

94252

ANL/ES/CP--94252

**Assessment of Capital Requirements for Alternative Fuels Infrastructure  
Under the PNGV Program\***

by

CONF-98 0112--

Kevin Stork

(PH: 630-252-1481, FAX: 630-252-3443, E-Mail: stork@anl.gov)

Margaret Singh†

(PH: 202-488-2440, FAX: 202-488-2413, E-Mail: singhm@smtplink.dis.anl.gov)

Michael Wang

(PH: 630-252-2819, FAX: 630-252-3443, E-Mail: mqwang@anl.gov)

Anant Vyas

(PH: 630-252-7578, FAX: 630-252-3443, E-Mail: avyas@anl.gov)

RECEIVED

AUG 26 1997

OSTI

Center for Transportation Research  
Energy Systems Division  
Argonne National Laboratory  
9700 S. Cass Avenue, 362-C211  
Argonne, IL 60439

The submitted manuscript has been authored  
by a contractor of the U.S. Government  
under contract No. W-31-109-ENG-38.  
Accordingly, the U.S. Government retains a  
nonexclusive, royalty-free license to publish or  
reproduce the published form of this  
contribution, or allow others to do so, for U.S.  
Government purposes.

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED

**MASTER** *ph*

Submitted for Presentation at the  
77<sup>th</sup> Annual Meeting of the  
Transportation Research Board  
2101 Constitution Avenue, N. W.  
Washington, DC 20418

\* Work performed for the U. S. Department of Energy under contract No. W-31-109-ENG-38

† Argonne National Laboratory, Suite 6000, 955 L'Enfant Plaza North, S.W., Washington, DC 20024

# **DISCLAIMER**

**Portions of this document may be illegible  
in electronic image products. Images are  
produced from the best available original  
document.**

# **Assessment of Capital Requirements for Alternative Fuels Infrastructure**

## **Under the PNGV Program**

by

K. Stork, M. Singh, M. Wang and A. Vyas

### **Abstract**

This paper presents an assessment of the capital requirements of using six different fuels in the vehicles with tripled fuel economy (3X vehicles) that the Partnership for a New Generation of Vehicles is currently investigating. The six fuels include two petroleum-based fuels (reformulated gasoline and low-sulfur diesel) and four alternative fuels (methanol, ethanol, dimethyl ether, and hydrogen). This study develops estimates of cumulative capital needs for establishing fuels production and distribution infrastructure to accommodate 3X vehicle fuel needs. Two levels of fuel volume — 70,000 barrels per day and 1.6 million barrels per day — were established for meeting 3X-vehicle fuel demand. As expected, infrastructure capital needs for the high fuel demand level are much higher than for the low fuel demand level. Between fuel production infrastructure and distribution infrastructure, capital needs for the former far exceed those for the latter. Among the four alternative fuels, hydrogen bears the largest capital needs for production and distribution infrastructure.

**[Keywords: PNGV, 3X Vehicles, Infrastructure Costs, Alternative Fuels]**

### **Introduction**

In September 1993, the U.S. government and the three large domestic automakers initialed the Partnership for a New Generation of Vehicles (PNGV). Among other goals, the PNGV established the goal of developing light-duty vehicles that can achieve up to three times the fuel economy (3X vehicles) of today's comparable vehicles. To reach the 3X goal, the PNGV is investigating use of alternative propulsion systems, lightweight materials, and alternative fuels. The National Research Council's PNGV Review Committee concluded in its first review of the program that production of these systems, materials, and fuels could poses potential substantial discontinuities in vehicle manufacturing and transportation fuels production and distribution infrastructure. Consequently, the Committee observed that a need existed for in-depth assessment of changes that could occur in "infrastructure, capital requirements, shifts in

employment, total environmental consequences, alternative safety strategies, and total costs of operation associated with each technology being explored in the PNGV program" (NRC, 1994).

A study was conducted at Argonne National Laboratory to investigate impacts of alternative fuels in 3X vehicles on transportation fuels infrastructure. Argonne's analysis included assessment of capital needs for producing and distributing alternative fuels for 3X vehicles and estimation of fuel-cycle energy use and emissions of 3X vehicles powered with six different fuels. This paper presents the results on fuels infrastructure capital needs.

## **Approach and General Assumptions**

### **Analytic Framework of the Study**

The cost analysis was conducted as part of a study that included energy and environmental impacts of the infrastructural changes (Wang, *et al*, 1997). In the course of that analysis, two market penetration scenarios – a low- and a high-penetration scenario – for 3X vehicles were developed. The market penetration scenarios covered the period from 2007 to 2030 and were used to make annual estimates of the total fuel cycle energy and emissions impacts. We used two points on the high market penetration curve – 2015 and 2030 – to estimate the capital costs associated with fuel infrastructure. The number of vehicles in service at these two points (based on new vehicle sales and vehicle survival) was translated into fuel demand attributable to 3X vehicles. Six fuels were selected for analysis as PNGV fuels. These are specified in the following section. Each fuel was assumed to meet the entire energy demand of the program. The required production, distribution, storage and refueling capacity, and the costs of such capacity, were estimated from the fuel volumes required. In the context of the capital analysis, we have assumed that each fuel analyzed will be used exclusively in 3X vehicles (though non-fuel uses would be sustained).

Many vehicle technologies are under consideration in the PNGV program. Some of these technologies require, or are envisioned to require, the use of alternative fuels. The development of production, distribution and refueling infrastructure for non-petroleum transportation fuels is a major impediment to the implementation of any program relying on the use of alternative fuels. This assessment gives a relative comparison of the costs associated with the development of the required infrastructure for several alternative fuels.

### **Candidate PNGV Fuels Analyzed**

The fuels included in this analysis are not intended to represent a comprehensive picture of available and potential transportation fuels. Rather, the choice of fuels (and the vehicle technologies with which they are paired) is based on specific advantage of the fuel-vehicle system in achieving the PNGV program goals.

This analysis includes two petroleum-based fuels (reformulated gasoline and low-sulfur diesel) and four alternative fuels (dimethyl ether [DME], methanol, ethanol, and hydrogen). Reformulated gasoline is the reference conventional light-duty-vehicle fuel for spark-ignition, direct-injection (SIDI) technology. Low-sulfur diesel is the reference fuel for compression-ignition, direct-injection (CIDI) technology which, though currently not a significant market presence in the U.S., is likely to play a role in the future of light-duty vehicles. In this study, methanol and ethanol are assumed to be used in SIDI engines, DME in CIDI engines, and hydrogen and methanol (via on-board reformers) fuel-cell vehicles.

### **Fuel Demand Volumes Used for Cost Estimation**

To estimate the capital required for fuel production and distribution, the amount of fuel that will be used by 3X vehicles must first be estimated. Because of time and resource limitations, we did not estimate capital requirements on an annual basis but rather selected two years within the period of study (i.e., 2007 to 2030) under the high market share scenario. In particular, we selected year 2015 and 2030. For each year, we used the IMPACTT model to estimate the amount of fuel used by 3X vehicles. In estimating fuel demand, the IMPACT model takes into account the 3X vehicle market share scenarios, vehicle survival rate, annual VMT, and fuel economy. In our analysis, we assumed that 3X vehicles would penetrate to both passenger car and light truck fleets. We assumed that 3X cars would achieve three times of fuel economy of today's cars and 3X light trucks three times of fuel economy of today's light trucks. The fuel demands were estimated to be  $70 \times 10^3$  bbl/d gasoline gallon equivalents (GGEs) in 2015 and  $1.6 \times 10^6$  bbl/d GGEs in 2030.

Capital needs were estimated for each of these two fuel demand levels. That is, the capital requirement estimates were based the capacity required to satisfy demand in each of the two target years. Thus, the estimates are discrete snapshots of accumulated capital investment through the target year rather than rates of capital spending in that year. Thus, all capital costs are cumulative. Reformulated gasoline was assumed to impose no incremental production cost and both RFG and LSD were assumed to impose no incremental storage or distribution costs.

### **Fuel Production Pathways**

To estimate capital needs for fuel production and distribution, fuel production pathways must be specified for each of the six selected fuels. On the basis of Argonne's previous research in fuels areas, we specified the fuel pathways presented in Figure 1 (Wang 1996). As the figure shows, RFG and diesel fuel will be produced from petroleum. Methanol and DME will be produced from natural gas. We assume that before 2020, hydrogen will be produced from natural gas through steam reforming, and beginning in 2020 and beyond, hydrogen will be produced from solar energy through water electrolysis. For ethanol, we assume that before 2020, ethanol will be produced from corn, and beginning in 2020 and beyond, ethanol will be produced from biomass (both woody and herbaceous).

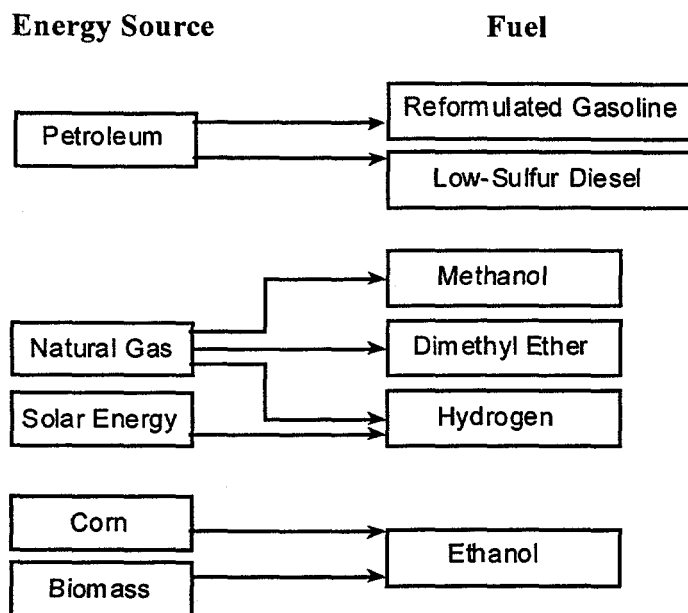


FIGURE 1 Fuel Pathways Considered in this Study

### Estimation of Capital Requirements

#### Capital Costs Related to Fuel Production

To estimate the capital needed for producing a specified fuel volume, presented in Table 1, we first estimated capital costs for a large-scale fuel production plant. We then calculated the number of plants required based on the volume of fuel required in each of the target years, 2015 and 2030. All costs are in 1995 dollars.

TABLE 1 Fuel Required by 3X Vehicles

Fuel	Volume or Mass of Fuel Required	
	2015	2030
Reformulated gasoline	$70 \times 10^3$ bbl/d	$1.6 \times 10^6$ bbl/d
Diesel fuel	$62.9 \times 10^3$ bbl/d	$1.4 \times 10^6$ bbl/d
Dimethyl ether	$123 \times 10^3$ bbl/d	$2.8 \times 10^6$ bbl/d
Hydrogen	$1.3 \times 10^9$ SCF/d <sup>a</sup>	$28.3 \times 10^9$ SCF/d <sup>b</sup>
Ethanol	$1.6 \times 10^9$ gal/yr <sup>c</sup>	$36.9 \times 10^9$ gal/yr <sup>d</sup>
From cellulosic biomass	—	$36.9 \times 10^9$ gal/yr
Methanol (natural gas) <sup>e</sup>	$6.6 \times 10^6$ t/yr	$148.1 \times 10^6$ t/yr

a from natural gas

b from solar H<sub>2</sub>O electrolysis

c from corn

d from cellulosic biomass

e t = metric tonnes.

DME and hydrogen are not currently used as transportation, and ethanol and methanol are used in limited amounts as additives or additive feedstocks, essentially all demand for these fuels will have to be met with new production facilities. The near total lack of fuel-oriented infrastructure for the alternative fuels greatly increased their cost relative to gasoline or diesel fuel. A summary of the production capital costs is presented in Table 2. Details of calculations for each fuel follow.

TABLE 2 Summary of Cumulative Capital Costs for Fuel Production

Fuel	Through 2015 Capacity = 70 x 10 <sup>3</sup> bbl/d GEG <sup>a</sup>		Through 2030 Capacity = 1.6 x 10 <sup>6</sup> bbl/d GEG	
	No. of Plants	Cost (\$ billions)	No. of Plants	Cost (\$ billions)
Methanol	2	3.2	50	84
Ethanol	40 <sup>b</sup>	4.5 <sup>b</sup>	737	81
Hydrogen	13	10	NA <sup>c</sup>	397
DME	3	3	66	66

<sup>a</sup> GEG = gasoline equivalent gallons

<sup>b</sup> Some ethanol may be diverted from current gasoline blending, which would reduce these values.

<sup>c</sup> No particular scale economies apply for solar hydrogen. Therefore, plant size and number of plants were not estimated for hydrogen in 2030.

## Hydrogen

In the near term, we assumed that the likely production route for hydrogen was conversion of natural gas to hydrogen via steam methane reforming. Production would occur in central facilities near gas fields and the hydrogen would be transported to user sites. Starting in 2020, we assumed a switch to solar electrolysis of water as the source of hydrogen to capture the environmental benefits. Interest in producing hydrogen from solar energy via water electrolysis has increased in the United States, and research and development (R&D) efforts have been undertaken so that in the long term, hydrogen can be produced from solar energy. Because solar hydrogen is not subject to significant economies of scale, this assumed switch raised the long-run capital cost of hydrogen production substantially. In both 2015 and 2030, we assumed that hydrogen would be produced domestically.

Hydrogen has multiple potential production routes but only two storage and distribution options. Hydrogen can be stored as a cryogenic liquid or as a gas. Because a large-scale fuel system is needed in the 2030 case, this study assumed gaseous storage and distribution of hydrogen in 2030. To simplify, and for consistency with the long-term goal of a gaseous hydrogen system, hydrogen was assumed to be gaseous in 2015 as well, although in reality a mix of gaseous and liquid storage, or a transition from liquid to gaseous hydrogen, is likely. The choice of gaseous hydrogen necessitates the development of a hydrogen pipeline system. The pipelines in this system likely would be developed as grassroots projects, rather than converted from existing natural gas or petroleum product pipelines.



We estimated that 13 large hydrogen plants, costing \$10 billion, would be sufficient to supply the hydrogen required in 2015. These plants would produce  $1.3 \times 10^9$  standard cubic feet (SCF) of hydrogen per year from natural gas.

After switching to solar hydrogen in 2020, we estimate that in 2030 sufficient solar panels to produce the required  $28.3 \times 10^9$  SCF hydrogen will cost \$397 billion.

## Ethanol

Ethanol was assumed to be domestically produced in this analysis. It is currently produced by fermentation of agricultural feedstocks (e.g., corn). Research and development efforts are underway to produce ethanol from woody and herbaceous biomass. In the 2015 analysis, we assumed that corn would continue to be the dominant feedstock for the production of ethanol. We also assumed that the capacity of ethanol plants would be in the range of approximately 40 million gallons per year — fairly large by current standards. Ethanol is currently used in the transportation sector ("fuel ethanol") in the form of oxygenated fuels (usually containing about 10% ethanol and 90% gasoline by volume). The volume of ethanol required for the 3X vehicles in 2015 is approximately equal to the current volume of fuel ethanol used (about 7% of gasoline).

The National Renewable Energy Laboratory (Wiselogle 1996) modeled the production of ethanol from cellulosic biomass, the production route used for the 2030 analysis, for Argonne. In the model runs, we assumed that each plant had a production capacity of 50 million gallons per year and consumed about 2000 dry tons per day of cellulosic biomass. Such a plant is extremely large relative to most current thinking on cellulosic facilities because of the large demand for feedstock and high feedstock transport costs.

We estimated that 40 large, grain-based ethanol production plants, using the wet-milling process, would supply 1.6 billion gallons of ethanol in 2015. The 40 plants, each producing 40 million gallons of ethanol annually, would cost \$4.5 billion. We have not assumed any reduction from nameplate capacity as these estimates are gross to begin with.

In 2030, 737 large cellulosic ethanol production plants would supply 36.9 billion gallons of ethanol. These plants would consume 2,000 dry tons per day of cellulosic biomass each, which is extremely large relative to typical current projections. It is not clear that sufficient cellulosic feedstock will be available locally to supply these plants, but the assumption of large facilities was consistent with the other analytical scenarios, given the large total volume of ethanol required. It is not likely that transporting cellulosic biomass over great distances would be economic, and 2,000 dry tons per day was the largest plant size that seemed justified. The projected cost of the plants is \$81 billion.

## Methanol

Production costs for methanol were estimated with assumed plant capacity of 10,000 tonnes/day. This capacity is approximately four times that of a current typical, large domestic methanol plant. The use of a much larger plant would provide considerable economies of scale. Previous studies by the U.S. Department of Energy and others have generally assumed that methanol would be imported and that assumption was retained for the present study as well. Moreover, current methanol import/export balances for the United States strongly suggest that we would be net methanol importers. In 1995, for example, the United States exported  $202 \times 10^3$  tonnes of methanol and imported  $1.8 \times 10^6$  tonnes, as compared to a demand of  $7.3 \times 10^6$  tonnes (approximately  $2.3 \times 10^6$  tonnes of which was used in transportation fuels [Chemical Market Associates 1996], primarily as tertiary methyl butyl ether [MTBE] or as tertiary amyl methyl ether [TAME], but also, in small quantities, as M85 [85% methanol with 15% gasoline by volume]).

Another reason for producing methanol in remote, and most likely foreign, plants is that the feedstock costs assumed in this study are low. Natural gas was assumed to be available at \$0.80 per  $10^6$  Btu in 2015 and at \$1.00 per  $10^6$  Btu in 2030. This price is reasonable only if use of remote natural gas is assumed. The prototypical plant using these feedstock price assumptions was taken to be in Venezuela. For a plant in Saudi Arabia to remain competitive, it would need to produce gas more cheaply than a plant in Venezuela to compensate for the higher shipping costs.

Two additional large methanol plants could supply the entire needs of the PNGV program in 2015 at a capital cost of \$3.2 billion. This analysis assumed that approximately 30% of the MTBE/TAME used in gasoline would become available due to displacement of gasoline vehicles by 3X vehicles and that other sources of methanol demand remained the same as a portion of the economy (i.e., demand growth or contraction collinear with economic activity). Other sources of demand include, primarily, production of formaldehyde and acetic acid, and to a lesser extent, solvent methanol and methyl methacrylate.

Under similar assumptions updated to 2030, 50 additional methanol plants would be required, costing \$84 billion in capital cost. In 2030, 60% of the MTBE/TAME was assumed to be available from gasoline due to displacement of gasoline vehicles.

## Dimethyl Ether

The current worldwide DME production level is less than 40 million gal/yr, and virtually all DME is produced from methanol. We assumed that, as large-scale production occurs, DME would be produced directly from natural gas and that production cost would decline. Recent studies by Amoco and Haldor-Topsøe have promoted the use of DME made from natural gas as an economic alternative, with benign environmental properties compared to diesel fuel (Fleisch, *et al.* 1995a). If DME is used extensively in 3X vehicles, DME production capacity must be

established from virtually nothing today, and large investments will be inevitable. DME was assumed to be produced abroad and imported to the United States

The production cost of DME was estimated by using data from the literature (Hansen, *et al.* 1995). Key assumptions were (1) inexpensive natural gas (\$0.80 per  $10^6$  Btu in 2015 and \$1.00 per  $10^6$  Btu in 2030) and (2) very-large-scale plants (40,000 bbl/d). The current capital cost for such a plant was estimated at approximately \$1 billion. Three such plants would be required in 2015, and 66 would be required in 2030. A study by Amoco and AVL indicated that DME produced in Venezuela and transported by tanker to the U.S. Gulf Coast would have a break-even price 35% higher than diesel fuel (Fleisch, *et al.*, 1995b).

### **Diesel**

Both costs and benefits are associated with a move from gasoline to diesel fuel for light-duty vehicles. Because higher thermal efficiencies are possible with a CI system, the switch may marginally reduce crude-oil throughput. On the other hand, distillate fuel requires more hydrotreating to remove sulfur than does gasoline. Additionally, distillate desulfurization is conducted under significantly higher pressure than naphtha desulfurization. Therefore, new desulfurization reactors would be required for a large-scale transition to diesel fuel, and additional energy costs may be imposed to operate the hydrotreaters. Finally, a change in the demand structure for petroleum fuels may alter the relative values of today's light products and complicate the issues. With additional diesel demand, gasoline may not be the preferred product.

Given the relatively moderate rate of market penetration of 3X vehicles, however, there is unlikely to be a problem supplying sufficient diesel fuel. We have assumed that the incremental cost of diesel production will be comparable to that of gasoline under the reference scenario.

### **Capital Costs Related to Fuel Distribution, Storage, and Refueling**

Existing literature was consulted to determine the storage requirements, extent of movement by various modes of transportation, and required number of refueling stations for the volume of fuel required. Cumulative costs of the physical infrastructure were then estimated from the literature and consultation with industry experts.

### **Methanol**

Figure 2 shows the methanol distribution infrastructure assumed for this study. The imported M100 would be stored in tanks at terminals until it is distributed. Trucks would distribute initial volumes of M100 (the first  $1 \times 10^6$  bbl/d gasoline equivalent) to service stations or inland terminals within 100 miles of marine terminals. In this way 75% of the U.S. population can be easily reached. For larger volumes, pipelines would be constructed. Currently, no methanol pipeline distribution system is available. Because of the corrosiveness of methanol,

existing steel pipeline systems would have to be modified to handle this fuel. Methanol refueling pumps would have to be added to existing stations. We assumed that 50,000 gasoline equivalent gallons would be supplied per station. The estimated capital needs for the specified methanol distribution infrastructure are presented in Table 3.

### Ethanol

Ethanol, all of which was assumed to come from domestic sources, would not be produced in evenly distributed regions (Figure 3). Initially, ethanol would be moved by truck, but eventually, as volumes increase, we assumed that it would be moved by pipeline (48%), barge (12%), and rail (40%) (agreeing with a study by EA Energy Technologies Group [1991]). Estimated ethanol distribution costs are presented in Table 4.

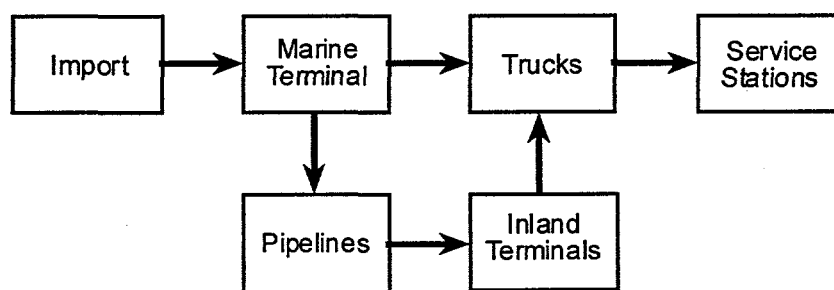


FIGURE 2 Methanol Distribution Infrastructure

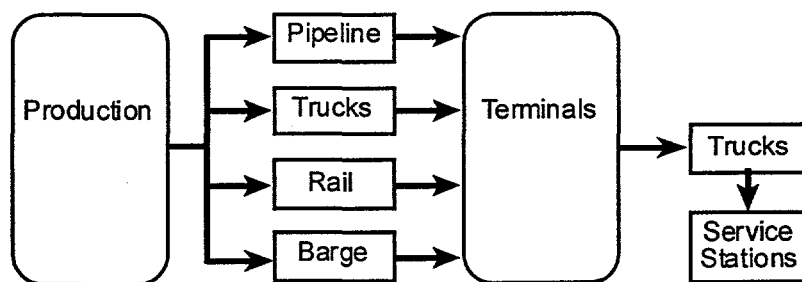


FIGURE 3 Ethanol Distribution Infrastructure

### Dimethyl ether

Figure 4 shows the DME distribution infrastructure. Like methanol, it would be stored at large marine terminals and transported to inland terminals and stations within 100 miles by truck for initial volumes and by pipeline for larger volumes. Dimethyl ether has physical properties similar to LPG, therefore DME fuel distribution requirements are based on those of LPG. However, LPG pipeline systems are not extensive, and LPG consumption would not be reduced as a result of DME use, so new pipelines would have to be constructed for widespread use of

DME. Gasoline refueling stations could be upgraded to handle DME refueling by adding DME pumps. Service station equipment and costs are based on those for LPG. DME distribution infrastructure costs are presented in Table 5.

## Hydrogen

Extensive transportation and distribution systems for hydrogen in either gaseous or liquid form are not currently available. A dedicated pipeline system would have to be built for gaseous hydrogen because it can diffuse through metals. Liquid hydrogen must be maintained below its boiling point (-252.7 C) and is generally shipped by truck or rail. These modes of transport are expensive, but it is not feasible to ship cryogenic liquids via pipeline. For this reason, we assumed that gaseous hydrogen transported through pipeline systems would be used in hydrogen fuel-cell vehicles (FCVs). Figure 5 shows hydrogen distribution infrastructure. Table 6 presents the hydrogen distribution infrastructure costs.

Figure 6 shows the distribution infrastructure costs for the alternative fuels. As the figure shows, hydrogen bears the greatest distribution infrastructure costs. Total fuel distribution costs increase dramatically between 2015 and 2030. This reflects the huge increase in fuel demand volume.

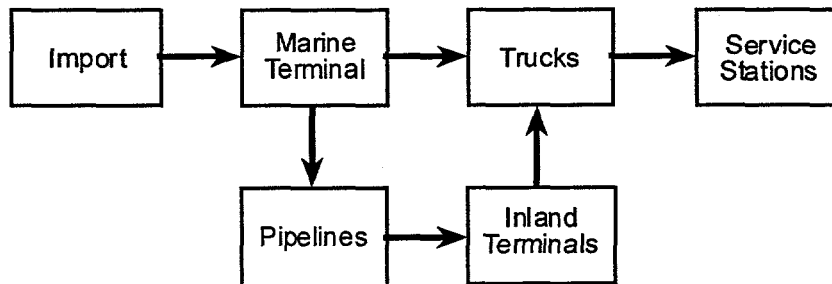


FIGURE 4 Dimethyl Ether Distribution Infrastructure

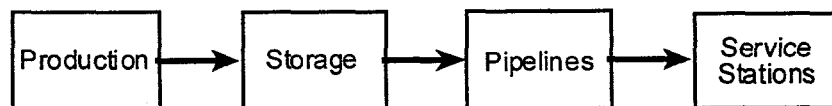


FIGURE 5 Hydrogen Distribution Infrastructure

TABLE 3 Distribution Infrastructure Requirements and Costs for M100

Infrastructure Element	Physical Requirements (Number)	Costs (\$10 <sup>6</sup> )
<i>Through 2015: 70,000 bbl/d GEG<sup>a</sup> Capacity</i>		
Total barrels terminal tanks	$2.90 \times 10^6$	28
Terminal truck racks	8	10
Total trucks	218	16
Pipelines	0	0
Service stations	1,793	<u>308</u>
Total		363
<i>Through 2030: <math>1.6 \times 10^6</math> bbl/d GEG Capacity</i>		
Total barrels terminal tanks	$8.91 \times 10^7$	873
Terminal truck racks	184	238
Total trucks	5,118	500
Pipelines	5	549
Service stations	40,277	<u>6,928</u>
Total		9,088

<sup>a</sup> GEG = gasoline equivalent gallons.

TABLE 4 Distribution Infrastructure Requirements and Costs for E100

Infrastructure Element	Physical Requirements (Number)	Costs (\$10 <sup>6</sup> )
<i>Through 2015: 70,000 bbl/d GEG<sup>a</sup> Capacity</i>		
Total barrels terminal tanks	$2.17 \times 10^6$	16
Terminal truck racks	6	8
Total trucks	241	12
Pipelines	0	0
Rail cars	143	9
Barges	4	0.4
Service stations	1,793	<u>289</u>
Total		334
<i>Through 2030: <math>1.6 \times 10^6</math> bbl/d GEG Capacity</i>		
Total barrels terminal tanks	$4.87 \times 10^7$	366
Terminal truck racks	138	178
Total trucks	3,656	260
Pipelines	5	375
Rail cars	3,216	209
Barges	84	9
Service stations	40,277	<u>6,485</u>
Total		7,882

<sup>a</sup> GEG = gasoline equivalent gallons.

### Exploration of Potential Impacts on Existing Petroleum Refineries

The potential impact of the PNGV program on the U.S. petroleum refining industry is an issue that arose during the August 1995 PNGV program review. We sought to assess the likely impact of reductions in crude-oil throughput in U.S. refineries due to efficiency improvements under the PNGV program and due to switching to a non-petroleum fuel.

Considerable amounts of gasoline will be saved as a result of using 3X vehicles. The gasoline saving is due to two factors: fuel efficiency gains by 3X vehicles and substitution of gasoline by other fuels. Figure 7 reveals the effects of fuel economy efficiency and fuel substitution of 3X vehicles on U.S. gasoline consumption. Although both effects are significant, the efficiency effect is about twice as large as the substitution effect. In the figure, the low market share assumes the use of gasoline by 3X vehicles. The low market share scenario replacement assumes the use of fuels other than gasoline by 3X vehicles. The same is true for the two cases under the high market share scenario. As the figure shows, even though vehicle usage will continue to rise from now until 2030, the commercialization of 3X vehicles, even

those using gasoline, in high volume will bring light-duty-vehicle gasoline consumption below the 1990 level beginning around 2020.

TABLE 5 Distribution Infrastructure Requirements and Costs for DME

Infrastructure Element	Physical Requirements (Number)	Costs (\$10 <sup>6</sup> )
<i>Through 2015: 70,000 bbl/d GEG<sup>a</sup> Capacity</i>		
Total barrels terminal tanks	$2.50 \times 10^6$	85
Terminal truck racks	8	10
Total trucks	187	26
Pipelines	0	0
Service stations	1,793	<u>441</u>
Total		563
<i>Through 2030: <math>1.6 \times 10^6</math> bbl/d GEG Capacity</i>		
Total barrels terminal tanks	$7.66 \times 10^7$	2,605
Terminal truck racks	182	235
Total trucks	4,400	843
Pipelines	5	1,259
Service stations	40,277	<u>9,908</u>
Total		14,850

<sup>a</sup> GEG = gasoline equivalent gallons.

TABLE 6 Distribution Infrastructure Requirements and Costs for H<sub>2</sub>

Infrastructure Element	Physical Requirements (Number)	Costs (\$10 <sup>6</sup> )
<i>Through 2015: 70,000 bbl/d GEG<sup>a</sup> Capacity</i>		
Pipeline mileage	7,533	5,273
Service stations	1,793	<u>2,510</u>
Total		7,783
<i>Through 2030: <math>1.6 \times 10^6</math> bbl/d GEG Capacity</i>		
Pipeline mileage	167,000	116,900
Service stations	40,277	<u>56,388</u>
Total		173,288

<sup>a</sup> GEG = gasoline equivalent gallons.



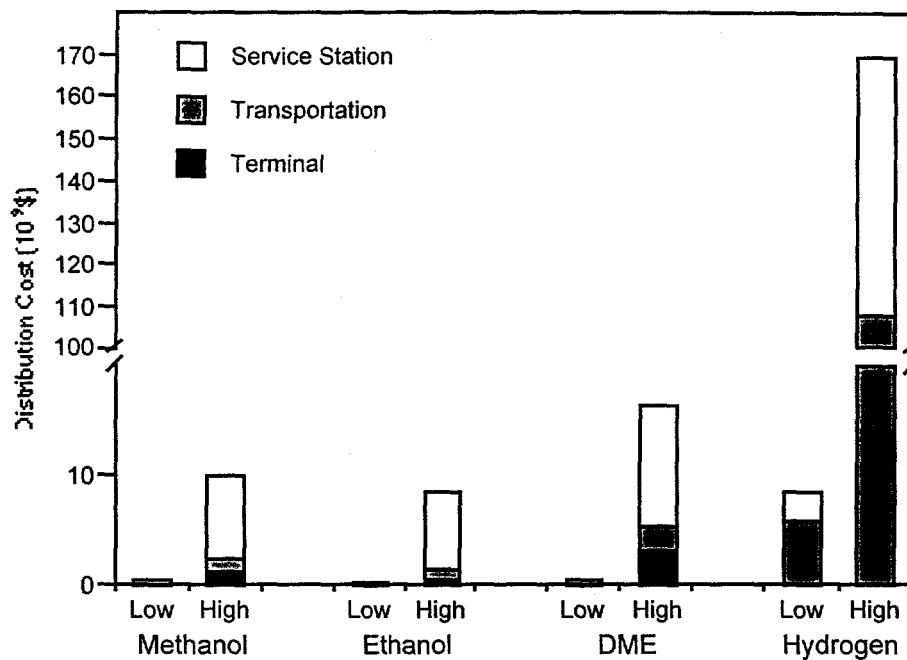


FIGURE 6 Capital Requirements of Fuel Distribution Infrastructure

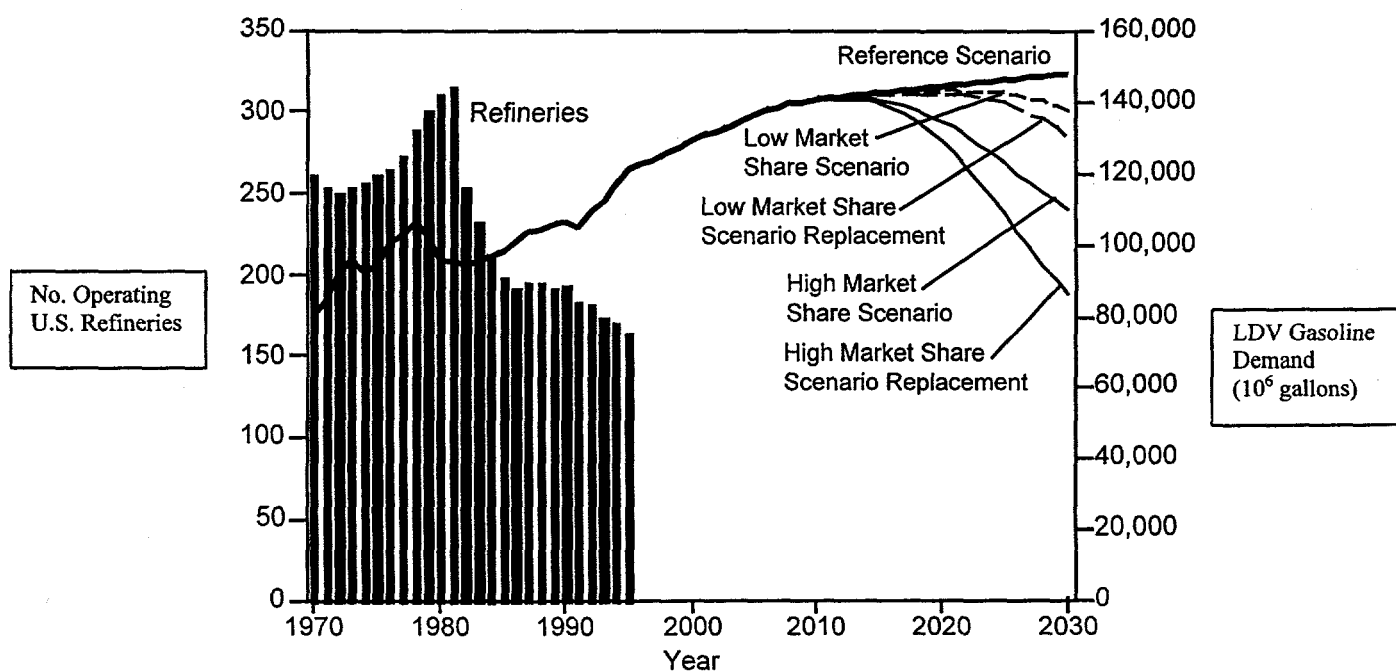


FIGURE 7 Light-Duty Vehicle Gasoline Consumption under the PNGV Scenarios and Historical Data on U.S. Refineries

Since diesel fuel is produced at the same refineries and from the same feedstock (petroleum) as gasoline, production of an increased amount of diesel fuel for 3X vehicles will not pose a major infrastructure problem. However, the U.S. petroleum refining industry has had a long history of maximizing gasoline production, so an increase in demand for diesel fuel would require refiners to modify the product balance. The flexibility of refineries with respect to product slate varies considerably among individual refineries, but there are some fundamental differences between producing diesel fuel and gasoline that could have a major impact on the industry as a whole. Such a change in the industry average product slate would not be as easily accommodated as a marginal change. Also, to reduce emissions from diesel combustion, clean diesel fuel will have to be produced for use in 3X vehicles; additional distillate desulfurization capacity will have to be installed at refineries. In summary, although new refineries may not need to be built for diesel, investments in existing refineries will be necessary for increased diesel fuel production.

The impact on the refining industry will not be as dramatic as had been feared in August 1995 under the market penetration assumptions employed in this study. First, foreknowledge of the program will be unprecedented and ample in terms of lead time and technical details. Reductions in projected fuel demand will not begin to be evident for about 10 years and then will occur only gradually. Demand for light-duty transportation fuel will be reduced significantly by introducing 3X vehicles. Due to fuel-efficiency effects alone, in 2030, light-duty-transportation fuel demand under the low market share scenario will be reduced to the reference scenario level for 2005. Demand will be reduced to the reference scenario level for 1990 under the high market share scenario. If other fuels are to be used, gasoline demand can be reduced by an additional one-third, and the impact of refineries will be greater.

The refining industry has survived more dramatic downturns over a shorter period of time in the past. In the period from the mid-1980s through the early 1990s, a large number of refineries were closed. The change in refining capacity was less dramatic than what we might see under PNGV, however, largely because the older and simpler (i.e., smaller) refineries were the ones that closed and the larger, more complex, newer refineries survived. In addition, the rationalization of the refining industry during that period suggests that there is no longer much slack in the system. Currently, refineries have higher capacity utilization rates than was the case prior to the rationalization. Capacity utilization was near 70% in the early 1980s and is over 90% now (API 1996). The higher utilization rate is necessary, in large part, for the refineries to run profitably. Nonetheless, the usual retirement of refining equipment should be sufficient to avoid massive refinery closures of an economically unrecoverable nature, if the reduction in capacity is planned for, as it can be for in the case of the PNGV program.

The U.S. refining industry continues to move abroad due to the high cost of environmental regulations in the United States. We expect this trend will continue regardless of the PNGV program. What influence there is, however, will tend to accelerate the movement of fuel production abroad. Still, the long lead time for the transition to the PNGV program provides some relief for the concerns of many refiners. The relatively modest shifts in fuel-product slate envisioned if diesel is used as the PNGV fuel (instead of gasoline) would probably put U.S.

refiners at a disadvantage relative to foreign refiners. Certainly, this statement would hold as refineries are configured today. However, with a 10-20 year average life cycle for refinery equipment, these gasoline-maximized refineries could be retooled to produce more diesel over time.

## Conclusions

Capital needs for developing fuel production and distribution infrastructure were estimated for four potential PNGV alternative fuels at two fuel demand levels – 70,000 bbl/d (gasoline-equivalent barrels) and 1.6 million bbl/d. While supplying the fuel volume of 70,000 bbl/d requires relatively modest capital, supplying the fuel volume of 1.6 million bbl/d requires a substantial amount of capital. Cumulative capital needs vary by fuel type, and hydrogen bears the greatest capital requirements. Facilities capable of producing 1.6 million bbl/d will require a cumulative capital investment of \$66–84 billion for DME, methanol, or ethanol versus about \$400 billion for hydrogen. Distribution facilities will cost \$8–15 billion for ethanol, methanol, or DME versus nearly \$175 billion for hydrogen. These hefty capital requirements pose a challenge to the widespread introduction of 3X vehicles. However, these investments will be spread over many years.

The impacts of vehicle efficiency gains and fuel substitution on petroleum displacement are substantial and their adverse impacts on refineries are inevitable. However, the commitment of time and resources to 3X technology development should provide ample economic signals and sufficient lead time for refinery operators to adjust their business to accommodate different fuel demands, including, perhaps, lower gasoline demand.

Needless to say that capital requirements for supplying the four alternative fuels are substantial. On the other hand, use of these fuels, together with PNGV's 3X goal, will help reduce U.S. light-duty vehicle petroleum use to the 1990 level around year 2020. This reduction in petroleum use will yield a substantial societal benefit. Among the four alternative fuels, costs for hydrogen are at least five times as much as those for any of the other three fuels. However, use of hydrogen, as shown in our overall study, achieves the largest energy and emissions benefits among the four fuels. Both costs and benefits must be considered in determining alternative fuel options for 3X vehicles.

## References

American Petroleum Institute, 1996, *Basic Petroleum Data Book*, Vol. XVI, No. 3, Washington DC, September.

Chemical Market Associates, Inc., 1996, *World Methanol Analysis*, Houston, July.

EA Energy Technologies Group, 1991, *Assessment of Ethanol Infrastructure for Transportation Use*, prepared for National Renewable Energy Laboratory, Golden, Colo., April.

Fleisch, T., C. McCarthy, A. Basu, C. Udovich, P. Charbonneau, W. Slodowske, S. E. Mikkelsen, and J. McCandless, 1995a, *A New Clean Diesel Technology: Demonstration of ULEV Emissions on a Navistar Diesel Engine Fueled with Dimethyl Ether*, SAE #950061, Society of Automotive Engineers, Warrendale, Penn., Feb.

Fleisch, T., P. Meurer, 1995b, *DME: The Diesel Fuel for the 21<sup>st</sup> Century?*, presented at AVL Engine and Environment 1995, Graz, Austria, April.

Hansen, J.B., B. Voss, F. Joensen, and I.D. Sigurardottir, 1995, *Large Scale Manufacture of Dimethyl Ether: A New Alternative Diesel Fuel from Natural Gas*, SAE #950063, Society of Automotive Engineers, Warrendale, Penn., Feb.

National Research Council, 1994, *Review of the Research Program of the Partnership for a New Generation of Vehicles*, National Academy Press, Washington, D.C.

Wang, M.Q., 1996, *GREET 1.0 Transportation Fuel Cycles Model: Methodology and Use*, ANL/ESD-33, Center for Transportation Research, Argonne National Laboratory, Argonne, Ill., June.

Wang, M.Q., K. Stork, A. Vyas, M. Mintz, M. Singh, and L. Johnson, 1997, *Assessment of PNGV Fuels Infrastructure – Phase 1 Report: Additional Capital Needs and Fuel-Cycle Energy and Emissions Impacts*, ANL/ESD/TM-140, Center for Transportation Research, Argonne National Laboratory, Argonne, Ill., January.

Wiseloge, A., 1996, personal communication with K. Stork, October and November.

## **Acknowledgements**

We thank Dr. Pandit Patil, Director of the Office of Advanced Automotive Technologies, for his guidance and technical input. We are grateful to Jerry Levine of Amoco Petroleum Products Company. We thank our colleagues Marianne Mintz and Larry Johnson, both of ANL's Center for Transportation Research, for guidance and technical input.