Chapter 3

U.S. Technical Potential for Replacing Imported Oil

Contents

Figures

Tables

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INTRODUCTION

This chapter looks at U.S. technical potential to replace imported oil in the residential, commercial, electric utility, industrial, and transportation sectors. Technical replacement potential refers to the capability to replace oil with other energy sources or to reduce oil use through efficiency improvements while providing an equivalent level of energy services (e.g., light, heat, power, transport). It is distinct from direct demand reduction measures such as voluntary conservation (e. g., driving less, turning down the thermostat) and mandatory restrictions on the availability of oil such as allocation or rationing systems.

The analysis focuses on oil replacement options that are technically and economical y feasible within the next 5 years in the event of a severe oil import disruption. They include fuel switching, alternative vehicle fuels, and efficiency improvements. These options use technologies that are commercial y available today, that can be manufactured in sufficient quantity and deployed within 5 years, and that require no significant changes in lifestyle or industrial mix. Some even offer additional benefits for environmental quality, economic growth, and international competitiveness.

This chapter briefly summarizes the oil disruption scenario and technology selection criteria used and identifies suitable technologies that could be deployed. Next, the oil replacement potential in the residential, commercial, electric utility, industrial, and transportation sectors is discussed. The chapter concludes with an examination of possible constraints in achieving the technical oil replacement potential, including manufacturing capability, personnel requirements, permitting requirements, and the uncertain contribution of domestic petroleum production.

Background

OTA first examined the Nation's technical potential to replace a major loss of oil imports in ***U.S. Vulnerability to an Oil Import Curtailment: The Oil Replacement Capability,*** published in September 1984.[1] That report assumed a scenario of an immediate loss of U.S. oil imports from the Persian Gulf of 3 million barrels per day (MMB/D), beginning in mid-1985 and continuing over an indefinite period of at least 5 years. The scenario represented a loss of 19 percent of the total U.S. oil supply of about 15 MMB/D, and over 60 percent of U.S. imports for 1983, the base year (see table 3-l). However, OTA found that the United States had the technical and manufacturing potential to replace 3.6 MMB/D over 5 years, as shown in table 3-2. With aggressive deployment, available energy technologies could replace about 0.6 MMB/D in the electric utility sector, and 1 MMB/D in each of the residential, commercial, industrial, and transportation sectors. Thus, in 1984, U.S. technical oil replacement capability exceeded what was then viewed as a serious import curtailment by the considerable margin of 600,000 barrels per day (B/D).

Our 1984 assessment of adequate capability to meet potential oil supply disruptions also sounded a cautionary note:

> In the longer term, declining domestic production, accompanied by an expected shift away from oil uses for stationary direct heat, will increase the Nation's vulnerability y to an oil shortfall. This will occur even if all stationary uses of fuel oil are replaced by alternative fuels and conservation because the decline in domestic production is expected to occur at an even greater rate, Only by relying more heavily on coal and biomass for chemical feedstocks, increasing efficiency in natural gas use and in all modes of transportation, and producing synthetic transportation fuels in addition to accelerating the replacement and conservation of stationary uses of oil, can the Nation expect to significantly reduce its vulnerability to an oil shortfall over the next few decades.[2]

The trends pointing to decreasing flexibility in our capability to respond to oil import disruptions have continued. From 1984 to 1989 (the base year for this report), U.S. petroleum consumption has risen from

[1] U.S. Congress, Office of Technology Assessment, *U.S. Vulnerability to an **Oil Import Curtailment: The Oil** Replacement Capability,* OTA-E-243 (Springfield, VA; National Technical Information Service, September 1984), hereinafter referred to as OTA, *The **Oil Replacement Capability.***

[2] OTA Report Brief, "U.S. Vulnerability to an Oil Import Curtailment: The Oil Replacement Capability," September 1984.

Table 3-1—U.S. Oil Use by Sector, 1983 and 1989 (million barrels per day)

Sector	1983	1989
Consumption		
Residential and commercial	1.29	1.40
industrial	3.85	4.26
Electric utilities	0.68	0.74
Transportation	9.41	10.85
Total consumption	15.23	17.24
supply		
Domestic production[a]	10.85	10.08
Net imports	4.31	7,12
Total supplies[b]	15.23	17.24

a Includes crude oil, natural gas plant liquids, and processing gain.
b includes stock drawdown.

SOURCE: Office of Technology Assessment 1991, from data in U.S. Department of Energy, Energy Information Administration, Annual Energy *Review* 1989, DOE/EIA-0384(89) (Washington, DC: U.S. Government Printing Office, May 1990), tables 50 and 61.

Table 3-2—U.S. Oil Replacement Technical Potential, 1984 and 1991 (million barrels per day)

Sector	1984[a]	1991[a]
Electric utilities	0.6	0.6
Residential commercial	1.0	1.0
Industrial	1.0	0.8
Transportation	1.0	0.6
Total replacement potential	3.6	2.9
Domestic oil production (decline)	0	(0.1)-(1 ,2)
Net replacement capability	3.6	1,7- 2.8

a Individual entries may not equal total because of independent rounding.

SOURCE: Office of Technology Assessment 1991.

about 15 MMB/D to 17.2 MMB/D, as shown in table 3-1. Net oil imports have risen by almost 3 MMB/D to 7.1 MMB/D, and the share of U.S. oil needs supplied by imports has grown from 33 to over 40 percent. If an oil supply disruption comparable to that analyzed in our 1984 report were to occur today (equivalent to the loss of almost all oil exports from the Persian Gulf—or a world supply shortfall of about 15 MMB/D), the 1991 shortfall in U.S. imports could be as much as 5 MMB/D, compared with 3 MMB/D faced in 1984. However, as the following analysis shows, U.S. ability to offset lost imports by resorting to purely technical replacement strategies has shrunk. The United States no longer enjoys a comfortable margin of safety. If faced with a loss of more than one-quarter of our 1989 oil imports, U.S. technical replacement potential comes up short.

Table 3-2 compares OTA's estimates of oil replacement potential in 1984 and 1991, based on 1983 and 1989 base years, respectively. OTA estimates that available oil replacement technologies could now displace only about 2.9 MMB/D of 1989 oil use within 5 years. Moreover, this replacement potential must be further offset by the expected continuing decline in domestic oil production over the disruption period. The extent of this anticipated decline cannot be calculated with any certainty, but we estimate it to be in the range of 0.1 to 1.2 MMB/D even at the higher oil prices resulting from the crisis. The net result is that after 5 years only about 1.7 to 2.8 MMB/D of lost imports can be replaced by technical means alone. An increase in oil demand, a decline in domestic oil production, and the failure of efficiency improvements and oil replacement technologies to keep pace with consumption have combined to yield a potential net shortfall of 2.2 to 3.3 MMB/D in an import cutoff of 5 MMB/D. Thus, in the past 7 years, U.S. ability to respond to a serious oil supply disruption has declined. Some may view this as a significant factor contributing to increased oil import vulnerability.

Revised Oil Disruption Scenario and Technology Selection Criteria

The changes in energy consumption and the mix of energy sources in nontransportation sectors preclude a direct extrapolation of OTA's findings from 1984 to the present. Therefore, to reassess U.S. oil replacement capability, we updated the oil disruption scenario used in our 1984 study to reflect a 1989 base year.

Oil Disruption Scenario 1990-1995

Since 1984, total world oil use and the level of Persian Gulf exports have risen. Accordingly, to create a comparable oil disruption scenario, we have adjusted the amount of imports affected by a supply crisis and the amount of available oil stocks to reflect 1989 conditions. The other assumptions are nearly identical to those used in the 1984 study. Our 1989 scenario assumes the following:

1. An immediate oil import shortfall of 5 MMB/D occurs in 1991 and continues over an indefinite period expected to last at least 5

years. International oil-sharing agreements commit the United States to absorb one-third of world oil import losses, so that a loss of 15 MMB/D of Persian Gulf exports would mean a 5 MMB/D reduction in U.S. imports, even though the United States does not currently import that much from the Persian Gulf. The worldwide loss of production means that the U.S. shortfall under this scenario could not be made up by increasing oil imports from other countries.
2. Private and governmental commitments are made early in the disruption to replace or reduce imported oil use to the maximum extent technically and economically feasible by relying on domestic sources. Sufficient capital is available to make the required conversions.[3]
3. The strategic petroleum reserve (SPR), private stocks, and other emergency, voluntary, and mandatory conservation measures cushion the initial impacts of the shortfall. Eventually, however, the oil reserves are drawn down to zero.
4. Oil replacement technologies meeting the technical criteria (described below) are deployed over a 5-year period. Concurrently, research, development, and demonstration (RD&D) efforts on long-lead technologies are pursued so that some of these technologies can be deployed commercially beyond 1995.
5. There are no major structural changes in the output mix or behavior of the economy that could deter the 5-year deployment objective.
6. Unless otherwise noted, there are no restrictions on imports that could limit the use of technologies dependent on foreign components or materials.
7. Unless specifically noted, there are no constraints on the availability of technical personnel needed for deploying technologies.
8. There are no new special tax incentives that favor or inhibit deployment of specific technologies.

The year 1989 is used as the baseline for energy consumption, Federal policies, and applicable environmental regulations for this analysis. More recent data are included, where available, to address technological and environmental issues.

Technology Selection Criteria

The assumptions and criteria used in selecting and reevaluating the oil replacement technologies are largely the same as those used in the 1984 report. As in 1984, the technologies were selected for evaluation based on their broad potential to reduce a significant fraction of the oil consumed over a 5-year period in each of the end-use sectors while satisfying environmental standards. The following criteria were used to select oil replacement technologies for further evaluation:

1. The technology is commercially available now or is likely to be by mid-1992.
2. Individual units can be produced or installed in 2 to 3 years and deployed commercially to replace oil no later than 1995.
3. The technology has a broad potential for replacing significant fraction—generally, more than 10,000 B/D of the oil consumed in its respective end-use sector.
4. The technology is currently among the least costly alternatives to oil in its respective end-use sector.[4]

Using these criteria we reexamined the technical replacement options identified in the 1984 study. Since the original evaluation by OTA's engineering contractors,[5] some technologies have improved slightly, but there have not been many significant advances in technology or commercial readiness. Table 3-3 identifies the candidate oil replacement options that meet the 1991 technological suitability criteria. Table 3-4 lists technologies that were excluded because they did not meet the selection criteria, in most cases because they lack enough potential for commercial deployment in 5 years. Over a longer period of time, however, some of these technologies hold some promise as alternatives to oil-using technologies and RD&D and commercialization efforts could continue while short to mid-term oil replacement options are deployed.

[3] Alternative policy options that would aid these commitments are discussed in ch. 5 of this report.

[4] The technical criteria and evaluations are based on Renova Engineering, P.C., "Oil Replacement Analysis-Evaluation of Technologies," OTA contractor report, February 1991, and comments from an OTA workshop on oil replacement technologies, Dec. 5, 1990.

[5] Gibbs & Hill, Inc., "Oil Replacement Analysis, Phase I—Selection of Technologies, " OTA contractor report, April 1983; and Gibbs& Hill, Inc. "Oil Replacement Analysis, Phase II—Evaluation of Selected Technologies," OTA contractor report, August 1983.

Table 3-3-Oil Replacement Options Selected for Assessment

Sector	Oil replacement option	Technology/alternative
Electric utilities	Natural gas*	Convert; replace with combustion turbines or combined cycle units
	Nuclear	Operate completed plants
	Renewable fuels*	Biomass, municipal solid waste (MSW), geothermal, solar thermal, wind energy, small hydro
	Coal*	Convert to coal or coal slurry fuel (CSF); replace with coal gasification combined cycle (CGCC)
	Demand management	Reduce peak demand and capacity needs
Residential/ commercial	Natural gas	Use for space heating, cogeneration
	Electricity	Use for hot water, space heating and cooling
	Coal	Coal or CSF for cogeneration
	Renewable fuels	Solar, wood
	Efficiency improvement	Energy management system, emulsion fuels
Industry	Reduce refinery throughput	(A result of less imported crude to refine)
	Natural gas	Fuel switching, convert oil-fired equipment, gas-derived feedstock
	Other fuels	Fuel switching, conversion of oil-fired equipment, use coal, CSF or biomass for cogeneration, alternative feedstocks
	Process changes	Increase recycling, process optimization, waste heat recovery from process and/or waste streams
Transportation improvement	Efficiency	Improved fuel economy in vehicles, airplanes, marine fleet, and railroads
	Natural gas	Use compressed and liquefied natural gas in fleet vehicles
	Other fuels	Ethanol, methanol, liquefied petroleum gas (LPG) biomass, electric vehicles
	Traffic management	Reduce and enforce highway speed limits, use highoccupancy vehicle lanes, reduce traffic congestion to improve traffic efficiency and reduce oil consumption.
Domestic oil production	Petroleum exploration and production	Increase domestic oil supply by improved conventional and enhanced oil recovery technologies

* Includes the options of self-generation and purchases from nonutility generators

SOURCE: Office of Technology Assessment, 1991, from Renova Engineering, P. C., “Oil Replacement Analysis—Evaluation of Technologies,” OTA contractor report, February 1991.

RESIDENTIAL AND COMMERCIAL SECTORS

In 1989 the residential and commercial sectors used 1.4 MMB/D of petroleum products.[6] Oil use was split among distillates, kerosene, residual fuel oil, and liquefied petroleum gases (LPG). (See table 3-5.) Space and water heating accounted for 98 percent of residential oil use and was also the predominant application in the commercial sector, although propane was used in many commercial establishments for cooking.

A vigorous effort to reduce oil use in the residential and commercial sectors by switching to natural gas, electricity, coal, and renewable fuels, and by speeding the adoption of efficiency improvement measures, could replace almost 1 MMB/D, or about 72 percent of 1989 petroleum consumption as shown in table 3-6. OTA’s analysis identified similar potential in these sectors in 1984.

Oil Use in the Residential and Commercial Sectors

According to Department of Energy (DOE) surveys, over 17 million residential and commercial units use distillate fuel, kerosene, or LPG as their

[6] U.S. Department of Energy, Energy Information Administration, *Annual Energy Review 1989*, DOE/EIA-0384(89) (Washington, DC: U.S. Government Printing Office, May 1990), table 61, p. 137. Hereinafter *Annual Energy Review 1989.*

Table 3-4-Oil Replacement Options Excluded From Assessment

Sector	Option	Basis for exclusion
Electric utilities	Increase imports	New imports of Canadian power above levels currently planned or projected are not included because of uncertainties over transmission system capability. Where possible, additional imports could displace oil.
	Large hydro	There are only a few suitable and environmentally acceptable new sites left in the country.[1]
	Ocean energy	Use of ocean energy in the form of temperature gradient or wave power is in the early stages of development.[1]
	Photovoltaic	Does not offer a large-scale potential, Currently 219 photovoltaic systems provide about 11 MWe with costs in excess of $5,000/kW. (Small PV systems for remote applications are considered elsewhere,)[2]
	Interregional power	Transmission constraints limit opportunities for increased interregional transfer of power from available non-oil based capacity.[3]
Residential/ commercial	Wind energy	Use of wind energy for buildings and in mechanical drives is not expected to make a significant contribution within 5 years.[4]
Industry	Wind energy	Use of wind energy for buildings and in mechanical drives is not expected to make a significant contribution within 5 years.[4]
	Biomass gasification	Biomass gasification will compete with direct use in industrial applications. Direct use of biomass fuels is covered as an option for industry.
	Coal gasification	Coal gasification combined cycle (CGCC) technology is used as an option for electric utilities and some industrial applications.
	Geothermal	Use of conventional geothermal in industry is limited because of the need for close proximity between the geothermal source and end-user,
	Materials and chemicals from biomass	Technology for biomass-based materials and chemicals is not yet established.
	Solar thermal	Use of solar thermal for power generation is economically more attractive than its use in industry.
Transportation	Coal in railroads and vehicles	Mild coal gasification technologies which could permit the use of clean coal char or coal-derived liquids in railroads and vehicles are in pilot plant or prototype demonstration plant phases.
Oil supply	Oil from tar sands, oil shale, and coal liquefaction	Long lead technologies that will require more than 5 years to significantly impact the domestic oil supply.

1 *Engineering News Record, Sept.* 13, 1990, p. 26.
2 U.S. Department of Energy, Energy Information Administration, *Power Engineering,* April 1990, p. 11.
3 *Estimates of Short Term Petroleum Fuel Switching Capability,* DOE/EIA-0526 (Washington, DC: U.S. Government Printing Office, May 1989).
4 Gibbs & Hill, Inc., "Oil Replacement Analysis, Phase I—The Technologies," OTA contractor report, April 1983.
5 *Chemical* Engineering& News, Sept. 10, 1990, P. 19.
6 Dennis Horgan, Luz international personal communication to Renova Engineering, P.C., Sept. 19, 1990.
7 Martin J. Hapeman, "Coal-Derived Fuels as Successful Petroleum Replacements and Unique Opportunities Offered to U.S. Railroads," PaPer presented at Coal—Targets of Opportunity Workshop. DOE, proceedings, Washington, DC, July 12-13, 1988.
8 Richard A. Wolfe and Chang J. Im, "Liquid Coal—The Future Fuel for Locomotive Engines," paper presented at Coal—Targets of Opportunity Workshop, ibid.
9 Richard A. Wolfe Coal Research Technology Corp., personal communication to Renova Engineering, P. C., Sept. 26, 1990.
10 Ken Markel, U.S. Department of Energy, Energy Information Administration, Morgantown, personal communication to Renova Engineering, P. C., Oct. 4, 1990.

SOURCE: Office of Technology Assessment, 1991, from Renova Engineering, P. C., "Oil Replacement Analysis—Evaluation of Technologies," OTA contractor report, February 1991.

primary heating fuel.[7] These include some 16.4 million residential units and about 0.8 million commercial buildings. Table 3-7 and figure 3-1 summarize energy use in the residential sector by region in 1987. A map of census regions can be found in the appendix. Table 3-8 shows selected characteristics of residential units using oil or LPG as their main heating fuel. Residential distillate and kerosene use is concentrated in the Northeast, while LPG use is largely split between the Midwest and South.

[7] The primary source for information on energy use in the residential sector is the Residential Energy Consumption Survey conducted by DOE about every 3 years. The latest published survey data indicated that in 1987 there were over 90.5 million residential housing units or households consisting of 60.5 million single family units including both attached and detached single family houses, 5.1 million mobile homes, and 25 million residential units in multifamily buildings of 2 or more units. U.S. Department of Energy, Energy Information Administration, ***Household Energy Consumption and Expenditures 2987,*** part 2, regional data, DOE/EIA-0321(87)/2 (Washington, DC: U.S. Government Printing Office, January 1990), table 2, pp. 28-29. Information on commercial energy use is published in U.S. Department of Energy, Energy Information Administration, ***Nonresidential Buildings Energy Consumption Survey: Commercial Buildings Consumption and Expenditures 1986,*** DOE/EIA-0318(86) (Washington, DC: U.S. Government Printing Office, May 1989). Hereinafter ***Commercial Buildings Consumption and Expenditures 1986.***

Table 3-5-Consumption of Petroleum Products in the Residential and Commercial Sectors, 1989
(thousand barrels per day)

Sector	Fuel oil & kerosene	Residual fuel oil	LPG	Total
Residential	563	0	294	857
Commercial	327	110	106	543
Total	890	110	400	1,400

SOURCE: Office of Technology Assessment, 1991, based on data from U.S. Department of Energy, Energy Information Administration, *Annual Energy Review 1989, DOE/EIA-0384(89)* (Washington, DC: U.S. Government Printing Office, May 1990), table 62. The total consumption was prorated among the sectors and type of fuel based on estimates in U.S. Department of Energy, Energy Information Administration, *Estimates of Short-term Petroleum* Fuel Switching Capability, DOE/EIA-0526 (Washington, DC: U.S. Government Printing Office, May 1989).

Although natural gas and electricity were the predominant heating fuels in new residential units in the 1980s,[8] the number of households burning oil products for heat increased from 15.8 million in 1981 to 16.4 million in 1987.[9] Most of the increase came in homes using kerosene or LPG. Over the same period, the number of households using distillate oil for heating declined from about 11.3 million in 1981 to 10.9 million. Between 1984 and 1987, over 600,000 homes changed from oil to gas heat.[10]

The United States has over 4 million commercial buildings, with a total floor area in excess of 56 billion square feet.[11] About 500,000 commercial buildings use fuel oil or kerosene as their main heat source, and some 250,000 use LPG.[12] Oil-heated commercial floorspace totals 8.7 billion square feet. Table 3-9 shows selected characteristics of commercial buildings heated by oil or LPG. Figure 3-2 shows commercial energy consumption by fuel and region.

Oil Replacement Options

The primary strategies for reducing oil use in the residential and commercial sectors are fuel switching and energy-efficiency measures. Most savings are

Table 3-8-Estimated Oil Replacement Potential in the Residential and Commercial Sectors
(thousand barrels per day)

Option	Residential	Commercial	Total
Natural gas	318	160	478[a]
Electricity	407	—	407[b]
Coal	–	62	62[c]
Renewable fuels and efficiency improvements	—	—	45[d]
Total	725	222	992

[a]consists of 440,000 barrels per day (B/D) of distillate oil/kerosene and

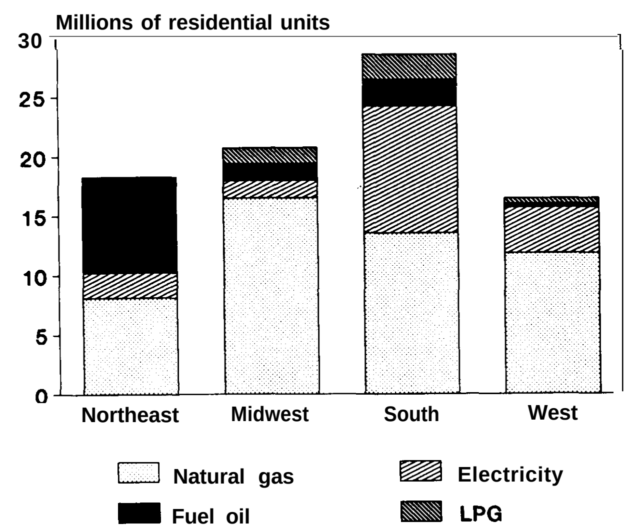
[b]Consists of 215,000B/D distillate oil/kerosene and 192,000 B/D of LPG.

[c]Consists of 39,000 B/D of residual oil, 16,000 B/D of LPG and 7,000 B/D of distillate oil/kerosene.

[d]Totals about 45,000 B/D savings in distillate, residual oil, kerosene, and LPG across both sectors (1 2,000 B/D from woodstoves and fireplaces and 33,000 B/D from various efficiency measures).

SOURCE: Office of Technology Assessment, 1991, based on Renova Engineering, P. C., "Oil Replacement Analysis-Evaluation of Technologies," OTA contractor report, February 1991.

Figure 3-l—Residential Space Heating by Region and Main Heating Source, 1987



SOURCE: Office of Technology Assessment, 1991, based on data from U.S. Department of Energy, Energy Information Administration, *Housing Characteristics 1987, Residential Energy Consumption Survey, DOE/EIA-0314(87)* (Washington, DC: U.S. Government Printing Office, May 1989).

[8]American Gas Association, *Gas Facts—1988 Data,* tables 11-5 and 11-6.

[9]U.S. Department of Energy, Energy Information Administration, ***Housing Characteristics 1987,*** DOE/EIA-0314(87) (Washington, DC: U.S. Government Printing Office, May 1989), table ES-1, page viii. Hereinafter referred to as *Housing Characteristics 1987.*

[10]Ibid., p. 12.

[11]*Annual Energy* Review 1989, supra note 6, table 28, p. 63.

[12]A total of 534,000 buildings reported using oil, but not all of these use it for space heating. Another 344,000 commercial buildings reported USe Of LPG, but only 250,000 used it for space heating. ***CommercialBuildings Consumption andExpenditures 1986,*** supra note 7, tables 16 and 34.

Table 3-7—Energy Use in the Residential Sector by Region, 1987

	Northeast	Midwest	South	West	Total U.S.
Residential space heating by region (millions of units)					
Main heating source					
Natural gas	8.1	16.5	13,5	11.8	49.9
Electricity	2.1	1.4	10.6	3.8	17.9
Distillates & kerosene	8.1	1.5	2.3	0.3	12.2
Liqufied petroleum gases	—	1.3	2.1	0,5	3.9
Wood	0.6	1.3	1.9	1.3	5.1
Residential fuel consumption by region (quadrillion Btus)					
Major fuels					
Natural gas	1,03	1.83	1,09	0.88	4.83
Electricity	0.44	0.61	1.22	0.48	2.76
Distillates&kerosene	0.87	0.16	0.17	0.02	1.22
Liquefied petroleum gases	O.O2	0.13	0.12	0.05	0,32
Total	2.37	2.73	2,61	1.42	9.13
Wood (million cords)	8.3	12.5	13.2	*8.6*	42,6

SOURCES: Office of Technology Assessment 1991, based on data from U.S. Department of Energy, Energy Information Administration, *Housing Characteristics 1987: Residentia/Energy Consumption Survey, DOE/EIA-0314(87)* (Washington, DC: U.S. Government Printing Office, May 1969); and U.S. Department of Energy, Energy Information Administration, *Household Energy Consumption and Expenditures 1987, Part 2 Regional Data, DOE/EIA-0321 (87)/2* (Washington, DC: U.S. Government Printing Office, January 1990).

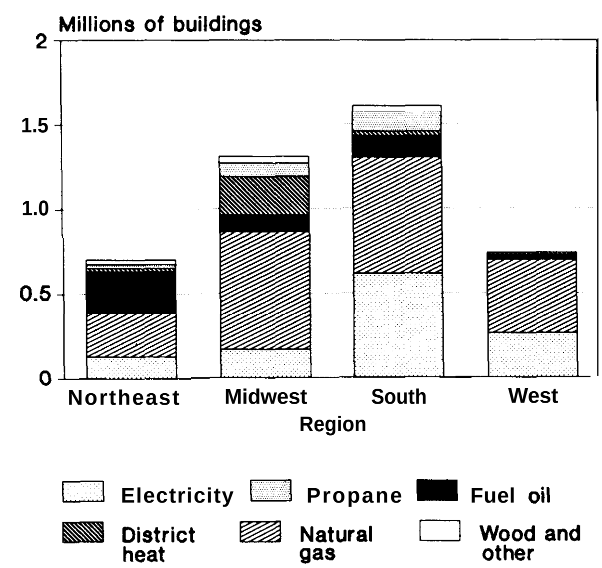
actually a combination of the two, since replacement equipment is often more energy-efficient than the old oil-burning units. We estimate that conversion to natural gas, electricity, and coal would reduce oil consumption from 1.4 MMB/D to 453,000 B/I) in 5 years--l32,000 B/I) in residential units and 321,000 B/D) in commercial buildings. This consumption could be further reduced by at least 45,000 B/I) by using renewable fuels and intensifying the use of efficiency improvement measures.

Natural Gas

OTA estimates that switching to natural gas in residential and commercial buildings could displace about 478,000 B/D in residential (318,000 B/D) and commercial (160,000 B/D) buildings over 5 years. Many oil-heated residential and commercial buildings are already connected to natural gas lines or located in areas served by gas distribution networks. These buildings would be prime candidates for conversion to natural gas-fired systems.

About 3.3 million households that use distillate oil and kerosene as their main heating fuel are connected to natural gas lines, as are 0.5 million units that use

Figure 3-2-Commercial Buildings Space Heating by Fuel and Region, 1986



SOURCE: Office of Technology Assessment, 1991, from data in U.S. Department of Energy, Energy Information Administration, *Non-residential Buildings Energy Consumption Survey: Characteristics of Commercial Buildings Consumption 1986, DOE/EIA-0246(86)* (Washington, DC: US. Government Printing Office, September 1988), table 36.

Table 3-8-Characteristics of Households Heated by Oil and LPG
(millions of units)

Housing units	Northeast	Midwest	South	West	Total U.S.
Oil as main heating fuel					
Total households	8	1.5	2.3	0.02	12.2
Single family	4.3	1.4	1.8	0.02	7.8
Mobile home	NA	NA	0.3	NA	0.8
Multi-family	3,3	NA	NA	NA	3.5
Ownership					
Owner-occupied	5.0	1.3	1.6	0.02	8.2
Rental	3.0	0.2	0.7	NA	4.0
Location					
Urban	2.8	0.3	0.5	NA	3.7
Suburban	4,3	0.7	0.6	NA	5.7
Rural	1.0	0.6	1.2	NA	2.8
Units with secondary heat	2.4	0.8	1.5	0.02	5.0
Hot water heating fuel					
Oil	5.0	NA	NA	NA	5.2
Natural gas	1.2	NA	NA	NA	1.5
Electric	1.6	1.3	1.9	0.02	5.1
Other	0.2	NA	NA	NA	0.4
LPG as main heating fuel					
Total households	0.5	1.3	2.1	0.6	4,1
Single family	NA	1.0	1.4	0.4	2.9
Mobile home	NA	NA	NA	NA	1.2
Multi-family	NA	0.3	1.7	NA	NA
Ownership					
Owner-occupied	NA	1.1	1,7	0.5	3.4
Rental	NA	0,2	0.5	NA	0,7
Location					
Urban	NA	NA	0.3	NA	0.3
Suburban	NA	0.4	0.8	0.3	1.5
Rural	NA	0,9	1.0	0.3	2,3
Units with secondary heat	O.5	0,7	1,1	0.4	2,3
Hot water fuel					
Oil	NA	NA	NA	NA	NA
Gas	NA	NA	NA	NA	NA
Electricity	NA	0.5	1.4	0.2	2.2
Other	NA	0,8	0.7	0.4	1.9

NOTE: NA = not available, data not reported.

SOURCE: Office of Technology Assessment 1991, from data in U.S. Department of Energy, Energy Information Administration, Household Energy *Consumption and Expenditures 1987 Part 2: Regional Data,* DOE/EIA-0321(87)/2 (Washington, DC: U.S. Government Printing Office, January 1990).

LPG.[13] Assuming that adequate natural gas supplies were available, it might be economically feasible in an oil shortfall to install the required network of small distribution lines in urban and suburban areas to connect many of the oil burning residential units without access to natural gas.[14]

We estimate that it would be feasible to convert about 6.5 million oil or LPG-heated residences to natural gas in an emergency. Switching the 3.3 million units already with gas service and connecting about 2.7 million new residential gas customers would replace about 280,000B/D of distillate oil and kerosene. Converting a1l 0.5million LPG users with gas service would save an additiona1 38,000 B/D.

Sixty percent of commercial buildings using fuel oil, and nearly three-quarters of the floor space, are concentrated in metropolitan areas, where it isgenerally easier to add gas service.[15] Of the half million commercial buildings that use distillate, kerosene, or residual oil, 10 percent, or about 0.05 million build-

[13] *Housing Characteristics* 1987, supra note 9, table 21, p. 61. U.S. Department of Energy, Energy Information Administration, *Estimates of Short-Term Petroleum Fuel Switching Capability*, DOE/EIA-0526 (Washington, DC: U.S. Governmen tPrintingOffice, May 1989) table 10, p.22.

[14] Gibbs & Hill, Inc., "Oil Replacement Analysis, Phase I-Selection of Technologies," OTA contractor report, April 1983.

[15] *Commercial Buildings Consumption and Expenditures 1986,* supra note 7, table 34, p. 188.

Table 3-9-Characteristics of Commercial Buildings Heated by Oil or Propane From 1986 Nonresidential Buildings Energy Consumption Survey

	Oil		Propane	
	Buildings (000s)	Million sq. ft.	Buildings (000s)	Million sq. ft.
All buildings reporting use	542	11,163	351	3,362
Buildings heated by oil or propane	513	8,846	252	1,832
Location				
Northeast	252	4,515	25	331
Midwest	100	1,426	81	411
South	131	2,140	120	929
West	30	765	NA	NA
Building floorspace (000 sq. ft.)				
1-5	*241*	*688*	179	488
5-lo	*135*	*988*	41	299
10-25	*69*	1,101	21	345
25-50	*38*	1,368	NA	NA
50-100	*16*	1,057	NA	NA
100-200	*7*	1,055	NA	NA
over 200	7	2,587	NA	NA
Building activity				
Assembly	71	1,387	66	456
Education	32	1,675	NA	NA
Food sales	NA	NA	NA	NA
Food service	NA	NA	NA	NA
Health care	9	737	NA	NA
Lodging	15	402	NA	NA
Mercantile/service	206	1,819		454
Office	69	918	NA	NA
Public order & safety	NA	NA	NA	NA
Warehouse	49	1,119	24	315
Other	18	302	NA	NA
Vacant	NA	NA	NA	NA
Buildings heated primarily by oil or propane	434	6,642	215	1,246

NOTE: NA= not available because of insufficient data.

SOURCE: Office of Technology Assessmen, 1991, based on data in U.S. Department of Energy, Energy Information Administration, *Commercial Buildings Energy Consumption Survey: Commercial Buildings Characteristics 1986, DOE/EIA-0246(86)* (Washington, DC: U.S. Government Printing Office, September 1988), tables 33, 34, 35, 36, and 37.

ings, are already connected to natural gas lines.[16] Converting half of these buildings, including those with dual-fuel capacity, and adding 200,000 new commercial natural gas customers would replace an estimated 160,000 B/D. Some of these conversions might entail installing cogeneration systems to provide hot water, space conditioning, and electric power with any excess power sold to a local utility.[17] Most commercial buildings using propane are inruralareas or do not have access to natural gas distribution networks and would, therefore, not be the most likely candidates for conversion.[18]

The 478,000 B/D in natural gas replacement potential for 1989 in the sesectors is slightly more than the 440,000 B/D in natural gas replacement potential estimated in our 1984 report, but involves a smaller number of units.[19] This translates into an increased demand for natural gas of about 0.96 trillion cubic feet (TCF).

Electricity

In a crisis, electric heat pumps and portable and fixed baseboard electric resistance heaters could replace the use of oil for comfort heating. Also, electric hot water heaters could replace oil-fired hot water heaters. The principal candidates for conversion to electricity would be some 9 million residential units that cannot be converted economically to naturalgas because of the lack of a gas supply infrastructure.[20] These include 5.4 million units using distillate oil or kerosene and 3.6 million units using LPG. Converting three-quarters of these homes, a total of about 6.75 million units, to electricity could replace about 4O7,OOO B/D of oil over a 5-year period. This changeover would increase the number of electrically heated homes significantly (i.e., by about one-third).[21]

[16] U.S. Department of Energy, Energy Information Administration, *Estimates of Short-Term Petroleum Fuel Switching Capability*, DOE/EIA-0526 (Washington, DC: U.S. Government Printing Office, May 1989) (Hereinafter *Short-Term Petroleum Fuel Switching)* table 12, p. 26. According to DOE, these buildings account for half of all oil-heated commercial floor space, but their oil consumption in 1983 was only 17,000 bbls/day,soitis unclear how much oil their conversion will actually displace.

[17] More than 600 cogeneration systems have been installed in commercial facilities through 1987. The commercial sector, in general, has a large untapped cogeneration potential of 40,000 MW, according to an analysis by Oak Ridge National Laboratory, ***Energy Technology R&D: What CouldMake a Difference? Volume 2, Part 1 of3, End-Use Technology,*** ORNL-6541/V2/P1, December 1989, p. 50.

[18] *Commercial Buildings* Consumption and ***Expenditures 1986,*** supra note 7, table 18, pp. '~91.

[19] The 1984 report estimated that 80 percent of urban households, 7 million units, and 80 percent of commercial buildings could be converted to natural gas, OTA, ***The Oil Replacement Capability,*** supra note 1.

[20] *Housing Characteristics* 1987, supra note 9, table 21, p. 61.

[21] Electric heat was used b, about 20 percent of homes and 30 percent of commercial buildings in 1987. According to U.S. Department of Energy (DOE) survey data, 17.9 million residences were electrically heated. ***Housing Characteristics 2987,*** supra note 9, footnote 9, p. 12. Over 90 percent of the electrically heated homes were located in areas without access to natural gas. By 1987, about half of all new homes used electric heat, often in the form of a heat pump that could be used for both heating and cooling. Almost **1.2** million commercial buildings used electric heat, about 60 percent of these in the South.

About 2.5 million of these oil to electric conversions would be in households using LPG. Many of these buildings are located in rural areas, and some could require upgrading of service and improvements to the local electric transmission and distribution systems to accommodate the increased load.[22]

Although electric space and water heating is common in commercial buildings, we have generally not assumed any large-scale replacement of oil heat with electricity in commercial buildings because for many it would not be the least expensive option. However, in a crisis, many small commercial buildings that use propane could opt for electric heat.

A share of these oil to electric conversions would occur in colder regions, where electric heat pumps alone could not maintain comfort in extreme cold. Below 20 to 30°F, electric resistance heat is more effective, and heat pumps are often equipped with resistance heat for low-temperature operation. If one-third of the heat pump conversions had to operate on electric resistance heating at the same time, it would increase the winter peak load in these regions by as much as 11,000 megawatts (MW).[23] Although capacity seems ample to absorb such an increase, some local systems may find capacity margins strained.[24] There is, however, as we noted in our 1984 report, a sticky technical issue of whether replacing oil heat with heat pumps in some very cold areas would effectively displace oil, especially if utilities must burn oil to generate the electricity.

Electric heat pumps typically have efficiencies (heat delivered to the inside air divided by the energy used to run the device) of over 100 percent, and some as high as 200 percent.[25] In contrast, oil heat has an efficiency of about 65 percent. This means that an efficient heat pump requires about one-third as much energy (in the form of electricity) as an oil furnace requires (in the form of oil) to deliver the same amount of heat. This makes the heat pump an attractive alternative for replacing oil, but only if the electricity is not generated from oil. If, however, the electricity is generated with oil, for which the efficiency of converting fuel to electricity is about 32 percent, this potential oil replacement is lost, since it would require at least as much oil to produce the electricity as would be saved by the heat pump. Consequently, in terms of oil replacement, heat pumps are attractive only where marginal electricity is generated from fuels other than oil.[26]

The Northeast is among the regions where some oil use for electric generation is most likely to continue after an oil shortfall. That region's cold winters reduce the efficiency of the heat pumps creating the possibility that burning oil to produce electricity for heat pumps could lead to a net increase in oil consumption; and it would be, at best, a questionable strategy to promote heat pumps as a means of displacing oil there.[27] Nonoil generating capacity additions in the Northeast region since 1984 have somewhat improved the potential for using electric heat to backout oil for some residential users.

Recent advances have made heat pump technology more energy-efficient, economical, and practical for commercial and residential installations in colder climates.[28] A dual-fuel, electric-gas heat pump jointly developed by the Lenox Corp. and the Electric Power Research Institute (EPRI) heats with natural gas in extreme weather conditions.[29] Electronic controls monitor the unit and switch to the most economical

[22] OTA, *The Oil Replacement Capability,* supra note 1.

[23] Renova Engineering, P. C., supra note 4.

[24] Planned winter capacity resources in the Northeast and Mid-Atlantic state.. in 1995 are projected to exceed the projected winter peak deman[d] [with] projected capacity margins of 26.9 pereent in the Northeast Power Coordinating Council (NPCC)regionand 30.2 percent in the Mid-AtlanticArea Council. North American Electric Reliability Council, *1990 Electricity Supply & Demand for 1990-1999* (Princeton, NJ: North American Electric Reliability Council, December 1990). With intensified deployment of electric heat pumps, the capacity margins could be squeezed. A detailed study is necessary to evaluate the regional breakdown of this decline in margin and its potential impact on the capacity needs and reliability of local electric utilities.

[25] Heat pumps equipped with resistance heat and/or air-conditioning capability generally have somewhat lower efficiencies.

[26] OTA, *Oil Replacement Capability,* supra note 1, pp. 60-61.

[27] OTA, The *Oil Replacement Capability,* supra note 1, pp. 59-60.

[28] Electric power Research Institute (EPRI) and Carrier Corp. have jointly developed an advanced unitary heat pump that features variable speed compressor, variable speed indoor fan, single speed outdoor fan, and integrated water heating. Two and three ton units are commercially available. A. Lannus, "Residential Program: Current Research Projects," Electric Power Research Institute, January 1990.

[29] Morton Blatt, Electric power Research Institute, personal communication to Renova Engineering, P.C., OTA contractor, Oct. 12, 1990; and "Heat Pumps: Developing the Dual-Fuel Option," *EPRI Journal,* December 1990, pp. 23-27.

fuel for prevailing temperatures. The units are targeted to replace existing gas furnace-electric cooling combination systems common in commercial buildings, but would be suitable for replacing oil units. The heat pump is commercially available in the 7.5- to 10-ton range, which is appropriate for commercial buildings of 2,000 to 4,000 square feet, including many stores, restaurants, and small office buildings. Initial commercial installations have resulted in savings of up to 41 percent on monthly utility bills. This combination could make conversion from oil togas electric systems an attractive alternative for commercial buildings, but we have not included such conversions in our oil savings. The most likely candidates are already in the target population for oil to gas switching in the commercial sector.

Coal

The large commercial buildings that are not converted to natural gas could be candidates for conversion to coal or coal slurry fuel (CSF), a coal-water mixture that contains up to 70 percent finely ground coal and can be pumped, transported, and stored much like heavy oil. Because of their energy intensity and large size, hospitals, nursing homes, educational institutions, hotels, and motels provide the most promising opportunities for installing coal-based cogeneration systems to provide heat, hot water, and electric power.[30] A number of such facilities have already installed coal-fired cogeneration systems to replace oil.[31]

The potential candidates for coal-based systems can be divided in three groups:[32]

- Group 1—100,000 buildings with large boiler systems that currently use 110,000 B/D) of resid.
- Group 11—300,000 buildings mostly in rural areas that currently use 106,000 B/I) LPG.
- Group III-200,000 other commercial buildings that use 160,000 B/I) of distillate oil and kerosene.

Converting to coal is not a small task and the decision would be determined by individual site characteristics. The site must be able to accommodate fuel storage, handling, and waste storage or disposal facilities, in addition to the actual boilers, generators, and pollution-control equipment. Group I buildings offer the best potential for coal conversion.

OTA has assumed conversion rates of 35,15, and 5 percent for Groups I, II, and III respectively. Thus, conversion of 88,000 commercial buildings to burn coal could replace about 62,000 B/D of oil.

Renewable Energy Sources

Increased use of wood as a primary or secondary heating source could provide a handy short-term means of cutting residential oil use in some areas.[33] The number of U.S. households that use wood as a primary heating fuel has declined from 6.5 million in 1984 to 5.1 million in 1987.[34] Over 19 million households have woodburning stoves or fireplaces as a secondary heat source, including 3.7 million homes primarily heated by oil or LPG.[35] If 250,000 households converted to wood in a crisis, it would save about 12,000 B/D.

About half of oil heated homes use oil for water heating as well. Some of these homes maybe appropriate candidates for solar water heating. Solar hot water heaters could replace, on average, about 300 gallons per year of oil per household.[36] The relatively high cost of solar equipment and limited insolation may limit the use of solar energy in colder regions, however.[37]

30A. John Rezalyn et al., "Site Specific Coal Energy System Assessments," paper presented at Coal-Targets of Opportunity Workshop, U.S. Department of Energy, July 12-13, 1988, Washington, DC.

31For example, micronized coal cogeneration plants have been installed at Missouri and Ohio hospital complexes. Micronized coal is pulverized to a fineness of 15 to 20 microns, more than 10 times finer than conventional pulverized coal and its burning characteristics are similar to oil or gas making it an attractive option for modifications of existing plants. Tom Elliott, "Latest Micronized Coal Mills Consume Less Energy, Cost Less," *Power,* July 1990, pp. 39,42-44.

32Renova Engineering, P. C., supra note 23, p. 39.

33OTA, The *Oil Replacement Capability,* supra note 1.

34*Housing Characteristics 1987,* supra note 9, table ES-1, p. 'iii.

35*Housing* Characteristics 1987, supra note 9, table 21.

36Michael Winerip, "A Gulf Question: Don't You Wish You Had Solar?" The *New York* Times, Tuesday, Sept. 25, 1990.

37Use of solar heating to replace oil use indirectly might be an attractive option in areas of the Southeast, such as Florida, as a means of reducing demand for oil-fired electricity.

Efficiency Measures

Our 1984 report estimated that residential and commercial oil use could be reduced on average by 25 percent per unit through a combination of weatherization and burner efficiency upgrades.[38] The residential sector is highly flexible in its ability to conserve energy and to respond to fuel price changes.[39] A significant number of households have already adopted one or more conservation measures in response to earlier oil supply crises, but some incremental efficiency savings likely remain.[40]

Replacing inefficient oil burners with more efficient ones can reduce oil consumption by as much as 25 percent.[41] Old oil burners typically have conversion efficiencies of 65 percent, at best. Newer burners can achieve efficiencies of 85 percent or more. For example, in one study in Michigan, retrofitting oil furnaces with flame retention burners, which improve oil and air mixing and thus burn fuel more completely than do conventional burners, yielded average fuel savings of 25 percent at installation costs of $570 per unit, or $0.27 per gallon of oil saved.[42]

Insulating hot water tanks and pipes and improving the efficiency of the area heated by adding ceiling and wall insulation, storm windows, caulking, and weatherstripping can also have paybacks in reduced oil consumption and lower energy costs.

The commercial sector could adopt similar options to reduce oil use. For example, almost two-thirds of commercial oil users surveyed by DOE reported adoption of building energy conservation measures.[43] Most cited preventive maintenance, ceiling and wall insulation, and weatherstripping and caulking, but the data did not indicate whether these measured had captured all of the potential energy savings available. Few respondents had adopted more sophisticated measures such as time clock thermostats, waste heat recovery, or energy management control systems. More than 85 percent of these buildings had never had an energy audit.

It is likely that there remains incremental energy conservation potential in the commercial sector as well. Improved operations and maintenance practices could optimize steam or hot water generation efficiency, reduce thermal losses in distribution piping, and improve system controls for conserving thermal energy.

OTA's earlier analysis found that replacing or retrofitting commercial equipment with more efficient burners also offers average fuel savings of 20 to 25 percent per unit.[44] Using oil-water emulsion fuels in residual oil-fired boilers can reduce oil consumption by 5 to 10 percent.[45]

We estimate that use of various energy conservation and efficiency improvements in existing equipment and buildings could save about 33,000 B/D additionally.

Deployment Considerations

Table 3-6 summarizes the breakdown of the estimated 1 MMB/D of oil that could be replaced in the residential and commercial sectors by the various options assessed above. The major concerns in meeting these oil replacement estimates involve: 1) the adequacy of the manufacturing and installation capability for new or retrofitted equipment, and 2) the availability of substitute energy resources—namely, natural gas and electricity. Neither of these concerns are expected to be constraints in achieving oil replacement targets if aggressive private and government efforts are made.

[38]OTA, *The Oil Replacement Capability,* supra note 1, p. 104.

[39]U.S. Department of Energy, "Energy Conservation Trends-Understanding the Factors that Affect Conservation Gains in the U.S. Economy," DOE/PE-0092, September, 1989. and U.S. Department of Energy, ***National Energy Strategy, Interim Report, a Compilation of Public Comments,*** DOE/S-OO66P, April 1990.

[40]*Housing Characteristics 1987,* supra note 9, table 33 shows installation of various weatherization measures in housing units and indicates there still are units in cold climates without, for example, storm doors and windows, or adequate insulation in ceilings, walls, and floors.

[41]Thomas J. Lueck, "Taking a New Look at Energy Saving," ***The New York Times,*** Sunday, Sept. 16, 1990.

[42]Sam Cohen, "Measured Savings: Fifty Million Retrofits Later," ***Home Energy,*** May/June 1990, pp. 11-16, at p. 16.

[43]*Commercial Buildings Consumption **and Expenditures 1986,*** supra note 7, table 34.

[44]OTA, *The **Oil Replacement Capability,*** supra note 1.

[45]John Dooher, Adelphi University, personal communication to Renova Engineering, P.C., OTA contractor, Oct. 3, 1990 and information received frOm Petrofirm, Inc.

Conversions to natural gas would involve 6.75 million residential and commercial units over 5 years. In 1988 manufacturers shipped 2.3 million gas-fired warm air furnaces and boilers.[46] The Gas Research Institute (GRI) has projected that gas-fired replacement systems will range between 2 and 2.8 million units per year between 1988 and 2010.[47] At this level, manufacturing capacity for replacement boilers is not expected to be a constraint.[48]

The manufacturing capacity for oil-to-gas conversion burners has declined by about 50 percent compared with the peak period of 1979-81.[49] Residential gas heating conversions peaked in 1980 at 583,000, of which 85 percent were oil-to-gas conversions.[50] In recent years, the annual conversions to natural gas have settled at 150,000 to 200,000, with an increasing share of conversions from electricity y to natural gas.[51] Assuming a 70-percent capacity utilization in 1980, the current manufacturing capacity for oil-to-gas conversion burners is thus estimated to be only 350,000 units per year. This major constraint could be overcome by shifting some of the new burner manufacturing capacity to the production of conversion burners during a crisis.

We have assumed, that based on our earlier analysis, there will not be any major manufacturing constraints in converting to electricity .[52]

Small, modular, pulverized, or micronized coal-fired cogenerating units can be designed, manufactured, and installed in 14 months, on average.[53] Conversion to CSF will take 2 to 3 years because of the need to erect CSF plants and obtain the necessary environmental permits relatively smoothly over a permitting process of 12 to 18 months.[54]

Natural gas availability and electric generation capability considerations are addressed more fully later in this chapter. While some natural gas and electricity supply constraints are possible in the Northeast and Mid-Atlantic States that might limit fuel switching, we believe that these are not insurmountable. The potential constraints on natural gas conversions may in fact be less than they were in our 1984 analysis because of more abundant supplies of natural gas and planned new pipeline capacity.

Table 3-1 O-Deployment Schedule for Oil Replacement Technologies in the Residential and Commercial Sectors (thousand barrels per day)

	Fuel switching option				
Year	Gas[a]	Elect.[a]	Coal[b]	Efficiency/ renew.[c]	Total
1991	96	81	0	15	192
1992	191	163	0	30	384
1993	287	244	0	45	576
1994	382	326	31	45	784
1995	478	407	62	45	992

[a]Assumes Uniform deployment over 5 Years.
[b]Assumes oil replacement in the last 2 years.
[c]Assumes uniform deployment in the first 3 years.

SOURCE: Office of Technology Assessment, 1991, based on Renova Engineering, P. C., "Oil Replacement Analysis-Evaluation of Technologies," OTA contractor report, February 1991.

Without these constraints, the conversion to natural gas and electricity could occur uniformly over the assumed 5-year period. The use of renewable fuels and efficiency improvement measures are expected to show results early in the first 3 years. Coal replacements of oil would begin only in the last 2 years. A deployment schedule based on such a scenario is shown in table 3-10.

The estimated investment costs for the various oil replacement options are shown in table 3-11. The table shows the range in cost in thousands of dollars per barrel of oil per day replaced for technologies considered. If all the identified residential and commercial oil replacement technologies were deployed, we estimate the total cost to be about $97 billion. The

[46]American Gas Association, *Gas Facts—1988 Data*, table 11-2.

[47]Gas *Research* Institute, "1990-1994 *Research* and Development Plan and 1990 Research and Development Program," 1989.

[48]Messrs Eisenbeis and Newton, Burnham America, Inc., personal communication to Renova Engineering, P. C., OTA contractor, Oct. 3, 1990. Ed Anderson, Brooklyn Union Gas Co., personal communication to Renova Engineering, P. C., OTA contractor, Oct. 4, 1990.

[49]Terry Adams, Adams Manufacturing, Inc., personal communication to Renova Engineering, P. C., OTA contractor, Oct. 3, 1990.

[50]American Gas Association, "The Outlook for Gas Energy Demand: 1990-2010," May 1990.

[51]Ibid.

[52]OTA, *The Oil Replacement Capability,* supra note 1.

[53]Elliott, supra note 31.

[54]Ed McHale, Atlantic Research Corp., personal communication to Renova Engineering, OTA contractor, Sept. 19, 1990. Clay Smith, Otisca Industries, Inc., personal communication to Renova Engineering, OTA contractor, Oct. 3, 1990.

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Table 3-1 l—Estimated Investment Costs for Oil Replacement Technologies in the Residential and Commercial Sectors
(approximate investment cost in thousand 1990 dollars per barrel per day of oil replaced)

Option	$000 per B/D replaced		Remarks [a]
	Minimum	Maximum	
Natural gas	25	38	Minimum-conversion of homes at $800 for a 160,000 Btu/hr burner. Maximum--conversion of commercial buildings at $25,000 for a 25 MM Btu/hr burner.[b]
	47	111	Minimum-replacement boiler for homes at $2,000 for a 160,000 Btu/hr unit. Maximum-new boiler for commercial buildings at $75,000 for a 25 MM Btu/hr unit.
Electricity	28	113	Electric resistance heat at $500 for heaters plus hot water heater at $1,000 per household.[c] Electric heat pumps at $5,000 plus hot water heater at $1,000 per household.
Coal	445	667	Assumes CSF-fired boiler cost at four to six times that of a gas-fired boiler in commercial buildings.[d]
Renewable fuels & efficiency improvements	147	179	Minimum—1 O% oil savings in a commercial building with a $10,000 Energy Management System.[e] Maximum-in a household, 300 gal./yr saving from a solar hot water heater at $3,500.

KEY: CSF . coal slurry fuel
[a]Fuel use estimated at 0.053 B/D) per residence and 0.679 B/D per commercial building.
[b]Conversion burner and replacement boiler costs from Eisenbeis and Newton, Burnham America, Inc., Personal communication to Renova Engineering, P. C., Oct. 4, 1990. Terry Adams, Adams Manufacturing, Inc., personal communication to Renova Engineering, P. C., Oct. 3, 1990. Assumes $500 for piping changes in all cases.
[c]Cost data from Gibbs & Hill, Inc., "Oil Replacement Analysis, Phase I—Selection of Technologies," OTA contractor report, April 1983.
[d]Cost of a 25 MM Btu/hr gas-fired boiler at $75,000, Eisenbeis and Newton, Burnham America, Inc., Personal communication to Renova Engineering, P. C., Oct. 4, 1990, plus $500 for piping changes.
[e]Solar hot water heater data from Michael Winerip, "A Gulf Question: Don't You Wish You Had Solar?" *The New York Times*, Sept. 25, 1990.

SOURCE: Office of Technology Assessment, 1991, from Renova Engineering, P. C., "Oil Replacement Analysis—Evaluation of Technologies," OTA contractor report, February 1991.

investment costs for individual technologies per B/I) replaced range from $25,000 B/D replaced for converting residential oil burners to natural gas to $667,000 B/D replaced for installation of a (CSF boiler in a commercial building.

ELECTRIC UTILITY SECTOR

Electric utilities burned about 731,000 B/l) of petroleum products to generate electric power in 1989.[55] Heavy oils (mainly No. 6 residual fuel oil) accounted for most of this demand, or 661,000 B/D (see table 3-12). Use of distillates was relatively small: about 70,000 B/D of light oils or distillates (No. 2 fuel oil), primarily for startup and flame stabilization in conventional steam plants or as a backup fuel in combustion turbines and combined-cycle plants. Oil-fired generation of electricity represents less than 5 percent of U.S. oil consumption and only about 4 percent of net generation. Utility oil use remains concentrated in the Northeast and Mid-Atlantic States, California, Florida, and Hawaii as shown in figure 3-3. These regions together accounted for about 95 percent of all utility oil consumption in 1989. Oil-fired generating

[55]*Annual Energy Review 1989*, supra note 6, table 62, p. 139.

Table 3-12—1989 Oil and Gas-Based Electric Generation and Fuel Consumption by Region (summer generation capacity in 1,000 MW[a])

Federal region	Oil[b]	Dual fuel: Coal/oil[c]	Dual fuel: Gas/oil[c]	Gas[b]	Generation, billion kWh: Oil	Generation, billion kWh: Gas	Fuel used: Oil MB/Dal	Fuel used: Gas million cubic feet/day[e]
1 New England	7.0	2.0	2.0	0.0	37.0	5.2	155	149
2 New York/New Jersey	8.0	0.4	9.2	0.0	46.7	21,8	195	624
3 Middle-Atlantic	5.7	3.9	2.9	0.0	21.9	3.1	91	89
4 South-Atlantic	5.8	3.6	11.7	0.6	28.0	21.8	117	624
5 Midwest	6.1	7.5	0.8	0.2	3.1	1.8	13	52
6 Southwest	0.0	2.8	47.7	8,4	2.8	145.0	12	4,152
7 Central	0.0	4,4	2.2	0.4	0.3	1.9	1	54
8 North Central	0.0	2.4	0.5	0.0	0.2	0.7	1	20
9 West	1.2	3.0	23.2	0.5	17.8	58.6	74	1,678
10 Northwest	0.1	0.0	0.0	0.0	0.5	4.9	2	140
Total	33.9	30.0	100.2	10,1	158,3	264.8	661	7,583

[a]U.S. Department of Energy, Energy Information Administration, *Monthly Energy Review, April 1990;* DOE/EIA-035(90/04) (Washington, DC: U.S. Government Printing Office, July 1990).

[b]Excludes units having dual fuel capability.

[c]Includes units that cannot burn either fuel continuously.

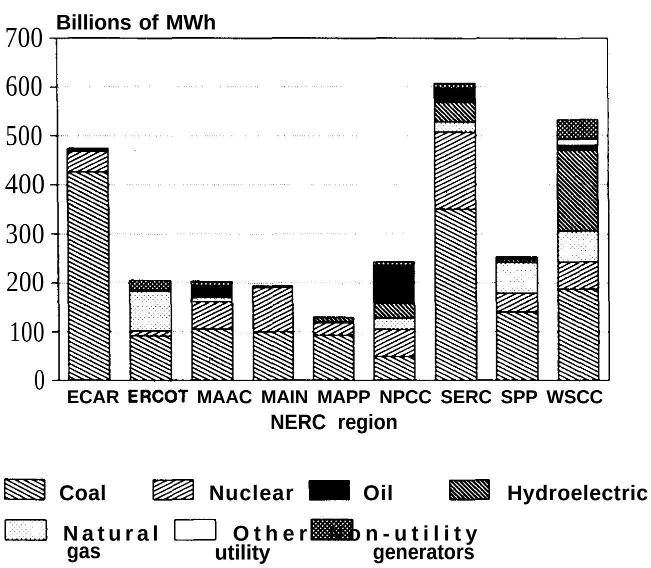
[d]Regional oil-based generation estimated based on 1989 utilities consumption of 241.4 million barrels of heavy oil. This amount was prorated for each region using oil-based generation reported in U.S. Department of Energy, Energy Information Administration, "Petroleum Fuel-Switching Capability in the Electric Utility Industry," *Electric Power Monthly: June 1990,* DOE/EIA-0226(90/06) (Washington, DC: U.S. Government Printing Office, September 1990).

[e]Reference a indicates that in 1989 utilities consumed 2,768 billion cubic feet of natural gas. This amount was prorated for each region using gas-based generation reported.

KEY: MW = megawatt; kWh = kilowatt hour; MB/D . thousand barrels per day.

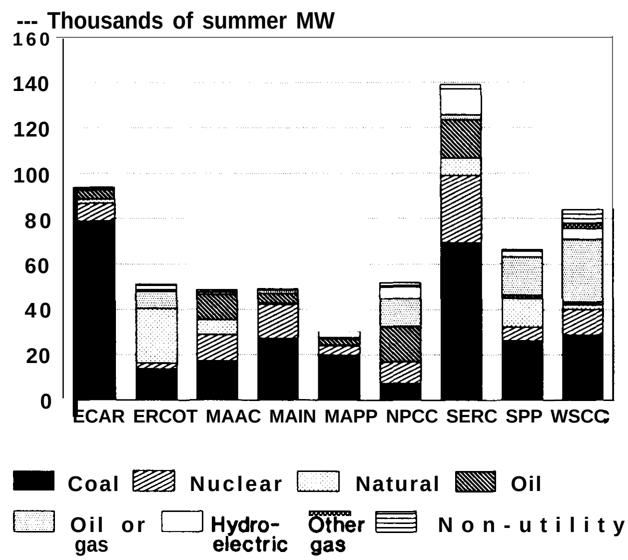
SOURCE: Office of Technology Assessment ,1991, from Renova Engineering, P. C., "Oil Replacement Analysis—Evaluation of Technologies," OTA contractor report, February 1991.

Figure 3-3-Generation of Electricity by Electric Utilities by Region and Energy Source, 1989



SOURCE: (Office of Technology Assessment, 1991, from data in North American Electric Reliability Council, 1990 *Electricity Supply and Demand for 1990-1999* (Princeton, NJ: North American Electric Reliability Council, December 1990), app. B.

Figure 3-4-Electric Utility Generating Capacity by Region and Energy Source, 1989



SOURCE: Office of Technology Assessment, 1991, from data in North American Electric Reliability Council, 1990 Electricity *Supply and Demand for 1990-1999* (Princeton, NJ: North American Electric Reliability Council, December 1990), app. A.

Table 3-13-Estimated Oil Replacement Potential in the Electric Utility Sector
(oil replacement potential–thousand barrels per day)

Federal region	Fuel Switching Option				Demand management[e]
	Gas[a]	Nuclear[b]	Renewables[c]	Coal[d]	
1 New England	9	22			
2 New York/New Jersey	35	0			
3 Middle-Atlantic	4	22			
4 South-Atlantic	14	0			
5 Midwest	7	0	95*	360*	15*
6 Southwest	4	0			
7 Central	0	0			
8 North Central	0	0			
9 West	12	0			
10 Northwest	0	0			
Subtotal	85	44	95*	360*	15*
Total (all sources)	599				

NOTE: *oil savings not allocated by region.

[a]U.S. Department of Energy, Energy Information Administration, "Petroleum Fuel-Switching Capability in the Electric Utility Industry," *Electric Power Monthly: June* 1990, DOE/EIA-0226(90/06) (Washington, DC: U.S. Government Printing Office, September 1990)

[b]Excludes the 809 MW Shoreham Unit in Region 2, if included, an additional 15,000 B/D could be displaced.

[c]Based on deploying 5,000 MW of renewable fuel-based nonutility generation (NUG) capaci~ in 5 Years.

[d]Based on a combination of four options --coal or CSF in coal/oil capable units, CSF in oil-only capable units, purchases from coal-based NUG plants, and coal gasification combined cycle plants.

[e]Based on 4,000 MW from demand management programs.

capacity is less concentrated geographically. As shown in figure 3-4, oil-based generating capacity (including oil/gas dual-fuel units) constitutes a significant share of the resource base in all regions. (Maps of Federal and NERC regions can be found in the appendix.)

Oil Replacement Options

The largest potential for oil replacement in the utility sector is for reducing the use of heavy oil, which constitutes most of utility oil use. Light oil consumption is not a significant factor, and most such uses cannot be easily replaced.[56]

OTA estimates that it is technically feasible to replace about 600,000 B/D, or over 80 percent of utility oil use (90 percent of residual oil use), within 5 years by fuel switching in dual-fuel capable units or by shifting generating loads to non-oil units. This potential has remained constant since 1984 even as non-oil generating capacity and fuel-switching capabilities have increased, because growing demand for electricity and narrow capacity margins have made reliance on oil-fired generation essential and the lower cost of gas and other fuels relative to oil (except for a brief period in 1986-87) have already induced many utilities to burn gas or coal in dual-fuel units.

Replacing oil could be accomplished by using existing equipment, completing planned capacity now under construction, converting existing equipment to other fuels, and installing new non-oil generating capacity.[57] These efforts could be facilitated by and additional savings could be gained through demand-side efforts, but these savings are not broken out separately in our estimates. Table 3-13 shows the estimated oil replacement capability in the utility sector in 1989.

We have included the oil replacement potential of new nuclear power plants that came online in 1990 in regions where there is heavy oil use. We also note the planned addition of new utility and nonutility generating capacity in these regions in 1991-94, but since these plants are not yet complete, we do not include

[56]Nevertheless, there maybe some potential to reduce the use of light oil. For example, tests are underway in coal-fired steam plants to evaluate the feasibility of using micronized coal in place of light oil for plant startup. Elliott, supra note 31. Similarly, utilities could switch to natural gas for firing turbines, wherever possible.

[57]Electricity demand growth and capacity margins are key variables in the ability to shift oil-fired generation to other plants.

them specifically in our totals. These capacity additions are, however, implicitly included in our estimates of oil replacement potential since they are part of utility resource planning.

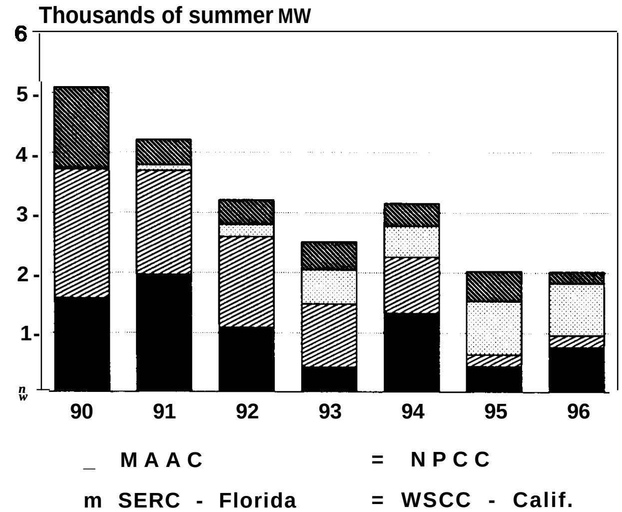
Natural Gas

Utilities can substitute natural gas for oil in three ways: by burning natural gas in existing oil/gas, dual-fuel units, by shifting load to existing gas-only units, and by shifting to new gas-fired capacity either in converted oil units or newly constructed gas units.

About 100,200 MW of existing capacity is classified as dual fuel-gas/oil capable units—and about two-thirds of these units can burn gas continuously .58 According to DOE, electric utilities can thus replace about 85,000 B/D of oil in less than 30 days by increasing natural gas-based generation in these units.[59] The fuel switching potential, however, is highly dependent on the seasonal availability of natural gas, and thus ranges from an average of 54,000 B/D in the second quarter to an average of 117,000 B/D in the fourth quarter. This appears to be the minimum potential that could be achieved almost immediately on an annual average and would not require any significant alterations of equipment.

Additional displacement of oil with new or retrofitted natural gas units within 5 years is also feasible, The American Gas Association has estimated that natural gas could replace approximately 50,000 B/D of oil for power generation boilers in the very short term and 300,000 B/D after 5 years.[60] A Gas Research Institute analysis estimates that natural gas could displace 95,000 B/D of oil in electric power generation in the short term (2 years or less) and 280,000 B/D over the longer term (10 years) under somewhat different supply disruption and policy scenarios.[61] Because of uncertainties over the availability of additional natural gas supplies in oil dependent regions, OTA has not included a higher estimate of gas replacement potential. If gas supplies are available, we expect that additions of new gas generating capability will reduce the use of coal to replace oil.

Figure 3-5-Planned New Non-Oil Capacity Additions in 1990 to 1995 in Oil Dependent NERC Regions



SOURCE: Office of Technology Assessment, 1991, from data in North American Electric Reliability Council, 1990 Electricity *Supply and Demand for 1990-1999* (Princeton, NJ: North American Electric Reliability Council, December 1990), app. D.

Utilities and independent power producers (also known as nonutility generators, or "NUGs") have announced plans to construct and operate new natural gas-fired generating units. According to figures published by the North American Electric Reliability Council (NERC), about 24,000 MW of gas-fired generating units are planned to come on line in 1991 through 1999.[62] See figure 3-5. It is not certain how

'Jeffrey Jones, "Petroleum Fuel-Switching Capability in the Electric Utility Industry," in U.S. Department of Energy, Energy Information Administration, *Electric Power Monthly: June 1990,* DOE/EIA-0226(90/06) (Washington, DC: U.S. Government Printing Office, September 1990), table FE4, p. 4.

[59]Ibid., p. 2.

[60]American Gas Association, "The Role of Natural Gas in Offsetting Oil, " A.G.A. Planning &Analysis Group, Mar. 21,1991, p. 9. Interstate Natural Gas Association of America, "Displacing Imported Oil With Natural Gas," Issue Analysis, Report No. 91-1, Rate and Policy Analysis Department, May 1991.

[61]Paul D. Holtberg and David O. Webb, 'The Potential for Natural Gas To Displace Oil in Response to the Middle East Crisis and the Implications for the GRI R&D Program," Gas Research Insights, Gas Research Institute, Chicago, IL, November 1990. Natural gas offers substantial promise for utilities in the 1990s; however, utility analysts believe that uncertainties over future natural gas prices and deliverability pose some financial and reliability risks for utilities that must be addressed in resource planning. See Strategic Decisions Group, ***Natural Gas for Electric power Generation: Strategic Issues, Risks, andOpportunities,*** EPRI P-6820 (Palo Alto, CA: Electric Power Research Institute, 1990); and Putnam, Hayes&Bartlett, Inc. and Energy Ventures Analysis, ***Fuel Switching and Gas Market Risks,*** EPRI P-6822, vols. 1 &2, final report (Palo Alto, CA: Electric Power Research Institute, July 1990).

@See North American Electric Reliability Council, 1990 ***Electricity Supply & Demand for 1990-1999*** (Princeton, NJ: North American Electric Reliability Council, December 1990) table 29, p. 48.

much of this planned capacity will be built on schedule and whether there is access to adequate natural gas supplies. It is clear, however, that utilities view new natural gas capacity as an important and economic option in the years ahead.

One of the largest new facilities in an oil dependent-region is the Ocean States Power Project (two 250-MW combined-cycle plants) under construction in Rhode Island. The first 250-MW gas-fired unit began operation in December 1990.[63] Ocean States is a "hybrid" independent power producer that includes several utility affiliates as partners.[64] The project will be dispatched as part of the New England Power Pool and will likely serve as baseload capacity. Gas supplies for the project will be under a contract for firm deliveries and one of its joint venture participants is an affiliate of its gas supplier.

Nuclear Power

Three nuclear power plants began commercial operation in 1990: the 1,150 MW Limerick Unit 2 in Pennsylvania, the l,150MW Seabrook in New Hampshire, and the 1,150 MW Comanche Peak Unit 1 in Texas (an area where oil consumption is not a major concern).[65] The Limerick and Seabrook units with a total of 2,300 MW are in areas that are heavily reliant on oil-fired generation and together could replace about 44,000 B/D in intermediate loads.[66]

In addition, the 809 MW Shoreham Unit in New York has been completed but has not proceeded to commercial operation.[67] Concerns over the feasibility of emergency evacuation plans led State and local officials to negotiate a takeover of the plant from Long Island Lighting Co. Under the takeover plans, the Shoreham Plant will be decommissioned. It is estimated that the Shoreham Plant might have displaced about 14,000 B/D of oil. Secretary of Energy Watkins has opposed decommissioning Shoreham and has joined litigation to stall the plant's dismantling.[68] No other nuclear units are scheduled to come on line before 1995 in the oil-dependent regions.

Renewable Energy

In 1989, renewable energy sources, including hydroelectric, geothermal, wood, solar, municipal solid waste (MSW), and wind, provided just under 10 percent of net electric generation.[69] Many of these facilities were built and operated by NUGS. In 1989 about 2,500 NUG plants were in operation with an installed capacity of about 28,000 MW. About 60 percent of these plants used renewable fuels and together had an installed capacity of about 11,000 MW, or about 40 percent of the total NUG capacity.[70] Various forecasts indicate a significant growth during the 1990s in the NUG capacity, including capacity based on renewable fuels. For example, in 1989 DOE estimated an addition of 4,000 MW of renewable fuels-based NUG capacity between 1990 and 1995. And, based on its database, RCG/Hagler, Baily Inc., has recently projected a 7,400-MW addition through 1996.

Hydroelectric Power—According to NERC, about 1,300 MW of new hydroelectric generation is scheduled to come on line between 1991 and 1999.[71]

@'ocean State power Comes on Early," *Energy Daily*, Jan. 15, 1991, P. 6.

64See Congress of th, United States, Office of Technology Assessment, *Electric Power Wheeling and Dealing: Technological Considerations for Increasing Competition, OTA-E-409* (Washington DC: U.S. Government Printing Office, May 1989), p. 129, for further discussion of the Ocean State Project.

65Mona Reynolds, "Utilities Bring a Variety of New Plants on Line," *Power Engineering*, p. 23, April 1990. Douglas J. Smith, "Non-Utility power Production Increases," *Power Engineering*, page 13, July 1990. Douglas J. Smith, *Power Engineering*, personal communication to Renova Engineering, Oct. 4, 1990.

66This Potential is based on displacing an equivalent oil-based capacity operating at a 50 percent capacity factor (intermediate duty) with an average heat rate of 10,000 Btu/kWh. The heat content of residual oil is assumed to be 6.3 million Btu/bbl.

67North American Electric Reliability Council, *Electric Supply & Demand* 1989-1998 (Princeton, NJ: North American Electric Reliability Council, October 1989).

68At DOE's request, th, Justice Department joined a lawsuit by two local groups opposed to the decommissioning. The challengers allege 'hat 'he Nuclear Regulatory Commission's (NRC) decision was improper because it failed to assess the environmental impacts of shutting down the plant as required under the National Environmental Policy Act of 1969. The Federal Appeals Court for the D.C. Circuit has rejected the plaintiffs request for an order staying the NRC's approval of a possession-only license that allows dismantling of the Shoreham plant. *INSIDE* ENERGY/with FEDERAL *LANDS*, July 22, 1991, p. 10.

69*Short-Term Petroleum Fuel Switching*, supra note 16, table FE2.

70These include electric generation from such renewable sources as Wrote, wood, agricultural waste, biometha,, MSW, solar, wind, geothermal, and hydro.

71North American Electric Reliability Council, supra note 62.

Expansion of transmission facilities in New England and Canada was recently completed to bring 2,000 MW of power from Hydro-Quebec to the Northeast under long-term contract.[72] The power deliveries that began in 1990 are considered an interruptible supply at present, but are expected to be reclassified as firm capacity in summer 1991. This bulk power purchase further increases regional capacity margins, providing additional flexibility to the region if oil generation is constrained by fuel shortages.[73]

Other Renewable Power Generation—During an oil supply shortfall, the growth in renewable fuels-based capacity is expected to accelerate, based on the mix of fuels specific to a region. For example, solar thermal technology is available commercially and could be deployed to a much greater extent in Western States.[74] Similarly, wind power, which has been concentrated in California, is expected to be deployed commercially within 2 to 3 years in colder climates such as that of the Northeast.[75]

OTA estimates that in a crisis, about 5,000 MW of renewable fuels-based generation—from MSW, biomass, solar, and wind—could be added to displace about 95,000 B/D.[76] Although this would be as significant increase in capacity (a 45-percent increase over 1989), it would not appear to be out of line with some current projections, given the current state of development of renewable technologies. For example, Luz International plans to have 680 MW of hybrid solar thermal capacity in California by 1994, with module size increasing from 80 to 200 MW. The first installed 80 MW unit has started operating, but financial difficulties threaten to delay completion of the remaining capacity additions. Moreover, the United States already has an installed wind turbine capacity of 1,500 MW. Finally, a 10,000 tons per day (TPD) MSW plant, equal to about 30 percent of New York City's daily waste generation, can produce 200 MW, based on an average potential of 2 MW per 100 TPD of MSW throughput. In general, utilities have been more receptive to renewable technologies as the result of their experience with existing units. Several independent power subsidiaries of large utilities are already participants in renewable energy ventures in California and elsewhere.

Coal

Electric utilities could further reduce oil consumption by greater use of coal-fired generation. Three technical options are available:

1. shifting to existing or new coal-fired generation,
2. switching from oil to coal in oil/coal-capable facilities, and
3. converting oil-fired generating plants to burn coal.

Load shifting from oil plants to coal-fired plants has been used within a utility or power pool and through negotiated agreements for sale and transfer of electric power from coal. Expansion of interregional "coal by wire" transfers may be limited by available transmission capacity in eastern utility systems. Even though construction and upgrading of transmission lines has become more controversial and difficult because of environmental and other siting concerns in recent years, new or upgraded lines have been built to take advantage of coal-fired generation. There may be some additional instances where such transfers and needed transmission upgrades may be cost-effective and feasible for backing out oil.

According to DOE, there are about 30,000 MW of dual-fired, coal/oil generating units. Most of these are in the South and Midwest.[77] Probably most of these

[72] See discussion Of the Phase I and Phase II Hydro-Quebec transmission projects in OTA, *Electric Power Wheeling and Dealing,* supra note 64, PP. 188-189.

[73] OTA *Electric Power Wheeling and Dealing,* supra note 64, and personal communication to OTA from Paul Shortley, Manager, New England power Exchange' (NEMEX) Operations, Planning and Procedures, Springfield, MA, Nov. 9, 1990.

[74] Dennis Ho, Luz International Personal communication to Renova Engineering, P. C., OTA contractor, Sept. 19, 1990 and Dan Jaffe and Robert E. Herbster, "SEGS VIII Solar-Power' Project: Apply Latest Technology at Solar-Powered Generating Plant," *Power,* April 1990, p. S-19.

[75] Mark T. Hoske ,"Vermont De-Icing Demonstration may Allow Northern Wind Farms," *Electric Light and Power, p.* 3, September 1990. David Ward, U.S. Windpower, Inc. personal communication, to Renova Engineering, P. C., OTA contractor, Sept. 26, 1990.

[76] We have assumed a deployment Of 5,00() MW in 5 years—a mid-range between the DOE estimate and that by RCG/Hagler. Assuming this capacity replaces an equivalent oil-based capacity operating at a 50 percent capacity factor with an average heat rate of 10,000 Btu/kWh, to yield an estimated oil replacement potential of 95,()()0 B/D.

[77] Jones, supra note 58.

dual-fuel units are burning coal for economic reasons, and little switching capability remains.

Many utilities converted to coal in response to the energy crises of the 1970s. The easiest conversions involved plants originally designed to burn coal and later converted to burn oil. It is likely that most such oil units have already been reconverted for coal, while the rest remain oil units because of cost, emissions problems, or lack of space for auxiliary coal transport, storage, handling, and waste disposal facilities.

Other oil-fired boilers suitable for conversion to coal are those that are technically similar to coal-designed boilers. OTA's 1984 analyses found that 114 oil-burning utility boilers in Federal regions 1 through 4 and 9 might be suitable for converting to coal or CSF.[78] Finally, the remaining oil boilers are so dissimilar to coal boilers that it would be neither technically nor economically practical to convert them to coal.

Converting oil-only units to burn CSF usually entails derating these units. The extent of derating depends on plant-specific and CSF-specific factors.[79] On average, the loss in capacity would be about 35 percent. If all 26,500-MW of oil-only capacity in Regions 1,2,3, and 4 (see table 3-12) were converted to CSF, capacity could be reduced by about 9,500 MW. Such coal conversion would require permit approvals and significant alterations to the generating plant. However, incorporating capacity and efficiency improvement measures as part of these conversions would minimize any potential derating of the units.

Building new coal-fired capacity to displace oil-fired units is also an option. Commercially available options include conventional coal-fired steam turbines, fluidized-bed combustion systems (now being adapted for use at utility scales), and integrated gasification combined-cycle (IGCC) systems (only recently available commercially for utility applications). According to NERC, 14,400 MW of additional utility and NUG coal-based generating capacity is planned to come on line between 1991 and 1999.[80]

Although the technology is relatively new, IGCC or coal gasification combined cycle (CGCC) plants have been successfully demonstrated at the Coolwater plant in California and at Dow Chemical 's Plaquemine, Louisiana, plant, and CGCC technology is now being offered for commercial deployment.[81] Several utilities plan to install CGCC plants.[82] The CGCC technology also has attracted independent power producers. For example, assuming that public opposition is overcome, Texaco plans to bring on line in 1995 a 440-MW plant in the Northeast. Destec Energy, a Dow Chemical subsidiary, is offering a 200-MW module and has announced a 230 MW repowering project in Indiana scheduled to go commercial in 1995.[83]

The oil-replacement potential for the above coal-based options will depend on the final decisions made by industry participants and may well rest on considerations other than the desire to reduce oil use. It is nevertheless technically feasible to use coal-fired generation to eliminate virtually all of utilities' heavy oil consumption. If natural gas, nuclear, and renewable fuels options replaced about 240,000 B/D, coal could, at a minimum, replace 85 percent of the remaining oil, or about 360,000 B/D. (This assumed use of coal-based options is tied to uncertainties over natural gas availability and the acceptability of coal burning to local communities. Greater availability of natural gas could reduce the amount of coal used to replace oil.)

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[78] OTA, *The oil Replacement Capability,* supra note 1, pp. 60-62 and 79-81.

[79] H.R. Beal et al., "Coal-Water Fuel Retrofit Evaluations," paper presented at Coal-Targets of Opportunity Workshop, U.S. Department of Energy, July 12-13, 1988, Washington, DC.

[80] Jean-Louis Polner, "How NUG Capacity Is Growing," *Electric Light and Power,* p. 22, February 1990. Douglas J. Smith, "Natural Gas Will Fuel Future Non-Utility Plants," *Power Engineering,* p. 13, September 1989.

[81] " Gasifier Demo Heralds New Era for Gas Turbines," *Power,* page S-24, October 1989. Jason Makansi, " Coal Gasification Breaks Out of Synfuels/Clean Coal Pack, ''Power, p. 56, April 1990. M. Rao Goineni et al., "Advanced Energy Technologies at Combustion Engineering, Inc.," paper presented at "Coal-Targets of Opportunity Workshop," U.S. Department of Energy, July 12-13, 1988, Washington, DC. Mark Roll, Destec Energy, personal communication to Renova Engineering, P. C., OTA contractor, Oct. 12, 1990 and information submitted by Destec. Robert Smock, "Repowering Old Plants Gains Favor," *Power Engineering,* p. 25, May 1990.

[82] Robert Smock, "New Gas Turbines Show High Efficiency, Low NOX Emission," *Power Engineering,* p. 43, August 1990.

[83] Marie Leone, "New Powerplant Projects, " *Power*, December 1990, p. 15.

Demand Management

In addition to conventional supply side resources, many utilities now look to improved efficiency and conservation efforts on the demand side as a cost-effective means to provide needed capacity. Demand management broadly refers to activities undertaken by a utility or a customer to influence electricity use. Among the variety of activities used for demand management are: utility rate programs (time of use or time of day, interruptible rates, real-time pricing, waiver of demand charge under certain conditions, and other financial incentives, such as rebates, for consumers who invest in energy efficient equipment.

The use of demand management programs by utilities for energy efficiency and peak load reduction is widespread and the benefits are obvious. For example, the Northeast Power Coordinating Council, which includes New England and New York, plans demand management programs totaling 3,850 MW between 1990 and 2000. During a crisis, oil dependent utilities could intensify demand management programs. A reasonable assumption is that such expanded efforts could reduce peak demand by about 4,000 MW (3 percent of peak for oil dependent regions). Thus, they could displace about 15,000 B/D of oil based on an equivalent oil-based capacity operating at a 10 percent capacity factor and an average heat rate of 10,000 Btu/per kilowatt hour (kWh).[84]

Deployment Constraints and Schedule

Achieving this level of oil replacement does, however, present some uncertainties. Areas of potential constraints include natural gas supplies, turbine manufacturing capability, environmental permitting, effects of electricity demand growth, and capacity margins.

Natural Gas Availability

Several new pipeline projects are being developed to supply domestic and Canadian natural gas to the Northeast and California and should make natural gas more available to all sectors. These projects are in various stages of development and approval[85] and, once approved, could displace more utility oil use directly or through NUGs. The Iroquois pipeline approved by the Federal Energy Regulatory Commission (FERC) in fall 1990 will bring 576 million cubic feet of natural gas from Canada to New York and New England—the equivalent of 100,000 B/D of crude oil. Some portion of this gas will be committed under firm deliveries to electric utilities and independent power producers. Natural gas availability issues are further discussed later in this chapter.

Manufacturing of Turbines

In 1989, the total installed summer generating capacity of the United States was about 673,000 MW. By 1995, that capacity is projected to grow by about 40,000 MW. Of this new capacity, about 16,000MW is not yet under construction, and of this amount about 10,000 MW will be based on short lead-time generators, such as combustion turbines (also known as gas turbines), jet engines, and internal combustion (diesel) engines. Some analysts have questioned whether the combustion turbine manufacturers can meet this normal growth in new orders, since most of the capacity will be installed after 1992. In our 1984 report we concluded that manufacturing capability should not be a problem, even with an acceleration in orders. We still believe that this conclusion is valid and note that other analysts have reached similar results.[86] The annual production capacity of major U.S. combustion turbine manufacturers in 1990 was 14,000 MW, more than adequate to meet U.S. and foreign demand, and manufacturers note plans to expand capacity to meet expected new demand in the 1990s. Annual planned additions of combustion turbines by domestic utilities, according to NERC data, were up to 5,000 MW per year. Lead-time from purchase to commercial operation is 18 to 24 months. It would appear that an increase of 1,000 to 2,000 MW in orders for accelerated oil replacement capacity could be met. We have therefore assumed that this would not delay the deployment of oil replacement technologies in the electric utility sector.

Environmental Permitting Process

All of the oil replacement technologies can attain compliance with environmental regulations. However, a relatively smooth permitting process would be

[84] Renova Engineering, P. C., supra note 4, at p. 23.

[85] American Gas Association, "New pipeline Construction Projects-Status Report," Issue Brief 1990-95, Apr. 13, 1990.

[86] John R. Riley, Gregory L. Gould, and Richard A. Klover, "Can Manufacturing Capacity Keep Up With New Orders for CTs?" *Power Engineering,* vol. *94, No. 4,* April *1990,* pp. *45-47.*

necessary so that the various conversion and replacement projects could obtain the required environmental permits in 12 to 18 months. This appears to be feasible. A survey of combustion turbine installations found that permitting is achieved in most cases in under 18 months.[87]

Shoreham Nuclear Plant

The State of New York is exploring the feasibility of converting the mothballed Shoreham plant to natural gas. Such a conversion will have to overcome natural gas supply, permitting, and financing hurdles. On the other hand, a nuclear restart might entail less financial difficulties but would have to overcome public, State, and local government opposition. We have not assumed the availability of Shoreham capacity.

Capacity Margins and Demand Growth

Some analysts have made dire projections of an impending crisis in supplying generating capacity if high rates of electricity demand-growth reappear and utilities do not accelerate construction plans. Others have voiced concern that oil replacement options might worsen any possible capacity shortfall.

Of the various options, only CSF firing in oil-only units would reduce generating capacity through derating, thus narrowing capacity margins. But capacity losses through plant derating are not expected to be a significant deterrent to fuel switching. The loss could be made up by other capacity additions, in particular, existing nuclear plants, renewable fuels, coal-based plants, and CGCC or by repowering some of the older oil and non-oil units. According to one study, repowering of old oil-steam plants to combined cycle gas turbines could add 2 MW of gas generation for every 1 MW of oil generation replaced.[86]

We have not made any detailed examination of the impacts of differences in electricity demand growth on our oil replacement estimates. We do note that capacity margin estimates include some consideration of demand growth. Where judgments are based on availability of sufficient capacity margins to displace oil, some demand growth is implicit.

Estimated Oil Replacement Technology Deployment

Table 3-13 summarizes the breakdown of the 0.6 MMB/D of oil that could be replaced in electric utilities by the various options assessed above. Assuming that the possible constraints are indeed overcome, the actual replacement of oil over the 5-year period could take place as follows:

1. Switching to natural gas immediately to replace 85,000 B/l) of oil.
2. Operation of the completednuclear plants could replace 44,000 B/D. The schedule would depend on debugging delays for Limerick Unit 2 and Seabrook Unit 1. We have assumed that the nuclear option displaces oil starting in 1993.
3. Several renewable fuel-based NUGs are probably under construction. There also exists a diverse mix of technology options for any new capacity that is in planning. Hence, renewable fuels might replace 95,000 B/I) uniformly over the 5-year period.
4. The coal-based options are a mixed bag. It is assumed that coal-based plants in the design and construction phases will replace about 90,000 B/I) over the first 3 years, while the remaining 75 percent, or 270,000 B/D, are replaced uniformly over the last 2 years. One reason for this delay is that the suppliers of CSF technology have shelved their developmental efforts during the last 3 to 4 years because of low oil prices and, therefore, a 12 to 18-month mobilization period will be required.

The estimated deployment schedule over 5 years is shown in table 3-14. Natural gas fuel switching, coal, renewable, and demand management are available to displace oil in the first 2 years. In years 3 to 5, nuclear capacity, and larger coal-fired units begin to come on line.

Estimated investment costs for the various oil replacement options are shown in table 3-15. Estimated investment costs for each B/D replaced range from $0 for use of available capacity from existing gas and nuclear units to as much as $420,000 for a MSW plant operating at a 50 percent capacity factor. Actual costs could vary significantly from these depending on the characteristics of local utilities and loads.

[87] Ibid.
[88] Smock, supra note 81, pp. 25-27.

Table 3-14-Deployment Schedule for Oil Replacement Technologies in the Electric Utility Sector (oil replacement potential-thousand barrels per day)

		Fuel switching option			Demand	
Year	Gas[a]	Nuclear[b]	Renewables[c]	Coal[d]	management	Total[c]
1991	85	0	19	30	3	137
1992	85	0	38	60	6	189
1993	85	15	57	90	9	256
1994	85	29	76	225	12	427
1995	85	44	95	360	15	599

a Assumes utilities could switch to natural gas in the first year.
b Uniform displacement after 1992. Excludes Shoreham Unit.
C Assumes a uniform oil displacement over 5 years.
d Assumes that coal-based NUG plants in the design and construction phase replace 25% of the oil over the first 3 years with the remaining 75% replaced by all coal-based options over the last 2 years.

SOURCE: Office of Technology Assessment, 1991, based on Renova Engineering, P. C., "Oil Replacement Analysis-Evaluation of Technologies," OTA contractor report, February 1991.

THE INDUSTRIAL SECTOR

The industrial sector includes both ***manufacturing*** enterprises (i.e., businesses that convert raw materials into intermediate or finished products) and ***nonmanufacturing*** activities, such as agriculture, forestry, construction, mining, and oil and gas production. This diversity is reflected in the variety of oil products, and end-use applications in the industrial sector. Although oil use is widespread in this sector, much of the oil consumption is concentrated in certain industries, applications, and regions. (See figure 3-6.)

Oil use in the industrial sector in 1989 totaled 4.26 MMB/D or about one-quarter of total U.S. oil consumption.[89] Petroleum accounted for about 36 percent of industrial sector energy use in 1989, down from 38 percent in 1983.[90] Petroleum products used in industrial applications consisted of 820,000 B/D of distillate and residual fuel oil, and 3.4 MMB/D of nonfuel oil products, mostly feedstocks.[91] By 1989, the industrial sector was using 1 MMB/D less oil, and less energy overall, than it was in 1979. Table 3-16 shows industrial oil use in 1979, 1983, and 1989.

The industrial sector is characterized by diverse, complex, and rapidly changing technology, which complicates estimates of future consumption and potential oil savings. The sector has a variety of effective options for adjusting to oil supply or price disruptions, including fuel switching, substitution of non-oil based products, process changes, and improvements in management and control technologies. OTA estimates that potential oil savings in the industrial sector during a prolonged oil import disruption could total about 800,000 after 5 years.

Patterns of Industrial Oil Use

The major energy and oil needs of the manufacturing sector are for heat, power, and feedstocks (see figure 3-7 and table 3-17). The manufacturing sector consumed 275,000 B/D of distillate and residual fuel oil in 1989, almost exclusively for steam generation in boilers, process heat, and cogeneration of electric power. Although these applications are but a small portion of total industrial oil use, they represent major opportunities for displacing oil use in the near-term. Nonfuel oil use in manufacturing was 979,000 B/Din 1989.

The nonmanufacturing sector consumed about 3 MMB/D of petroleum products in 1989 (see table 3-17). Distillates, primarily diesel fuel, accounted for about 493,000 B/D, and residual fuel oil consumption

[89] *Annual Energy Review 1989*, supra note 6, table 61.

[90] Among the major factors that account for the decline in oil use and energy demand in the industrial sector in the past two decades are increased efficiency, greater use of electricity, and waste and byproduct fuels, and structural changes in the composition of the industrial sector. Precise estimates on the relative contributions of these factors to oil savings are not easily derived. However, OTA's own review found that for the economy as a whole, increased efficiency was responsible for two thirds of the decline in energy consumption and structural change for the remaining third. Changes in the manufacturing sector accounted for two fifths of these savings. U.S. Congress, Office of Technology Assessment, *Energy Use and the U.S. Economy,* Background Paper, OTA-BP-E-57 (Washington, DC: U.S. Government Printing Office, June 1990), p. 4.

[91] *Annual Energy* Review *1989*, supra note 6, table 62.

Table 3-15-Estimated Investment Costs for Oil Replacement Technologies in the Electric Utility Sector
(approximate investment cost in thousand 1990 dollars per barrel per day of oil replaced)

Option	$000 per B/D replaced[a] Minimum	$000 per B/D replaced[a] Maximum	Percent capacity factor	Remarks
Natural gas	0	34	50	Maximum cost based on replacing the capacity with a 240-MW combined cycle plant at $650/kW.[b]
Nuclear	0	13	50	Maximum cost assumed at $250/kW to debug plants that went into commercial operation in 1990.[b]
Renewable fuels				
Solar	131	153	36	80-MW solar thermal plant with gas firing at supplemental $l,800-$2,100/kW.[c]
Wind energy	63	125	21	21 Wind energy farm at $500-$l,000kW.[d]
Wood	79	95	50	50 20-MW wood-fired plant at $l,500-$l,800/kW.[e]
Municipal solid waste	263	420	50	50 20-MWMSW-fired plant at $5,000-$8,000/kW.[e]
Coal				
Coal/CSF	4	16	50	Conversion of coal capable units assumed at at $80-$300/kW.[f]
CSF	4	29	50	Conversion of oil-only capable units at $80-$550/kW of derated capacity.[f]
Coal	68	89	50	150-MW plant using pulverized or circulating fluid–ized bed coal at $1,300-$1,700/kW.b
CGCC	63	74	50	200- to 360-MW CGCC plant at $1,400-$1,200/kW.g
Demand management	92	105	10	Equivalent to an 80-MW combustion turbine at $350-$400/kW.[b]

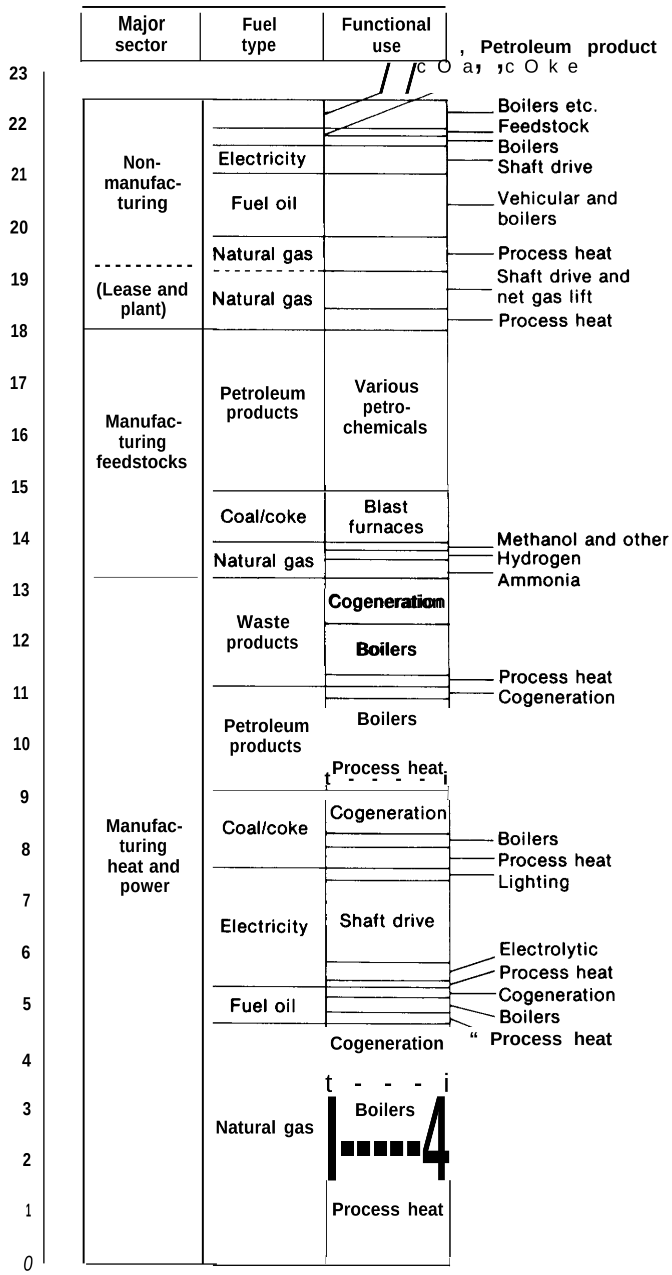
[a]Asumed that the option replaces an equivalent oil-based capacity operating at 10,000 Btu/kWh and the specified capacity factor.
[b]Robert W. Smock, "Need Seen for New Utility Capacity in '90,' *Power Engineering,* April 1990, P. 29.
[c]Dennis Horgan, Luz International, personal *communication* to Renova Engineering, P. C., Sept. 19, 1990, and information made available by Luz International.
[d]David Ward, U.S. Windpower, Inc. personal communication to Renova Engineering, P. C., Sept. 26, 1990.
[e]In-house Renova Engineering files.
[f]H.R. Beal et al. "Coal-Water Fuel Retrofit Evaluations," paper presented at Coal —Targets of Opportunity Workshop, DOE, July 12-13, 1988, Washington, DC mentions 1985 conversion cost of $60-$420/kW of derated capacity for noncoal-capable units, depending on the CSF quality and unit constraints. This cost was increased by 30 percent to get 1990 dollars. For coal capable units, it was assumed that the cost would vary between $80-$300/kW depending on the CSF quality and the extent of flue gas clean-up system.
[g]Mark Roll, Destec Energy, personal communication to Renova Engineering, P. C., Oct. 12, 1990. Eric Jeffs, "Coal Fired IGCC Plants are at the Threshold of Commercial Operation," Gas *Turbine World,* March-April 1988. U.S. Congress, Office of Technology Assessment, New *Electric Power Technologies: Problems and Prospects for the 1990s, OTA-E-246* (Washington, DC: U.S. Government Printing Office, July 1985).

SOURCE: Office of Technology Assessment ,1991, from Renova Engineering, P. C., "Oil Replacement Analysis—Evaluation of Technologies," OTA contractor report, February 1991.

was about 52,000 B/D. Farm use includes fuel for tractors, irrigation pumps, agricultural machinery, crop drying, space heating, and cooking. Off-highway distillates are used to power construction equipment (cranes, compressors, and generators) and for other applications. The remaining nonmanufacturing uses include fuels for oil drilling and production equipment, remote electric generators, and nondiesel construction equipment, and other miscellaneous activities.[92] There are *only* limited short-to mid-term

[92]OTA estimates based on data from *Annual Energy Review 1989,* supra note 6, and product shares reported in *Short-Term petroleum Fuel Switching,* supra note16, pp. 12-14, and tables 5 and 8.

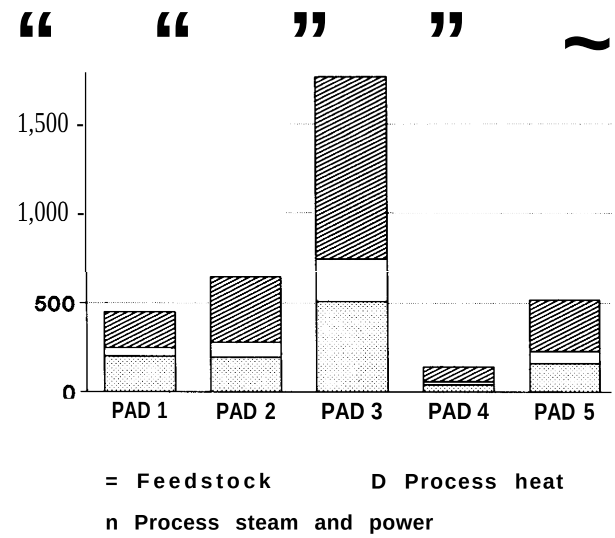
Figure 3-6--Oil Use in the industrial Sector by Region and Application



NOTE: Excludes about 315,000 B/D of off-highway use in agriculture. mining, and construction for which regional data-are not available.

SOURCE: Office of Technology Assessment, 1991, adapted from data in Paul D. Holtberg and David O. Webb, 'The Potential for Natural Gas to Displace Oil in Response to the Middle East Crisis and the Implications for the ORI R&D Program," Gas *Research Insights, Gas* Research Institute, November 1990.

Figure 3-7—Profile of Energy Use in the industrial Sector, 1985



SOURCE: Office of Technology Assessment, 1991, from data in Gas Research Institute, "Industrial Natural Gas Markets: Facts, Falacies and Forecasts," March 1989.

options for replacing most of these nonmanufacturing oil uses.

In 1989 over 2.46 MMB/D of nonfuel oil products were consumed in nonmanufacturing activities. The products in this category include LPG, petrochemical feedstocks, still gas (a byproduct of the petroleum refining process used primarily as a captive fuel and not sold commercially), petroleum coke (another refinery byproduct), asphalt, road oil, motor gasoline, kerosene, lubricants, waxes, and other petroleum products (table 3-16).[93] This category, often referred to simply as "feedstocks," accounts for over 11 percent of total U.S. petroleum consumption—an amount second only to transportation uses. As in our 1984 report, we found that there continues to only limited technical potential for replacement of nonfuel oil products in the short term.

LPG accounts for the largest quantity of nonfuel oil products in the industrial sector. About 97 percent of industrial LPG consumption is for nonmanufacturing applications, such as crop drying or feedstocks in the petrochemical industry.

[93] Annual *Energy Review 1989*, supra note 6, table 62, *Short-term Petroleum Fuel Switching,* supra *note 16, table 8.*

Table 3-18-industrial Consumption of Oil Products, 1979,1983, and 1989
(million barrels per day)

Oil product	1979	1983	1989
Fuel oils	1.55	0.93	0.82
Distillate	0.83	0.61	0.57
Residual	0.72	0.32	0.25
Feedstocks & other non-fuel oil products	3.80	3.02	3.44
Asphalt and road oil	0.48	0.37	0.45
Liquefied petroleum gases	1.27	1.17	1.25
Lubricants	0.09	0.08	0.08
Motor gasoline	0.08	0.06	0.10
Kerosene	0.08	0,07	0.02
Other products	1.79	1.27	1.54
Total	5.34	3,93	4,26

SOURCE: Office of Technology Assessment, 1991, based on data from U.S. Department of Energy, Energy Information Administration, *Annal Energy Review 1989, DOE/EIA-0384(89)* (Washington, DC: U.S. Government Printing Office, May 1990); *Annual Energy Review 1984, DOE/EIA-0384(89), April 1985; and Annual Energy* Review 1985, DOE/EIA-0384(85), May 1986.

Also included among nonfuel oil products are waste fuels and byproducts such as still gas and petroleum coke used in the petroleum refinery and petrochemical industries in preference to purchased fuels such as natural gas. This pattern of internal-captive fuel use means that operators will tend not to replace these oil products even when technically feasible to do so unless there are significant cost advantages to switching to other fuels.Moreover, some of these byproducts could not be easily diverted to other applications and might have to be disposed of in some other manner if not used as waste fuels.

Oil Replacement Potential

OTA estimates that theindustrial sector could technically displace about 800,000 B/D of petroleum products, or about 20 percent of its consumption, as shown in table 3-18. The oil replacement options in the industrial sector include credit for reducing refinery throughput (360,000 B/D) and the savings that would result from switching to natural gas (297,000 B/D) and other fuels (50,000 B/D) for process heat, steam, and power generation, and from intensifying the adoption of more energy-efficient process changes (100,000 B/D) in manufacturing.

In our 1984 report, we estimated that the industrial sector could save 1 MMB/D, or 25 percent of its energy use through increased efficiency and process changes (including credit for reducedrefinery throughput of 220,000 B/D).

Our present analysis suggests that U.S. flexibility in replacing oil in the industrial sector has declined by over 340,000 B/D since 1984 (exclusive of net savings from reduced refinery throughput). This decline partly reflects a greater reliance on natural gas, electricity, and byproduct fuels and already achieved efficiencies in oil use.

Reduced Refinery Throughput

OTA estimates that about 360,000 B/l) of oil could be saved through reduced internal fuel consumption in the next 5 years. Refineries use about 580,000 Btu, or about 0.1 barrel of fuel per barrel of crude input as fuel for various internal processes such as distillation and cracking.[94] A reduction in crude oil processed through U.S. refineries yields a net savings in refinery oil consumption of about 10 percent of the lost throughput. In 1989, U.S. refineries imported about 5.8 MMB/D of crude oil and 2.2 MMB/D of other petroleum products.[95] Based on this import mix, we have assumed that the 5 MMB/D of total shortfall in imports consists of about 3.6 MMB/D of crude oil and 1.4 MMB/D of petroleum products.

[94] OTA, *The Oil Replacement capability,* supra note 1, p. 112 and Oak Ridge National Laboratory, ***Enery Technology R&D: What could Make a Difference,*** vol. *2,* Part 1 of 3, End Use Technology, ORNL 6541/V2/Pl (Oak Ridge, TN: Oak Ridge National Laboratory, December 1989), p. 74.

[95] Annual Energy ***Review 1989, supa note 6.***

Table 3-17—Industrial Oil Use: Consumptionin the Manufacturing and Nonmanufacturing Subsectors, 1989
(thousand barrels per day)

Product	Manufacturing use[a]	Nonmanufacturing use: Farm and off-highway diesel use[a]	Nonmanufacturing use: Other nonmanufacturing[a]	Total nonmanufacturing[b]	Total manufacturing and nonmanufacturing
Fuel oil					
Distillate	77	310	183	493	570
Residual	198	0	52	52	250
Subtotal	275	310	235	545	820
Non-fuel oil					
LPG	42	c	c	1,208	1,250
Other	937	c	c	1,253	2,190
Subtotal	979	c	c	2,461	3,440
Total	1,254	c	c	3,006	4,260

[a]Consumption prorated from U.S. Department of Energy, Energy Information Administration, *Estimates of Short-Term Petroleum Fuel Switching* Capability, DOE/EIA-0526 (Washington, DC: U.S. Government Printing Office, May 1989).
[b]Total consumption as reported in U.S. Department of Energy, Energy Information Administration, *Annual Energy Review, DOE/EIA-0364(89)* (Washington, DC: U.S. Government Printing Office, May 1990), table 62.
[c]The breakdown of non-fuel oil use in nonmanufacturing applications is not reported separately. The non-fuel oil amount is reported as a subtotal for non-manufacturing use.
[d]Includes asphalt and road oil, still gas, petroleum feedstocks, petroleum coke, and other petroleum products.

SOURCE: Office of Technology Assessment, 1991, from Renova Engineering, P. C., "Oil Replacement Analysis-Evaluation of Technologies," OTAcontractor report, February 1991 .

Table 3-18-Estimated Oil Replacement Potential in the Industrial Sector (thousand barrels per day)

Oil replacement option	Manufacturing: Fuel oil[a]	Manufacturing: Non-fuel oil[b]	Manufacturing: Subtotal	Nonmanufacturing: Fuel oil[a]	Nonmanufacturing: Non-fuel oil[b]	Nonmanufacturing: Subtotal	Total
Reduce refinery throughput					360	360	360
Switch to natural gas	177	65	242	55		55	297
Convert to other fuels	c		c	c			
Process changes	d		d		d	d	100
						Total	807

[a]Consists of distillate and residual oil.
[b]Consists of LPG and other non-fuel oil products.
[c]Less than 50,000 B/D in all uses.
[d]Less than 100,000 B/D in all uses.

SOURCE: Office of Technology Assessment, 1991, from Renova Engineering, P. C., "Oil Replacement Analysis-Evaluation of Technologies," OTA contractor report, February 1991.

In the significant oil supply shortfall assumed in this study, refinery throughput would be reduced by 3.6 MMB/D, thus cutting internal fuel consumption by about 0.36 MMB/D. This would effectively reduce the imported crude oil shortfall from 3.6 MMB/D to 3.24 MMB/D, an amount offset somewhat by any increase in refinery runs from increased domestic production or crude oil stock drawdown from the SPR or private stocks.

Conversion to Natural Gas

Natural gas is already a major fuel and feedstock in the industrial sector, representing about 37 percent of industrial energy use. Switching-to natural-gas could displace 232,000 B/D of fuel oil. Natural gas could displace oil in dual-fuel capable facilities and as a feedstock for some uses. Existing oil-only facilities might be converted for natural gas, provided that gas supplies are available.

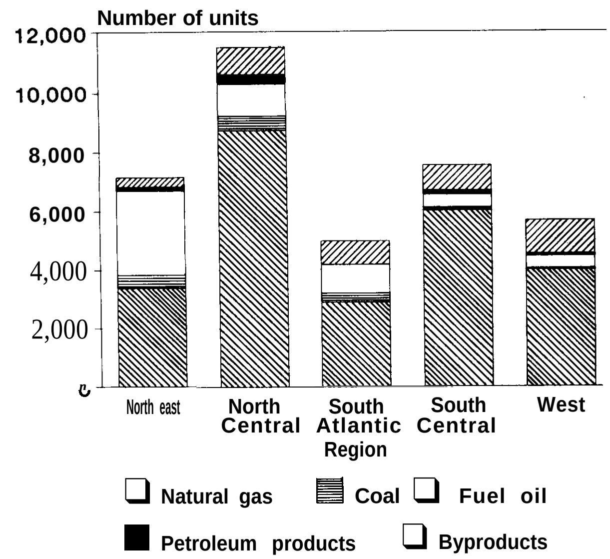
DOE lacks the detailed information on fuel switching capability in the industrial sector comparable to that for electric utilities. Their estimates are based on extrapolations from surveys of a carefully selected pool of industrial users in the five most energy intensive manufacturing industries. Estimates of potential savings are based on assumptions that certain comparable savings could be achieved across the sector.

Fuel Oil Replacement—In the industrial sector, switching from fuel oil to natural gas could displace 177,000 B/D of oil. Price volatility and gas supply curtailments have spurred U.S. industry to improve its flexibility in fuel choices for industrial facilities over the past 2 decades. Many dual-fuel capable industrial facilities are already using gas rather than oil because of the lower relative price of natural gas. The switching that has already occurred, however, limits the potential for further switching from oil to gas.

The major target for fuel switching in the industrial sector is oil used for industrial boilers. Some 36,820 boilers are used in the manufacturing sector.[96] (See figure 3-8.) Natural gas is the dominant boiler fuel in 68 percent of all industrial boilers. Oil-fired boilers include 5,845 units that burn fuel oil (mostly residual) and 575 that burn petroleum products (mostly still gas). Oil-fired boilers make up a large share of boiler units and capacity in the Northeast and South Central regions as shown in figure 3-8.

About half of all industrial boilers now have dual-fuel or backup fuel capability. About 53 percent of fuel oil-fired boilers and almost all of the petroleum product boilers have dual-fuel capability.[97] Among some dual-fuel boilers, the backup fuel is distillate or residual fuel oil. There is no oil replacement capability for these boilers, but perhaps some flexibility in fuel choice could ease demands for fuels in shorter supply in a crisis.

Figure 3-8--Distribution of Industrial Boilers by Region and Primary Fuel Type



SOURCE: Office of Technology Assessment, 1991, from data in Gas Research Institute, "Industrial Natural Gas Markets: Facts, Falacies and Forecasts," March 1989.

DOE estimates that the manufacturing sector's large built-in flexibility for switching residual and distillate fuel oil to other fuels, primarily natural gas, could reduce fuel oil consumption in less than 30 days by about 79,000 B/D of fuel oil, consisting of 7,000 B/D of distillate oil and 72,000 B/D of residual fuel oil.

The almost 2,700 oil boilers that do not have fuel switching capability may be attractive candidates for replacement with gas-fired units. Assuming a 20-year equipment life, typically 25 percent of the boilers would be replaced over a 5-year period under normal conditions.[98] (About 67 percent of the oil-fired boilers were installed before 1970, and 44 percent were installed before 1960).[99] This normal replacement rate, assumed by DOE, could be doubled in a crisis. Doing so would displace an additional 50 percent of the remaining 196,000 B/D, or about 98,000 B/D of fuel oil, consisting of 35,000 B/D of distillate oil and 63,000 B/D of residual fuel oil.

[96] Gas Research Institute, *Industrial Gas Markets: Facts Falacies and Forecasts, March* 1989.

[97] Ibid.

[98] U.S. Department of Energy, *Manufacturing Energy* Consumption *Survey: Fuel Switching 1985,* DOE/EIA-0515(85) (Washington, DC: U.S. Government Printing Office, May 1989), figure 1, p. 18.

[99] Gas Research Institute, supra note 96.

Information on the fuel oil-switching capability in the nonmanufacturing sector is sparse to nonexistent. However, patterns of oil product use in these sectors suggest that farm and off-highway diesel usages offer a very limited potential. In its analysis DOE assumed that oil companies and other miscellaneous users in the nonmanufacturing sector have a switching potential comparable to that for the manufacturing sector. As a result, DOE has estimated the gas conversion potential in the nonmanufacturing sector to be about 10 percent, or about 55,000 B/D.[100] In the absence of more detailed information on manufacturing fuel-switching capability, we have adopted the DOE estimates.

Nonfuel Oil Replacement—The near-term potential for replacing oil directly in nonfuel oil uses is limited to the manufacturing sector where natural gas could substitute for some LPG and marketable petroleum coke. Assuming a switching capability comparable to that for coal and coal coke used as fuel in the manufacturing sector, DOE has estimated the potential to be about 6 to 7 percent of the 979,000 B/D of nonfuel oil products consumed in the manufacturing sector, or about 65,000 B/D of nonfuel oil petroleum products.[101]

In summary, natural gas could replace about 297,000 B/D of petroleum products, comprising 232,000 B/D of fuel oil (177,000 B/D in the manufacturing sector and 55,000 B/D in the nonmanufacturing sector), and 65,000 B/D of nonfuel oil products in the manufacturing sector.

Conversion to Other Fuels

About 10 percent or 50,000 B/D of the remaining consumption of distillates and residual fuel oil could be displaced by some combination of coal, electrification, and renewable technologies.

Coal-Some manufacturing applications that use residual fuel oil might be suitable for coal-based technologies such as CSF, micronized coal, and coal gasification. Assuming that 50 percent of the oil-only capable units are replaced by natural gas-fired units over 5 years, coal-based technologies could, in principle, displace the remaining 50 percent, or about 63,000 B/D of residual fuel oil. The CSF and coal gasification technologies are commercially available, as discussed in the previous section on electric utilities. Some ongoing experiments and demonstrations involving the use of coal in utility boilers might be applicable to industrial uses. Micronized coal technology has also been used successfully in packaged oil-fired boilers.[102] It is not known how suitable some of these uses may actually be for conversion to coal burning from a size, applications, or environmental permitting perspective. However, based on earlier reviews, it seems technically feasible to convert at least some of these facilities to coal. There are already several examples of coal gasification-driven industrial applications in operation or planning.[103]

Renewables-Small, biomass-fired, electric generating units could be deployed to displace distillate oil used in some of the agricultural applications such as space heating, irrigation pumps, and farm machinery. Units in the range of 1.5 to 5 MW are offered commercially.[104] These would seem most appropriate to larger operations, however. Units fired by agricultural and wood wastes are increasingly used in the timber and food processing sectors. Small, mobile biomass gasifiers could be deployed in rural areas.[105]

In our 1984 report we estimated that contributions from solar photovoltaic (PV) systems and wind turbines would be negligible. Experience since then has indicated that they can be appropriate alternative technologies for certain remote applications. Wind turbines and PV units could be deployed to generate electricity and displace some of the distillate oil used in nonmanufacturing applications. Wind turbine technology is commercially available, as discussed earlier under electric utility technologies. Solar PV systems for remote applications have also been used. They can be cost-effective when compared with tie-ins to central generation. In 1988 about 9,700 kilowatts (kW) (peak) of PV modules were shipped, of

[100] *Short-Term Petroleum Fuel Switching,* supra note 16, at p. 18.

[101] Ibid., tables 5 and 7.

[102] Ibid., table 8.

[103] See for example, Dow's plant in Louisiana, under the utility sector earlier in this chapter.

[104] "Biomass-fired Projects Promoted by Cost of Oil," *Engineering News Record,* Sept. 25, 1990, page 25.

[105] OTA, The Oil *Replacement Capability,* supra note 1.

which 2,200 kW were for water pumping and industrial or commercial applications.[106]

Electricity could be used in some manufacturing and nonmanufacturing applications to substitute for fuel oil and distillates in limited applications, but the amount saved is probably small.

Efficiency Gains and Process Changes

In the past 20 years, the industrial sector has grown less energy intensive (and less oil intensive), reflecting improved efficiencies in manufacturing and processing facilities, especially in process control equipment, electrification, industrial cogeneration, and use of waste heat. This improvement also partly reflects a structural shift in the industrial sector toward goods that require less energy to produce per dollar of final product, and this trend is expected to offer continued savings.[107]

Among the major energy-intensive applications in the industrial sector are thermal processes-heat, distillation, separation, and drying. Several options are available to improve efficiencies in these processes and to replace or reduce oil use. For example, the industry could use alternate non-oil-based feedstocks in certain applications. Heat pump and membrane technologies could cut the demand in chemical and petrochemical plants for heat required in distillation columns. Finally, both industry and consumers could intensify waste minimization and reduction programs.

Use of Heat Pumps in Distillation—Distillation is the most widely practiced energy-intensive/thermal method of separating the components of chemical mixtures in the chemical, petroleum, and gas liquids industries.[108] Almost 30 to 60 percent of the energy demand in chemical and petrochemical plants is for heat required in distillation columns. This energy consumption can be reduced by using heat pumps having payback periods of 1 to 2 years. For example, a propylene plant with a conventional distillation column for propane-propylene splitting uses 2.4 lb of steam per pound of product. This consumption can be replaced by electricity by using a heat pump, saving 600 to 700 B/Din a small 120,000 tons/yr propylene plant. Similarly, a typical 250,000 tons/yr styrene plant could save about 400 to 500 B/D of oil.[109]

In 1990, propylene and styrene plants are estimated to produce about 21 and 8 billion pounds, respectively.[110] More detailed analysis would be necessary to verifiy the actual industrywide potential of heat pumps in these plants because some plants use waste heat or natural gas, some already have heat pumps, and retrofitting plants for heat pumps would increase the consumption of electricity. Also, many petrochemical plants that already use waste products as a source of heat or electricity may not see a net savings from the use of heat pumps.

Use of Membrane Technology-Membrane technology provides a mechanical means for separating individual chemicals from mixtures by exploiting the differential rates at which various components permeate membrane structures because of their molecule sizes.[111] The traditional applications of membrane technology include gas separation and water desalination plants. Other commercial applications are air drying and dehydration of organic solvents. The dehydration applications use pervaporation membranes in which the permeate is removed as vapor from the downstream side. DOE has identified pervaporation as a top research priority. If a sufficient quantity of selective pervaporation membranes could be made available, these membranes could replace oil products used to provide process heat for distillation.[112]

Waste Minimization—Each year U.S. industry generates 300 million tons/yr of liquid and solid hazardous wastes. It also generates millions of tons of waste gases, which contain about $500 million worth of chemicals. Those nonhazardous industrial solid wastes and wastewater classified as solid waste by the Environmental Protection Agency (EPA), are estimated to be about 613 million tons/yr.[113]

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[106] *Annual Energy Review 1989,* supra note 6, table 103.

[107] *Energy Use* in the *U.S. Economy,* supra note 90.

[108] ORNL, supra note 94, at p. 70.

[109] Albert Meili, "Heat pumps for Distillation Columns," *Chemical Engineering Progress,* June 1990, p. 60.

[110] *Chemyclopedia 91,* Vol. 9, American Chemical Society, 1991.

[111] ORNL, supra note 94.

[112] Joseph Haggin, "Membrane Technology Has Achieved Success, Yet Lags Potential," *Chemical & Engineering News,* Oct. 1, 1990, p. 22.

[113] U.S. Department of Energy, *National Energy Strategy, Interim Report,* supra note 39.

The industrial sector has intensified its efforts to minimize waste and reduce emissions through process changes in order to attain environmental compliance in a cost-effective manner. For example, 3M Co. switched from a solvent-based to a water-based carrier in a tablet-coating operation.[114] Du Pont Co. cut its plastics waste disposal by 50 million lb/yr through tighter equipment and process controls and by finding markets for off-spec material. Air Products and Chemicals reduced its plants' emissions by over 90 percent, largely by recycling or substituting for solvents. In general, the industry has begun to emphasize that efforts aimed at waste minimization could also improve product yields.[115] Clearly, reduction in petroleum consumption is a potential added benefit, but no estimates of specific overall savings have been calculated.

Post Consumer Recycling

Because of the costs and environmental consequences from solid waste disposal, recycling of wastes has gained added significance. As an additional benefit, some recycling efforts could contribute to reduced oil consumption.

Recycled Plastics—In 1988, 10.3 million tons of plastics were discarded as MSW. Only about 1 percent, or 125,000 tons, was recycled.[116] Recently, several firms have announced plans to expand plastics recycling.[117] To the extent that these plans become successful in substituting or reducing the need for virgin plastics, they could lead to a corresponding decrease in oil consumption.

Redesigned Packaging-Replacing plastic packaging with biodegradable, nonpetroleum-based material has also been suggested as a way to reduce the environmental impacts of waste disposal. McDonald's Corp. has announced plans to switch from polystyrene to (ultimately recyclable) paper packaging.[118] Replacing nonrecycled with recycled plastic packaging has also been suggested as an alternative, but it is not clear how much oil, if any, this would save.

Used Oil—About 720 million gallons of used oil are recycled each year, mostly by burning it as fuel. Most of the remaining 400 million gallons represents the amount generated at households and then disposed of in the trash, on the ground, or down sewers. With proper education, incentives, and enforcement, the portion of such oil recycled might be increased. Reuse of this oil as fuel oil has been limited because of costs and technical problems, but it has been done.[119]

Used Tires-The mountains of used tires accumulated around America represent a resource that potentially could be tapped for materials or fuel.[120] Old tires can be burned as fuel-either directly or in a processed tire-derived fuel. Pulverized rubber from old tires can be added to asphalt. Efforts are under way to develop an 18-percent rubberized asphalt. If successful, such a ground rubber asphalt could not only consume more than 1,000 old tires in every lane mile,[121] but also reduce the Nation's asphalt and road oil consumption, which was about 450,000 B/D in 1989.[122] Efforts at increasing recycling or reuse of tires must confront the challenges of removing nonrubber belting and additives in a cost-effective way.

Use of Alternate Feedstocks

LPG and petrochemical feedstocks are used primarily to produce plastic resins, accounting for almost 30 percent of industrial petroleum consumption. It

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114 A number of additional examples are presented in U.S. Congress, Office of Technology Assessment, *Serious Reduction of Hazardous Waste for Pollution Prevention and Industrial Efficiency, OTA-ITE-317* (Washington, DC: U.S. Government Printing Office, September 1986), ch. 3.

115 "Reducing Wastes can be Cost-Effective," *Chemical Engineering,* July, 1990, p. 31.

116 U S Congress, Office of Technology Assessment, *Facing America's Trash: What Next for Municipal Solid Waste?,* OTA-O-42,4 (Washington, DC: U. S. "Government Printing Office, October 1989).

117 Ann M. Thayer, "Solid Waste Concerns Spur plastic Recycling Efforts," *Chemical& Engineering News,* Jan. 30, 1989, p. 7. "Plastics Recycling Expansion Planned," *Chemical& Engineering News,* Oct. 1, 1990, p. 5.

118 "McDonald's to Drop polystyrene Packaging," *Chemical& Engineering News,* Nov. 12, 1990, p. 5.

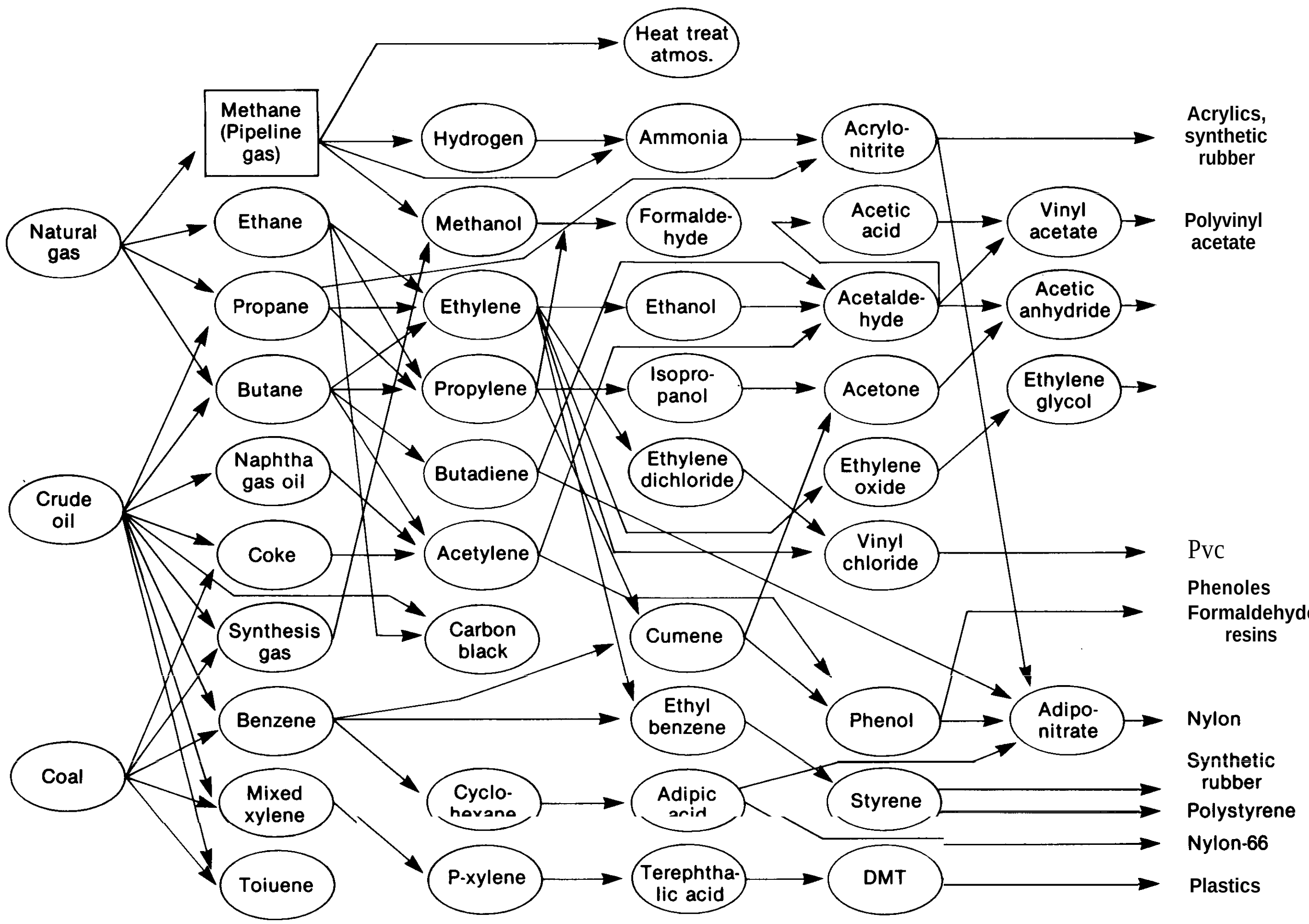
119 Facing America's Trash, supra note 116.

120 EPA estimates that about 250 million tires are discarded annually and that the stockpile of old tires could total 2 to 3 billion nationwide. Only about *30* percent of the tires discarded each year are recycled in some form. *Hearings on Scrap Tire Management and Recycling Opportunities* before the Subcommittee on Environment and Labor and the Subcommittee on Regulation, Business Opportunities, and Energy of the House Committee on Small Business, 101st Cong., 2d se-w., Apr. 18,1990.

121 "Superior Materials are in the Offing," *Engineering News Record,* Oct. *4,* 1990, p. *33.* Such efforts to tap resources contained in old tires present a limited opportunity, however. If just 10 percent of U.S. annual needs for asphalt cement were required to be rubberized asphalt concrete, that use alone would exhaust almost all the tires discarded in a single year. Hearings, supra note 120, at p. 55.

122 *Annual Energy Review* 1989, supra note 6.

Figure 3-9-Chemical Feedstocks: Sources and Applications



SOURCE: Office of Technology Assessment, 1991, adapted from U.S. Congress, Office of Technology Assessment, *Industrial Energy Use, OTA-E-198* (Washington, DC: U.S. Government Printing Office, June 1983), figure 28, p. 117.

might be possible to use natural gas, coal, or biomass to produce alternatives to oil-based feedstocks. In theory, it is possible to replace crude oil with natural gas in feedstock production, as shown in figure 3-9. Whether it can be economically feasible to do so will require additional study. At present, there are several examples of commercial ventures that use alternative feedstocks.

Eastman Chemicals Co. has been producing about 560 million lb/yr of acetic anhydride using Texaco's coal gasification technology. The plant, which went on line in 1984, uses about 900 tons/day of high-sulfur coal. Construction is currently underway to double the output by early 1992.[123]

Warner-Lambert Co. has announced that it will build a corn and potato starch-based plastics plant in Illinois. The 100 million lb/yr plant is scheduled to go on line by the end of 1991.[124]

Many ethylene plants are capable of operating on a wide range of hydrocarbon feedstocks; for example, some of the alternate feedstock requirements for 100 lb of ethylene are: 125 lb of ethane, 240 lb of propane, or 320 lb of naphtha.[125]

[123] Calvin Anderson, Eastman Chemicals CO., personal communication to Renova Engineering, OTA contractor, Jan. 25, 1991.

[124] "Warner-Lambert Revs Up Starch-based Plastic," *Environment Today,* October 1990, p. 27.

[125] Bruce F. Greek, "Margins Plunge for Steam Cracker Ethylene and Coproducts," *Chemical & EngineeringNews,* Oct. 29, 1990, p. 14. Petroleum reduction estimated by Renova from the data reported in the paper.

The 1989 ethane and propane production was about 470,000 B/D each, while the natural gas production was about 17 trillion cubic feet (TCF).[126] Of the total ethane and propane used in the country, about one-third is derived from natural gas.[127] During a crisis, if natural gas production is increased by 1 TCF, ethane and propane supply would increase by about 9,000 B/D each. This increase could displace, in principle, about 35,000 B/D of naphtha.[128] The 1990 ethylene production is forecasted to be about 36 million lb.[129] Since some of the plants already use non-oil-based feedstocks and the feedstocks also determine the quantity of ethylene coproducts, a detailed study would be necessary to verify the actual potential.

Potential Savings

Based on the above discussion, we conclude that process changes would embrace a multitude of options. Each of the foregoing options could replace a small amount of petroleum on an individual basis, leading to a significantly larger collective potential. While we were not able to analyze each option in detail, we have assumed an optimistic scenario, wherein the overall replacement from these and other process changes is assumed to be about 100,000 B/D, or approximately 3 percent of the remaining petroleum consumption.

Deployment Considerations and Costs

A deployment schedule, based on such a scenario, is shown in table 3-19. We have assumed that reduced refinery throughput will decrease oil consumption in the first year. Similarly, about two-thirds of the natural gas conversions, corresponding to the DOE estimates of short-term fuel switching capability, will also occur in the first year. The remaining third of the natural gas conversions are assumed to occur uniformly over the 5-year period. Conversion to other fuels and process changes would become effective in the last 2 years as they generally would require longer lead times for construction.

Estimated capital costs for the various oil replacement options are shown in table 3-20. These investment costs are representative of oil replacement projects in the industrial sector and do not include the full range of replacement options. Minimum investments costs per barrel of oil replaced range from $0 for reduced refinery throughput, natural gas fuel switching in existing equipment, and some process changes to about $31,000 B/D for converting a 100,000 lb/hr steam boiler to use CSF. More extensive process changes and fuel conversions would be considerably more expensive. It is conceivable that some replacement options would result in net cost savings, but none are assumed here.

For reasons discussed at length in our 1984 report and background paper, the availability of manufacturing capacity and of engineering, technical, and craft personnel to convert industrial boilers to non-oil fuels is not expected to be an absolute constraint. As discussed later in this chapter, shortages of qualified engineering and craft personnel could result in some delays in completion of large-scale conversions and retrofits, however. It is also assumed that the necessary environmental permits for plant modifications and/or fuel conversion projects will be obtained relatively smoothly over a 12- to 18-month permitting process.

As discussed in the section on resource availability later, natural gas supplies and delivery capabilities are assumed to be adequate. Seasonal limitations currently exist on the deliverability of natural gas for some industrial users. To overcome these limits, some industrial and utility natural gas consumers are examining the possibility of constructing or reopening liquefied natural gas[130] plants and storage facilities to stockpile natural gas for continued use during periods of peak demand.[131]

[126]" Warner-Lambert Revs Up Starch-based Plastic," supra note 124.

[127] *Short-Term Petroleum Fuel Switching,* supra *note* 16.

[128]Petroleum reduction estimated by Renova from the. data reported in Greek, supra note 125.

[129]*Annual Energy Review* 1989, tables 159 and [71]"

[130]Natural gas *that* has *been* turned into *a* liquid by coolin_g ittominu_s 260'Fat atmospheric pressure. Liquefaction allows natural gas to be mom easily stored and transported long distances by ship.

[131]Discussions at OTA workshop, Dec. 5, 1990.

Table 3-19-Deployment Schedule for Oil Replacement Technologies in the Industrial Sector (oil replacement potential, thouaand barrels per day)

Year	Reduced refinery throughput	Fuel switching: Natural gas[b]	Fuel switching: Other fuels[c]	Process changes[c]	Total
1991	360	219	0	0	579
1992	360	238	0	0	598
1993	360	258	0	0	618
1994	360	277	25	50	712
1995	360	297	50	100	807

a Oil replacement occurs in the first year.
b About 75% oil replacement in the first year.
c Assumes uniform deployment in the last 2 years.

SOURCE: Office of Technology Assessment, 1991, from Renova Engineering, P. C., "Oil Replacement Analysis—Evaluation of Technologies," OTA contractor report, February 1991.

Table 3-20-Estimated Costs for Oil Replacement Technologies in the Industrial Sector

Option	$000 per B/D replaced[a]: Minimum	$000 per B/D replaced[a]: Maximum	Remarks
Reduce refinery throughput	0	0	
Natural gas	0	5	Minimum assumes existing equipment, maximum assumes that a replacement boiler rated at 25,000 lbs/hr steam costs $250,000 and it replaces an oil-fired unit operating at 75 percent efficiency and 40 percent capacity factor.
Other fuels !	31	98	CSF conversion of a 100,000 to 400,000 lbs/hr steam boiler operating at a 40 percent capacity factor.
Process changes	0	20	LPG could displace naptha in ethylene plants at essentially zero cost. At the other extreme, assumes a $10 million retrofit cost for a heat pump add-on to a 250,000 tons/yr styrene plant to reduce oil consumption by 500 B/D[b].

a Approximate investment cost in thousand 1990 dollars per barrel Per day of oil replaced.
b A cost of $40 to $125 per lb/hr of steam derated output (1985 dollars) was cited in H.R. Beal et al.,''coal-water Fuel Retrofit Evaluations," paper presented at Coal-Targets of Opportunity Workshop, DOE, Washington, DC July 12-13, 1988. This cost was increased by 30 percent to reflect 1990 dollars.

SOURCE: Office of Technology Assessment, 1991, from Renova Engineering, P. C., "Oil Replacement Analysis—Evaluation of Technologies," OTA contractor report, February 1991.

TRANSPORTATION SECTOR

The transportation sector is the U.S. economy's largest oil user, accounting for almost 63 percent of the Nation's total oil consumption. In 1989 the transportation sector used about 10.8 MMB/D of petroleum products, more than twice as much as the second largest user (the industrial sector) and more than domestic oil production.[132] Over 80 percent of transport sector oil is consumed by motor vehicles (cars, trucks, and buses), about 14 percent is used by aircraft, and the rest is split between water and rail transport. Table 3-21 summarizes the 1989 oil consumption in the transportation sector.

The most promising opportunities for fuel savings in both the short- and long-term in this sector involve oil replacement options for automobiles and light trucks. These light-duty vehicles (LDVs) represent the largest number of vehicles on the road and well over half of transport oil use. Although one can expect continued incremental improvements in fuel efficiency in other motor vehicles and other modes of transportation, the short-term technical potential for reducing petroleum consumption there is relatively small, and no net savings are included in our estimates.

Oil Use in the Transportation Sector

Petroleum products supply over 95 percent of this sector's energy needs. The transportation system is basically locked into petroleum use for all but the long-term, and efforts to shift to alternate energy sources face significant hurdles. Transportation's share of total oil use has increased from 54 percent in 1979 to 63 percent in 1989. Since 1984, transport sector oil use has grown by 1.15 MMB/D. As transportation uses make up an even larger share of domestic energy use, U.S. flexibility to respond to oil supply and price disruptions has shrunk.

Motor vehicles consumed 8.8 MMB/D of oil in 1989, divided between passenger cars (about 4.9 MMB/D, or about 56 percent), and buses, trucks, and other vehicles (3.9 MMB/D). Aviation used about 1.5 MMB/D or about 14 percent of the total.

Energy consumption in the transportation sector is driven by five factors: technical potential, existing fleet characteristics, manufacturing capacity for replacement vehicles and retrofit equipment, consumer preference (i.e., for model size or horsepower, as influencing fleet replacements), and consumer behavior (miles driven, driving habits, other practices). Our analysis of technical options focuses primarily on the first three factors. Measures targeted at the last two factors could also result in (sizable) fuel savings. More than with any other sector, achieving fuel savings in the transportation sector is like hitting a moving target, because of the continuing growth in transportation demand and the importance of behavioral factors.

Oil Replacement Options for Light-Duty Vehicles

The major short-term oil replacement opportunities for LDVS are improved fuel efficiency, conversion of some fleet vehicles to natural gas and other alternate fuels, and better traffic management. Electric vehicles,[133] while offering significant promise, are not expected to contribute substantial fuel savings within the next 5 years. We estimate that these options could displace about 555,000 B/D of petroleum products, about 5 percent of the consumption in the transportation sector. This would be accomplished using existing technologies and with some shifts in customer preference and new-vehicle fleet mix favoring higher fuel efficiency. The estimated savings are highly contingent on manufacturers' willingness to accelerate dispersion of existing fuel economy technologies in the new vehicle fleet and consumer acceptance. Additional savings are possible with considerable effort if there is a major shift in consumer preferences toward smaller, more efficient models, and if manufacturers accelerate the use of available fuel saving technologies to more models in advance of current product plans.

Fuel Efficiency Improvement

We estimate that under our severe import disruption scenario the introduction of new, more fuel-efficient vehicles in the LDV fleet could reduce

[132] *Annual Energy Review 1989,* supra note 6, table 62.

[133] Larry O'Connell, Electric Power Research Institute, personal communication to Renova Engineering P. C., OTA contractor, Oct. 12, 1990. "A Los Angeles Clean-Air Car," ***The New York Times,*** Monday, Sept. 10, 1990.

Table 3-21-Oil Consumption in the Transportation Sector, 1989

Transportation mode	Oil consumption MMB/D[a]	Vehicles[b] (millions)	Vehicle miles per year (thousands)[c]
Motor vehicles			
Passenger cars[d]	4.86	144.4	10,12
Others[e]	3.95	48,6	12.50
Subtotal[f]	8.81	193.0	10.72
Aircraft[g]	1.49		
Ships[h]	0.33		
Railroads[i]	0.22		
Total	10.85		

a Estimaed breakdown from U.S. Department of Energy, Energy Information Administration, Annual Energy Review 1989, DOE/EIA-0364(89) (Washington, DC: U.S. Government Printing Office, May 1990), table 62.
b Registered vehicles in 1989 from Annual *Energy Review 1989, table 24.*
c Assumes that the 1988 data for passenger cars and all motor vehicles from Annual Energy Review 1989, table 23 is valid for 1989. Mileage for other vehicles calculated by difference.
d Includes passenger cars only as reported by DOE. Assumes that passenger cars consumed 55.2% of the total for all motor vehicles, the ratio calculated for 1988 from *Annual Energy Review* 1989, tables 23 and 24.
e Other vehicles include about 44.2 million buses and trucks, and about 4.4 million motorcycles. Calculated consumption for other vehicles by difference.
f Includes motor gasoline, gasohol, distillate fuel oil (diesel oil), and LPG and kerosene, when used in highway vehicles.
g Assumes 100% of the jet fuel.
h Assumes 100% of the residual fuel.
i Equal to the total supply of 10.85 MMB/D of petroleum less consumption by all other sectors.

SOURCE: Office of Technology Assessment, 1991, from Renova Engineering, P. C., "Oil Replacement Analysis—Evaluation of Technologies," OTA contractor report, February 1991.

overall fuel consumption by from 67,000 B/D to as much as 545,000 B/D over 5 years. This range in estimates of fuel savings are tied to different assumptions about the characteristics of the existing LDV fleet (e.g., size and fuel economy) and future changes (e.g., fuel economy and market share of new vehicles, fleet growth, and changes in vehicle miles traveled).

Although fuel efficiency has increased since 1973, these gains have eroded in recent years. From 1973 to 1988, fuel efficiency improved dramatically, with average fleet fuel economy increasing by about 50 percent from 13.5 mpg to 20 mpg.[134] Table 3-22 summarizes the historical fuel economy for LDVs. By 1987-88, sales-weighted new car fuel economy had increased to over 28 mpg. These gains were not as great as they could have been, however, from 1984 through 1988 consumers sought more luxury options and performance in cars at the expense of fuel economy.[135] Moreover, light trucks, including minivans and sport/utility vehicles (i. e., 4x4's and other machomobiles) became more popular; by 1989 they comprised about one-third of the combined passenger car and light truck sales. The fuel economy of new light trucks showed a smaller gain than that of cars, reflecting the increased market share of less fuel efficient small vans and small utility vehicles[136] These factors, combined with an increase in average fleet age to about 8 years,[137] limited the 1984 to 1988 gain in onroad miles per gallon to about 7 percent. The LDV data for 1989 and 1990 model years shows an actual decline in the fuel economy compared with the 1988 model units.[138]

OTA estimates that in the absence of a crisis, the 1995 model year car fleet could attain a fuel economy of about 32 to 33 mpg (EPA rating) if each automobile manufacturer applies existing technology to improve

[134] Stacy C. Davis and Patricia S. Hu, *Transportation Energy Data Book: Edition 11*, ORNL 6649, (Oak Ridge, TN: Oak Ridge National Laboratory, January 1991), tables 3.18 and 3.8.

[135] *National Energy Strategy, Interim Report,* supra note 39.

[136] Linda S. Williams, and Patricia S. Hu, "Light Duty Vehicle MPG and Market Shares Report: Model Year 1989," Oak Ridge National Laboratory, ORNL-6626, 1989.

[137] *National Energy Strategy, Interim Report,* supra *note 39.*

[138] *Transportation Energy Data Book: Edition 11,* supra note 134, figure 3-33.

Table 3-22—Fuel Economy Data for Light-Duty Vehicles, 1984-90

	1984	1988	Percent change 1984-88	1989	1990 6-months
New light-duty vehicles sold[a]					
Automobiles	10,2 million	10,4 million	2.0%	10.1 million	4.3 million
Light trucks	3.6 million	4.7 million	30.6%	4.8 million	2.2 million
Total	13.8 million	15.1 million	9.4%	14.9 million	6.5 million
Fuel economy					
New vehicles (EPA)[a]					
Automobiles	26.3 mpg	28.5 mpg	8.4%	28.0 mpg	27.7 mpg
Light trucks	20.0 mpg	20.7 mpg	3.5%	20.2 mpg	20.6 mpg
Total new fleet	24,3 mpg	25.5 mpg	4.9%	25.0 mpg	24.8 mpg
On road fuel economy all light-duty vehicles[b]	16.4 mpg	17,5 mpg	6.6%	NA	NA

NA = Not Available.

a Includes automobiles and light trucks. Model year new vehiclesales and EPA fuel economy data from Linda S. Williams and Patricia S. Hu, "Light-DutyVehicle Summary: First Six Months of Model Year 1990," ORNL-6626/S1, Oak Ridge National Laboratory, July 1990.

b Includes cars and light trucks. On-road mpg data from U.S. Department of Energy, Energy [formation Administration, Energy Conservation Trends-*Understanding the Factors That Affect Conservation Gains in the U.S. Economy,* DOE/PE-0092, September 1989, table 16, app. A. The efficiency of atl light-duty vehicles would be 15 to 20 percent higher, if expressed in terms of EPA mpg which is a laboratory-based measure of fuel economy.

SOURCE: Office of Technology Assessment, 1991, from Renova Engineering, P. C., "Oil Replacement Analysis-Evaluation of Technologies," OTA contractor report, February 1991.

its fuel economy according to the technological potential of its fleet and assuming a new fleet mix comparable to 1990.[139] Mechanisms for this shift in fuel economy trends could be in the form of direct requirements on auto fuel efficiency through revised Corporate Average Fuel Efficiency (CAFE) standards, increased gas guzzler taxes, or, most unlikely, a sudden enlightenment about and dedication to fuel efficiency among auto industry executives. The 1995 new car fleet economy could be even greater if buyer preferences changed significantly in response to, for example, higher oil prices or anticipated gasoline shortages, resulting in a shift in sales toward smaller, less powerful cars and/or to more fuel-efficient models within size classes.[140] Without dramatic shifts in manufacturers' perceptions of consumer preferences, substantially higher oil prices, or changes in fuel economy standards, OTA estimates that new car fleet fuel economy under the manufacturers' business as usual product plan will be only about 29 mpg by 1995.[141]

OTA estimates that 1995 model year light trucks could attain a fuel economy of about 24 mpg. Assuming that new light trucks continue to account for one-third of all new LDV sales, the fuel economy for the total new 1995 LDV fleet would be about 29 mpg.[142] Compared with the 1990 new fleet fuel economy of about 25 mpg (see table 3-22), this would amount to an average increase of about 3 percent per year.

Achieving these efficiency gains is contingent on automobile manufacturers making more efficient vehicles and on consumers buying them. Under normal circumstances, automobile manufacturers will have already put into place their design and production plans and schedules for model years 1991 through 1995 based on the anticipated market demand. Supplier contracts will be out for bid and negotiation. Radically altering these schedules to produce a different mix of vehicles or to accelerate introduction of more efficient technologies could cause financial, logistical, and legal headaches. Of course, disastrous

139 See U.S. Congress, Office of Technology Assessment, *ImprovingAutomobile Fuel Economy: New Standards, New Approaches,* expected to be published in October 1991. This OTA report examines the technical potential of various fuel economy technologies and alternative government standards. Interim results were presented in congressional testimony. Steven E. Plotkin, ''Estimating Levels of Corporate Average Fuel Economy, " testimony before the Senate Committee on Energy and Natural Resources, Mar. 20, 1991. Steven E. Plotkin, Senior Associate, U.S. Congress, Office of Technology Assessment, "Legislative Proposals to Increase Automotive Fuel Economy and Promote Alternative Transportation Fuels," testimony before the Subcommittee on Energy and Power of the Home Committee on Energy and Commerce, Apr. 17, 1991.

140 Oak Ridge National Laboratory, supra note 94.

141 Steven E. Plotkin, supra note 139.

142 Steven E. Plotkin, Senior Associate, U.S. congress, Office of Technology Assessment, "Increasing the Efficiency of Automobiles and Light Trucks-A Component of a Strategy to Combat Global Warming and Growing U.S. Oil Dependence,' 'presentation before the Consumer Subcommittee, Committee on Commerce, Science, and Transportation, U.S. Senate, May 2, 1990.

Table 3-23-Alternate Scenarios for Efficiency Gain in the Light-Duty Vehicle Fleet, 1991-95

	Efficiency gain		
	Low	High	Notes
Average new sales, million units/year	10.0	12.0	a
Average fleet growth, percent per year ..,.,.	1.0	0.0	b
New vehicle fuel economy, EPA mpg			c
1991 model year	25.0	25.0	
1995 model year ..,.............,......,............	30.4	33.4	

a Assumes 30 and 10 percent declines respectively from the 1990 sales of 13 million units.

bThe 1984-88growth rate was about 2 percent per year basad on DOE's data on registration of passenger cars, U.S. Department of Energy, Energy Information Administration, Annual Energy Review 1989, DOE/EIA-0384(89) (Washington, DC: U.S. Government Printing Office, May 1990). The low gain scenario assumes half of this rate. The high gain scenario assumes no growth based on an intensified retirement of older cars by consumers.

cAssumes that the 1991 new LDV fleet fuel economy is same-that in 1991. Assumes an annual increase of 5 and 7.5 percent, respectively. The resulting 30.4 mpg in 1995 implies a reduced market share for light trucks at a level of about 20 percent using OTA's 1995 estimates. The 33.4 mpg in 1995 implies a major shift towards smaller cars and much lower sales of light trucks.

SOURCE: Office of Technology Assessment, 1991, from Renova Engineering, P. C., "Oil Replacement Analysis—Evaluation of Technology -," OTA contractor report, February 1991.

car sales from offering only gas-guzzling powercars can also produce manufacturer headaches and, manufacturers obviously must maintain some flexibility to modify product lines and options. During an oil supply shortfall, the major option available to manufacturers would be to shift existing production capacity toward the most fuel-efficient configurations for each model.

The actual oil savings from a shift in new-vehicle fuel efficiency also depends on consumer behavior, such as vehicle miles traveled per year, market share of light trucks, total new vehicle sales, and growth in the overall LDV fleet. Different assumptions about these factors can yield considerable differences in estimates of improved auto fuel efficiency and oil savings. To reflect these uncertainties, we used two alternate scenarios—low-efficiency gain and high-efficiency gain—to assess the fuel savings from fleet turnover for the 1991 to 1995 period. The key assumptions used in these scenarios are shown in table 3-23.

Both scenarios assume 1) an existing 1988 LDV fleet of 160 million vehicles with an onroad fuel economy of 17.5 mpg[143] and (2) a fleet growth of 2 percent per year between 1988 and 1990. Based on these two assumptions and new-model year sales data for 1989 and 1990 (table 3-22), we estimate the 1990 LDV fleet size to be about 167 million vehicles, with an on-road fuel economy of about 18 mpg.[144] We have also assumed the vehicle miles traveled to be 10,100 miles per vehicle per year, the average reported by DOE for passenger cars in 1988 (table 3-21).

The low-efficiency gain scenario corresponds to a slight improvement in the new fleet fuel economy based on renewal of past efficiency gains, depressed new car sales, a modest growth in the fleet size, and a reduced market share for light trucks. The high-efficiency gain scenario corresponds to a more substantial improvement in the new fleet fuel economy, a modest decline in new car sales, zero growth in the fleet size, reduced market share for light trucks and a major shift towards lighter more fuel-efficient cars.

Our analysis, shown in table 3-24, indicates that in 5 years, under the low-efficiency gain scenario, the LDV fleet could save about 67,000 B/D. In contrast, under the high-efficiency gain scenario, shown in table 3-25, which assumes a 34-percent improvement in fuel economy, the LDV fleet could save about 545,000 B/D over 5 years. We have used a mid-range value of 300,000 B/D as the potential fuel savings.

The potential mid-range savings of about 300,000 B/D from the turnover in the LDV fleet is significantly less than the 1984 OTA estimate of 700,000-800,000 B/D.[145] The 1984 study assumed that in a crisis, the new-car fuel efficiency could be increased from 27.5 to 36 mpg, or a gain of about 31 percent. The primary reason for the difference is that under the updated scenarios, the new 1991-95 cars are replacing old cars that are, on average, more fuel efficient

143This reflects a lower miles per gallon value than DOE estimate. We have used the Motor Fuel Consumption (MFC) Model estimate of about 160 million LDVS in 1988 as the basis for our estimates. The data on the number of registered vehicles in the country are not consistent. For example, DOE indicates that in 1986, about 181.5 million vehicles were registered, consisting of 135.4 million passenger cars, 5.3 million motorcycles, and 40.8 million buses and trucks, *Annual Energy Review 1989*, supra note 6, table 24. On the other hand, the MFC Model used by DOE for evaluating the impact of conservation policies, indicates a total 1986 fleet of 162.1 million vehicles, consisting of 117.3 million passenger cars, 37.1 million light trucks with Gross Vehicle Weight (GVW) of less than 8,500 lb each, and 7.8 million heavy trucks (GVW >8,500 lb). Energy and Environmental Analysis, Inc., "The Motor Fuel Consumption Model, 14th Periodical Report," prepared for Martin Marietta Energy Systems, Inc., app. B, Dec. 15, 1988.

144This estimate is lower than that for passenger cars published by DOE in its *Annual Energy Review 1989,* supra note 6.

145OTA, Th, *Oil Replacement Capability*, supra *note* 1.

Table 3-24--Low Efficiency Gain Scenario, 1991-95 Efficiency Improvement for the Light-Duty Vehicle Fleet

	Millions of light-duty vehicles			Vehicle fuel efficiency		Fuel use	Fuel savings	
Year	Total[a]	New[b]	Old[c]	New LDVs[d] EPA mpg	All LDVs[e] on-road mpg	Billion[f] gal/year	Billion gal/year	Thousand B/D
1988	160.0	15.1	144.9	25.5	17.5	—	—	—
1989	163.2	14.9	148.3	25.0	17.7	—	—	—
1990	166.5	13.0	153.5	24.8	17.9	94.0	base year	
1991	168.1	10.0	158.1	25.0	18.0	94.2	(0.28)	(18.24)
1992	169.8	10.0	159.8	26.3	18.2	94.3	(0.02)	(1.56)
1993	171.5	10.0	161.5	27.6	18.4	94.0	0.22	14,32
1994	173.2	10.0	163.2	28.9	18.7	93.6	0.45	29.24
1995	175.0	10.0	165.0	30.4	19.0	92.9	0.66	43.09
Total savings after 5 years								66 .85

LDVs = Light-duty vehicles

[a]Assumes 160 million LDVs in 1988 and a 2 percent per year increase in fleet size from 1988 to 1990 and 1 Percent per year thereafter.

[b]1988 and 1090 data from tables 3-22. Assumes 1990 new car sales at 13 million units and 10 million units/yr therea

[c]Caculated by subtracting new vehicles from total.

[d]l988, 1989 and 1990 data from table 3-22. Assumes that 1991 model year cars have the same EPA rating as that Of the 1988 model year (table 3-22) and there is a 5 percent increase per year beyond 1991.

[e]Based on the 1988 on-road mpg for all cars at 17.5 mpg. For new vehicles, assumes that the on-road mpg is 80 percent

[f]Assumes 10,000 miles/car per year.

SOURCE: Office of Technology Assessment ,1991, from Renova Engineering, P. C., "Oil Replacement Analysis—Evaluation of Technologies," OTA contractor report, February 1991.

than those replaced over the 1985-90 scenario in our earlier report. Other factors also have contributed to this difference. In 1984 we assumed continued progress in fuel efficiency. The CAFE standards have not been raised beyond 1985 and in fact were rolled back from 27.5 to 26 mpg for the 1986 to 1988 period. Perceived consumer demands for power and luxury resulted in production decisions favoring these options at the expense of fuel economy. Also, the market share of less fuel-efficient light trucks and vans increased substantially.

Conversion to Natural Gas

Currently, about 30,000 vehicles in the United States and 700,000 worldwide run on compressed natural gas (CNG).[146] Interest in natural gas vehicles (NGVs) has increased significantly in recent years, with major auto manufacturers announcing plans to market NGVs commercially.[147] For example, General Motors plans to offer 1,000 new natural gas-powered light trucks in California, Texas, and Colorado by 1991.[148] Most of the existing NGVs are gasoline-powered vehicles that have been retrofitted to burn natural gas, and most still retain a dual-fuel capability. Expanded sales of new NGVs and the conversion of more existing vehicles to natural gas offers a promising opportunity for replacing 130,000 B/D of oil in the near term.

The fleet vehicle market offers perhaps the greatest potential for natural gas conversions to cut oil use. Fleet vehicles include buses, trucks, local delivery vans, and police, government, and public utility vehicles. About 16 million vehicles are part of fleets of 10 or more vehicles.[149] We estimate that about 12

146 *U.S. Congress, Office of Techno]ogy Assesment, Rep/acing Gasoline: Alternative Fuels for Light-Duty Vehicles, OTA-E-354 (Washington, DC:* U.S. Government Printing Office, September 1990) (hereinafter Replacing ***Gasoline),*** p. ***97.*** This includes Italy (300,000), Australia (>100,000), New Zealand (150,000), and Canada (15,000).

147American Gas Association, "Outlook for Gas Energy Demand: 1990-2010," May 1990; and Robert Fani, Brooklyn Union Gas Co., personal communication to Renova Engineering, P. C., OTA contractor Oct. 15, 1990.

148Wfald, "Proposals for a U.S. Energy Policy: Some possible, Most Not," ***The New York Times,*** Monday, Sept. 24, 1990. "Bright Hopes for the Blue Flame," ***Time,*** Sept. ***24, 1990,*** p. ***68.***

149American Gas Association, supra note 147.

Table 3-25-High-Efficiency Gain Scenario, 1991-95 Efficiency Improvement for the Light-Duty Vehicle Fleet

	Millions of light-duty vehicles			Vehicle fuel efficiency		Fuel use	Fuel savings	
Year	Total[a]	New[b]	Old[c]	New LDVs[d] EPA mpg	All LDVs[e] on-road mpg	Billion[f] gal/yr	Billion gal/yr	Thousand B/D
1988	160.0	15.1	144.9	25.5	17.5	—	—	—
1989	163.2	14.9	148.3	25.0	17.7	—	—	—
1990	166.5	13.0	153,5	24.8	17,9	94.0	base year	
1991	166,5	12.0	154.5	25.0	18.0	93.2	0.79	51.6
1992	166.5	12.0	154.5	26.9	18.3	91.9	1.27	82.7
1993	166.5	12.0,	154.5	28.9	18.6	90.2	1.71	111.7
1994	166.5	12.0	154.5	31.1	19.1	88.1	2.11	137.9
1995	166.5	12.0	154.5	33.4	19.6	85.6	2.46	160.7
Total savings after 5 years								544.6

LDVS = Light-duty vehicles

aAssumes 160 million LDVS in 1988 and a 2 percent per year increase in fleet size from 1988 to 1990 and O Percent per year thereafter.

b1988 and 1989 data from table 3-22. Assumes 1990 new car sates at 13 million units (table 3-22) and 10 million units/yr thereafter.

cBy difference.

d1988, 1989 and 1990 data from table 3-22. Assumes that 1991 model year cars have the same EPA rating as that Of the 1988 model year (table 3-22) and there is a 7.5 percent increase per year beyond 1991.

eBased on the 1988 on-road mpg for all cars at 17.5 mpg. For new vehicles, assumes that the on-road mpg is 80 precent of EPA mpg.

fAssumes 10,100 miles/car per year.

SOURCE: Office of Technology Assessment, 1991, from Renova Engineering, P. C., "Oil Replacement Analysis—Evaluation of Technologies," OTA contractor report, February 1991.

million of these vehicles are cars, pickups, vans, and minivans.[150] We further estimate that these fleet LDVs used about 1.3 MMB/D of fuel in 1989.[151] In 1983, fleet automobiles averaged about 30,000 mi/yr compared with about 10,000 mi/yr for household automobiles.[152]

The attractiveness of fleet vehicles as conversion targets rests on two characteristics: central refueling capability and high annual mileage, which allows for quicker payback on the investment than for most private cars.

Switching fleet LDVs to run on natural gas entails two changes. First, the vehicle must be retrofitted to burn natural gas, and an onboard gas storage tank must be installed. Second, and perhaps more critical for successful penetration of NGVs, the vehicles must have a network to provide for refueling and servicing.

Many, but not all, fleet vehicles use a central refueling location that could be equipped to refill their tanks with natural gas. However, a considerable number of fleet vehicles in fact refuel at commercial gasoline stations.[153] Nevertheless, it is possible for a network of central fleet refueling operations and commercial gas stations to be deployed to support the introduction of NGVs.[154]

Recent experience in British Columbia confirms the technological feasibility and economic attractiveness of fleet vehicle conversions.[155] In British Columbia, a small retail gasoline company began converting fleet vehicles to natural gas to stimulate sales of batteries and tires. Taxis were the first to accept the conversion. With an annual fuel consumption of over 1,500 gal per vehicle, the fleet owners recovered the conversion cost in less than 2 years. Sensing an opportunity, major oil companies also entered the

150This estimate assumes that the breakdown of the fleet by the type of vehicles is similar to that reported for the 1985 fleet population, Oak Ridge National Laboratory, *Transportation Energy Data Book: Edition 9,* ORNL 6325 (Oak Ridge, TN: April 1987), figure 2.14.

151This is based on an assumption that fleet vehicle fuel consumption is still reflects the 1983 ratio. In 1988, the 157.5 million private cars used a total of about 82.4 billion gallons of fuel, or about 5.4 million bbls/day. *Annual Energy Review 1989,* supra note 6, table 22.

152*Transportation Energy Data* Book: Edition 9, supra note 150, tables 2.28 and 2.34.

153*Replacing Gasoline*, supra note 146.

154Ibid., and Gas Research Institute, supra note 61.

155Patrick L. McGeer and Enoch J. Durbin, "Natural Gas in Cars—And Step On It," The New *York* Times, Friday, Sept. 14, 1990.

market, and the refueling network grew from the original 20 stations to about 50 refueling stations serving fleet and private vehicles.[156]

We have assumed that in response to an oil supply crisis, about 10 percent of the fleet LDVs could be converted to natural gas by 1995. This would require converting about 1.2 million vehicles at an average conversion rate of 240,000 vehicles per year. The converted vehicles would consume about 0.25 quads of gas per year and displace about 130,000 B/D of oil.[157] This would involve a 40-fold increase in U.S. CNG vehicles in just 5 years, no small task. The 10-percent penetration in the fleet population is comparable to that achieved in New Zealand.[158]

In our 1984 report, we estimated that every 1 million vehicles converted would require about 50,000 compressors for refueling stations, each rated at 20 standard cubic feet per minute (SCFM).[159] If, however, the average compressor size is increased to 50 SCFM to serve larger fleets, the required units would decrease to about 20,000 per million vehicles. Thus, a conversion of 10 percent of the fleet LDVs would require 24,000 to 60,000 compressors over a 5-year period.

Delivery constraints for storage cylinders and compressors could pose a potential limitation on this rate of conversion. The Department of Transportation (DOT) certifies the manufacture of storage cylinders. Currently, there are some delays for cylinders because of the lack of vendors with proper DOT certification.[160]

The peak production rate of 5,770 gas compressors occurred in 1974.[161] The currently estimated need is for 5,000 to 12,000 units per year. This has led potential customers to look at foreign sources. Italy, for example, with over 300,000 NGVs on the road, has a large base of cylinder manufacturers. Some gas utilities are already planning to test compressors offered by foreign vendors.[162] U.S. compressor technology is somewhat outdated, and currently, the units available from the United Kingdom are considered to be superior.[163] It is assumed that in a crisis the industry would intensify production efforts and the required compressors would be made available. Given a demand, U.S. companies that manufacture large-diameter pressure piping could fabricate the required cylinders.[164]

Conversion to Other Fuels

An oil supply shortfall would also stimulate use of alternative fuels that would replace or be mixed with gasoline. Over the relatively short replacement horizon considered here, synthetic fuels-such as oil from oil shale or coal liquefaction, even if commercially ready—would not make a significant contribution because of time needed to site, permit, and construct such facilities. The primary short-term alternative fuels are various alcohol fuels, either neat (alone) or blended with gasoline. Currently available fuels include gasohol, a gasoline/alcohol blend (90 percent gasoline, 10 percent ethanol); a substantially pure alcohol, such as neat methanol; and so-called M-85 (85 percent methanol, 15 percent gasoline), an alcohol/gasoline blend that is predominantly alcohol. “Oxygenated fuels” comprise about 25 to 30 percent of the gasoline sold in the country.[165] They contain gasoline blended with low amounts of alcohols or other oxygen-containing compounds, such as methyl tertiary butyl ether (MTBE), and tertiary amyl methyl ether (TAME).

156 Enoch Durbin, personal communication to Renova Engineering, OTA contractor, Nov. 8, 1990.

157 The published data on the near term potential for converting U.S. fleet vehicles to natural gas is limited. For example, an analysis by the American Gas Association (AGA) estimates that NGVs could consume 0.7 quads by the year 2000 under two alternate scenarios - “low energy use” corresponding to significant energy conservation and high environmental standards, and “high environment/high demand use” corresponding to high environmental standards and moderate energy conservation. In its forecast AGA assumed that the major market penetration would occur beyond 1995. American Gas Association, “The Outlook for Gas Energy Demand: 19(90 -2010,” May, 1990. Assuming that 5 to 10 percent of AGA’s year 2000 projection could be achieved by 1995, it would indicate a conversion rate of about 35,000 to 70,000 vehicle-s per year.

158 Enoch Durbin, supra note 156.

159 OTA, *The @l Replacement Capability*, supra note 1.

160 Fani, supra note 147.

161 Office of Technology Assessment, *The Oil Replacement Capability*, supra note 1.

162 Fani, supra note 147.

163 Durbin, supra note 156.

164 Durbin, supra note 156.

165 American Institute of Chemical Engineers, “Methanol and Ethanol as Alternate Fuels for Motor Vehicles,” April 1990.

Gasohol now holds about 8 percent of the gasoline market, and therefore the current consumption of ethanol as a fuel is estimated to be about 54,000 B/D, or about 825 million gals/yr. Most of this ethanol is derived from corn.[166] Ethanol does not replace oil on a gallon-for-gallon basis. Because ethanol has an energy content of 75,700 Btu/gal, compared with gasoline's 125,000 Btu/gal,[167] the 50,000 B/D of ethanol now used actually displaces about 30,000 B/D of gasoline.

At present there is excess domestic ethanol production capacity of about 475 million gal/yr, comprising 375 million gal/yr of corn-based and 100 million gal/yr of synthetically produced ethanol.[168] If, in a crisis, available capacity could be expanded by constructing five new corn-based ethanol plants, each rated at 50 million gal/yr, sufficient ethanol would be available to displace an additional 700 million gal/yr, equivalent to 25,000 B/D of gasoline.

Natural gas feedstocks provide most of current methanol needs, but technology exists to derive methanol from coal and biomass.[169] Of the 1,380 million gal/yr of methanol consumed in the country, about 85 percent is used as a feedstock in the production of other chemicals, mainly formaldehyde, acetic acid, and chloromethane. DOE estimates that about 280 million gal/yr of methanol, about 20,000 B/D, are used as fuel additives.[170] At an energy content of 56,600 Btu/gal,[171] compared with gasoline's 125,000 Btu/gal,[172] the 20,000 B/D of methanol in current use displaces about 9,000 B/D of gasoline.[173]

Because of the recently enacted Federal Clean Air Act amendments and the changes proposed by the California Air Resources Board, the demand for MTBE is expected to rise dramatically.[174] Methanol is the feedstock for MTBE. Since no new methanol plants are under construction, the supply of methanol could be a limiting factor by the mid- 1990s.[175] We do not assume the construction of any new domestic gas-based methanol plants.

In an oil crisis, it could be possible to shift methanol uses from other uses to MTBE. It might also be possible to import gas-based methanol from countries with large gas reserves. We have, however, not included the oil displacement potential of these options because of the uncertainty in supply. Moreover, given the long lead-time required, we have also excluded the feasibility of building any new domestic coal-based methanol plants. In short, we have assumed a negligible oil displacement potential for methanol during the crisis.

Improvements in Traffic Management

Motor vehicle fuel efficiency goes down at both low and very high speeds. Therefore, efforts at improving traffic management to promote more efficient vehicle travel could make modest contributions to saving oil. Various mechanisms have been suggested for improving the use of existing transportation capabilities. We have focused only on relatively passive or voluntary methods and do not include direct means to constrain driver behavior (other than enforcing existing 55 mph, speed limits), such as restrictions on vehicle use or gas purchases, parking bans, and similar measures. Each of these measures alone offers only limited fuel savings, but taken together they could save 100,000 B/D-equal to other options considered here.

In a crisis the Nation could adopt further measures aimed at improving traffic efficiency and management. Examples of such measures are as follows:

Reduced Highway Speed Limits—The fuel economy of an automobile changes with its speed. Test results on 15 different vehicles of 1981-83 model years that were equipped with 4-, 6- and 8-cylinder

166 *Short-Term Petroleum Fuel Switching,* supra note 16.

167 ORNL, *Energy Technology,* What Could Make *a Difference?,* supra note 17, table 1.1-1, p. 10.

168 *Short-Term* Petroleum *Fuel Switching,* supra *note* 16.

169 *Replacing Gasoline,* supra note 146.

170 *Short-Term Petroleum Fuel Switching,* supra note 16.

171 Ibid.

172 *ORNL Energy Technology R&D: What* Could Make a *Difference?,* supra note 17, table 1.1-1, p. 10.

173 *Short-term* Petroleum *Fuel Switching,* supra note 16.

174 Gerald Parkinson, "Shortages Slow, but Cannot Stop Gasoline Reformulating," Chemical Engineering, October 1990, p. 56.

175 "Growth in Methanol Supply Lags Demand," *Chemical& Engineering News,* Sept. 3, 1990, p. 17.

gasoline and diesel powered engines indicate a wide variation in fuel economy at speeds between 15 and 65 mph. The average data for the 15 cars showed an increase in fuel economy from about 26 mpg at 65 mph to about 31 mpg at 55 mph.[176] We estimate that a reduction in the highway speed limit to 55 mi/h would reduce fuel consumption by about 60,000 B/D, provided that the speed limit is enforced strictly.[177]

Increased Use of Ride Sharing and High Occupancy Vehicle Lanes—A 1985 report on 13 high-occupancy vehicle (HOV) lane highways showed an annual saving of 50,000 to 150,000 gal of fuel during peak periods per HOV lane mile. In six projects, the number of ridesharing vehicles increased by 25 percent to over 300 percent, while vehicle occupancy showed an increase of 3 to 15 percent. Shirley Highway in Virginia showed an increase of over 1,000 percent in the number of ridesharing vehicles and over 200 percent in vehicle occupancy.[178] HOV lanes also reduce commuting time by 40 to 50 percent on highly congested highways.[179]

In an oil crisis, additional HOV lanes could promote more ridesharing. For example, one vanpool could replace up to 15 automobiles and save a significant amount of fuel even given the lower fuel economy of vans compared with that of automobiles.[180] The American Council for an Energy-Efficient Economy (ACEEE) estimates that using HOV lanes in cities with populations in excess of 500,000 could reduce fuel consumption by 11,000 to 40,000 B/D.[181]

Employers could further encourage ridesharing by offering preferential parking, flexible schedules, and guaranteed ride-back incentives for emergencies.[182] Existence of free parking is a deterrent against carpooling. A study in downtown Los Angeles indicates that in one case increased parking fees reduced single occupancy vehicles by 25 percent.[183] Such steps combined with improvements in traffic patterns would reduce traffic congestion.

A detailed study would be necessary to estimate the potential fuel reduction from more HOV lanes. We have assumed a savings of about 15,000 B/D based on establishing 100 to 150 HOV lane highways of 10 miles each, for an average saving of 150,000 to 200,000 gallons per lane mile.

Reducing Traffic Congestion—It is estimated that in 1987 traffic congestion increased consumption of gasoline by about 2.2 billion gallons, about 144,000 B/D.[184] the absence of a detailed study, we have assumed that reduced traffic congestion could lead to a savings of 15 to 20 percent, or about 25,000 B/D.

Limited Oil Replacement Potential in Other Transport Sectors

While there have been significant gains in fuel efficiency in aviation, motor freight, and railroads over the past 2 decades, the gains have not been as dramatic as those for LDVs. Moreover, increasing fuel savings have been more than offset by growth in use of these transport modes. We believe that the short-term potential for reducing petroleum consumption in other modes of transportation is relatively small and therefore exclude these modes from our analysis for reasons briefly set out below. At the same time, we believe that modest fuel efficiency improvements in these sectors will continue and that a crisis may reduce fuel demand through a combination of cost-induced conservation, mode shifts, and changing demand for services resulting from associated economic impacts. These shifts, however, are not quantified.

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[176] *Transportation Energy Data Book: Edition 9,* supra note 159, table 2.21.

[177] In 1985, there were about 376 million highway trips with an average trip distance of 730 miles. These household trips involved the USe of automobile=, trucks, and recreation vehicles. Moreover, vehicles which were less than 5 years old accounted for almost 60 percent of the travel miles. ***Transportation Energy Data Book: Edition 9,*** supra note 150, tables 2.23 and 2.8.

[178] *Transportation Energy Data* Book: Edition 9, supra note 150, tables 2.32 and 2.33.

[179] Stacy c Davis et al *Transportation Energy Data Book: Edition 10*, ORNL-6565 (Oak Ridge, TN: Oak Ridge National Laboratory, September 1989), table 3-44, p. 3-75.

[180] Oak Ridge National Laboratory, ***Transportation Energy Data Book: Edition 9,*** supra note 150, tables 2.23 and 2.8.

[181] Monica C. Burke, "High-Occupancy Vehicle Facilities: General Characteristics and Fuel Savings," American Council for an Energy-Efficient Economy, September 1989.

[182] Sandra Spence, Association for Commuter Transportation, personal communication to Renova Engineering, P.C., OTA contractor, Nov. 13, 1990.

[183] Ibid.

[184] *National Energy Strategy, Interim Report,* supra note 39, p. 14.

Table 3-2&Estimated Oil Replacement Potential in the Transportation Sector

Option	Estimated oil replacement potential-thousand B/D	Remarks
Improved fuel efficiency	300	Based on turnover in light-duty vehicle fleet by more efficient new cars. (range of about 67,000 B/D to 545,000 B/D)
Conversion to natural gas	130	Based on conversion of 10 percent of fleet LDVs.
Conversion to other fuels	25	Increased use of ethanol.
Improved traffic efficiency and management	100	Adoption of various measures for promoting fuel saving.
Total	555	

SOURCE: Office of Technology Assessment, 1991, from Renova Engineering, P. C., "Oil Replacement Analysis—Evaluation of Technologies," OTA contractor report, February 1991.

Highway freight transportation has seen modest gains in fuel efficiency. There is less potential for improvements in fuel economy because the options of reducing the weight or power are not readily available. Engines of heavy trucks are already designed more for fuel economy than performance.[185] Nevertheless, some incremental savings can still be achieved through improved aerodynamics, improved tire designs, and development of low-heat rejection engines. Operational changes such as improved maintenance, less idling, and the limiting of empty backhauls can also provide some fuel savings.

Aircraft consumed 1.5 MMB/D of jet fuel in 1989. Commercial aviation accounted for 76 percent; general aviation, 4 percent; and Department of Defense peacetime uses, 20 percent.[186] Significant reductions in military fuel consumption, even during peacetime, are probably unlikely during an imported oil supply disruption.[187] Fuel savings in commercial and general aviation have been more than offset by increases in passenger travel and air freight.

Airline travel has been the fastest growing mode of passenger travel.[188] At the same time, more fuel-efficient jet aircraft are replacing older, less fuel-efficient planes as airlines seek to cut costs. This has helped aviation fuel consumption grow at a slower rate than passenger and freight miles traveled.[189] It is possible that during a crisis airline passenger travel could decline, cutting fuel consumption, but we have assumed that such a decline would not appreciably change the total consumption of about 1.2 MMB/D.

Waterborne shipping and railroads consumed an estimated 550,000 B/D in 1989, or about 5 percent of the consumption in the transportation sector. Domestic shipments accounted for over 50 percent of the tonnage shipped by water. Of this amount, over 62 percent were coal and petroleum products. These energy products also accounted for over 45 percent of the tonnage shipped by freight railroads.[190] Any decrease in domestic petroleum shipments during an oil crisis will be offset at least somewhat, perhaps more, by increased coal shipments. Hence, we have assumed that there will not be any appreciable change in the total consumption of about 550,000 B/D. Table 3-26 summarizes the breakdown of the estimated 555,000 B/D of oil that could be replaced in the transportation sector by the various options assessed above.

185 ORNL, *Energy Technology: What Could Make a Difference?*, supra note 17, p. 3-4.

186 *Annual Energy Review 1989*, supra note 6, table 10. Percentage distributions estimated from 1987 data in ORNL *Energy Transportation Data Book: Edition 10*, supra note 179, table 2.8, p. 2-14.

187 Military fuel needs in the Persian Gulf were largely met by local production and imports. Insignificant refinery capability in Saudi Arabia and other Gulf states were damaged, imports of jet fuel, gasoline, and distillates might have been needed to supply coalition forces and local needs.

188 ORNL, *Energy Technology R&D: What Could Make a Difference?*, supra note 17, p. 5.

189 Ibid. Between 1982 and 1988, fuel consumption grew 44 percent. Passenger miles traveled grew over 8 percent per year, and airfreight increased over 9.5 percent per year. FAA projects air travel to grow at 5 percent per year to the year 2000. Between 1970 and 1988 passenger air traffic tripled, while fuel consumption grew only 43 percent. At least part of the doubling in seat mpg of efficiency was due to more seats per aircraft and higher load factors.

190 ORNL, *Energy Transporation Data Book 9*, supra note 150, tables 3.5, 3.10., and figure 3.4..

Table 3-27—Deployment Schedule for Oil Replacement Technologies in the Transportation Sector (oil replacement potential, thousand barrels per day)

Year	Fuel efficiency improvement(a)	Natural gas(b)	Other fuels(c)	improved traffic management(a)	Total
1991	60	13	5	20	98
1992	120	26	11	40	197
1993	180	39	16	60	295
1994	240	85	21	80	425
1995	300	130	25	100	555

aAssumes a uniform deployment over 5 years.
bAssumes 30 percent deployment in the first 3 years with the remaining 70 percent deployed during the last 2 years.
CAssumes that the excess ethanol capacity replaces 65 percent of the total in the first 3 Years, with new plants replacing the remaining 35 percent during the last 2 years.

SOURCE: Office of Technology Assessment, 1991, from Renova Engineering, P. C., "Oil Replacement Analysis—Evaluation of Technologies," OTA contractor report, February 1991.

Table 3-2&Estimated Investment Costs for Oil Replacement Technologies in the Transportation Sector (approximate investment cost in thousand 1990 dollars per barrel per day of oil replaced)

Option	$1,000 per B/D replaced Minimum	Maximum	Remarks
Improvement in fuel efficiency	0	0	Assumes that automobile manufacturers shift production towards more efficient cars.[a]
Conversion to natural gas	21	26	1.2 million conversions at $1,500-$2,000 per vehicle plus $988 million for refueling stations to displace 130,000 B/D.[b]
Conversion to other fuels	60	90	Assumes $100-$150 million cost for 50 million gallons/year ethanol plant operating at 85% capacity factor.[c]
Improved traffic management	0	0	Adoption of various measures to promote fuel saving.[a]

[a]Negligible cost.
[b]Vehicle conversion costs in British Columbia were about $l,500 each. Patrick L. McGeer and Enoch J. Durbin, "Natural Gas in Cars—and Step on It," The New *York Times, Sept.* 14, 1990. A conversion cost of $2,000/vehicle based on American Gas Association, The *Outlook for* Gas *Energy Demand: 1990-2010,* May 1990. Refueling station cost from: U.S. Congress, Office of Technology Assessment, *Replacing Gasoline: Alternative Fuels for Light Duty Vehicles,* OTA-E-364 (Washington, DC: U.S. Government Printing Office, September 1990), p. 104.
cOne gallon of ethanol replaces 0.6 gallons of gasoline.

SOURCE: Office of Technology Assessment, 1991, from Renova Engineering, P. C., "Oil Replacement Analysis—Evaluation of Technologies," OTA contractor report, February 1991.

Deployment Considerations and Schedule

The estimated deployment schedule for each of the oil replacement options is shown in table 3-27. The schedule assumes that the gains in fuel savings are evenly spread over the 5-year period.

Possible constraints on achieving these savings have been noted in the text and we have reflected these limitations in our estimates. Sufficient supplies of natural gas for transport needs have been assumed in these estimates. Some of the uncertainties about natural gas availability are discussed later in this chapter.

Estimated investment costs for the various oil replacement options in the transportation sector are shown in table 3-28. The costs of more fuel efficient replacement LDVs have been excluded, because this is a continuing activity. The costs for improved traffic management actions also have been assumed to be minimal because they largely utilize existing mechanisms and infrastructure. This treatment of these costs is consistent with the 1984 analysis. Estimated costs for oil replacement range from about $21,000 to $26,000 B/D for the assumed natural gas vehicle conversions and refueling network network to $60,000 to $90,000 B/D for construction of additional ethanol production capacity.

DOMESTIC PETROLEUM SUPPLY

In 1989 domestic sources supplied about 10.1 MMB/D of petroleum—7.6 MMB/D of crude oil, 1.6 MMB/D of natural gas plant liquids NGPL), and about 0.9 MMB/D of processing gain.[191] (See figure 3-lo.)

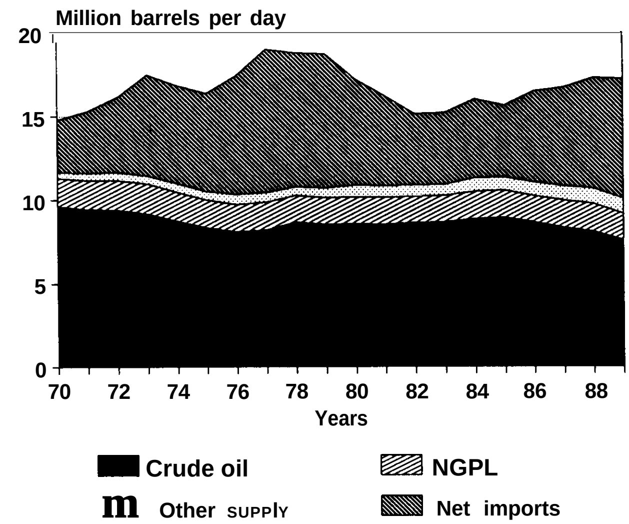
Since 1985, when domestic crude oil production peaked at about 9 MMB/D,[192] production has been declining largely owing to the following factors: a sharp drop in oil prices; reduced drilling activity; abandonment of high-cost, low-volume wells; and impediments to production in environmentally sensitive areas.[193]

In a 1987 study, OTA analyzed these factors and the changes that had taken place in the oil industry. Based on its analysis, we concluded the following:[194]

- Even with optimistic assumptions about the productivity of future drilling, a continuation of 1986 drilling rates would lower production in year 2000 to about 6 MMB/D--a third lower than the 1985 production level—if oil prices remained in the range of $12 to $18/bbl (in 1986 dollars).
- Estimates of the magnitude of the production decline should be viewed as "best guesses" because most forecasts had been based on historical trends and relationships, which might no longer be valid.
- It was not clear whether a break with past trends would lead to higher or lower production levels.

Clearly, the difficulties identified by OTA are further compounded in the present study because there is no historical precedent for the recent sharp drop in oil prices of the last few years and the subsequent possibility of an imported oil cutoff. A continuing decline in domestic production could aggravate any future crisis or policy-driven oil replacement program by

Figure 3-10--U.S. Petroleum Supply, 1970-89



SOURCE: Office of Technology Assessment, 1991, based on data in U.S. Department of Energy, Energy Information Administration, *Annual Energy Review 1989, DOE/EIA-0384(89)* (Washington, DC: U.S. Government Printing Office, May 1990), table 50.

offsetting gains from the deployment of oil-saving technologies.

We estimate that with an extension of current trends, domestic oil production could decline to a level of 8.9 to 10 MMB/D by 1995, thus creating an internal shortfall of 0.1 to 1.2 MMB/D on top of an imported oil cutoff of 5 MMB/D under our oil disruption scenario.

Potential Oil Production

Compared to other oil-producing regions, the United States has been extensively explored. Experts estimate that 80 percent of the oil and gas eventually to be found in the United States lies in fields that have already been discovered.[195] The remaining exploratory potential is also substantial. But much of this

[191] *Annual Energy Review 1989*, supra note 6, tables 50 and 51. Processing gain is the amount by which total refinery output volume exceeds the volume of input fora period of time. The gain is created because the refinery process converts crude oil and other hydrocarbons into products that are, on average, less dense than the input.

[192] Ibid.

[193] *National Energy Strategy, Interim Report,* supra note 39.

[194] U.S. Congress, Office of Technology Assessment, *U.S. Oil Production: TheEffect ofLowOil Prices-Special Report*, OTA-E-348 (Washington, DC: U.S. Government Printing Office, September 1987), pp. 1-2.

[195] W.L. Fisher, "Factors in Realizing Future Supply Potential of Domestic Oil and Natural Gas," paper presented to the Aspen Institute Energy Policy Forum, July 10-14, 1991, Aspen Colorado.

undiscovered oil and gas will come from smaller fields than in the past.

This maturity does not mean that the future for the U.S. oil industry is a rapid and inevitable decline in production from increasingly high-cost deposits. Many in the oil industry hold to a belief that domestic production can be stabilized or slightly increased. In support they note the continuing strength in U.S. reserves additions and a more sophisticated understanding of the nature of U.S. oil and gas resources.

Even as drilling activity has slowed, reserve additions since 1986 have averaged 90 percent of those in the high oil price-high activity years 1978 to 1985. An estimated 86 percent of these reserve additions are attributable to reserve growth in existing fields—that is, increases in the estimates of conventionally recoverable oil resulting from extensive and intensive drilling within existing fields, improved recovery, and identification of new pools.[196]

The past decade has brought recognition that sizable quantities of conventionally mobile oil remain to be recovered in existing fields. The greatest potential recovery is contained in complex reservoirs that will require improved geologic models to make infill drilling and enhanced oil recovery more effective in tapping these deposits. Evolving enhanced oil recovery techniques eventually could allow production of the immobile, residual oil in existing reservoirs.

Tapping these resources is contingent on the economic attractiveness of the prospects at present and anticipated world oil prices, and continued technology development. The higher oil prices and sense of urgency accompanying a severe oil import disruption would likely provide some impetus for expanded exploration and development.

In September 1990 a leading petroleum industry trade magazine, ***Oil & Gas Journal (O&GJ),*** estimated that 1990 domestic crude oil production would be about 7.2 MMB/D,[197] or a decline of about 5.3 percent from the 1989 production of 7.6 MMB/D. Preliminary estimates peg actual 1990 U.S. crude oil output at 7.4 MMB/D, a decline of about 3.4 percent.[198] The higher than expected production levels have been attributed to the higher world oil prices after the Iraqi invasion of Kuwait, and expanded production in Alaskan oil fields following completion of North Slope maintenance projects.

The higher oil prices in 1990 also brought about a brief upswing in exploration indicators, but by late spring 1991, these critical indicators were again trending downward as lower world oil prices returned and domestic natural gas prices all but collapsed.[199] Even so, for the first time since 1985 domestic crude oil production increased in 1991—up 0.6 percent over the first six months of 1990. The rise was attributed to better economic conditions for producers, the expanded exploration and development activities in 1990, and improved technology.[200] This brief surge in investment and drilling activity reaffirms the expectation that higher prices accompanying a severe oil import disruption could boost the exploration and production of domestic crude oil.

Potential opportunities for increased domestic production rest with the discovery of new fields in frontier areas and with improving oil recovery in existing fields. Over the 5-year horizon of our oil replacement scenario, incremental production from existing fields is the most promising option. However, available data are neither consistent nor reliable for estimating potential production increases and, most particularly, for predicting the natural decline in production. Moreover, it is not clear that available technologies and resources could slow the natural decline over the next 5 years stemming from the low levels of drilling activity over the past 5 years.

Production from new, large reservoirs is excluded from our assessment because there are no near-term prospects. Even if the coastal plain areas of Alaska's Arctic National Wildlife Refuge (ANWR) and the most promising offshore frontier areas were to be

[196] Ibid.

[197] "Despite Output Push, U.S. Probably Cannot Avoid Oil Production Decline in 1991", *Oil & Gas Journal,* vol. 88, Sept. 17,1990, page 21.

[198] U.S. Department of Energy, Energy Information Administration, *Monthly Energy Review: July 1991,* DOE/EIA-0035(91/07) (Washington, DC: U.S. Government Printing Office, July 1991), table 3.2a.

[199] U s Department of Energy, Energy Information Administration, *Monthly Energy Review: June 1991,* DOE/EIA-0035(91/06) *(Washington,* DC: U.S. Government Printing Office, June 1991) and Institute of Gas Technology, *International* Gas Technology Highlights, vol. 21, July 15, 1991.

[200] See "Oil Demand Falls to Lowest Level Since 1983," *The Energy Daily,* Jul. 18, 1991, p. 4.

made available for exploration and development today, production could not start until after the year 2000.[201]

The 1990 O&GJ review concluded that under an optimistic price scenario, using the best efforts of U.S. producers, existing fields could be expected to provide an additional 374,000 B/I) within 1 year. However, O&GJ then proceeds to subtract a hefty natural decline of 5 percent, an amount comparable to the 1989-90 decline, thus concluding that the actual net increase by the end of 1991 would be negligible.[202] Since past natural decline rates reflect the strong impact of low oil prices on production and new drilling activities,[203] this rationale would not be valid during a crisis scenario.

We have taken a different approach for estimating potential production gains. Using the data below on potential opportunities identified by O&GJ, we reviewed the prospects for achieving their production capability over a 5-year period in light of known constraints. We address the issue of natural decline separately.

The major potential opportunities identified by O&GJ are as follows:[204]

- Bringing back some 75 percent or about 100,000 B/l) of the 150,000 B/I) of (mostly heavy) oil production in California lost since 1985,
- Bringing on line new production from offshore fields in California to add 140,000 B/l) from the Santa Barbara Channel, 75,000 B/I) from the Point Arguello field, and 65,000 B/I) from the Santa Ynez Unit.
- Increasing production from existing Alaskan fields by about 200,000 B/D, or almost 11 percent over its 1989 production.
- Increasing the combined production in the Gulf Coast, Mid-continent, Midwest, and Rocky Mountain regions by about 70,000 B/D.

Constraints to Production

There are several constraints that could reduce this potential. In 1988, enhanced oil recovery (EOR) supplied about 640,000 B/D. Of this supply, thermal EOR had an 80 percent market share, or about 510,000 B/D.[205] The majority of the thermal EOR projects are in California. Any increase in the deployment of thermal EOR projects would have to overcome strict environmental constraints. For example, currently in California, if an existing steam generator is relocated, the new permit reduces the allowable environmental offsets by a factor of 2 to 5.[206] These regulations could limit the flexibility of a producer to shift production from one field to another. Moreover, any new EOR projects would require an increased supply of coal or natural gas. It is not clear whether increased use of coal would be allowed in California, even if coal technologies could meet environmental limitations.

With respect to increasing the natural gas supply, there is a jurisdictional dispute between the California Public Utility Commission and the FERC.[207] Any delay in resolving this dispute in the courts could result in a delay of new pipeline projects aimed at bringing additional natural gas to California. As of August 1991, most of the pending disagreements had been resolved.

Even if environmental permits could be obtained in 1 or 2 years, typically an additional l-year period would be necessary to achieve breakthrough in California's heavy crude oil fields.[208] Thus, any delays in the permitting process would further reduce the prospects for incremental production in California. We have assumed a range of O to 100,000 B/l) for California's onshore incremental production over 5 years.

The $2 billion Point Arguello project in the Santa Barbara Channel off California has been lying idle for

[201] Ibid. John H. Gibbons, Director, U.S. Congress, Office of Technology Assessment, "On Relieving U.S. Oil Dependence," testimony before the Senate Committee on Energy and Natural Resources, Oct. 2, 1990.

[202] *Oil & Gas Journal,* supra note 197.

[203] Robert Williams, *Oil & Gas Journal*, personal communication to Renova Engineering, P. C., OTA contractor, Oct. 26, 1990.

[204] *Oil & Gas Journal,* supra note 197.

[205] Robert Williams, personal communication, supra note 203.

[206] Raymond L. Schmidt, Chevron Oil Research Company, personal communication to Renova Engineering, P. C., OTA contractor, Oct. 25>1990.

[207] New Pipeline Construction Projects-Status Report, American Gas Association, Issue Brief 1990-5, Apr. 13, 1990.

[208] Raymond L. Schmidt, personal communication, supra note 206.

the last 3 years because of debate over the initial mode of transportation to market—tankers v. existing pipeline.[209] It is not clear when the dispute between Santa Barbara County and the California Coastal Commission and the project sponsors, led by Chevron, will be resolved to permit the projected flow of 75,000 B/D from the mothballed project. In the meantime Chevron announced that it is planning to begin production of about 20,000 B/D from Point Arguello.[210]

The proposed expansion by Exxon of its Santa Ynez project, also in the Santa Barbara Channel, is projected to supply an additional 65,000 B/D by 1994-95.[211] Any delays in its environmental permitting process would extend this production date.

Thus, only under an optimistic scenario could California's offshore production be increased by the full 140,000 B/D over the next 5 years. A more likely projection would be a range of 70,000 to 140,000 B/D.

Production from Alaska's Prudhoe Bay is already declining. Some of Alaska's other fields could go into production over the short term because they were idled for economic reasons. DOE estimates that a resolution of permitting problems could result in a production of up to 100,000 B/D from two developed fields, Niakuk and Point McIntyre, in the Beaufort Sea.[212] On the other hand, given technical and environmental constraints, it is not clear that marginal fields in Alaska could reach full commercial production in 5 years. We have assumed a range of 100,000-200,000 B/D for incremental production from Alaska.[213]

Geologically targeted infill drilling (GTID), or horizontal drilling, could be used to produce unrecovered mobile oil that is not amenable to conventional primary and secondary techniques.[214] A combination of GTID, polymer-augmented water flooding, and permeability profile modification could be deployed to increase production in the 48 contiguous States. For example, based on an analysis of a limited resource base in Texas, Oklahoma, and New Mexico, it is estimated that a price of $20/barrel could justify the recovery of over 1 billion barrels using a combination of infill drilling and waterflood methods. Such a program would require drilling about 26,000 new wells at one-half of current spacing.[215]

The number of drilling rigs in operation has declined from a peak of 3,970 in 1981 to 869 in 1989.[216] The 1990 count is expected to rise to about 1,000. In some areas, this turnaround has already created a shortage of competent people necessary for operating the rigs.[217] With intensified training programs some of the mothballed rigs could be redeployed in a crisis. However, it is not clear whether the intensive drilling entailed in a GTID program could add any significant amount of production in 5 years. Moreover, although independent producers drill the vast majority of wells, and supply about 40 percent of the Nation's needs, many of them probably lack the resources for intensifying the geological studies that are essential for GTID.[218]

Increased carbon dioxide (CO_2) flooding projects, while feasible, are probably limited by cost considerations to those companies that have a captive access to CO_2.[219] Research projects are under way to improve the economics of EOR using chemical flooding, as, for example, using lignin-based chemicals. The new processes are not commercially proven.[220]

As a result, we estimate that Gulf Coast, Midcontinent, Midwest, and Rocky Mountain regions would face serious constraints in achieving a com-

209 *Oil & Gas Journal,* supra note 197.

210 Thomas C. Hayes, "Breaking Logjam on California Oil," The New York Times, Nov. 29, 1990.

211 *Oil & Gas Journal,* supra note 197.

212 " DOE Plans to Help Boost U.S. Oil Production," *Oil & Gas Journal,* vol. 88, Sept. 24, 1990, page 52.

213 "U.S. Oil Flow Hike Unlikely Outside W. Coast," *Oil & Gas Journal,* vol. 88, Oct. 15, 1990, page 32.

214 Oak Ridge National Laboratory, *Energy* Technology R.-D: *What Could Make a Difference ?, Vol. 2, Pt 2 of3, Supply Technology,* ORNL-6541/V2/P2 (Oak Ridge, TN: Oak Ridge National Laboratory, December 1989) pp. 10-15.

215 A.B. Becker, J.P. Brashear, K. Biglarbigi and R.M. Ray, "Evaluation of Unrecovered Mobile Oil in Texas, Oklahoma, and New Mexico," paper presented at the SPE/DOE Seventh Symposium on Enhanced Oil Recovery, Tulsa, Oklahoma, Apr. 22-25, 1990.

216 *Annual* Energy Review 1989, supra note 6, table 41.

217 Guntis Moritis, "Drilling Continues Upward Momentum," *Oil & Gas Journal,* vol. 88, Sept. 24, 1990, page 65.

218 Raymond L. Schmidt, personal communication, supra note 206.

219 Bobby Hall, American petroleum Institute, personal communication to Renova Engineering, P. C., OTA contractor, Oct. 23, 1990.

220 Janice R. Long, "More Energy Research ailed for to Stem Oil, Climate Change Crisis," *Chemical& Engineering News,* Sept. 10, 1990, p. 16.

bined production increase of about 70,000 B/D. Rather, we believe that 70,000 B/D would beat the high end of a range that could be as low as zero.

Natural Decline

Characteristically, there is a natural decline in output from existing production fields as the reserve is exhausted. There are technical means to slow the rate of decline, but depletion is inevitable.[221] At an assumed rate of about 1.0 percent per year, the 1995 domestic oil production would be in the range of 6.8 MMB/D, for a total natural decline of about 400,000 B/I) compared with the 1990 production. At a rate of 3 percent per year, the production would be about 6.2 MMB/D for a decline of about 1 MMB/D.

Incremental Production of NGPL

In 1989 the Nation produced about 17.3 TCF of natural gas and 1.6 MMB/D of NGPL.[222] A similar production level was assumed for 1990. At a heat content of 3.8 MM Btu/bbl for NGPL[223] and 1,000 Btu/ft^3 for natural gas, the NGPL production was about 13 percent of the natural gas production. Assuming that during a crisis, the natural gas production could be increased by 1 to 2 TCF over a 5-year period, an additional supply of 0.13 to 0.26 quads of NGPL, or about 100,000 to 200,000 B/I) of NGPL could be realized.

Estimated 1995 Domestic Petroleum Supply

We estimate, therefore, that by 1995, the Nation's domestic petroleum supply would more likely be in the range of about 8.9 to 10.0 MMB/D, as shown in table 3-29. At this level, the domestic supply would create an additional shortfall of 0.1 to 1.2 MMB/D, as compared with the 1989 supply of 10.1 MMB/D.

Investment Cost

In an earlier report, it was estimated that solid fuel-fired steam flooding EOR projects would require an investment of $10,000 to $20,000 per B/D.[224] The cost for CO_2 flooding was estimated to be $20,000 to

Table 3-29-Estimated 1995 Domestic Petroleum Supply (million barrels per day)

Source	1990	1991-95
Crude oil production		
Current level[a]	7.20	
Incremental crude oil production		
New fields		0,00-0.00
Existing fields		
California (onshore)		0.00-0.10
California (offshore)		0.07-0.14
Alaska		0.10-0.20
Other Lower 48 States		0.00-0.07
Subtotal incremental production		0.17-0.51
(Offset for projected production decline)		(1 .00) -(0.40)
NGPL production		
Current level[b]	1.60	
Incremental NGPL supply		0.10-0.20
Processing gain[c]		0.81-0.91
Total 1995 domestic supply		8.88-10.02

[a]"Despite Output Push, U.S. Probably Cannot Avoid Oil Production Decline in 1991," Oil & Gas *Journal,* vol. *88, Sept. 17,* 1990, p. 21. Oak Ridge National Laboratory, *Energy Technology R&D: What Could Make a Difference, vol. 2,* Part 1 of *3,* End-Use Technology, ORNL-6541/V2/PI (Oak Ridge, TN: Oak Ridge National Laboratory, December 1989), p. 5.
[b]Assumed at the 1989 level based on data reported in U.S. Department of Energy, Energy Information Administration, *Annual Energy Review 1989, DOE/EIA-0384(89)* (Washington, DC: U.S. Government Printing Office, May 1990), table 62.
[c]Ibid., prorated from 1989 data which indicates that the processing gain amounts to about 10% of the crude oil and NGPL supplies.
SOURCE: Office of Technology Assessment, 1991, from Renova Engineering, P. C., "Oil Replacement Analysis—Evaluation of Technologies," OTA contractor report, February 1991.

$40,000 per B/D.[225] A 50-percent escalation of these 1982 costs would indicate that the 1990 costs would be in the range of $15,000 to $60,000 per B/D.

OTHER FACTORS AFFECTING OIL REPLACEMENT POTENTIAL

By deploying various short-term oil replacement technologies, OTA believes that it is technically feasible to displace about 2.9 MMB/D of petroleum products at the end of the 5-year period between 1991 and 1995. Table 3-30 and figure 3-11 summarize the oil replacement potential that could be achieved in

[221] Thomas C. Hayes, supra note 210.

[222] *Annual Energy Review* 1989, supra note 6, tables 50 and 51.

[223] U.S. Department of Energy, Energy Information Administration, *Monthly Energy Review: April 1990*, DOE/EIA-0035(90/04) (Washington DC: U.S. Government Printing Office, July 1990.

[224] Gibbs & Hill, Inc., Supra note 5.

[225] *Monthly Energy* Review: *April 1990,* supra note 223.

each sector. Natural gas, coal, and electricity could displace about 1.8 MMB/D of the total. See figure 3-12. Renewable fuels, nuclear, and other options such as fuel efficiency improvement, industrial process changes, and improved traffic management could displace about 0.7 MMB/D. Finally, an additional 0.36 MMB/D could be saved by reduced refinery throughput.

These potential oil savings must, however, be offset by the likely continuing decline in the domestic petroleum supply, even with the advent of higher prices stemming from a shortage of oil imports that could spur additional drilling. The magnitude of this decline cannot be projected with any certainty. We estimate it to be in the range of 0.1 to 1.2 MMB/D below 1989 production by 1995. The net result is that, of the 5 MMB/D of imported oil lost in a crisis, only about 1.7 to 2.8 MMB/D can be replaced by energy technologies.

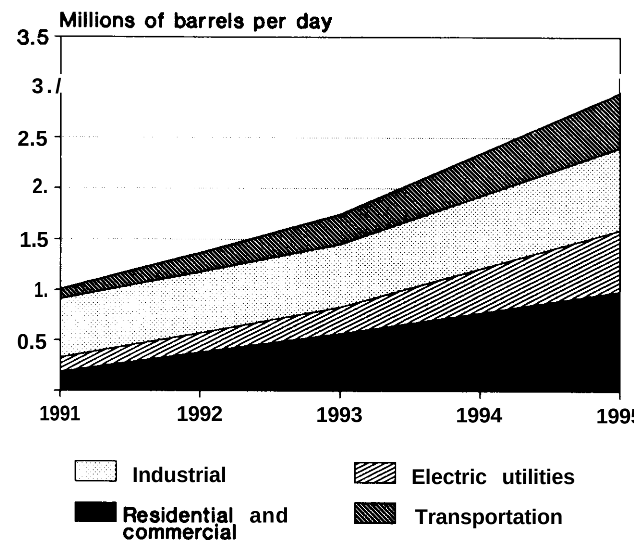
The total investment needs during a crisis will depend on policy, regulatory, and economic decisions adopted by the Nation to spur the deployment of technologies. For illustration purposes only, we have summarized in table 3-31 a breakdown of the estimated capital requirements for deploying all of the technologies identified in this analysis. Using the average of the range of costs for each technology, the investment needs would be about $140 billion. The range is estimated to be $70 to $210 billion.

Uncertainties in Achieving Technical Replacement Potential

For purposes of this analysis, we have assumed that legislative and policy initiatives to promote the use of oil replacement technologies are adopted promptly after the onset of the crisis. We have also assumed that adequate capital is made available to finance the manufacture, purchase, and installation of the needed equipment. Uncertainties remain about the availability of four critical resources: natural gas, electricity, refinery capacity, and technical personnel.

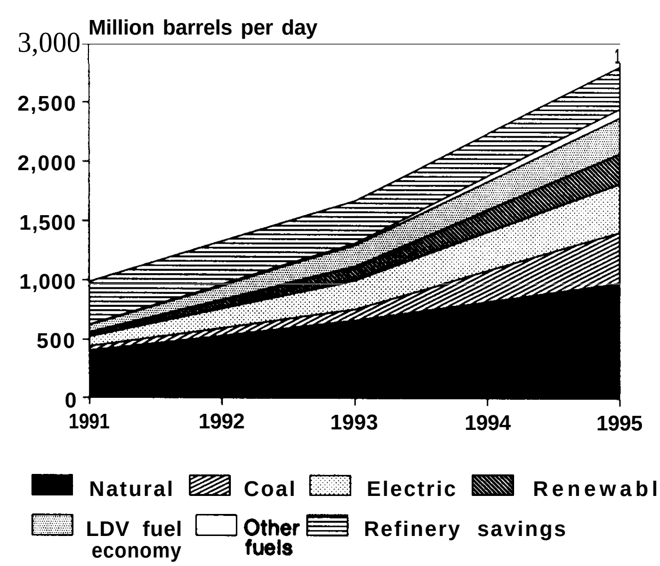
Our review concluded that the supplies of natural gas and electricity are not likely to raise substantial impediments to full deployment of oil replacement technologies at present. However, the availability of

Figure 3-11—U.S. Technical Capability To Replace Lost Imports in an Oil Supply Disruption, 5-Year Deployment Schedule by Sector



SOURCE: Office of Technology Assessment, 1991.

Figure 3-12—U.S. Technical Capability To Replace Lost Imports in an Oil Supply Disruption, Replacement Potential by Source



SOURCE: Office of Technology Assessment, 1991.

Table 340-Summary of Estimated Oil Replacement Potential
(thousand barrels per day)

Petroleum products replaced	Natural gas	Coal	Elec-tricity	Renewable fuels	Nuclear	Other	Total
Electric utility							
residual oil[a]	85	360	NA	95	44	15	599
Residential/commercial							
Distillate oil							
and kerosene	440	7	215	23	NA	22	
Residual oil	NA	39	NA	b	NA	b	
LAG	38	16	192	b	NA	b	
Subtotal	478	62	407	23	NA	22	992
Industrial							
Crude oil[c]	NA	NA	NA	NA	NA	360	
Distillate and	232	17	16	17	NA	100	
residual oil	NA	d	d	d	NA	NA	
LPG & other products	65	NA	NA	NA	NA	e	
Subtotal	297	17	16	17		460	807
Transportation							
Gasoline and diesel	130	NA	NA	25	NA	400[f]	555
Total replacement potential end-use sectors	990	439	423	160	44	897	2,953
Offset for expected domestic petroleum production[g]							(100)-(1,200)
Total net replacement potential							1,700-2,800

NA = not appiicable

aOther non.fuel option is demand management.

bRenewable fuels and efficiency improvement options replace a total of 45,000 B/D of petroleum producys in the residential commercial sectors.

cSavings resulting from reduced refinery throughput.

d Coal, electricity and renewable fuels replace a total of 50,000 B/D of distillate and residual oil in the industrial sector.

e process changes replace a total of 100,000 B/D of products.

f Includes fuel efficiency improvemnt which saves 300,000 B/D, and improved traffic efficiency management which saves 100,000 B/D.

g Difference between the 1989 supply and the potential supply in 1995. (See table 3-29.)

SOURCE: Office of Technology Assessment, 1991, from Renova Engineering, P. C., “Oil Replacement Analysis—Evaluation of Technologies,” OTA contractor report, February 1991.

adequate refinery capacity and trained technical and craft workers could be of concern. These subjects warrant a more detailed study of their full impacts.

Natural Gas Supplies

Switching to natural gas could displace about 1 MMB/D of petroleum products. We estimate (based on an average heat content of 5.5 million Btu/bbl for the products displaced) that this switching could increase the annual natural gas consumption in 1995 by about 2 quads—10 percent more than the 1989 consumption of about 19.4 quads. Domestic natural gas production was about 17.7 TCF in 1989, and imports were about 1.4 TCF.[226] For much of the 1980s, there was a surplus of natural gas production capacity that kept prices down. Various estimates have placed the size of the gas “bubble” at 2 TCF or more, and gas reserve additions have been growing. Most industry analysts project that U.S. gas producers could match increased demand rather quickly. The American Gas Association (AGA) has forecasted that under a high-price scenario, the industry could supply about 19.9 TCF in 1995.[227] AGA’s

[226] *Annual Energy Review 1989,* supra note 6, table 71

[227] American Gas Association, “The Gas Energy Supply Outlook 1989 -2010,” September 1989..

Table 3-31-Summary of Estimated Investment Costs for Oil Replacement Technologies

Sector	Natural gas	Coal	Elec-tricity	Renewable fuels	Nuclear	Other	Total
	($1,000 per B/D of petroleum products replaced[a])						
Electric utility	17	4 3	—	166	7	99	
Residential and commercial	155	556	71	—	—	163	
Industrial	3	65[b]	b	b	—	10'	
Transportation	24	—	—	75	—	—	
	$ billion (1990)						
Electric utility	1.4	15.6	—	15.8	0.3	1.5	34.6
Residential and commercial	26.4	34.5	28.7	—	—	7.2	96.7
Industrial	0.7	3.3	—	—	—	1.0	5.0
Transportation	3.1	—	—		—	—	4.9
Total replacement	31.7	53.4	28.7	17.7	0.3	9.6	141.3
Domestic oil production[d]							5.0
Total							146.3

a An average of the amounts for individual replacement optionsforeach end-use sector.
b Coal, electricity and renewable fuels replace a total of 50,000 B/D of distillate and residual oil in the industrial sector. Assumes that average cost is equivalent to that for coal.
c Excludes the reduced refinery throughput because of oil shortfall.
d Assumes 100,000 B/D from enhanced oil recovery at $50,000/B/D.

SOURCE: Office of Technology Assessment, 1991, from Renova Engineering, P. C., “Oil Replacement Analysis-Evaluation of Technologies,” OTA contractor report, February 1991.

high-price scenario assumed a 1995 oil price of $30/bbl (1988 dollars). By contrast, the low-price scenario of oil at $ 18/bbl forecasted a supply of about 17 TCF. Natural gas prices were not driven up following the invasion of Kuwait in August 1990, in large part because of the ample supplies of natural gas available.

For some regions the pipeline capacity to deliver natural gas and the storage capability are the critical constraints on natural gas availability. At present, in winter months, utility and industrial customers switch from gas to oil because of deliverability constraints. Switching these customers as well as new residential customers to gas could be hindered if local gas deliverability and storage capability are limited. Several pipeline projects, currently under various stages of development across the country, would improve gas availability, even in the absence of a crisis.[228] In particular, several projects are aimed at bringing domestic and Canadian gas to the Northeast and California. The projects in the Northeast are driven by industrial, utility, and independent power demand, while those in California are driven by the demand in EOR applications. Assuming that these pipelines receive the necessary license and permit approvals, the supply of natural gas should not be a constraint to oil replacement on either a national or regional scale.

Electricity

Oil-based electric generation capacity is concentrated in the Northeast, Florida, and California. New England and the Middle Atlantic States also depend on oil for residential heating. The combined impacts of backing out utility oil use and at the same time converting a sizable number of residential heating

[228] American Gas Association, “New Pipeline Projects—Status Report,” Issue Brief 1990-5, Apr. 13, 1990.

Table 3-32-Summer Electricity Supply Data for Oil-Dependent NERC Regions (MW)

NERC Region[a]	Installed capacity 1989[b]	Projected capacity and additions: Installed capacity 1995[b]	Total capacity additions 1990-95[c]	NUG capacity additions 1990-95[d]	Demand management 1990-2000[e]
NPCC	54,622	63,151	8,259	5,791	3,850
WSCC	129,533	131,472	5,834	3,409	NR
CNV	53,921	58,317	4,191	2,484	300
SERC	143,325	162,418	17,215	4,181	NR
Florida	30,857	34,352	2,882	1,097	NR
MAAC	49,829	57,092	7,213	3,491	NR

aNorth American Electric Reliability Council (NERC) Regions and Subregions with large oil-based generating capacity—
- NPCC : Northeast Power Coordinating Council, includes New England States and New York.
- WSCC : Western Systems Coordinating Council, includes Northwest Pool (northern California) and CNV (California-southern Nevada) among others.
- SERC : Southeastern Electric Reliability Council, includes Florida.
- MAAC : Mid-Atlantic Area Council, includes New Jersey, Delaware, Maryland, Washington DC, Virginia, and eastern Pennsylvania.

b North American Electric Reliability Council, 1990 ,Electricity *Supply & Demand for 1990-1999 (Princeton,* NJ: North American Electric Reliability Council, November 1990), table 11.

c Ibid., table 28.

d Ibid., table 30.

e North American Electric Reliability Council, 1990 *Reliability Assessment* (Princeton, NJ: North American Electric Reliability Council, September 1990).

NR . Not reported.

SOURCE: Office of Technology Assessment, 1991, from Renova Engineering, P. C., "Oil Replacement Analysis—Evaluation of Technologies," OTA contractor report, February 1991.

systems from oil to electricity could possibly strain available electricity-generating capability in these regions. If the impact were significant, reduced electricity-generating capacity margins could be a limiting factor to achieving full oil displacement potential.

Table 3-32 shows the summer electricity supply data for the relevant NERC regions, including projections for 1990 through 1995. Based on this assessment, the supply of electricity on a regional basis should not be a limiting factor because utilities in these regions have readily available capacity and technological options to reduce their dependence on oil. Recent developments that have aided utility flexibility in responding to potential oil disruptions include the following:

- Newly added utility and NUG capacity has increased capacity margins and enhanced the potential for contract purchases of non-oil based capacity from other utilities and NUGs to meet new demand.
- Demand management programs have already successfully deferred the need for new capacity and could be accelerated to reduce the impacts of an oil supply crisis.
- New and planned transmission system upgrades are improving capability for interregional transfers of non-oil based electricity. For example, the Mid-Atlantic Area Council plans to strengthen interconnections between utilities in the western part of Pennsylvania and in the Baltimore-Washington area. Similarly, several projects are being developed by the Northwest power pool to bring electricity from the northwestern parts of the United States and Canada to California.[229]
- Planned imports of Canadian power are another alternative that might be accelerated to meet a crisis. For example, New York plans to import an additional 500 MW from Hydro Quebec beginning in the summer of 1995.

[229] North American Electric Reliability Council *1990 Reliability Assessment* (Princeton, NJ: North American Electric Reliability Council, September 1990).

Refinery Capability and the Availability of Residual Fuel Oil

In 1989, about 610,000 B/D of residual oil were imported, about 45 percent of total residual consumption. During the 1980s, production of residual fuel oil by U.S. refineries decreased as demand declined and refineries upgraded their capabilities to handle a wider range of crudes and to produce more light products.

Our analysis found that backing out most oil use in the electric utility sector could displace almost all of the residual fuel oil imports in 1989. Although this offers oil savings, it is not at all clear that cutting residual fuel use in a crisis by over 600,000 B/D would free up oil for other uses or allow the residual oil to be processed into lighter products. First, uses of residual fuel oil are already fairly limited. Second, an import shortfall may not translate into a shortage of residual fuel oil. Domestic refiners would continue to produce residual fuel oil as a remnant of the refining process, and only a portion of the residual fuel imports would likely be lost in a crisis. The output of residual fuel by U.S. refineries is dependent on the quality of the crude oil input and the capability of the individual refineries. Simple refineries, which lack cracking capacity, yield a higher portion of residual fuel than do complex and very complex refineries, which have thermal and catalytic crackers and other downstream processing capabilities. In the 1980s, as the portion of input by heavy oils to U.S. refineries grew, many simple refineries shut down, and refinery capacity came to be dominated by the larger, and more flexible, complex and very complex refineries.[230] Several industry observers have suggested that an increase in domestic refining of heavy oils during a crisis might actually result in a surplus of residual fuel oil.

Between 1980 and 1989, the domestic production of residual oil has declined from a level of about 4.4 percent to 2.2 percent of the refinery output.[231] A more detailed study is necessary to evaluate the actual capability of U.S. refineries to produce products of higher value from residual oil as well as the potential for increased transfer of excess refinery products to friendly countries during a crisis.

Technical Personnel

Many of the oil replacement technologies are highly capital-intensive and require very specialized technical skills. Several oil replacement options involve construction projects for implementing energy technologies. In addition to EOR, the major options requiring construction are those related to the use of coal and renewable fuels in electric utilities, commercial buildings, and industries.

We estimate that such construction projects would require about $75 billion. Services typically account for around 40 percent of the cost of such projects, the balance being for material and equipment. Of the amount allocated for services, engineering and construction management (E/CM) would use about 25 percent, with construction craft labor using the remaining 75 percent. Typically, most of the expenditure on services would be incurred over a 2-year period.[232]

On this basis, E/CM services would amount to about $4 billion per year and field construction craft labor to about $13 billion. Based on $125,000 and $60,000 per person per year for E/CM and craft labor, respectively, the incremental manpower needs would be 32,000 E/CM personnel and 375,000 craft labor.

In 1983, the E/CM and heavy construction craft labor pools were estimated to be about 0.1 and 1 million, respectively. Accordingly, we believe that this demand could strain the existing pool of skilled professional and craft workers and possibly create delays in deploying the technologies. Our oil replacement estimates have assumed that labor shortages do not constrain deployment of fuel-saving technologies. More study would be necessary to assess the personnel availability limitations, taking into account such issues as use of modular and standardized designs, intensified retraining programs, and the impact of an economic slowdown brought on by an oil crisis.

[230] U.S. Department of Energy, Energy Information Administration, *The U.S. Petroleum Refining Industry in the 1980's*, DOE/EIA-0536 (Washington, DC: U.S. Government Printing Office, October 1990).

[231] *Annual Energy Review 1989*, supra note 6, tables 57 and 60.

[232] Gibbs & Hill, Inc., supra note 5.