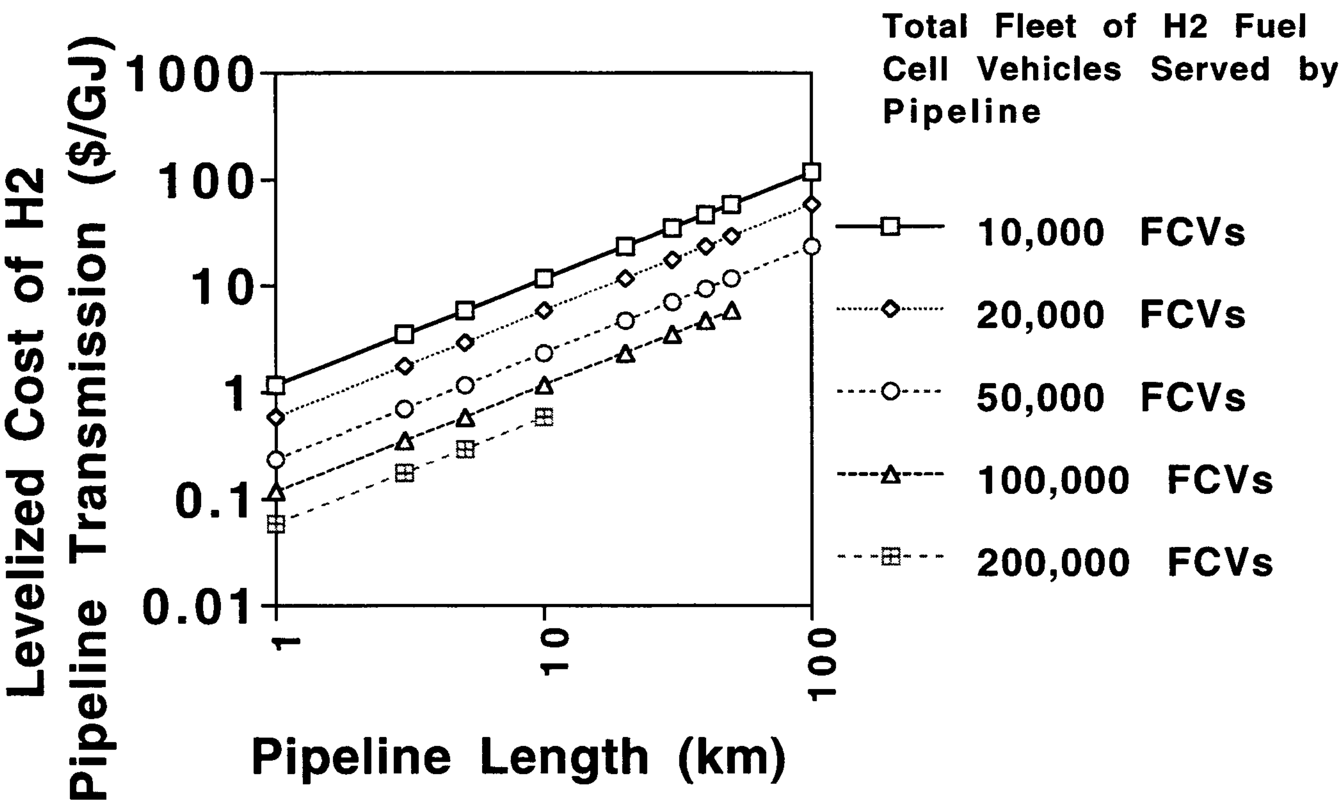


Figure 19. Cost of Hydrogen Pipeline Transmission vs. Pipeline Length and Vehicles Served



3" Hydrogen Pipeline Rated up to 1000 psi

Pipeline cost = $1 million/mile

Inlet Pressure = 1000 psia
Outlet Pressure > 200 psia

Figure 20. Delivered Cost of Hydrogen Transportation Fuel: Onsite vs. Centralized Production in SMRs

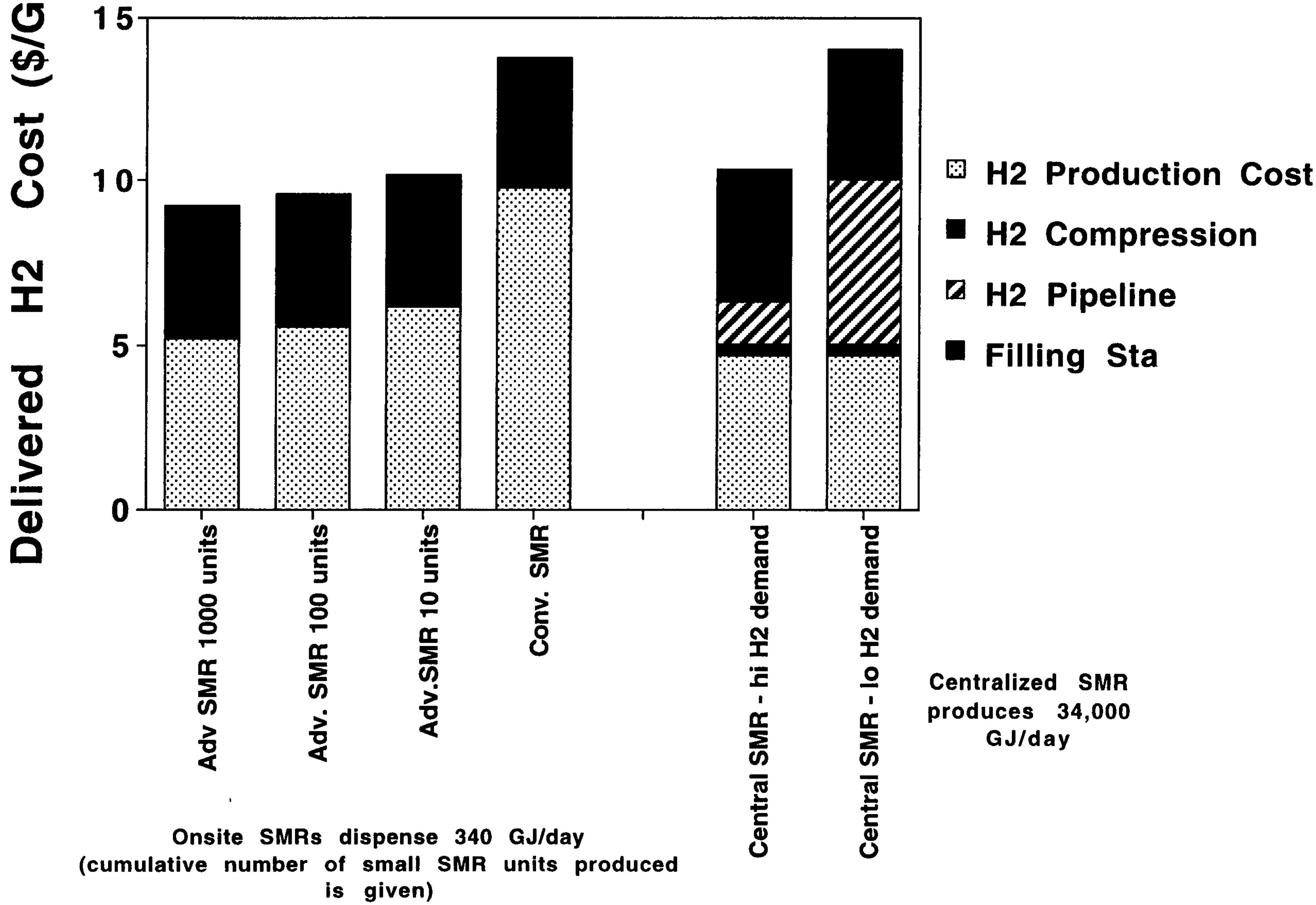


Figure 21. Delivered H2 Cost with CO2 Separation and Collection Central vs. Onsite SMR

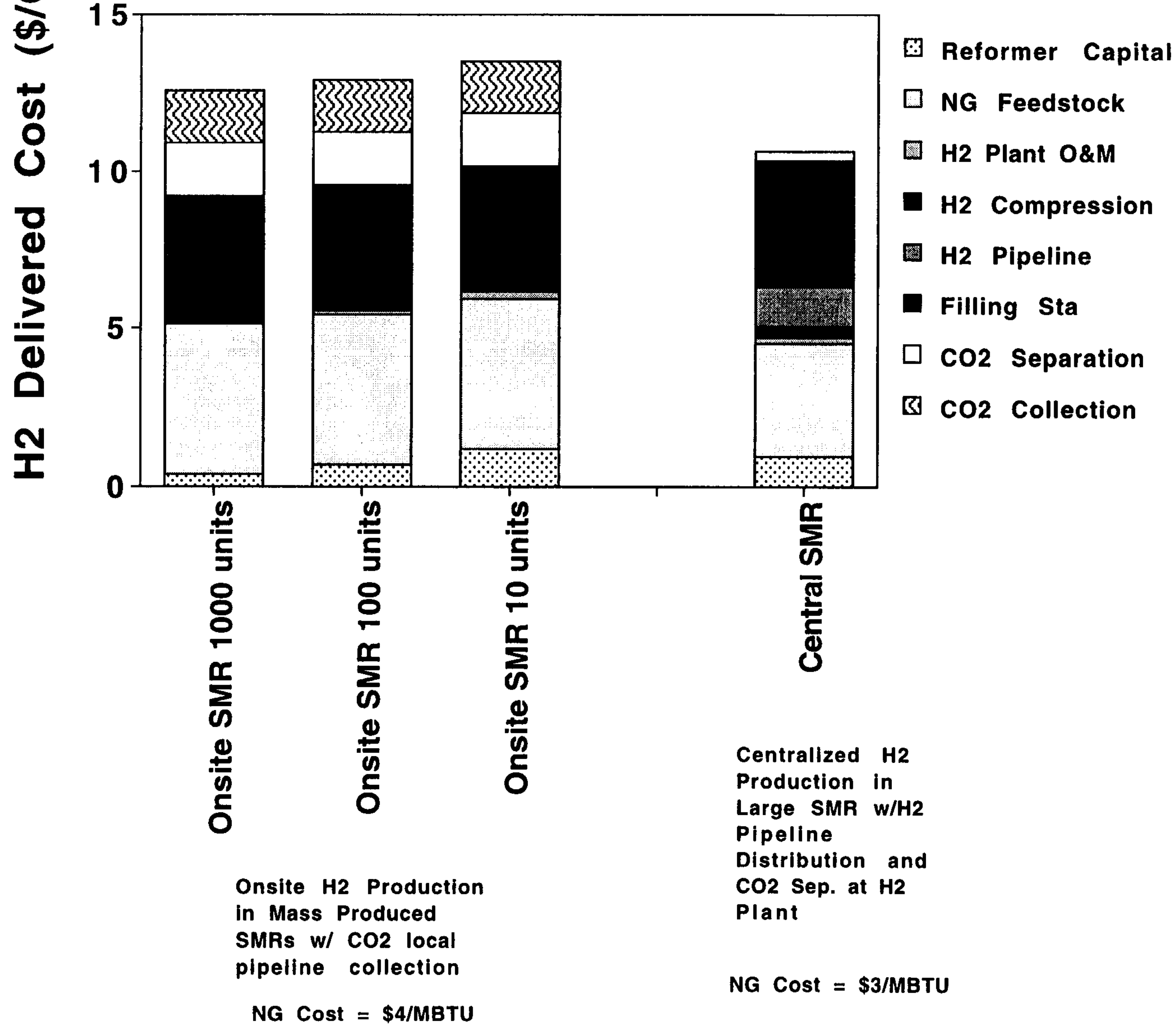
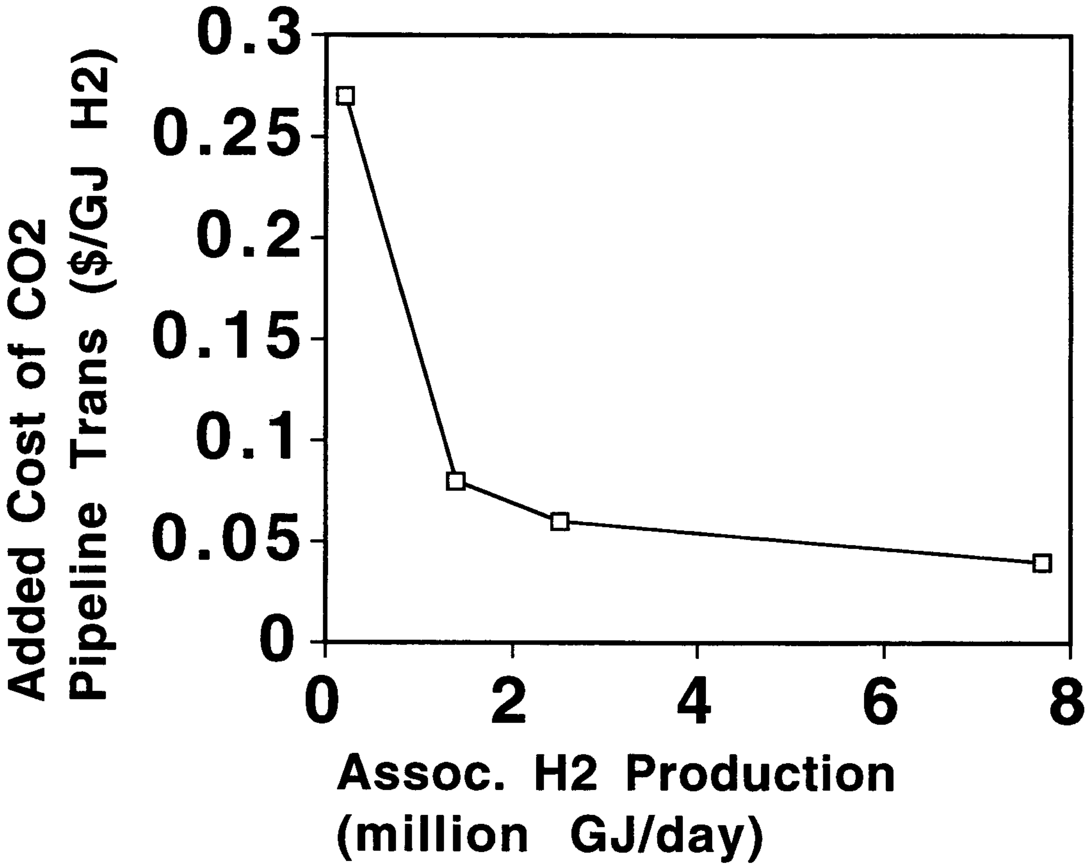


Figure 22. Cost of CO2 Pipeline Transmission 250 km: Added Cost to H2 ($/GJ)

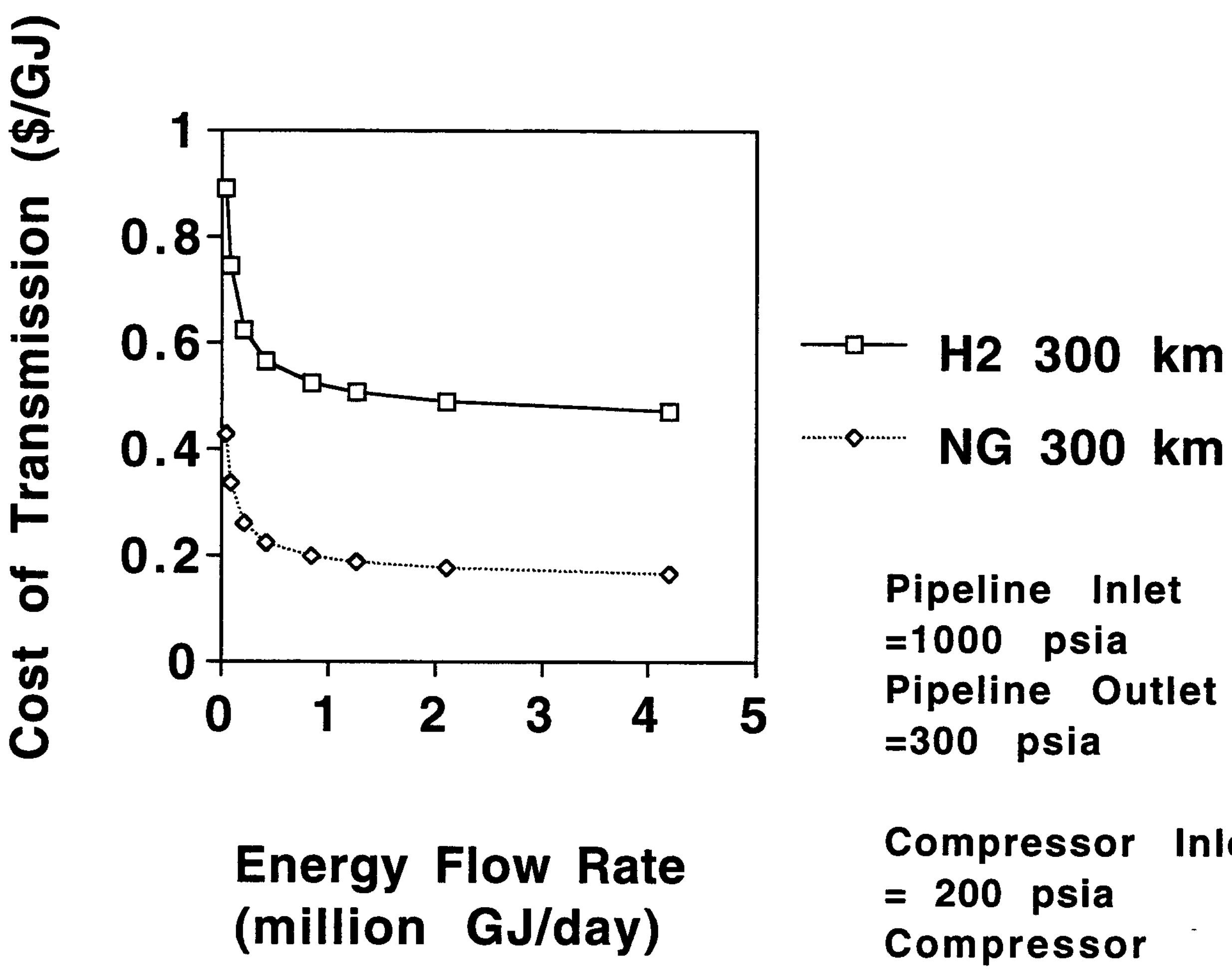


27 GJ/day = fleet of 10 H2 FC buses

362 GJ/day = fleet of 10,000 H2 FCVs

36,200 GJ/day = fleet of 1 million H2 FCVs = 10% of vehicles in LA Basin

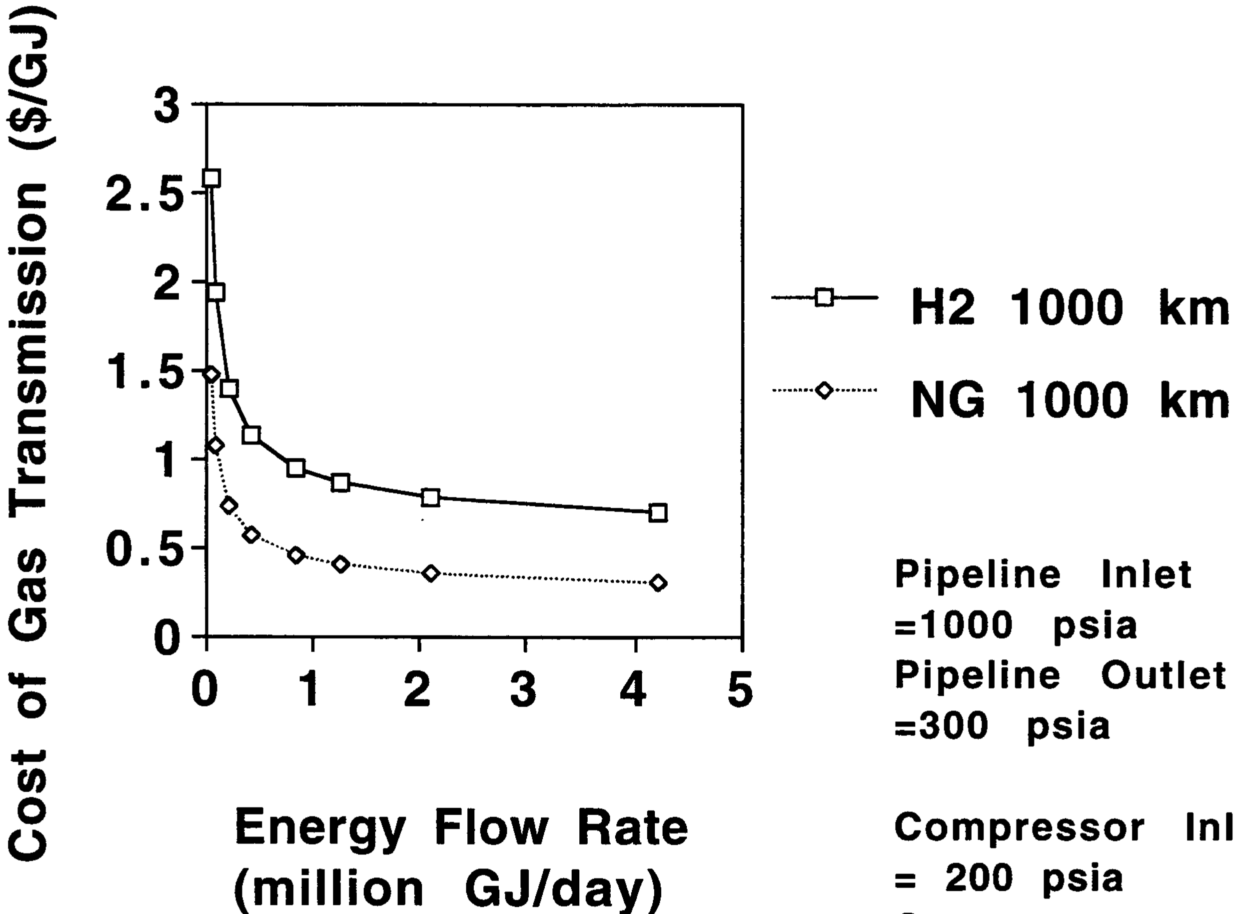
Figure 23. Levelized Cost of Transmission for 300 km Hydrogen and Natural Gas Pipelines



Pipeline Inlet =1000 psia
Pipeline Outlet =300 psia

Compressor Inlet = 200 psia
Compressor Outlet=1000 psia

Figure 24. Levelized Cost of Transmission for 1000 km Hydrogen and Natural Gas Pipelines



Pipeline Inlet =1000 psia
Pipeline Outlet =300 psia

Compressor Inlet = 200 psia
Compressor Outlet=1000 psia

27 GJ/day = fleet of 10 H2 FC buses

362 GJ/day = fleet of 10,000 H2 FCVs

36,200 GJ/day = fleet of 1 million H2 FCVs = 10% of vehicles in LA Basin

Figure. 25. Configurations for PEM Fuel Cell Cogeneration for Residential Users