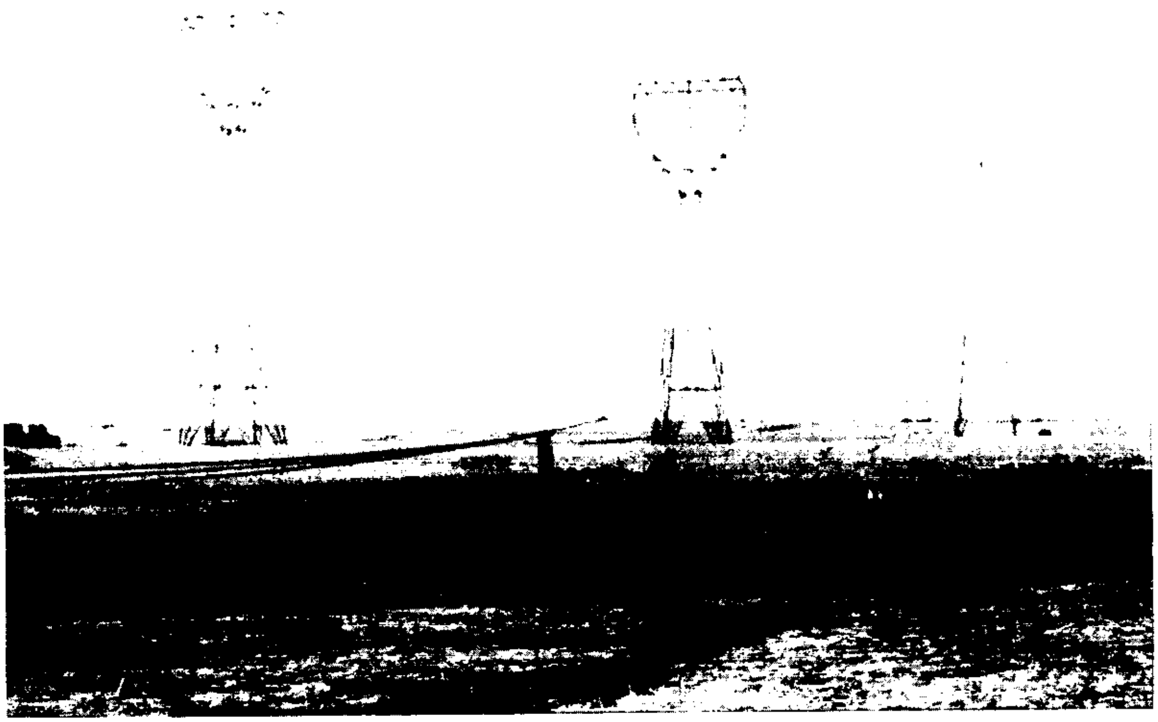
Chapter 3

Energy Supply



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A high-voltage transmission corridor

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INTRODUCTION

This chapter examines carbon dioxide and methane emissions from world and U.S. energy production and distribution and looks at technical alternatives for reducing those emissions during the next 25 years.

At the broadest level, four options exist for reducing carbon dioxide (CO_2) emissions in the energy supply sector:

- switch from high-carbon sources (i.e., coal) to low-carbon sources (i.e., natural gas);
- switch from carbon-based fuels to noncarbon-based fuels;
- convert fossil fuels to usable heat and electricity more efficiently; and
- remove carbon from fossil fuels before the fuel is burned, or capture CO_2 from combustion exhaust gas for deep-well or ocean disposal.

This chapter focuses on the first three approaches; we do not consider the fourth a near-term, proven technical option, though it is certainly worthy of further research and development effort.

Primary energy sources include nonrenewable fossil fuels (coal, petroleum, natural gas), nuclear power, potentially renewable biomass, and renewable such as solar, geothermal, and hydropower. Electricity is a *secondary* energy source produced from the primary energy sources. From the standpoint of greenhouse gas emissions, primary sources can be divided into two categories--carbon-bearing (coal, oil, gas, biomass) and carbon-free (wind, solar, hydropower, geothermal, nuclear).

The four carbon-bearing fuels are discussed in terms of their impact on global warming; their availability (location, production, and consumption); and the technical alternatives and policy options that exist for reducing CO_2 and methane emissions during their production and transport. We also discuss carbon-free energy sources and their potential for substituting for fossil fuels; the conversion of carbon and noncarbon energy sources into electricity; and key issues associated with implementing or changing technologies.

Assuming current trends and regulations, U.S. carbon emissions from electricity generation might double by 2015, as compared to 1987 levels. We estimate that stringent measures to lower the *demand* for electricity (discussed in chs. 4 through 6) have the potential to lower emissions to 10 percent below 1987 levels by 2015. Further measures applied to utilities—in particular, increased use of natural gas and nonfossil sources-have the potential to lower emissions further, to about 50 percent below 1987 emissions by 2015.

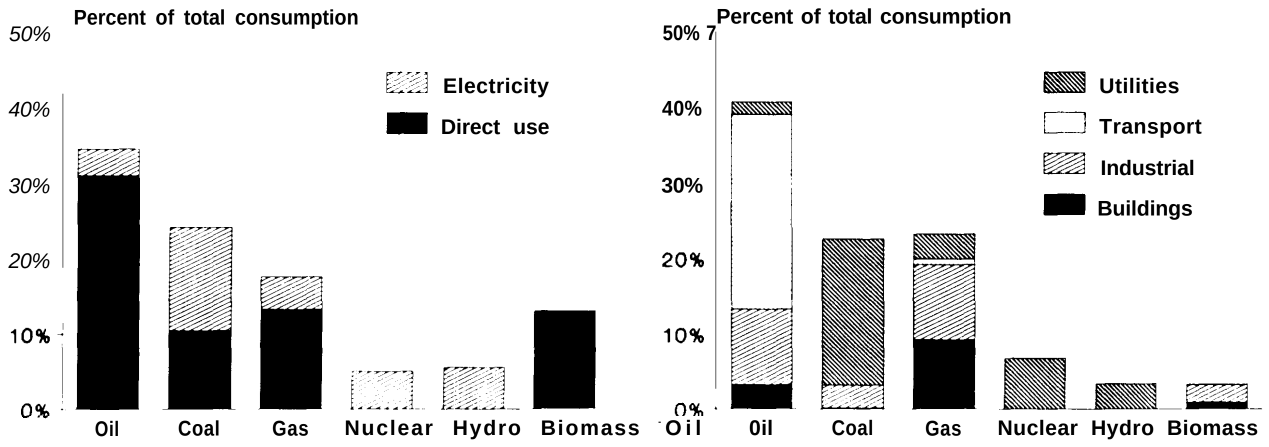
However, it will be increasingly difficult to hold emissions at this low level past the 25-year time horizon of this assessment. Ultimately demand for electricity will begin to rise again. Moreover, much of the potential for lowering emissions comes from switching from coal to natural gas, which will become increasingly difficult to obtain in quantities sufficient to meet the increasing demand. If emissions are to remain low, intensive research, development, and demonstration activities will be needed so that abundant and acceptable nonfossil sources of energy will be available by 2015.

Fuels and Their Carbon Emissions

Total world energy consumption in 1988 was between 350 and 400 quadrillion Btu's (quads). Fossil fuels provided 78 percent of energy consumed (35 percent from oil, 25 percent from coal, 18 percent from natural gas), biomass roughly 13 percent, and noncarbon emitting sources (mainly hydropower and nuclear) the remainder (see figure 3-l). In the United States, the percentages are 87 (fossil fuels), 3 (biomass), and 10 (noncarbon), respectively. Total U.S. energy consumption in 1989 was about 84 quads, with oil accounting for 40 percent, coal and gas about 23 percent each, nuclear power 7 percent, and hydropower and biomass about 3 percent each.[1] Table 3-1 shows commercial fuel consumption in 1988 by region, country, and fuel.

[1]Data for 1988 energy consumption is from Energy Information Administration (80), The 2 8 quads of biomass fuels is an estimate for 1987.

Figure 3-l—World and U.S. Energy Consumption, By Fuel, 1988-89



1989 total ■ 385 quadrillion Btu

1989 total = 84 quadrillion Btu

SOURCES: U.S. Department of Energy, *International Energy Annual, 1988,* DOE/EIA-0219(88) (Washington, DC: Energy Information Administration, November 1989) and U.S. Department of Energy, *Annual Energy Review, 1989,* DOE/EIA-0384(89) (Washington, DC: Energy Information Administration, May 1990).

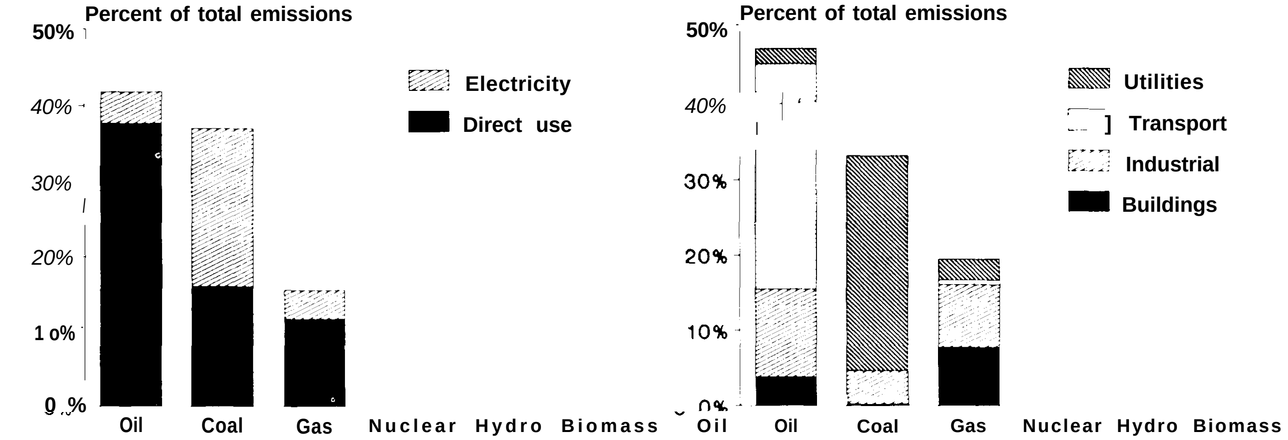
Table 3-l—Commercial Fuel Consumption in 1988 (quads) by Region, Selected Countries, and Fuel Type

Region/country	Oil	Natural gas	Coal	Hydroelectric	Nuclear	Total
OECD[a] Total	74.64	32.08	35.07	11.81	15.13	168.73
	(44.20/.)	(19.0%)	(20.80/o)	(7.0%0)	(9.0%)	
Austria	0.45	0.17	0.16	0.31	—[b]	>1.09
Denmark	0.43	—	0.29	—	—	>0.72
France	3.69	1.01	0.74	0.73	2.24	8.41
Japan	9.61	1.68	2.90	0.90	1.75	16.83
Sweden	0.78	—	—	0.71	0.65	>2.27
United States	34.21	18.49	18.84	2.64	5.68	79.86
West Germany	5.01	2.01	3.51	0.39	1.46	12.39
U.S.S.R./Eastern Europe-Total	22.77	25.25	25.52	2.62	2.95	79.11
	(28.8%)	(31 .9%)	(32.30/.)	(3.3%)	(3.7%)	
U.S.S.R.	18.82	21.78	14.00	2.27	2.26	59.13
Bulgaria	0.60	0.21	0.52	—	o.13	>1.46
Czechoslovakia	0.69	0.39	1.88	0.07	0.23	3.26
East Germany	0.72	0.39	2.76	—	0.11	>4.00
Hungary	0.43	0.41	0.19	—	0.13	>1.16
Poland,	0.72	0.47	5.28	0.04	—	>6.57
Romania	0.73	1.59	0.85	0.12	—	>3.30
Developing—Total[c]	34.50	10.07	32.35	6.62	0.82	84.36
	(40.9%)	(11 .9%)	(38.3%)	(7.8%)	(1 .0%)	
China	4.54	0.54	19.51	1.08	0	25.67
India	2.24	0.26	3.83	0.63	0.07	7.04
Other Asia and Oceania	7.02	1.84	3.59	0.93	0.69	14.07
Brazil	2.74	—	0.41	1.96	<0.01	5.23
Other Latin America	7.90	2.82	0.45	1.48	0.06	12.71
Middle East	6.11	3.23	0.12	0.09	0	9.56
Africa	3.96	1.38	3.46	0.45	0.11	9.37
Total	132.22	67.64	92.97	21.31	19.06	333.21
	(39.7%)	(20.3%)	(27.9%)	(6.40/0)	(5.7%)	

[a]Organization for Economic Cooperation and Development.
[b]—means included in "Other" category in U.S. Department of Energy (1989) database.
[c]Excluding U.S.S.R. and Eastern Europe.

SOURCE: U.S. Department of Energy (1989),

Figure 3-2—World and U.S. Carbon Emissions From Energy Use, By Fuel, 1988-89



1988 total = 63 million metric tons/year **1989 total ■ 1.4 million metric tons/year**

SOURCE: **Office of Technology Assessment, 1991, calculated using data from U.S. Department of Energy, *International EnergyAnnua/(19S8)* and *Annual Energy Review (1989).***

About two-thirds of the total world energy was used directly to fuel end uses; for example, gasoline is used to run cars and natural gas to heat homes. One-third of the energy was used to generate electricity, Oil dominates direct uses; coal dominates electricity generation.

U.S. energy consumption mirrors the world pattern: about two-thirds of the energy was used directly in end uses (60 percent of that was provided by oil), and one-third to generate electricity. Well over half the electricity in the United States is generated from coal.

Carbon dioxide emissions from fossil and biomass fuels are estimated to be responsible for half the greenhouse warming that occurred during the 1980s (83). Coal and wood contain the highest concentration of carbon per unit energy--commonly about 55 to 60 pounds of carbon per million Btu (lbs C/mmBtu). Natural gas has the lowest concentrations (32 lbs C/mmBtu) and petroleum is intermediate (45 lbs C/mmBtu),

World CO_2 emissions from energy use total about 6.3 billion metric tons of carbon per year.[2] Of that, about 6.0 billion metric tons derive from fossil fuels either burned directly for end uses or to generate electricity. Included in this estimate are the relatively small but significant emissions of $C0_2$ associatcd with making carbon-bearing fuels available to consumers, primarily during fuel processing (e.g., to refine petroleum).

Oil accounts for about 42 percent of carbon emissions, coal follows closely with 38 percent, natural gas emits about 15 percent, and biomass between a few and 10 percent (see figure 3-2). The range of estimates for biomass emissions is wide because it is not known how much of biomass fuel burned in developing countries is harvested on a sustainable basis (see ch. 7). Although actual burning of such fuels releases 1.1 billion tons of carbon per year, we estimate that *net* emissions from biomass fuels are about 0.3 billion tons per year. This estimate assumes that about half of the wood used for fuel is not being regrown on a sustainable basis. Figure 3-3 shows emissions from fossil fuel only, by region.

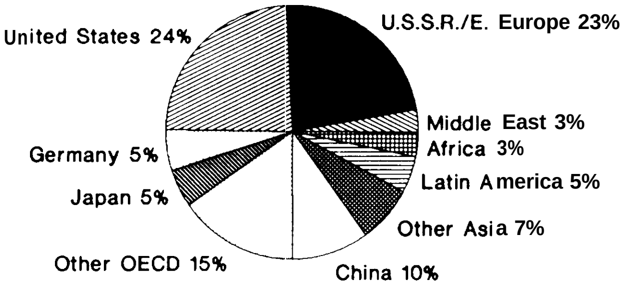
U.S. carbon emissions from energy use are about 20 percent of the world total, or about 1.4 billion metric tons each year. Oil is the largest source, followed by coal, and then natural gas. [3] The percentages of U.S. emissions from oil and gas are both somewhat higher than the world average; coal emissions somewhat lower (see figure 3-2),

Fossil fuels also are a major source of methane, accounting for perhaps 15 percent of al1 methane emissions throughout the world each year. Because, molecule for molecule. methane is far more effectivc

[2] To convert to metric tons of CO_2, multiply by 3.67. To convert to short tons of CO_2, multiply by 4.03.

[3] *In figure 3-2, biomass fuels in the United States are shown contributing no net emissions, which assumes that all harvested fuel wood is replanted.* If, for example, only half of the fuel wood is used on a sustainable basis, biomass emissions would account for 2 percent of the total.

Figure 3-3—World Carbon Emissions From Fossil Fuels, By Region, 1988



Total 1988 emissions:
6 billion metric tons/year

SOURCE: Office of Technology Assessment, 1991, calculated using data from U.S. Department of Energy, *International Energy Annual* (1988).

than CO_2 in trapping energy in the atmosphere, smaller emissions of methane can have as powerful an impact as larger emissions of CO_2. Methane, however, is converted in the atmosphere to CO_2 after 10 to 20 years (see ch. 2).

Fossil-fuel-related methane emissions occur primarily through leakage from natural gas production and transport, oil production, and coal seams. Methane emissions from all sources are estimated to be responsible for about 15 to 20 percent of the greenhouse warming that occurred during the 1980s (83).

While carbon-free energy sources themselves do not release climate-modifying gases to the atmosphere, the steps required to exploit them may nevertheless entail some emissions. For example, the uranium required to run most nuclear powerplants must be extracted, processed, enriched, and manufactured into fuel rods prior to use. The energy this requires typically is provided by fossil fuels. The resulting emissions, however, are still quite low compared to those that would result from using carbon-bearing fuels in place of noncarbon fuels. The latter therefore are gaining attention as low-emission alternatives to fossil fuels.

Electricity Generation

In 1987, nearly two-thirds of the approximately 2,500 gigawatts (Gw) of" electric generating capacity in the world ran on carbon-bearing fossil fuels; this accounted for nearly all of the CO_2 emissions associated with generating electricity. Most of the balance (over one-third) of world generating capacity operates on carbon-free energy sources and does not routinely emit comparable quantities of climate-modifying gases. These low-emission options are dominated by hydropower (about one-quarter of the total world electric capacity) and nuclear power.

Over three-quarters of the world's generating capacity is concentrated in the developed countries of Europe, the U. S. S. R., North America, and Japan. The largest electricity generator is the United States, which in 1987 accounted for about 30 percent of world capacity.

About 30 percent of U.S. electric power in 1987 came from carbon-free energy sources; nuclear power dominated, followed closely by hydropower. All other carbon-free energy-sources (e.g., wind, geothermal, and solar) accounted for less than 0.5 percent of the electric power generated in the United States in 1987. For the United States to supply a large portion of its current electric power from solar, wind, and geothermal energy, enormous growth in those industries would have to occur.

The average efficiency of a U.S. powerplant is 33 percent (14)—that is, only one-third of the energy in the fossil fuel leaves the plants as electric power. The rest is discharged as waste heat. Conversion efficiencies in most industrialized countries are comparable, but they often are quite low (around 25 percent) in developing countries and regions such as China, the Middle East, and Africa (66, 83).

Worldwide growth in capacity has been extremely rapid over the last quarter century. Growth was fastest in the developing world, though this occurred from a much smaller base than in the industrialized countries. In 1987, developing countries accounted for only about a quarter of all the electricity used in the world (see ch. 9). China, India, and Brazil together accounted for nearly a third of the capacity in the developing countries in 1987. Demand for electric power has increased at an annual rate of over 8 percent for the last 20 years (ch. 9; also see refs. 1, 87). The developing countries are expected to continue to increase their share of world capacity during the next quarter century.

CARBON-BEARING ENERGY SOURCES

Fossil Fuels

Introduction

Important international variations exist in the magnitude of fossil fuel reserves, production and consumption, imports and exports, and prices (see tables 3-2 through 3-4), These variations are key considerations in any U.S. effort to limit production, consumption, or trade of fossil fuels.

Reserves--Globally, the most plentiful fossil fuel is coal. Proven reserves of both petroleum and natural gas are far smaller. The largest proven reserves of fossil fuels are within the U.S.S.R. and Eastern Europe; very large amounts are also found in the United States.

***Production** and C'onstimption-in 1988, petro-*leum accounted for over 40 percent of the world's fossil fuel production, coal for nearly a third, and natural gas for the rest.[4] The U.S.S.R. and the United States account for between 40 and 45 percent of the world's fossil fuel production and also for a very large portion of consumption.

Trade—The extent to which each country's production meets its demand varies widely. Some countries, such as Japan, are heavily dependent on imports of all three fossil fuels. Others, such as the U. S. S. R., are large exporters of all three fuels. The most commonly traded fossil fuel is petroleum; nearly 40 percent of crude oil production and 20 percent of refined products were traded internationally, World trade is far less important for natural gas and coal, largely because they are more difficult to handle. The industrial market economies are the largest importers of fossil fuels. The Middle East region is the most important exporter of fossil fuels.

Prices—Typically, coal prices are considerably lower than those of other fossil fuels. U.S. coal[5] prices (per Btu) in 1988 were about one-third lower than natural gas prices. Fossil-fuel prices have gone up considerably since 1970, but declined between 1980 and 1988. Coal prices have been less volatile than gas and oil prices. The relatively low and stable price of coal has much to do with its popularity. U.S. energy prices, in general, are lower than those of most other developed countries. This is particularly true for petroleum products, and to some extent reflects much higher tax rates outside the United States (76).

Coal

Emissions-Coal combustion produces approximately 40 percent of the global CO_2 emissions from fossil fuels and 35 percent of U.S. CO_2 emissions. Electricity generation accounts for about 50 percent of coal use globally, and 80 percent of U.S. coal use. Coal also accounts for a significant portion of the world's methane emissions, mostly from newly opened mines. Preliminary estimates suggest coal production may contribute around 5 to 10 percent of methane emissions directly attributable to human activities worldwide (35a). In the United States, coal may contribute between 10 and 20 percent of total anthropogenic methane emissions.

Resources and Their Use---Coal is the most abundant fossil fuel and is available in many parts of the world. Nevertheless, three countries-the United States, China, and the U.S.S.R.—together account for roughly two-thirds of world reserves. These three countries also were the world's largest producers and consumers of coal in 1988. In recent years, increases in coal production and consumption have been most rapid in China and in India. Very large increases in production also have occurred in Australia, largely to meet rapidly growing export markets, Far smaller, though important, increases occurred in the United States, Canada, and the U.S.S.R. (76).

China, already the world's largest consumer of coal, might triple its consumption of coal to over 3 billion tons by the year 2030, which would increase total world coal production by 50 percent (10). Coal use in India (currently fifth worldwide) also is likely to rise in the future. Many development organizations have encouraged coal use in developing countries because of the availability of domestic supplies.

Over 10 percent of world coal production is traded, at a total value of about $16 billion per year. The United States and Australia are the world's largest coal exporters. Several other countries export

[4] Including natural gas plant liquids.

[5] Bituminous and subbituminous coal, and lignite.

Table 3-2-Coal Resources, Consumption, and Trade (percentage share of worldwide total)

Reserves, 1989	Production, 1989	consumption, 1989	Imports, 1987	Exports, 1987
1. United States. 24.1	1. United States. 23.9	1. China 22.6	1. Japan 27.0	1. Australia. 29.7
2. U.S.S.R. 22.1	2. China 22.9	2. United States. 21.2	2. South Korea 7.4	2. United States. 22.6
3. China 15.4	3. U.S.S.R. 13.9	3. U.S.S.R. 12.9	3. Italy 5.7	3. South Africa. 10.9
4. Australia. 8.4	4. Poland 5.0	4. Poland[a]. 5.7	4. Canada 4.3	4. Canada 8.3
5, India 5.7	5. Australia. 4.4	5. India[a]. 4.1	s. France , --. , ...3. $$	5. U.S.S.R. 7.6
6. 'West Germany 5.4	6. India 4.1	6. Japan 3.4	6. Netherlands. 3.6	6. Poland 7.3
7. South Africa ... , ...5.1	7. West Germany 3.3	7. South Africa[a], ...3.4	7. Belgium/Luxembourg 3.0	7. West Germany 3.0
8. Poland 3.7	8. East Germany 2.9	8. West Germany 3.3	8. Denmark 2.9	8. Colombia 2.4
9. East Germany 1.9	9. United Kingdom. 2.7	9. East Germany[a].. ....3.0	9. West Germany 2.8	9. China 2.1
10. United Kingdom 0.6	10. Czechoslovakia ., ...1.8	10. United Kingdom 2.8	10. U.S.S.R. 2.3	10. United Kingdom ., ...0.8
Other 7.6	Other 15.1	Other 17.6	Other 37.1	Other 5.3
100.0	100.0	100.0	100.0	100.0

[a]Apparent consumption for Poland, India, South Africa, and East Germany is obtained from U.S. Department of Energy (1989). It represents their share of world apparent consumption in 1987 (not 1989).

NOTE: Approximately 10 percent of coal production/consumption is traded internationally.

SOURCES: Unless otherwise specified, data for resources/reserves/production and consumption are from the British Petroleum Company, *BP Statistical Review of World Energy* (London, UK: British Petroleum, June 1990). Data on imports and exports are derived from U.S. Department of Energy, Energy Information Administration, *International* Energy Annual, *1988* DOE/EIA-021 9(88) (Washington, DC: November 1989).

Table 3-3-Petroleum Resources, Consumption, and Trade (percentage share of worldwide total)

Reserves, 1989	Production, 1989	Consumption, 1989	Imports, 1987	Exports, 1987
1. Saudi Arabia 25.2	1. U.S.S.R. 19.7	1. United States , ...25.6	1. United States 18.5	1. U.S.S.R. 10.8
2. Iraq 9.9	2. United States 14.0	2. U.S.S.R. 14.0	2. Japan 12.5	2. Saudi Arabia. 10.5
3. Kuwait 9,3	3. Saudi Arabia 8.3	3. Japan. 7.5	3. West Germany 6.5	3. United Kingdom 5.7
4. Iran 9.2	4. Mexico . . . . , ...4.6	4. China 3.8	4. Italy 5.6	4. Iraq 5.0
5. Abu Dhabi 9.1	5. Iran 4.6	5. West Germany 3.5	5. France ... , ...5.4	5. Iran 4.8
6. U.S.S.R. 5.8	6. China 4.5	6. Italy 3,0	6. Netherlands 4.8	6. Kuwait 4.4
7. Venezuela 5.8	7. Iraq 4.5	7. France 2,9	7, Spain 2.9	7. United Arab Emirates .. .4.3
8. Mexico 5.6	8. Venezuela 3.2	8. United Kingdom 2.6	8. United Kingdom 2.8	8. Venezuela 4.2
9. United States 3.4	9. United Kingdom 3.0	9. Canada ... , ...2.5	9. Singapore 2.7	9. Mexico 4.0
10. Libya 2.3	10. Canada 2.6	10. Brazil[a]. 2.0	10, Belgium 2.2	10. Nigeria ... , ...3.3
Other 14.4	Other 31.0	Other 32.6	Other 36.1	Other 43.0
100.0	100.0	100.0	100.0	100.0

[a]Brazil's apparent consumption is obtained from U.S. Department of Energy (1989). It represents Brazil's share of world apparent consumption in 1987 (not 1989).

NOTE: Imports and Exports, as listed above, include both crude oil and refined petroleum products. Nearly 40 percent of crude oil production was traded internationally in 1987; nearty 20 percent of production was traded internationalty in the form of refined products.

SOURCES: Unless otherwise specified, data for resources/reserves/production and consumption are from the British Petroleum Company, *BP Statistic/ Review of World Energy* (London, UK: British Petroleum, June 1990). Data on imports and exports are derived from U.S. Department of Energy, Energy Information Administration, International Energy *Annual*, 1988 DOE/EIA-0219(88) (Washington, DC: November 1989).

Table 3-4--Natural Gas Resources, Consumption, and Trade (percentage share of worldwide total)

Reserves, 1989	Production, 1989	Consumption, 1989	Imports, 1987	Exports, 1987
1. U.S.S.R. 37.6	1. U.S.S.R. 37.5	1. U.S.S.R. 33.0	1. West Germany 17.8	1. U.S.S.R. 33.6
2. Iran 12.5	2. United States 25.5	2. United States 28.6	2. Japan 16.0	2. Netherlands 13.7
3. Abu Dhabi 4.6	3. Canada 5.1	3. Canada 3.1	3. United States 11.3	3. Norway 11.7
4. Saudi Arabia 4.5	4. Netherlands 3.1	4. West Germany 2.6	4. France 10.7	4. Canada 11.2
5. Qatar 4.1	5. Algeria 2.3	5. United Kingdom 2.6	5. Italy 9.3	5. Algeria 9.8
6. United States 4.1	6. United Kingdom 2.2	6. Japan 2.5	6. United Kingdom 4.9	6. Indonesia 8.5
7. Algeria 2.9	7. Romania[a] 2.0	7. Italy 2.2	7. Belgium/Luxembourg 3.7	7. Malaysia 3.2
8. Venezuela 2.5	8. Indonesia 1.9	8. Romania[a] 2.0	8. Poland 2.9	8. United Arab Emirates 1.2
9. Iraq 2.4	9. Nonway 1.6	9. Netherlands 1.8	9. Czechoslovakia 2.9	9. United States 0.6
10. Canada 2.4	10. Mexico 1.3	10. France 1.4	10. East Germany 2.9	10. West Germany 0.0
Other 22.4	Other 17.5	Other 20.2	Other 17.5	Other 6.6
100.0	100.0	100.0	100.0	100.0

[a]Romania's production and consumption are obtained from U.S. Department of Energy (1989).

NOTE: Approximately 13 percent of world natural gas production/consumption is traded internationally.

SOURCES: Unless otherwise specified, data for resources/reserves/production and consumption are from the British Petroleum Company, *BP Statistical Review of World Energy* (London, UK: British Petroleum, June 1990). Data on imports and exports are derived from U.S. Department of Energy, Energy Information Administration, *International Energy Annual, 1988* DOE/EIA-0219(88) (Washington, DC: November, 1989).

large quantities of coal, and still others intend to become major traders. By far the largest importer of coal is Japan, accounting for 25 percent of world imports (76).

Issues--several technical options exist to reduce coal-related emissions without abandoning coal as a fuel. For example, methane emissions from coal mines can be relatively quickly reduced with available technology, Coal can be used to simultaneously provide heat and electricity through cogeneration. The efficiency of coal use can be markedly improved in other ways as well, as detailed later in this chapter.

The fact remains, however, that coal emits more carbon per unit of energy than any other fuel. There is no cheap and otherwise acceptable way of removing *and* disposing of the large amounts of CO_2 generated through coal combustion (see box 3-B below). Consequently, beyond the limited options just mentioned, the only other near-term alternative to reduce emissions by large amounts is to switch to lower carbon-emitting fuels.

Unfortunately, even limited actions will be difficult to implement because coal is an important and low-priced source of energy for many countries of the world, including the United States. Aggressive attempts to limit its production, consumption, and trade will have profound social and economic impacts. Both at home and abroad, great resistance may develop from entities heavily dependent on coal; these range from unions of coal miners to countries, such as China, whose ambitious plans for development rest squarely on the greatly expanded use of coal.

Petroleum and Natural Gas

Emissions—Petroleum combustion contributes about 40 percent of worldwide CO_2 emissions and 45 percent of U.S. emissions. End uses account for about 90 percent of world and 95 percent of U.S. petroleum consumption. Natural gas combustion is the source of about 15 percent of worldwide CO_2 emissions and about 18 percent of U.S. emissions. About 75 percent of the world's natural gas consumption directly fuels end uses and 25 percent is used to produce electric power. For the United States, these figures are 85 and 15 percent, respectively.

Methane is also released to the atmosphere when oil and gas are produced and when natural gas is transported and stored; two of the more important sources include venting of methane at the well-site and leaks from pipelines. The global magnitude and distribution of methane emissions from these sources remain largely undefined and are matters of contention. However, evidence suggests that emissions are greatest at the extreme ends of natural gas systems—the production end and in low-pressure distribution systems. Also, anecdotal evidence suggests that the Soviet Union's emissions may be extremely high; the U.S.S.R. accounted for nearly 40 percent of world natural gas production in 1989 and its transmission and distribution system is notoriously leaky. One estimate places transmission losses and direct losses during extraction at 8 percent of total U.S.S.R. production (22a).

Resources and Their Use—Proven natural gas reserves are heavily concentrated in two regions: the U.S.S.R. and the Middle East. Large additional resources, including *probable* reserves, exist, though estimates of their precise magnitudes are highly disputed and vary widely.[6]

The world's largest gas producer is the U.S.S.R. (about 40 percent of world production). Overall world production increased by over a third between 1977 and 1987, though production in the United States has declined by 25 percent from a peak in the early 1970s. Global production during the next quarter century will continue to increase, particularly in the U.S.S.R. and in developing countries (42).[7] The U.S.S.R. was also the largest exporter of natural gas in 1986, accounting for over a third of world exports. The major importers were the European countries, with West Germany far in the lead (27).

While natural gas is important in developing countries such as Mexico, Argentina, Venezuela, China, and Algeria, many developing countries have not exploited their natural gas reserves because of the large infrastructure required for a natural gas distribution system. In addition, most of the market for gas is local, making it difficult for foreign oil and gas companies to recoup investments through hard currency earnings (39).

[6] For a discussion of natural gas resources, see refs. 40, 45, and 53.

[7] Also see refs. 22, 32.

Petroleum reserves are concentrated in the Middle East and, to a lesser extent, Latin America. The United States produced about 14 percent of the world's petroleum in 1989, ranking it second behind the U.S.S.R. (which produced 20 percent). About a dozen other countries, concentrated in the Middle East, accounted for most remaining production. Unlike coal and natural gas, which tend to be consumed by the countries that produce them, petroleum is heavily traded; indeed, 40 percent of crude oil and 20 percent of refined products are transferred internationally. Exports are dominated by the huge quantities of oil that flow from the Middle East. The largest world importer is the United States, followed by the European nations (both East and West) and Japan.

Excluding China, oil accounted for over half of the commercial fuel use in developing countries. Compared with the United States, the developing countries use relatively more oil for electricity generation and for industry than for transportation (35). While some countries have large oil supplies, many others must use hard currency to purchase oil on the international market. Even so, while oil consumption decreased in the OECD during the price shocks of the mid-1970s and early 1980s, it steadily increased in the developing countries. Its relative share of commercial fuel use in developing countries, however, has been declining since 1979.

Issues—As with coal, options exist for ' 'tightening' the petroleum and natural gas systems to make them less emissive without necessarily affecting the relative attractiveness of the fuels. One of these is to limit emissions of unburned natural gas, especially in the U.S.S.R. and Eastern Europe. Another is to place greater emphasis on the efficient use of petroleum and natural gas, through cogeneration and by more efficient end-use technologies in general.

Beyond these steps, further measures can be taken to make petroleum less attractive as a fuel. Aside from reduced emissions, the advantages of reduced petroleum use include reduced petroleum imports, trade deficits, and vulnerability to oil-supply cutoffs. Of the many alternatives, the most commonly discussed supply-side alternative is increasing the tax on gasoline (see ch. 5).

Policies affecting the relative attractiveness of natural gas must balance two needs:

I. the need to limit natural gas use because of its methane and CO_2 emissions, and
2. the need to promote its use as a near-term alternative to higher emission alternatives such as coal or coal-based electric power.

Policies will have to improve the position of natural gas *relative* to coal, while simultaneously reducing its appeal relative to options with still lower atmospheric impacts.

A carbon tax could provide an incentive to switch to lower carbon-content fuels such as natural gas. However, care must be taken to structure the tax such that it reflects the methane emissions associated with supplying natural gas. For imports, this will require detailed information on methane emissions in the exporting country as well as leakage in transit.

Biomass Fuels

Emissions

During photosynthesis, plants transform solar energy into chemical energy as they convert atmospheric carbon and water from the soil into carbon-based compounds. The resulting plant tissues are known as "biomass."[8] Plant biomass and animal wastes are used as energy sources around the world. "Biomass fuel' is burned for cooking and space heating in developing countries, and for industrial processes and electricity generation.[9]

When biomass fuels are burned for energy (or when residues from harvesting and processing of plants into fuel decompose), the carbon in them is released to the atmosphere. Unlike fossil-fuel carbon, however, the carbon released from biomass fuels was taken from the atmosphere over the past few decades. If biomass fuels are used on a sustainable basis (e.g., if harvested trees are always replanted), the carbon emitted will be resequestered over the *next* few decades as the plants grow and become available once again for use.

[8]' 'Biomass' in general refers to any living material, including animals and their wastes.

[9]Burning biomass fuels should be distinguished from burning vegetation to clear forests for crop and range land or to remove crop residues from harvested areas; in these latter cases, use of biomass for fuel does *not occur.* Biomass burning and natural decomposition of biomass are major sources of CO_2, methane, and other greenhouse gases (see chs. 7 and 8).

In contrast, the carbon emitted from fossil fuels was taken from the atmosphere millions of years ago. Essentially no carbon is recycled back to fossil fuel (in timeframes of interest to the next several generations) when fossil fuels are burned, since coal and other fossil fuel feedstocks form only very slowly over geologic time.

The net carbon emissions from biomass fuels depends on how they are managed and on the timeframe considered. Dung and agricultural waste used as fuel are typically not considered net emitters because they would rapidly decompose anyway. Twigs and branches will regrow, taking carbon from the atmosphere, over a few years. Carbon emitted by burning harvested trees can be reclaimed in decades, assuming that replacement trees are replanted (see box 7-A in ch. 7).

Resources and Their Use

Data on biomass fuel use are sketchy. By one rough estimate, about 15 percent of the world's energy was obtained from biomass fuels in 1987 (57), considerably more than was provided by nuclear and hydroelectric power combined. Wood accounted for about 60 percent of the biomass fuels, dung and agricultural residue for most of the remainder (55).

The importance of these fuels varies among different countries, largely according to economic conditions, Developing countries may derive up to one-third of their energy needs from biomass (55), but even among these counties, the percentage varies greatly. For example, biomass energy in China, India, and Kenya accounts for about 25, 40, and 80 percent of the total energy use in each country, respectively (74). In rural areas in many of these countries the energy contribution of biomass is often much higher. Traditional biomass fuels (wood, crop residues, animal dung) are relied on for household cooking and heating, particularly in rural areas and in the poorer developing countries in general (21; also see chs. B and 9). While logs and charcoal are often traded in commercial markets, most biomass use is not reflected in statistics on primary commercial energy consumption.

In industrialized countries, biomass fuels account for only about 3 percent of energy supplies, although in a few cases—-particularly in the forest products industry-wood is a significant part of the fuel mix. In Finland, wood accounted for about 15 percent of total energy use in the early 1980s (58, 62). In the United States, forest residues and wood wastes supplied about 2 percent of energy use during the late 1980s, with one-third used at residences and two-thirds by industry (59).

Today, biomass fuels are most commonly used in their unprocessed forms (e.g., wood logs) and are burned directly in residential stoves or industrial boilers or combustors. However, biomass can also be processed into liquid or gaseous fuels for use in boilers, gas turbines, or highway vehicles. Municipal solid waste can be a biomass fuel source in some situations-through combustion in incinerators, with subsequent use of steam (either directly or to drive turbines), or from collection of methane produced when biomass (e.g, paper, food wastes) decomposes in landfills. (See box 3-A for a discussion of how biomass can be used for energy.)

Issues

The Department of Energy (DOE) estimated (86) that using fast-growing, short-rotation woody crops as biomass fuels could offset 3 to 5 percent of current annual U.S. CO_2 emissions, assuming current production and conversion technologies, and up to 35 percent, assuming technology advances and using a high estimate of land availability. OTA's more moderate estimate indicates that planting 0.5 million ha/year in short-rotation woody crops might offset about 1,2 percent of current U.S. CO_2 emissions (see ch. 7).

The major constraint on production and use of biomass fuels as an energy source in the United States is their general lack of economic competitiveness with fossil-fuel energy sources. A recent report by several national laboratories, though, projected that biomass fuels might account for 7 to 13 percent of energy use—two to three times current levels—by the year 2030, depending on the level of Federal support for R&D of different conversion technologies (59) and on whether vigorous measures are taken to promote them. However, developing a sustainable and balanced biomass energy industry also depends on how several questions are resolved, including whether: productivity of short-rotation crops can be maintained over long periods, sufficient infrastructure to support a biomass fuel industry can be developed, market conditions will be conducive to investments in such an industry, and alternative land uses are more desirable.

CARBON-FREE ENERGY SOURCES

Renewable Energy Sources

The use of renewable, carbon-free energy sources results in no or relatively low emissions of climate-modifying gases. ’”

Water

Hydroelectric power is the largest worldwide nonfossil source of electricity. Most installed capacity is located in the United States, Canada, and the U.S.S.R. From 1977 through 1987, worldwide hydroelectric power production expanded by about 40 percent, though by less than 15 percent in the United States.

Worldwide hydropower capacity could ultimately triple (19). Among the developed countries, the U.S.S.R. has by far the largest resources, followed by the United States and Canada. In the developing countries, the largest potential is in Zaire, China, India, Indonesia, Colombia, and Brazil.[11] Hydropower does not directly contribute greenhouse gas emissions, but its high capital costs, associated flooding and deforestation, and impacts on indigenous peoples make it controversial in many developing countries. As a result, U.S. Agency for International Development policy is to no longer fund large hydropower projects. Some governments (e.g., China, Brazil) also have scaled down some large projects because of environmental concerns or the realization that end-use energy efficiency could reduce the need for some new generating capacity.

Geothermal Energy

Geothermal energy is heat, hot water, or steam obtained from the Earth’s crust.[12] In some cases, the hot water comes from wells. In others, cold water (or other working fluid) is pumped down to the hot rock, heated, and returned to the surface to drive a turbine. This heat has many possible applications, but the most common is the generation of electricity. The technology to convert geothermal energy to electricity is relatively well developed for some types of sources (i.e., geysers) but not for all (9).

Photo credit: California Energy Co.

Coso Geothermal project in California.

In 1989, worldwide geothermal capacity totaled over 5,400 megawatts of electricity (MWe). Forty-seven percent of this capacity was in the United States (about 0.4 percent of U.S. generating capacity). Other countries with some geothermal electric capacity were the Philippines, Mexico, Italy, Japan, New Zealand, and Indonesia.

Despite the low absolute use of geothermal energy, growth over the last decade has been extremely rapid; from 1970 to 1988, total geothermal generating capacity in the United States increased from 78 to 2,409 MW of electricity. An additional 7,325 MW were planned worldwide as of April 1989 (20). By the year 2000, U.S. geothermal capacity could reach 6,800 MW. Most will be located in California, Hawaii, Arizona, New Mexico, Nevada, and Utah (52). Rough estimates indicate substantial reserves. The U.S. Geological Survey estimates that on the order of 23,000 MW might be recoverable from high-temperature geothermal resources in the United States (59).

Wind

Wind power is widely used for pumping water. The technology used to turn wind into electricity is well developed, though advanced wind turbine designs (e.g., variable speed rotors) are just begin-

[10] Note that there are hybrid technologies that Supplement noncarbon sources of energy with carbon fuels. Most existing solar thermal electric powerplants, for example, are supplemented with natural gas.

[11] For a detailed listing, see ref. 85.

[12] For more on the technology of geothermal power, see ref. 69.

Box 3-A—Energy From Biomass

Biomass is a renewable energy resource obtained from organic, nonfossil materials such as wood and wood byproducts, agricultural crops and their residues, animal wastes, municipal solid waste (MSW), and sewage sludge (see figure 3A-l). Most biomass energy currently comes from direct combustion of solid biomass (e.g., wood, plant herbage, MSW) for space and process heating, cooking, and a small amount of electric generation. Biomass also can be converted to various gaseous and liquid fuels (often called ***biofuels)*** which can be easily stored and transported

In the United States, biomass sources currently supply about 2.8 quadrillion Btu's (quads), or about 3 percent of the Nation's energy needs (81), an amount typical of industrialized countries. About 87 percent of this energy comes from wood and its byproducts; wastes and alcohol fuels made from biomass account for about 10 and 3 percent, respectively. If fully developed, biomass energy might eventually contribute about 14 quads, or about 17 percent of current U.S. ***energy*** consumption (59); Oak Ridge National Lab (47, 48) estimates a potential 14 quads from biomass-based liquid fuels alone.

Direct Combustion of Wood and Wood Wastes—In the United States, the largest amounts of energy from biomass come from the direct combustion of wood and wood wastes. (See ch. 7 for a discussion of forest product resources.) The lumber, pulp, and paper industries account for about 65 percent of all wood consumed for energy, and the residential sector about 35 percent (79). In industry, about 95 percent of this energy is used to produce process heat or steam, while the remaining 5 percent is converted to electricity using onsite cogeneration systems.

Direct Combustion of Municipal Solid Waste—Today, about 14 percent (by weight) of the MSW generated in the United States is incinerated (84).[1] About 120 facilities out of the 160 in the United States that incinerated MSW also produced energy in the form of steam (45 perent of the plants), electricity (26 percent), cogenerated electricity (20 percent), and refuse-derived fuel burned elsewhere (8 percent) (25,70). These "waste-to-energy" plants account for about 4 percent of the biomass energy consumed in the United States (59). Expansion of this capacity in the United States is uncertain because of public concern over air pollution and possible health impacts of incinerator emissions and ash.

Methane Gas From Landfills-Municipal solid waste (MSW) landfills produce methane gas due to the anaerobic decomposition of organic wastes, which makeup approximately three-quarters of all **MSW** (70). While current estimates of methane emissions from landfills and other sources are highly uncertain, waste disposal in landfills around the world might account for 5 to 18 percent of all methane emissions (8).[2] Since methane is a more potent short-term greenhouse gas than CO_2 (ch. ***2),*** from a climate perspective it would be most desirable to recover and process it for energy. Out of the approximately 6,000 active U.S. landfills in operation in 1986, only 123 collected methane for energy recovery (70). Methane emissions are drawn, sometimes with vacuum pumps, through a series of trenches and/or collection pipes running throughout the landfill. The gas is later purified and can be used to generate steam for heating or electric generation. Today, landfill gas accounts for only 0.3 percent of energy from all biomass sources (36), but if fully developed this resource could supply between 0.2 to 1.0 quads of energy -between 1 and 5 percent of all natural gas consumption, or 0.2 to 1 percent of total U.S. energy demand (59,82).

Methane Gas From Anaerobic Digesters-The decomposition of organic material inside devices called ***anaerobic digesters essentially mimics similar processes in*** oxygen-poor environments such as landfills **and rice** paddy muds, but methane is produced more efficiently because the process can be carefully controlled Ideal biomass feedstocks include sewage sludge, fresh animal manure, aquatic plants, and wet food-processing wastes. The amount of energy that could be recovered from these sources in the United States is about 1 quad (59).

Syngas From Wood, Crops, and Waste--Solid biomass can be converted, through a process called "gasification, " into **gas** suitable for fuels or chemical synthesis. Lower Btu gas produced using air-blown gasifiers is used as boiler fuels or furthered processed into liquid fuels (e.g., methanol, see below), whereas higher Btu gas from oxygen-blown gasifiers can be added to the natural gas distribution system

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1 **About 83 percent by weight of MSW** consists of ***combustible*** **materials such as paper and paperboard,** plastics, **rubber, leather,** wood, and food and **yard wastes;** the **remainin17 percent, consists of** ***noncombustibles,*** **such as glass, metals, and miscellaneous** inorganic wastes (81).

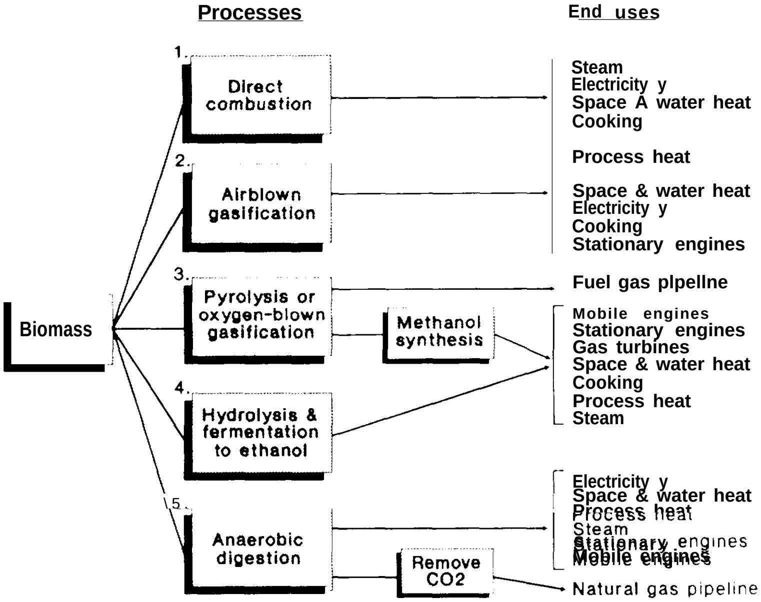
2 **The Clean Air Act Amendments of 1990 directed EPA to study methane emissions associated with natural gas and coal extraction, transportation, distribution, storage, and use; solid waste management (which includes landfills); agriculture; and biomass burning.**

Ethanol From Grains and Sugar Crops—In 1987, about 3.2 billion liters of ethanol were sold in the United States, mainly as a transportation fuel, making it the world's second largest consumer after Brazil (see chs. 5 and 8) (61). Over 80 percent of U.S. ethanol plant capacity in 1986 was dedicated to fermentation of corn feedstocks (78). Other grain and sugar crops, such as grain sorghum, molasses, and food-processing wastes, also can be used for feedstock; in Brazil, sugarcane is used. More than 8 percent of the gasoline sold in the United States is a 10 percent ethanol blend (i.e., "gasohol").

Methanol From Wood, Crop Residues, and Grass Crops—Methanol is used primarily as a feedstock in chemical manufacturing, but also as a transportation fuel. In 1986, 1.1 billion liters of methanol were consumed in the United States for transportation, accounting for about 0.09 percent of this sector's energy demand (78). Methanol has traditionally been produced using natural gas feedstocks, but it can also be produced from biomass through pyrolysis or oxygen-blown gasification (as described above) and then converted to methanol using catalysts (67). Significant improvements in both conversion technology and all aspects of the growing and harvesting cycle for biomass-to-methanol production are necessary for biomass-based methanol to become competitive with natural gas feedstocks (73).

Certain plant seeds, such as rape seed, sunflowers, or oil palms can be pyrolyzed to form intermediate biocrude liquids, and then catalytically converted to gasoline, diesel, or jet fuel. Oil seeds maybe able to supply as much as 0.4 quads (47).

Figure 3A-l—Alternative Methods of Using Biomass Energy



Examples of how biomass can be processed

Process number:	(see boxes above)
1,2,3,4	Wood & wood wastes
2,3,4	Agricultural crops
1,2,3,4	Crop residues
1,2,3,5	Municipal solid waste
5	Sewage sludge
5	Animal wastes
5	Aquatic plants

SOURCE: Adapted from U.S. Congress, Office of Technology Assessment, *Energy From Biological Processes, Volume I/--T& nical and Environmental Analysis,* OTA-E-1 28 (Springfield, VA: National Technical Information Service, September 1980).

ning to emerge.[13] In areas with good winds, wind turbines can be a cost-effective method for meeting a portion of power needs. 'Generally, the wind energy flux is greatest in coastal areas in the mid and northern latitudes and along exposed mountain ridges throughout the world. In the United States, good wind resources are widely dispersed, from coastal New England to the mountain passes of southern California (17).

In mid-1989, installed wind turbine electric capacity was roughly 1,760 MW worldwide. In the United States, capacity amounted to roughly 1,520 MW[14], triple the capacity 5 years earlier but still only a fraction of a percent of total U.S. electric generating capacity (26). However, a study sponsored several years ago by the Electric Power Research Institute indicated that the market potential by the end of the century could be as high as 21,000 MW (54). Worldwide, the magnitude of the usable wind energy resource cannot be accurately determined because of the current lack of data. Though the annual theoretical potential is quite large, only a small portion of this could be exploited during the next quarter century (19). India reportedly has plans for 5,000 MW of wind power by the year 2000(1 1).

Solar Energy

The amount of solar energy reaching the Earth's surface in a year is thousands of times that of worldwide annual fossil fuel use (28). Of course, many factors limit the usefulness of this energy, Much of the solar energy shines onto oceans or other locations where it is not easy to capture. Furthermore, insolation (exposure to sunlight) varies geographically, seasonally, daily, and over other periods of time. Despite these limitations, the amount of available energy is enormous. Solar energy can be used to provide light, heat, steam, and even air conditioning for buildings and industry.

Solar Thermal Energy—The sun can provide power for diverse applications in buildings and industry either in passive or active solar energy systems. Passive systems usually use building structures (e.g., windows, walls, floors) for collection and storage. Active systems rely on pumps and fans for heat distribution from solar collectors to areas of use,

Passive solar techniques have been used since at least the days of ancient Greece, and are used to varying degrees in virtually all buildings today. They include many conceptually simple methods, such as orienting buildings north-south, planting trees to block the sun in the summer and let it through in the winter, installing skylights to provide light, and using building materials that absorb or reflect heat (also see ch. 4).

Active solar technologies are much more common than expressly designed passive systems. They are also better suited to the needs of the retrofit market. The central feature of an active solar energy system is the collector, which captures the solar radiation and turns it into heat to warm buildings and provides steam to drive machinery. Solar air-conditioning is developed, but has yet to be widely commercialized.

The outlook for active and passive solar technology is mixed. The field could experience rapid growth over the next 25 years (59). However, even optimistic market forecasts see this technology contributing 1 percent or less of U.S. energy needs over the next 25 years (59,47).

Solar Electricity Generation-Currently, solar power supplies only a minuscule amount of the world's electricity and only 0.07 percent of U.S. electricity. Few expect solar power to provide a significant fraction of electricity world-wide within the timeframe considered in this report (i.e., by 2015)--at most, only a few percent of projected U.S. electricity supply will be solar-based in 2015. On the other hand, this does represent tremendous growth in the *relative* share of solar energy in the United States, and this could set the stage for even more dramatic increases in the ability of solar power to meet U.S. and world energy demands after 2015. In the optimistic scenario of one study, solar energy (not just solar electricity) could meet roughly 15 percent of U.S. energy needs by 2030 (59).

While growth in the use of solar and wind power in developing countries is expected, it is unclear whether this will represent much of an increase in the share of the power generation market. Solar and wind power may be most competitive in rural areas where fuel supplies and maintenance services are expensive and energy infrastructure (e.g., power lines) is minimal (see ch. 9).

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[13]For a description of the technology, see ref. 59.

[14]California alone accounts for 80 percent of the world total, with most of that capacity located in three mountain passes.

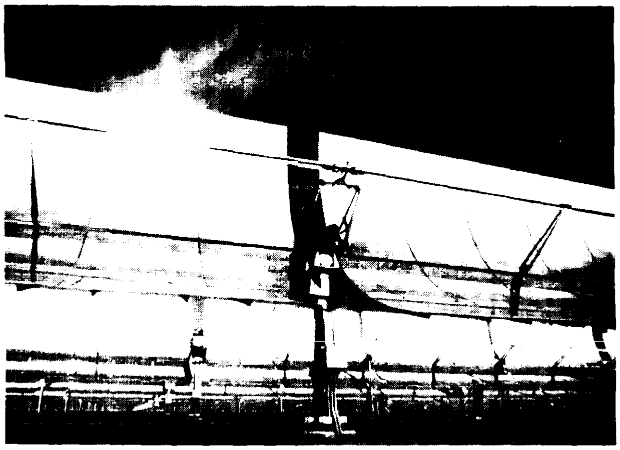


Photo credit: Solar Energy Industries Association

Parabolic trough collector at the Luz solar thermal plant in California.

Issues

Renewable, carbon-free energy sources collectively are now a major source of energy around the world, and they have the potential to meet a sizable h-action of *future* electric and nonelectric energy needs. These sources cannot, however, fully displace fossil fuels in the near term. The greatest near-term potential lies in hydropower and the radiant energy of the sun; a large but substantially smaller potential also exists for wind and geothermal energy. All are economically competitive to some degree today, but their competitiveness varies widely depending on location, application, and other variables. Hydroelectric and wind power are the least expensive; photovoltaics are currently expensive and therefore competitive only in remote or specialized applications.

Each alternative possesses some advantages over fossil fuels, ranging from photovoltaics' remarkable modularity to the short lead-times of small geothermal units. But the technologies also suffer from serious disadvantages relative to the fossil fuels. Among these are the difficulty of access to transmission capacity, the intermittent nature of photovoltaics, lack of information about the quality and distribution of the resources, high capital costs relative to fossil-fuel competitors, and various regulatory constraints. Rapid and favorable changes must occur in many of these areas if the technologies are to realize their full potential during the next quarter century.

Nuclear

The emissions of CO_2 from the use of nuclear powerplants are small compared to those from use of fossil-fuel-fired plants.

Resources and Their Use

Worldwide, nuclear power provided about 15 percent of electricity in 1988. The United States possessed the largest amount of nuclear capacity, with about 30 percent of the total; other countries with large amounts of nuclear generating capacity were France, the U. S. S. R., Japan, and West Germany (34). A few countries, such as France, draw more than 50 percent of their electric power from nuclear plants (64). Despite the strong presence of nuclear power in many countries, and in contrast to the rapid increase in nuclear capacity over the last two decades, the immediate future suggests relatively slow growth in capacity. Some countries, such as France and Japan, are continuing to press ahead with ambitious nuclear programs (46), but in many countries growing concern over the safety and long-term appropriateness of nuclear energy has led to a virtual halt in development,

Though several developing countries have operating nuclear power capacity (Argentina, Brazil, India, Mexico, Pakistan, South Africa, South Korea, Taiwan) (64), it plays a minimal role in most. Nuclear power is unlikely to increase substantially in developing countries in the near future, even though some are planning on building facilities by the end of the century (e.g., Bangladesh, China, Cuba, Egypt, Israel, Morocco, Turkey) (64). Most developing countries have not signed the nuclear weapons Non-Proliferation Treaty, which makes it difficult for nuclear nations to assist these countries in further developing their nuclear energy industry.

Issues

Nuclear power's strong point is that its emissions of CO_2, methane, and other pollutants are quite low compared to those of its fossil-fuel competitors. Moreover, if the public is willing to accept nuclear power, it could once again become a viable alternative to fossil-fuel-fired generation in the United States. However, several key issues cloud the future of nuclear power and restrict its near-term potential:

Lead Times-*Many* of the steps required to commercially deploy additional nuclear power, ranging from the development and demonstration of new designs to the licensing and construction of commercial plants and reactors, require long periods of time. This limits the near-term contribution of nuclear power.

Safety and Environmental Issues—These range from concerns about the possibility of catastrophic failure of nuclear plants to questions about waste disposal and decommissioning.

Costs-The cost of nuclear powerplants has been high compared to electricity from fossil fuels. Considerable uncertainty exists over what the future costs—including decommissioning and waste disposal-might be.

Proliferation—Increased dependence on nuclear power will aggravate nuclear proliferation problems. This raises a host of domestic and international issues. Promotion by the United States of nuclear power in key developing countries will be limited by these considerations and related legal obligations.

Some of these concerns are being addressed by efforts to develop improved reactor designs and to change government regulations; however, they are certain to remain important in the near term. For a more complete discussion of these issues, see ref. 68.

REDUCING CO_2 EMISSIONS FROM ELECTRICITY GENERATION

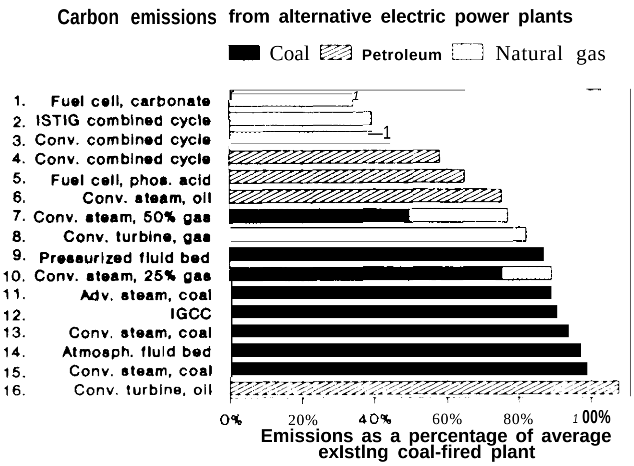
Introduction to Technical Options

There are four basic ways to reduce emissions from electricity generation:

1. reduce demand for electricity (see chs. 4 and 6),
2. use more nonfossil energy sources (see previous section),
3. switch to fossil fuels with a lower carbon content per unit energy, and
4. lower the rate of CO_2 emissions from fossil fuels through improvements in combustion efficiency and electricity manumission and distribution.

The third and fourth strategies-lowering the rate of emissions from fossil fuels by switching to lower carbon fuels and by using more efficient electric generating and transmission technology-are discussed below.

Figure 3-4-Carbon Emissions From Electric Generating Technologies as Compared to Emissions From the Average Existing Coal-Fired Powerplant



NOTE: The numbers of the technologies on this figure are the same as those presented in table 3-5. Additional details on the technologies are presented in the table.

SOURCE: Office of Technology Assessment, 1991, calculated using data from EPRI, *Technical Assessment Guide* (1989).

Fuel Switching and More Efficient Generating Technologies

The amount of CO_2 that fossil fuels release when burned depends, in part, on their carbon content, which varies from fuel to fuel. Therefore, even if the total quantity of fossil fuels in the energy supply remains the same, CO_2 emission levels can be affected by changing the ratios of coal, oil, and natural gas we burn-a CO_2 abatement strategy called fuel switching. Fuel switching can bring large reductions in emissions, since 85 percent of U.S. utility CO_2 emissions now come from coal-burning plants.

Emission levels also depend on the efficiency of the plants that burn those fuels. Another way to reduce CO_2 emissions from this sector, therefore, is to make powerplants more efficient. Small gains (less than 5 percent per plant) are possible with relatively minor “tune-ups” (49). Similar measures may well have bigger impacts-on the order of 10 percent-in developing countries (66). Larger gains are possible through ‘‘repowering’ ‘—the replacement of the basic combustion components of existing powerplants with new technologies.

Table 3-5--CO_2 Emission Rates From Fossil-Fuel-Fired Electric Generating Technologies

Technology	Fuel	Net heat rate full load	lb C/kWh (from fuel only)[a]	Technology development rating
1. Dispersed fuel cell, advanced molten carbonate	Natural gas	6,450	0.20	Laboratory
2. Intercooled steam-injected gas turbine (ISTIG)	Natural gas	7,260[b]	0.23	Pilot
3. Combined cycle, conventional	Natural gas	8,230	0.26	Mature
4. Combined cycle, advanced, reheat steam cycle	Distillate	7,580	0.34	Demonstration
5. Dispersed fuel cells, phosphoric acid, first generation	Distillate	8,550	0.38	Demonstration
6. Steam powerplant	Distillate	9,680	0.45	Mature
7. Conventional subcritical, w/wet lime flue gas desulfurization, 200 MW unit	50% pulverized bituminous coal, 50°/0 natural gas	10,210	0.46	Mature
8. Conventional combustion turbine	Natural gas	15,040	0.49	Mature
9. Pressurized fluid bed combustion-combined cycle	Bituminous coal	8,980	0.51	Pilot
10. Conventional subcritical, w/wet lime flue gas desulfurization, 200 MW unit	75% pulverized bituminous coal 250/~ natural gas	10,210	0.53	Mature
11. Supercritical, demonstration state of the art, advanced limestone flue gas scrubber	Pulverized bituminous coal	9,080	0.52	Demonstration
12. Integrated gasification-combined cycle (IGCC), 200 MW unit	Bituminous coal	9,320	0.53	Demonstration
13. Conventional supercritical w/wet lime flue gas desulfurization,	Pulverized bituminous coal	9,640	0.56	Mature
14. Atmospheric fluidized bed combustion (circulating bed))	Bituminous coal	10,060	0.57	Demonstration
15. Conventional subcritical, w/wet lime flue gas desulfurization, 200 MW unit	Pulverized bituminous coal	10,210	0.59	Mature
16. Combustion turbine, conventional	Distillate	14,020	0.64	Mature

[a]This does not include other CO_2 emissions that maybe associated with use oft he technology. For example, the figure for the fluidized bed technologies does not include the CO_2 emissions released by the limestone used.
[b]Based on efficiency of 47%.

SOURCES: All heat rates are average annual heat rates. Heat rate values, with the exception of that for the ISTIG and liquid-fuel-fired steam plants, are from Electric Power Research Institute, *TAG—Technical Assessment Guide, Vol.1 Rev.6 Electricity Supply—1989* (Palo Alto, CA: November 1989), EPRI P-6587-L.
Liquid-fuel-fired steam values from Electric Power Research Institute, *TAG—Technical Assessment Guide, Vol.1: Electricity Supply—1986* (Palo Alto, CA: December 1986), EPRI P-4436-SR.
Heat rate for ISTIG f rom R. H. Williams and E. D. Larson, *Aircraft-Derivative Turbines for* Stationary Power (Princeton, NJ: Center for Energy and Environmental Studies, Princeton University, 1988), review draft.

Alternatives to the average existing coal-fired powerplants vary by emission rate (see figure 3-4). Far greater gains are possible by switching away from coal to other fossil fuels (shown as lighter bars) than by switching among coal technologies (the black bars).

Technology options also vary by heat rate—the amount of fuel needed to generate 1 kilowatt-hour (kWh) of electricity—and by CO_2 emissions per kWh for the particular combination of technology and fuel (see table 3-5).

Burning conventional pulverized coal with a sulfur dioxide scrubber (technologies 13 and 15 in figure 3-4 and table 3-5), yields emission rates typical of coal boilers installed during the 1980s. With the most efficient coal technologies, CO_2 emissions are about 10 percent lower. These include: 1) pressurized fluid bed combustion; 2) state-of-the-art pulverized coal boiler; and 3) integrated coal gasification, combined cycle (IGCC) (technologies 9, 11, and 12, respectively, in figure 3-4 and table 3-5). By replacing conventional coal plants with high-efficiency turbines burning natural gas, the same amount of electricity can be generated with about a 60-percent reduction in $C0_2$ emissions (technologies 2 and 3). This is, in part, because gas releases far less CO_2 per unit energy than does coal.

However, coal plants need not be completely repowered to achieve some of the benefits of fuel switching. One option is to change coal-fired plants to natural gas co-fired or intermittently fired plants, that is, plants that use both coal and natural gas simultaneously or sequentially to heat the boilers (technologies 7 and 10). Since the boiler technology remains essentially unchanged, a co-firing boiler is about as efficient as a purely coal-fired one, though efficiency may drop a few percent when burning gas (18). The CO_2 reductions result mostly from the fact that natural gas has less carbon. A co-firing plant burning 25 percent gas and 75 percent coal would emit about 10 to 15 percent less CO_2 than a pure coal-burning plant. Burning 50 percent natural gas would lower emissions by 20 to 25 percent.

Fuel switching, however, is not without its problems. The major one is that it can deplete gas reserves and strain the gas pipeline distribution network. This fact is especially germane since several other strategies discussed in this report rely on increased gas use. Just how much natural gas exists is poorly quantified, If natural gas does become a "lynch pin" of domestic or global CO_2 reduction strategy, demand and prices could rise to very high levels. Increased use of natural gas also carries with it the risk of increased leakages of methane.

One additional control option is theoretically possible-the removal of CO_2 from combustion exhaust gases for disposal in the deep oceans or wells. Box 3-B discusses this concept, which we do not consider to be a feasible near-term alternative.

Electricity Transmission and Distribution Improvements

The electricity transmission and distribution (T&D) system connects the producer of electricity with consumers. During T&D, a certain amount of electricity is lost due to resistance as well as inefficient operation and maintenance of the distribution network. This loss averages 5 to 10 percent in the developed countries (83). The United States loses roughly 8 percent of its electricity in T&D (14).

In developing countries, Eastern Europe, and the U.S. S. R., T&D losses can be much higher. Losses in developing countries commonly exceed 20 percent (India, for example, loses 21 percent (66) and some countries report losses as high as 30 percent between generation and delivery (83; also see ch 9)). Less is known about the T&D losses in Eastern Europe. Still, a large number of cost-effective opportunities exist to reduce losses.[15] The one limitation is that in some countries up to half the T&D loss maybe from theft (66). Eliminating theft could be more difficult than eliminating other losses (and might not lower overall demand very much).

Transmission and distribution systems also affect the ability of low-emission generators to fill the need for electric power. Many of the opportunities for relatively low emission power generation are remote from existing transmission facilities. Geothermal and wind resources, for example, are often located far from existing lines. Similarly, one region may have excess hydroelectric or nuclear capacity at the same time another region is experiencing a power shortfall and being forced to burn more fossil fuels. [16]

OTA EMISSION REDUCTION SCENARIOS

OTA developed a simple energy accounting model that allows us to estimate the effectiveness of various technical options for lowering CO_2 emissions (see app. A). The model is based on a much larger system of energy and economic models used by the Gas Research Institute (GRI) to forecast energy use through 2010 (29).

About 35 percent of total U.S. CO_2 emissions comes from fossil fuels burned to generate electricity. By 2015, this might increase to 45 percent. In this section we examine how changes in supply-side characteristics can lower $C0_2$ emissions from electricity generation. We class@ supply-side options into two categories-' 'Moderate' measures and more aggressive and costly ''Tough' measures. Because supply-side options will have different effects depending on the demand for electricity, however, we frost review our estimates of electricity

[15] One World Bank study, for example, notes that ''Witi realistic limits, for many distribution systems,]0sS reduction is a far cheaper alternative than adding new generating and bulk transmission capacity" (44,66). For examples with rapid paybacks in the United States, see ref. 43.

[16] Options relating to these issues are discussed in a recent OTA report (71).

Box 3-B-Carbon Dioxide Scrubbing

In addition to reducing CO_2 emissions *from* fossil-fuel-fired plants by using more efficient combustion technologies and fuel switching, it is also possible to remove CO_2 from flue gases and liquefy--through a process known as "scrubbing." Theoretically one could pump the liquefied $C0_2$ through pipelines to disposal sites, for example, the deep ocean, where it is hoped it will remain rather than entering the atmosphere. While each individual component appears technically feasible, the entire system has never been tried. We do not consider CO_2 scrubbing as one of our near-term technical options, but the concept merits further research.

Carbon dioxide scrubbing basically involves:

- compressing and cooling the stack gases;
- removing $C0_2$ from the gases via *a* reaction with a solvent solution;
- heating and steam-stripping the CO_2-enriched solution to reverse the reaction, yielding uncondensed steam and CO_z;
- condensing and removing water vapor, leaving the recovered CO_2; and
- compressing and liquefying the recovered CO_2.

The Department of Energy (DOE) examined the feasibility of using scrubber systems at all fossil-fuel-fired powerplants operating as of 1980 (74a). To remove 90 percent of CO_2 emissions would require about 11 to 16 percent of total electrical power capacity in gas- and coal-burning regions, respectively. Electricity production costs would increase between 50 and 120 percent, depending on the region, averaging 75 percent nationwide. About 85 to 90 percent of the cost was for removal, recovery, and liquefaction; the remainder was for pumping liquefied CO_2 through pipelines for disposal.

DOE suggested three possible disposal methods for liquefied ***$C0_2$—1) injection*** in ***the*** deep ocean (i.e., at least 500 meters deep, 100 miles offshore); 2) storage in depleted oil and gas wells; and 3) storage in excavated salt caverns. Some concern has been expressed over whether 500 meters is deep enough for permanent ocean disposal; injection to 3,000 meters would require a 200-mile pipeline. For any of these methods, DOE envisioned carrying the recovered liquefied CO_2 in small (6-inch diameter) pipelines from each powerplant to collection centers, and then carrying it from the centers to ultimate disposal sites in larger (36-inch diameter) pipelines. DOE concluded that most of the CO_2 would have to be disposed of in the ocean.

A recent study in the Netherlands (27a), however, suggests that the increased electricity costs might be less-perhaps half as much per kWh--if an intermediate gas product from an Integrated Gasification, Combined Cycle (IGCC) powerplant is used (technology 12 in table 3-5). This process involves:

- using a gasifier to convert coal into heat and a gas composed primarily of hydrogen (H_2) and carbon monoxide (CO);
- converting the CO to CO_2 using an iron-chromium or nickel-chromium catalyst (the H_2 would subsequently be used as fuel in the combined cycle process);
- recovering CO_2 from the gas mixture by using a physical absorption process, with a solvent known as selexol; and
- drying and compressing the CO_2.

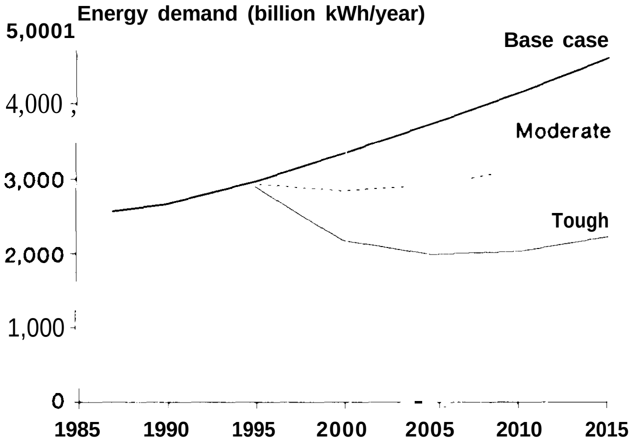
To remove 88 percent of the CO_2 from the exhaust gas, about 13 percent of the plant's electrical production would be needed to run the system. Electricity production costs would rise about 25 percent for recovery and compression and an additional 5 to 10 percent for pumping to final disposal sites. (For the Netherlands, exhausted natural gas fields were proposed as disposal sites.)

demand over the next 25 years under our model's alternative demand-side scenarios.

Alternative Scenarios of Demand for Electicity

Under OTA's Base case scenario, electricity demand grows from about 2.7 trillion kWh in 1990 to 4.6 trillion kWh by 2015, an average increase of about 2.2 percent per year. In this and later chapters, we present two other scenarios of energy demand: one lowers demand by imposing a series of Moderate demand-side measures; a second lowers demand even further through an ambitious set of Tough demand-side measures. Under the Moderate scenario, demand for electricity is held to 3,4 trillion kWh by 2015, an average increase of 1.0 percent per year over the next two decades (see figure 3-5), The

Figure 3-5-OTA Electricity Demand Scenarios



NOTE: Scenarios of electricity demand are discussed in detail in chs. 4 through 6 (Buildings, Transportation, and Manufacturing). For the analysis of electricity supply-side measures discussed in this chapter, we have summed demand from each of these sectors.

SOURCE: Office of Technology Assessment, 1991.

measures used initially require some capital investment, but result in lower fuel costs in the future. Over the life of the investment, these measures cost little or even save money.

The Tough measures lower energy demand even further, but only at a higher cost for the same or similar service. In this scenario, demand for electricity in 2015 is 2.2 trillion kWh-somewhat lower than demand in 1990 (see figure 3-5). Demand drops fairly sharply until about 2005 and then begins to rise again. Existing generating capacity is adequate to meet demand until sometime between 2015 and 2020. Descriptions of the sector-specific technical options that lower demand from the Base case in each of the two scenarios are included in chapters 4 through 6.

Emissions generally reflect electricity demand, with some variation due to the changing mix of fossil and nonfossil sources through time. The changing mix is especially important in the Tough demand scenario. Because demand for electricity in this scenario is less than potential supply from existing plants, fossil sources can be idled and hydropower and nuclear sources can supply a larger fraction of total supply. Thus, CO_2 emissions decline in the Tough demand scenario because *both* electricity demand and CO_2 emission rates (pounds of carbon per kWh) are lower than they are today.

Technical Options for Lowering CO_2 Emissions From Electricity Generation

As mentioned, we also categorize methods for lowering CO_2 emissions from the supply side (i.e., from utilities) as Moderate or Tough, thus creating two alternatives to the Base case or business-as-usua1 supply-side scenario. We evaluate Base case, Moderate and Tough supply-side options for each of the three demand-side scenarios to create nine possible approaches to emission reductions (see figure 3-6). The highest CO_2 emissions (twice 1987 levels by 2015) will occur under the combined business-as-usual scenarios-demand for electricity follows Base case projections with no supply-side changes. Still assuming the base case demand for electricity, Moderate supply-side measures will limit the growth of emissions somewhat, to about a 75 percent increase above 1987 levels by 2015; Tough supply-side measures can hold emissions to about a 45 percent increase by 2015.

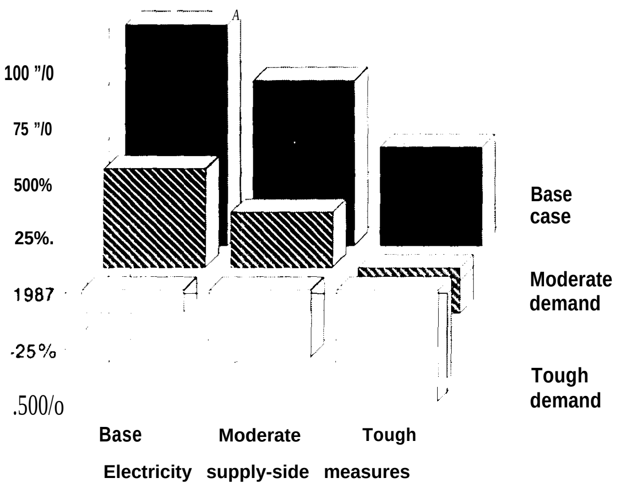
Supply-side measures have somewhat greater impacts under the Moderate demand scenario. With no supply-side changes (i.e., only lowered demand), emissions will increase by about 45 percent by 2015. By adopting Moderate supply-side measures as well, emissions will increase by only about 25 percent. Tough electricity supply-side measures in combination with Moderate demand for electricity can lower emissions to about 20 percent below 1987 levels by 2015.

Supply-side measures have slightly lower effects under the Tough electricity demand scenario. The Tough demand scenario alone (i.e., with no change in supply-side technologies) will lower emissions to about 20 percent below 1987 emissions by 2015. By adopting Moderate supply-side measures in addition, emissions can be lowered to 30 percent below 1987 levels by 2015. Tough supply-side measures can cut emissions to about half of 1987 levels by 2015.

In each of the supply-side scenarios, we examine measures that apply to existing sources, measures that apply to new sources, and measures that require early retirement of existing sources with more stringent requirements for the replacement sources (see table 3-6).

Technical options for lowering emissions from existing plants include:

Figure 3-6--CO_2 Emissions From Electricity Generation Under the OTA Demand and Supply Scenarios



SOURCE: Office of Technology Assessment, 1991,

1. increased utilization of nuclear powerplants,
2. increased efficiency of fossil-fuel-fired plants through improved maintenance practices,
3. substituting natural gas for some fraction of the fuel burned in coal-fired powerplants, and
4. increasing the output from hydroelectric plants.

For lowering emissions from new plants, the options that we consider include:

1. increased reliance on such renewable energy sources as hydropower, geothermal, biomass, and solar energy;
2. revitalizing the nuclear industry so that the next generation of nuclear power technology is ready for use by 2005; and
3. limiting the number of new coal-fired powerplants in the base case demand scenario and declaring a moratorium on coal-fired powerplants in both lower demand scenarios, with natural gas being the fossil fuel of choice until 2015.

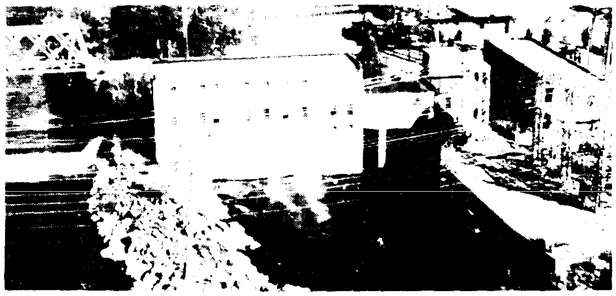


Photo credit: U.S. Department of Energy

This demonstration project at Idaho Falls, Idaho, consists of redeveloping the city's three existing hydroelectric powerplant sites. The three sites will receive new turbines that are economical for small-scale, low-head hydroelectric power generation. The technology can be used immediately; it does not need extensive research and development.

We classify four of the technical options above as Moderate, that is, able to reduce emissions at little or no cost over the life of the investment. These include:

1. modestly improving the efficiency of existing fossil-fuel-fried plants (about a 5-percent improvement from better maintenance and dispatching procedures),[17]
2. increasing the output of existing hydroelectric plants (by about 11 percent, primarily by adding additional generating units to capture energy from water currently bypassing the plants),[18]
3. increasing utilization of existing nuclear powerplants (from 60 percent of the time, on average, to 70 percent)[19] as well as lengthening their useful life to 45 years, and
4. using the most efficient generating technologies for new fossil-fuel-fired poweplants.[20]

We classify three of the supply-side options as Tough, that is, technically feasible but not without extra cost. The first is to regulate the mix of new plants being built with the goal of using nonfossil electricity sources whenever possible, or using natural gas rather than coal when it is not feasible or

[17]An Electric power Research Institute (EPRI) survey estimated that cost-effective improvements of about 4 percent were achievable (16).

[18]The U.S. Army Corps of Engineers (12) estimated that by adding, replacing, or modifying generating units at between 165 and 300 of the approximately 1,300 existing hydroelectric plants in the United States, output could be increased by 10 to 12 percent in a cost-effective manner.

[19]Nuclear plants in both Japan and Western Europe operate about 75 percent of the time (23).

[20]A state-of-the-art pulverized coal plant will emit 10 per-cent less CO_2 than a conventional new plant. US@ cost data from EPRI (15), generating electricity from a state-of-the-art coal plant may actually be a few percent cheaper than generation costs from a new conventional plant, after fuel savings are included. A combined cycle gas turbine emits about 45 percent less CO_2 than a conventional one. If used for more than infrequent peaking power, the higher capital costs are justifed by lower fuel costs.

Table 3-6—Electricity Generation Measures

	Base case supply	Moderate controls	Tough controls
OTA Base case demand.			
1. Operation and maintenance/ existing stock			
Fossil fuel efficiency	1985 average (10,500 Btu/kWh)	5% efficiency improvement	5% efficiency improvement
Nuclear utilization	60% capacity factor	70% capacity factor	70% capacity factor
Gas co-fire	None	None	None
Hydroelectric improvement	None	11% increased capacity	11% increased capacity
2. New investments			
Retirement rate	60 years for fossil fuel plants	40 years for fossil fuel plants	
	35 years for nuclear plants	45 years for nuclear plants	45 years for nuclear plants
Total new capacity	435 GW above 1990 by 2015	365 GW above 1990 by 2015	545 GW above 1990 by 2015
Coal-fired	60-75% of new builds, varies by year	Same as Base	Limited to 50% of new builds
Gas-fired	15-25% of new builds	Same as Base	30% of new builds
Nonfossil	45 GW above 1990 by 2015	35 GW above 1990 by 2015	20% of new builds (100 GW above 1990 by 2015)
Moderate demand scenario:			
1. Operation and maintenance/ existing stock			
Fossil fuel efficiency	1985 average (10,500 Btu/kWh)	5% efficiency improvement	5% efficiency improvement
Nuclear utilization	60% capacity factor	70% capacity factor	70% capacity factor
Gas co-fire	None	None	None
Hydroelectric improvement	None	11% increased capacity	11% increased capacity
2. New investments			
Retirement rate	60 years for fossil fuel plants	60 years for fossil fuel plants	40 years for fossil fuel plants
	35 years for nuclear plants	45 years for nuclear plants	45 years for nuclear plants
Total new capacity	160 GW above 1990 by 2015	90 GW above 1990 by 2015	305 GW above 1990 by 2015
Coal-fired	60-75% of new builds, varies by year	Same as Base	Moratorium on new coal
Gas-fired	15-25% of new builds	Same as Base	70% of new builds
Nonfossil	15 GW above 1990 by 2016	10 GW above 1990 by 2015	30% of new builds (85 GW above 1990 by 2015)
Tough demand scenario:			
1. Operation and maintenance/ existing stock			
Fossil fuel efficiency	1985 average (10,500 Btu/kWh)	5% efficiency improvement	5% efficiency improvement
Nuclear utilization	60% capacity factor	70% capacity factor	70% capacity factor
Gas co-fire	None	None	50% gas co-fire for coal units
Hydroelectric improvement	None	11% increased capacity	11% increased capacity
2. New investments			
Retirement rate	60 years for fossil fuel plants	60 years for fossil fuel plants	40 years for fossil fuel plants
	35 years for nuclear plants	45 years for nuclear plants	45 years for nuclear plants
Total new capacity			50 GW above 1990 by 2015
Coal-fired			Moratorium on new coal
Gas-fired	None needed bef 2010	None ee ed before 2010	55% of new builds
Nonfossil			45% of new builds (22 GW above 1990 by 2015)

SOURCES: Office of Technology Assessment, 1991.

extremely costly. We assume that between 20 and 45 percent of new powerplants will use nonfossil energy sources (depending on the demand for new construction), as compared to about 10 percent in the Base case. Most utilities would likely choose renewable energy sources—primarily wind power, hydroelectric power, and biomass—rather than nuclear powerplants, However, we also assume that by 2000 new and safer designs for nuclear powerplants will be available and able to meet some of this demand within the next decade.

As a second Tough option, we force existing fossil-fuel-fired plants to retire after 40 years of operation. In the absence of new regulations, existing utility boilers will probably last between 55 and **65 years** before they are retired ***(83).*** Early retirement, combined with a moratorium on replacement with coal, will remove inefficient plants and open up additional opportunities for nonfossil energy sources as well as additional gas-fired generation. Public utility commissions typically allow a utility to recover capital costs of building a new plant over a 30-year period, Thus, if a utility is forced to retire the plant at any time after **30 years,** it will have already paid off the stockholders and bondholders who paid for the plant. The additional costs incurred by early retirement and rebuilding will be paid by the ratepayers.

We assume that there are limits on the amount of electricity that can be generated from both nonfossil energy sources and natural gas. After reviewing projections by the national laboratories for DOE (47, 59) and others, we believe that 100 GW is a reasonable estimate of the potential for nonfossil sources between 2000 and 2015 under a high demand scenario. This is equal to about half of today's total nuclear and hydroelectric capacity. We assume that under slower growth, fewer nonfossil plants are likely to be built, though the percentage of new plants using nonfossil sources will be higher. Natural gas is limited to an increase of 3 quads above the Base case-about twice today's consumption of natural gas by utilities (and about 15 percent of forecasted total gas use by 2015). Under the Moderate and Tough demand scenarios, the need for new plants is low enough that a moratorium on construction of new coal plants is possible through 2015. Under the Base case demand scenario, some new coal plants must be built.

A third Tough alternative is to use some of the additional 3 quads of natural gas to lower emissions from existing coal-fired powerplants. This can be accomplished by either gas co-firing, (i.e., simultaneously burning both gas and coal) or by switching back and forth between gas and coal intermittently (e.g., gas could be used in the summer when demand from other uses is low). Under the Base case demand scenario, we allow natural gas to substitute for up to 20 percent of coal use in existing plants. Under the Tough demand scenario, we allow natural gas to substitute for 50 percent of coal use.

The Effects of Supply Changes Under the OTA Base Case Demand Scenario

Under the OTA Base case supply and demand scenarios CO_2 emissions from electricity generation are 35 percent higher than 1987 levels by 2000 and almost 100 percent higher than 1987 levels by 2015. By 2015, 435 GW of new electric generating capacity must be built to meet demand that is increasing at an average rate of 2.2 percent per year.[21] (Current U.S. generating capacity is about 680 GW.) About 10 percent (43 GW) of this new capacity uses nonfossil sources and thus would lead to little or no increase in $C0_2$ emissions. About 60 to 75 percent of each year's new construction is coal-fired and 15 to 25 percent uses natural gas. The relative shares of each of the generating technologies for new construction in this Base case scenario closely follows the projections developed by GRI (29).

The Moderate supply-side measures discussed above achieve CO_2 reductions of about 11 percent of 1987 levels by 2000, assuming all existing plant improvements are made by that time. By 2015, the combination of efficiency performance standards in plants built after 2000 and the effects of the nuclear

[21] Note that the Gas Research Institute (GRI) model used as a basis for the OTA analysis forecasts that electricity demand will increase at about 1.5 percent per year through 2010. This is about 0.5 to 1.0 percent lower than most other forecasts. The primary reason is that the GRI model uses a "bottom up' approach, that is, it forecasts the demand for electricity from current goods and services-the televisions and electric water heaters in our homes, lights in our offices, and the energy to manufacture electricity-intensive goods and materials such as chemicals and aluminum. However, just as 10 years ago a bottom up forecast would have missed the demand for electricity from personal computers and FAX machines, so too is the GRI forecast likely to miss demand from new products by 2000. OTA has added an extra increment of demand—0.75 percent per year--on top of the GRI forecast in our base case. This results in electricity demand growing at about 2.2 percent per year, an estimate much closer in line with those forecasts that use a statistical ''top down' approach to forecast demand using recent economic and energy use trends.

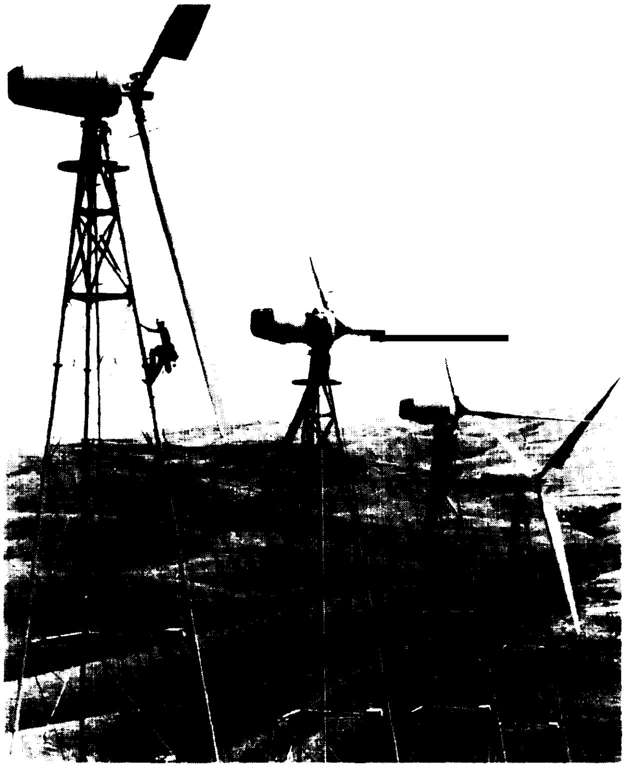
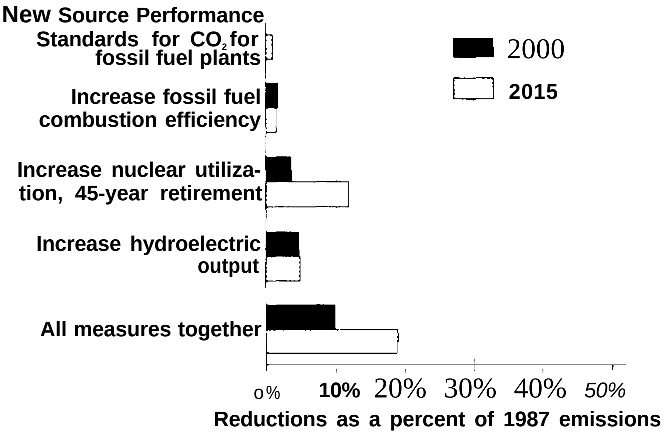


Photo credit: U.S. Windpower, Ed Linton, photographer

Maintenance crews performing a routine inspection of a small wind turbine.

Figure 3-7--C0$_2$ Emissions Reductions From Moderate Supply-side Measures, Expressed as a Percentage of 1987 Electricity y Emissions, Under the Moderate Demand Scenario



NOTE: The data presented above are the emissions reductions achievable in some future year expressed as a percentage of 1987 electricity emissions, not as a percentage dacrease in emissions *below* 1987 levels.

SOURCE: Office of Technology Asessment, 1991.

plant life extension boost reductions to about 21 percent of 1987 levels. Thus, the Moderate measures lower emissions from about a 100 percent increase above 1987 levels in the Base case to about a 77-percent increase above 1987 levels by 2015.

In our Tough scenario, we require all fossil fuel plants to retire after 40 years and limit the amount of construction of new coal plants to 50 percent of total new builds. About 100 GW of nonfossil sources are built between 2000 and 2015. This amounts to about 20 percent of the new plants needed to replace retired facilities and to meet increasing demand for electricity. The Tough measures yield reductions of about 31 percent of 1987 levels by 2015. Combined with the Moderate measures, utility emissions are held to a 45-percent increase above 1987 levels by 2015.

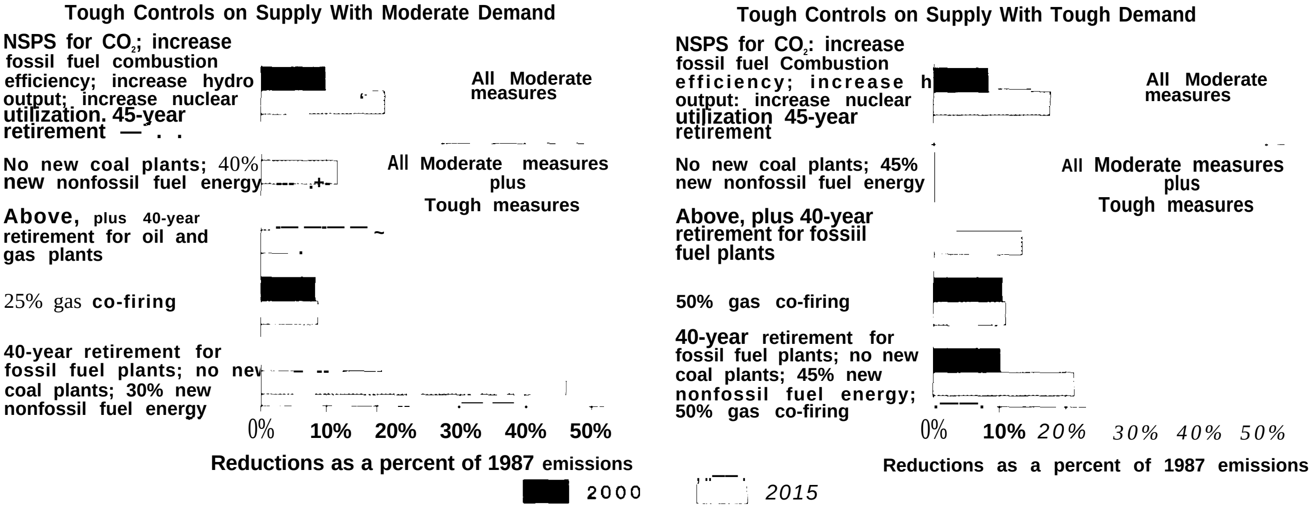
The Effects of Supply Changes Under the OTA Moderate Demand Scenario

Under the OTA Moderate demand case, CO_2 emissions from electricity generation are about 10 percent higher than 1987 levels by 2000 and 45 percent higher than 1987 levels by 2015. Emissions are lower than under the Base case demand scenario, reflecting a relatively lower consumption of electricity and a greatly reduced need for new generating capacity (35 percent of requirements under the base case demand scenario). Nevertheless, by 2015, 160 GW of new electric generating capacity must be built to meet increasing demand. Similar to the Base case demand scenario, we assume that most of the new capacity would be fossil-fuel-fired, with about 60 to 75 percent of each year's new construction using coal and 15 to 25 percent using natural gas. About 10 percent of new plants use nonfossil energy sources.

By implementing our Moderate supply-side measures, additional reductions equal to about 10 percent of 1987 levels can be achieved by 2000. Almost half of the additional reductions comes from improving the efficiency of existing fossil-fuel-fired plants, one-third from increased utilization at nuclear powerplants and the remainder from improvements at existing hydroelectric facilities (see figure 3-7).

By 2015, the Moderate supply-side measures achieve reductions equal to about 19 percent of 1987 levels. Most of the additional improvement comes from extending the lifetimes of nuclear powerplants

Figure 3-8—CO_2 Emissions Reductions From Tough Supply-side Measures, Expressed as a Percentage of 1987 Electricity Emissions, Under the Moderate and Tough Demand Scenarios



NOTE: The data presented above are the emissions reductions achievable in some future year expressed as a percentage of 1987 electricity emissions, not as a percentage decrease in emissions *below* 1987 levels.

SOURCE: Office of Technology Assessment, 1991,

thereby avoiding replacement with coal-fired ones. Efficiency performance standards for new coal- and gas-fired powerplants have only a modest effect (see figure 3-7), in part because the need for new construction is already much reduced under this scenario. The combination of Moderate demand measures and Moderate supply-side measures holds utility emissions to about a 25-percent increase above 1987 levels by 2015 (as compared to a 100 percent increase under Base case supply and demand).

Again, we considered Tough supply-side options that are technically feasible but not without extra cost. A series of Tough options together can achieve reductions equal to about 45 percent of 1987 emissions by 2015 (see figure 3-8). These measures include, first, accelerating the replacement of older, higher emitting facilities by requiring all fossil fuel plants to retire after 40 years of operation. Next, we regulate the mix of new plants being built with the goal of building nonfossil sources whenever possible. When it is not feasible or extremely costly, natural gas is chosen for fuel (i.e., we impose a moratorium on the construction of new coal-fired power-plants from 2000 through 2015). About 30 percent of new electricity demand is met by nonfossil sources (85 GW between 2000 and 2015).

Figure 3-8 also illustrates the relative importance of each of these and other Tough measures one at a time. Changing the mix of new plants (i.e., no coal, 40 percent nonfossil sources, and the remainder natural gas) achieves reductions equal to about 12 percent of 1987 levels by 2015. Forcing oil and natural gas plants to retire after 40 years (and replacing them with the mix of new plants listed above) achieves another 9 percent reduction. Co-firing existing coal plants with 25 percent natural gas can achieve another 8 to 9 percent reduction. Note that this last option is the only one of the Tough supply-side measures that can achieve significant reductions by 2000.

The combination of Moderate demand, Moderate supply-side measures, and all Tough supply-side measures except natural gas co-firing lowers utility CO_2 emissions to about 20 percent below 1987 levels by 2015. Demand for electricity under this *scenario* is too great to allow both natural gas co-firing and 40-year retirement of all fossil fuel sources, and hold the increased demand for natural gas to below 3 quads.

The Effects of Supply Changes Under the OTA Tough Demand Scenario

Under the Tough demand scenario, with no additional supply-side measures, emissions drop to 10 percent below 1987 levels due to lowered demand alone. No *new* plants are needed before 2010. Thus, supply-side measures that apply to existing facilities (i.e., efficiency improvements and gas co-firing) can still lower emissions, but measures relevant to new plants have no effect unless existing plants are retired early. The effect of' the Moderate supply-side measures is about the same under this scenario as under the other two. All Moderate measures together achieve reductions equal to about 8 percent of 1987 levels by 2000 and 18 percent by 2015 (see figure 3-8).

By adopting a package of Tough supply-side measures, additional reductions of 10 percent of 1987 levels by 2000 and 21 percent by 2015 are possible. These measures include: co-fining of all existing coal-fired plants with 50 percent natural gas, forced retirement of all fossil fuel plants after 40 years of operation, and altering the mix of new plants to 45 percent nonfossil sources and the remainder gas-fired. All of the reductions in 2000 come from co-firing existing units (see figure 3-8). By 2015, somewhat over half of the Tough measure reductions come from the combination of early retirement of fossil sources and their replacement with new nonfossil and natural gas-fried plants.

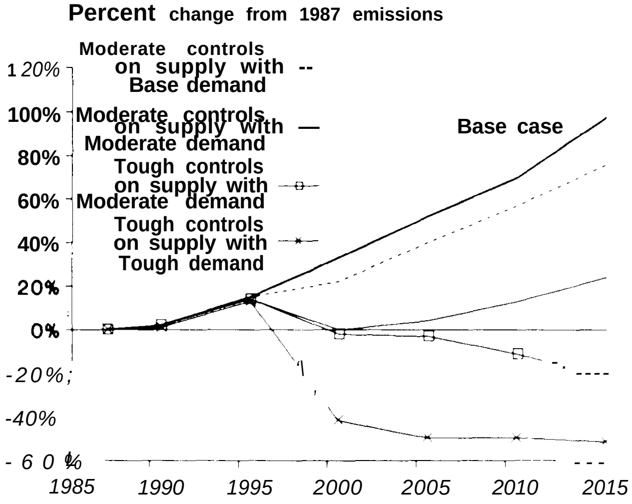
The combination of Tough demand measures and all Moderate and Tough supply-side measures lowers utility CO_2 emissions to about 50 percent below 1987 levels by 2015.

Summary of Emissions Reductions From the OTA Electricity Supply Scenarios

Figure 3-9 summarizes the aggregated effects of the Moderate supply-side measures (under the Base case and Moderate demand scenarios) and Tough supply-side measures (under the Moderate and Tough demand scenarios) through 2015. Note that under the two scenarios with Moderate supply-side measures, emissions continue to rise after 2000, though at a slower rate than under the Base case. Under the scenarios with Tough supply-side measures, emissions drop to 1987 levels or below by 2000 and continue to decline through 2015.

Figure 3-10 displays fuel consumed by electric utilities under the Base case and several scenarios by 2015. Under the Base case, coal use grows from about 55 percent of total fuel use to about 65 percent. Under the scenario of Moderate supply-side measures and Moderate demand for electricity, the mix of

Figure 3-9--CO_2 Emissions From Electricity Generation Under the Base Case and Selected Control Scenarios, By Year



SOURCE: Office of Technology Assessment, 1991.

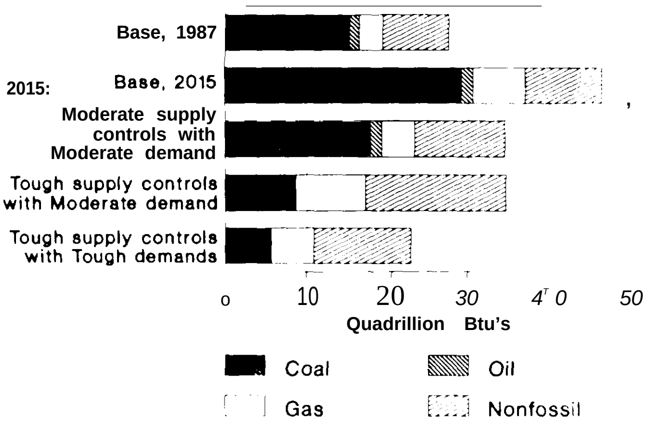
fuels remains quite similar to today's mix, but the total increases about 25 percent above 1987 levels. Under both scenarios with Tough supply-side controls, coal use falls to about 25 percent of the total and the share of nonfossil sources rises to about 50 percent.

Costs of the Tough Electricity Supply Scenario

We estimate that the Tough electricity supply--side scenario will cost about $35 billion per year (1987 dollars) by the year 2015, assuming it is implemented along with all Tough demand measures. This is the cost of the Tough supply-side measures alone and does not include the costs of lowering electricity demand. (These are presented in chs. 4 through 6.)

About half of the costs come from co-firing existing coal plants with natural gas. By 2015, natural gas is forecasted to cost over three times more than coal on an energy equivalent basis. The remaining costs come from forcing existing fossil-fuel-fired plants to retire after 40 years of operation and replacing them with natural gas and nonfossil sources. Forcing the coal plants to retire early and replacing them with highly efficient natural gas-fired combined cycle turbines could increase electricity costs at affected plants by $0.04 to $0.05 per

Figure 3-10—Fuel Use By Electric Utilities In 2015 Under the Base-Case and Selected Control Scenarios, By Year



SOURCE: Office of Technology Assessment, 1991.

kWh.[22] However, forcing existing oil and natural gas plants to retire early saves money—about $0.01 to $0.02 per kwh-because the replacement facilities are so much more efficient. We have assumed that *the* cost of electricity from nonfossil sources (either renewable sources or nuclear power) will be comparable to natural gas-fired combined cycle turbines.

The cost effectiveness of early retirement of existing fossil-fuel-fired sources and replacement with natural gas and nonfossil sources is about $280 per ton of carbon eliminated. The cost effectiveness of co-firing existing coal plants with natural gas is about $510 per ton of carbon.

POLICY OPTIONS

A variety of *policy* options can be used to implement the *technical* options to lower greenhouse gas emissions. Overarching approaches include: 1) energy and emissions taxes and tax incentives, 2) marketable emission permits, and 3) research and development on lower emitting technologies. Many of these themes will be addressed again in chapters on individual emission sources (see chs. 4 through 6). Broad approaches such as energy and carbon taxes or marketable emission permits have the advantage of affecting *all* emitters simultaneously, but their effects are extremely difficult to predict. They can be adopted alone or in concert with source-specific options (e.g., appliance or automobile efficiency standards).

Options specific to the energy industries include: 1) ways to lower emissions associated with the extraction and delivery of fossils fuels, and 2) options for controlling the amount of CO_2 emitted per kilowatt-hour of electricity generated. Sector-specific options for lowering the *demand* for energy are discussed in chapters 4 through **6.**

Energy Taxes and Tax Incentives

Congress could impose direct financial burdens (or benefits) on energy to curtail the use of energy sources that are major contributors of greenhouse gases. Two options that have been proposed are a general energy tax and a carbon tax. Whereas a general energy tax might be based on, say, the Btu content of energy sources, a carbon tax would be calculated on carbon emissions. Under such a formula, the tax would be highest on coal, low for natural gas, and zero for noncarbon sources.[23] The carbon tax is a particularly effective way of levying the heaviest economic sanctions against the worst emitters of CO_2. Either type of tax would lower energy users' overall demand. A carbon tax would also change the *mix* of energy sources in the economy. It would stimulate greater demand for natural gas relative to other fossil fuels. That, in turn, most certainly would drive natural gas prospecting and resource recovery technology development. It could also provide added motivation to develop more noncarbon energy sources and more quickly bring on line existing low-carbon technologies such as natural gas-fired combined cycle turbines.

Using several econometric models, the Congressional Budget Office (CBO) estimated that a carbon tax of $100 per ton would, at minimum, hold CO_2 emissions to just about current levels and might lower them as much as 25 percent below current

[22]Note, however, that this estimate is very sensitive to forecasted natural gas prices. The increase would be about $0.03 to $0.04 per kWh assuming 2010 prices. Note also, that once these existing facilities retire, costs must be compared to replacement coal plants. Electricity costs from new coal-find powerplants would be about $0,02 per kWh less than electricity from natural gas-fired combined cycle turbines assuming our 2015 prices and about $0.01 per kWh less assuming 2010 prices,

[23]Congress would have to decide whether to tax biomass fuels. Though biomass fuels emit carbon, if fuels are used on a sustainable basis, the carbon emitted will be recaptured over the next few decades, Ideally, fuels grown sustainably would be exempt from a tax but those harvested with no provisions for replanting would be taxed at a rate similar to coal, In practice, this would be extremely difficult.

levels by 2000 (66a). By the end of the first decade, the Gross National Product (GNP) would be lowered by about 0.5 to 2.0 percent (about $40 to $130 billion per year), though the GNP effects over the first few years of a suddenly instituted policy could be 5 percent or more.

CBO looked at two different economic models that forecast energy use past 2000, one used by the Environmental Protection Agency (EPA) and the other by the Electric Power Research Institute (EPRI). Although they widely diverge by 2100, primarily due to assumptions about Base case growth, at 2015 they are reasonably similar to each other and to our own base case and thus offer a useful comparison of reductions and costs. The EPA model forecasts that holding emissions to 10 to 15 percent below current levels would lower GNP by about 1 to 1.3 percent by the year 2015. The EPRI model forecasts that holding emissions to 20 percent below current levels would lower GNP by about 3 percent by that year.

Congress might also choose to adopt a modified carbon tax that reflects methane emissions in addition to emissions of CO_2. Such a tax would still favor natural gas, but not quite as much as when methane emissions are ignored.

Oil and gas producers presently benefit from tax incentives (e.g., through write-offs of intangible drilling costs and a depletion allowance for small producers). During the 1970s the depletion allowance was eliminated for large producers and significantly reduced for small producers. New tax incentives could be structured such that taxes decrease as carbon content decreases. This would help make natural gas (the lowest carbon-emitting fossil fuel) more economically competitive, stimulate the search for new sources, and spur development of techniques for producing unconventional gas. Thus, an appropriately crafted package of tax incentives focused on natural gas would increase its role in the U.S. energy system. If gas replaced some coal and oil, CO_2 emissions would also be reduced. The primary difficulty with tax incentives is that as the price of natural gas is reduced, the incentives for its efficient use also decrease.

Tax incentives could also be used to encourage electric utilities to use high-efficiency gas turbines. Turbines historically have had shorter life spans than conventional plants. A tax incentive program based on efficiency could reduce the overall cost of using the most efficient turbines. Similarly, cogeneration activities could be made more attractive with tax incentives.

Marketable Permits

Another market mechanism that can be used to control CO_2 emissions is the marketable emission permit, an approach recently applied to control use of CFCs and to limit emissions of sulfur dioxide to control acid rain.

This regulatory mechanism, like carbon taxes, is simple in theory. The government issues a limited number of permits to energy users allowing a certain level of carbon emissions. More permits would be needed to burn coal than natural gas to produce the same amount of energy, Permits can be bought and sold on the open market.

As the economy expands and the demand for energy rises, the price of a carbon permit will rise to reflect the cost of holding emissions at a level fixed by policymakers. Holders of permits will find ways to lower emissions (e.g., purchase more efficient equipment, switch from coal to natural gas, etc.) so that they can sell their permits (at a profit) to others. In theory, the effective price of fossil fuels (the cost of the fuel plus the cost of the emission permit) will rise just high enough to meet the allowed carbon emission target. Just how high prices will rise, however, is difficult to forecast.

With a carbon tax, the increased cost of fossil fuels brings about similar results (more efficient equipment and fuel switching), but the exact level of emissions is difficult to predict. Theoretically, the two approaches should yield the same result. If a carbon tax of $100 per ton can lower emissions to 10 percent below current levels by the year 2000, issuing marketable permits equivalent to emissions 10 percent below current levels should result in the price of permits rising to $100 per ton. *Taxes allow* more certain control over *price. Permits* offer more certain control over *emissions.*

Marketable permits can be required for all fossil fuel users or only large users such as utilities, factories, and even large commercial installations. For some uses (e.g., gasoline) regulations can be written so that permits are required for wholesalers, rather than individual end users (i.e., drivers).

A marketable permit system that applies to utilities is discussed below (see ''Improving Electricity Supply").

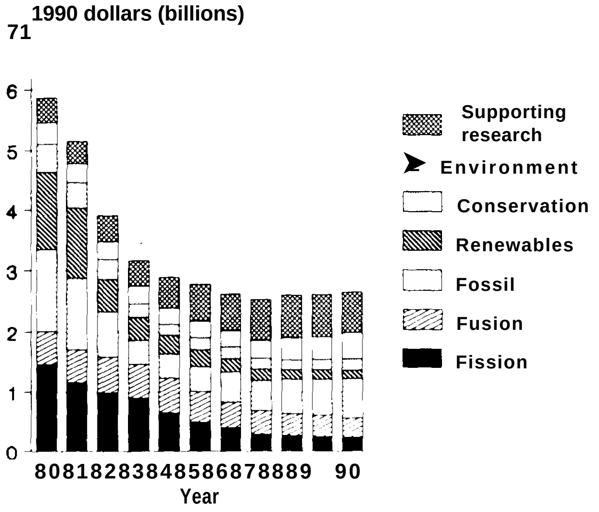
Increase Research Development and Demonstration Efforts

Over the last decade, Federal funding for renewable energy research development and demonstration (RD&D) has fallen rapidly (see figure 3-1 1). Expressed in constant dollars, the 1990 combined energy technology RD&D budgets were less than half of what they were in 1980. Several recent studies have suggested that for a comparatively small increase in investment, the Federal Government could significantly hasten the development and deployment of technologies that would reduce greenhouse gas emissions. A study by the Oak Ridge National Laboratory (ORNL) (47) recommends that the government and major energy industry research groups-namely the Electric Power Research Institute and the Gas Research Institute-increase spending levels by about a third over 1988 combined RD&D budgets (to a level that is still below the 1980 combined budgets). Improved energy efficiency and nuclear power are considered the two most promising RD&D approaches to achieving major reductions in CO_2 emissions.

The Solar Energy Research Institute (SERI) reached somewhat different conclusions about where to spend the money. In a 1990 report (59), SERI focused strictly on nonnuclear, nonfossil energy sources. Nevertheless, it came to many of the same conclusions as ORNL about how much energy nonfossil-fuel sources could be contributing to the U.S. economy over the next 20 to 40 years. In the SERI Business-as-Usual scenario, nonfossil sources contribute 15 percent of U.S. energy supply in 2030. ORNL's "Base Case" projected a 5 percent contribution by 2020. In SERI's "Intensified R&D" scenario, the nonfossil contribution in 2030 is about 30 percent. In the "High Efficiency' scenario for ORNL, that figure is about 35 percent.

At the very least, increased governmental RD&D activity could result in some reduction in greenhouse gas emissions if some of the fossil fuel conversion technologies now in testing phases could be brought on line sooner. The development of a commercial fuel cell, could for example, lower CO_2 emissions per unit of energy from electricity generation. In addition, even if the role of nuclear power in the

Figure 3-1 1—US. Energy Technology Research and Development Budgets, 1978-88



Funding for energy research in the United States has declined sharply since 1980. The bars represent Federal budget authority for research, development and technology demonstrations, in 1990 dollars. "Supporting" refers to research in basic energy sciences.

SOURCE: J.P. Holdren, **"Energy in Transition,"** ***Scientific American,*** **September 1990, pp. 157-163.**

energy supply system is to continue at a modest level, research into better designs, waste disposal, and related issues will have to continue. Of particular interest is the development and prototyping of advanced reactors with ''passively safe' features.

Renewable energy sources face a host of technical and institutional barriers that increased R&D support could help overcome. In addition to supporting efforts to develop some of the more promising technologies (e.g., storage technologies for solar-electricity, biomass-driven turbines, and variable-speed wind turbines), government actions could reduce the risk of new technologies and help integrate renewable in existing energy systems. The former could be achieved with demonstration projects or, perhaps, government-backed loans. Both SERI and ORNL concluded that the Federal budget in this area was only about half of what it should be.

Increased resource characterization could also help reduce CO_2 emissions. For wind, geothermal, solar, and natural gas to play a bigger role in meeting global energy needs, it is vital to improve prospecting techniques and expand what is known about these resources' potential. In some instances, increased demand for an energy source or a properly

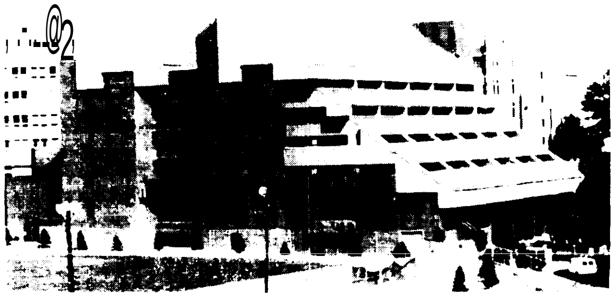


Photo credit: U.S. Department of Energy

The south-facing roof of Georgetown University's Intercultural Center supports a 300 kilowatt photovoltaic power system, the largest roof-mounted photovoltaic system in the world consisting of over 4,400 PV modules. Electricity generated by the roof is channeled into the local power grid.

designed tax structure will provide an adequate incentive for the private sector to undertake prospecting on its own. In other cases, however, market forces alone may not provide enough incentive. It could be difflcult to keep information on, for example, wind or geothermal resources proprietary. The financial commitment necessary for extensive exploration might be prohibitive. The government could perform, subsidize, and provide regulatory incentives for resource assessment.

If natural gas is to play a significant role in CO_2 emission reductions, it is important to find ways of retrieving ''unconventional' gas reserves, geologic reservoirs that hold significant amounts of the resource but are difficult to exploit for one reason or another. Accelerated development of leak-resistant transportation systems could also be encouraged.

Plugging the Leaks in the Existing System

The present energy supply system could be tightened to reduce energy and methane losses. As noted earlier, significant electricity losses occur during transmission and distribution. Better information is needed on the extent and nature of these losses worldwide, particularly in non-OECD countries. Assistance in the form of money, equipment, or expertise could help reduce losses in these countries.

Some fossil fuel is lost during geologic extraction and transport to the end user. Leaked gas is of particular concern because of its contribution (of methane) to the greenhouse effect. Several actions could help reduce the amount of emissions from natural gas extraction and delivery, oil extraction, and coal mining. Regulations against venting gas in the United States have effectively limited the release of' methane to the atmosphere in this country. The U.S. rate is about 0.5 percent of annual production of natural gas (83). The United States could encourage other nations to follow suit. The United States also has a well-developed infrastructure to transport and sell gas with little leakage. Development aid to other nations (see ch. 9) could support their construction of the requisite infrastructure. The United States could also export the technology and ''know-how' to deal with unwanted gas without releasing it to the atmosphere. Such techniques, like the reinfection of gas into oil wells, have been developed here in association with production in remote locations, most notably Alaska (83).

Improved data is needed on methane emissions through leakage, particularly in non-OECD countries. Better and more meters to track gas distribution, along with improved monitoring practices, could provide information crucial to formulating response strategies for all sectors using natural gas in these countries. Finally, incentives are needed (both financial and regulatory) for the development of technology to capture coal seam methane.

Improving Electricity Supply: Meeting Demand With Lower CO_2 Emissions

Emissions of CO_2 from utilities can be lowered in two ways: by *reducing demand* for electricity, and by *changing supply characteristics* to lower the *rate* of emissions (i.e., pounds of CO_2 per kilowatt of electricity generated). This section focuses exclusively on the latter approach, presenting policy options for encouraging more efficient use of current powerplants, use of fuels with inherently lower $C0_2$ emissions, and use of nonfossil energy sources. Demand-side management programs are discussed briefly in box 3-C and in greater detail in chapter 4.

We present options designed for existing plants and for those not yet built, as well as a set of overall policies that affect all plants.

Measures That Apply to Existing Plants

Earlier we presented three "Moderate" technical options that can lower CO_2 emissions from existing plants at little or no additional cost when averaged over the life of the program. These include:

Box 3-C--Electric Utility Demand-Side Management Programs

Utility planners are already beginning to look at ways to encourage the adoption of energy conservation measures among residential, commercial, and industrial ratepayers as a way to reduce the need to build expensive new powerplants. Conservation and other measures are part of a larger concept known as demand-side management (DSM). In addition to encouraging energy conservation, DSM programs also include "load management" options such as alternative rate structures to change the timing of eletricity use and measures to reduce excessive demand during peak hours (e.g., hot summertime afternoons).

Electric utilities conduct DSM programs in various ways (27b):

- information dissemination (e.g., mass media attachments to electric bills);
- onsite energy audits and technical assistance;
- financial incentives (e.g., rebates, low-interest loans, and rate discounts);
- direct installation (e.g., low-flow showerheads, water heater wraps); and
- cooperation with trade allies (e.g., manufacturers and dealers, architects, engineers, builders).

Utility Conservation Case Study: The Northwest Power Planning Council 1990 Power Plan

The Northwest Power Planning Council[1] (NPPC) is an interstate compact agency approved by Congress that reviews the activities of the Bonneville Power Administration, the Federal power marketing agency in the Pacific Northwest. Recently the NPCC proposed a series of cost-effective conservation measures to reduce electricity demand by 8 percent in the region by 2010, compared to forecasted levels (46a). These measures will eliminate the need for six new coal-fired powerplants, at roughly half the cost.

Residential measures include those that lower space heating demands in new and existing homes (e.g., improved insulation, storm windows, reduced air leakage); more efficient water heating (e.g., insulated water heaters, pipe wraps); and more efficient refrigerators, freezers and other appliances. The measures proposed by the NPCC can reduce electricity demand in the residential sector by about 10 percent by 2010. Well over half is from measures to lower space heating demands.

In **the** commercial building sector, the NPCC has proposed conservation memsures targeting lighting, space heating, and cooling that can reduce commercial electricity use by about 13 percent by 2010. Measures that can be retrofit in existing buildings are responsible for the majority of these reductions.

For the industrial sector, the NPCC has identified such conservation measures as improved motors, motor controls, and lighting that can lower electricity demand in this sector by 3 percent by 2010. The NPCC has proposed conservation measures that apply to agricultural irrigation that can reduce electricity use by about 12 percent (46a).

[1] In accordance with the Pacific Northwest Electric Power Planning and Conservation Act (Public Law 9&501), the four Northwest States of Idaho, Montana, Oregon, and Washington entered into an interstate compact in 1981. The Act required the NPPC to develop and adopt a 2&year electrical power plan and a program to protect, mitigate, and enhance f@ and wildlife resources in the region.

1. improving the efficiency of fossil-fuel-freed plants through improved maintenance,
2. increasing the use of existing nuclear power-plants not currently operating at full capacity, and
3. renovating existing hydroelectric generating facilities to increase their output.

A fourth "Tough" option is to change the fuel mix at existing plants.

Improved Operation--Overseeing the operation of utilities is, in general, the responsibility of the States. Theoretically, utilities should already be operating their powerplants at optimal efficiency so as to provide electricity to their consumers at the lowest cost. State public utility commissions (PUCs) have the authority to regulate retail electricity rates, and thus have considerable influence over utility operations. In practice, however, a few percent gain in efficiency is not a top priority for many utilities or States, nor are efficiencies routinely monitored.

Recently, however, some industry attention has been given to methods for improving efficiencies (15). The Electric Power Research Institute (EPRI) has a multi-year research program underway on methods to lower electricity costs through efficiency improvements. The Federal Government could participate in this effort as well. In addition to DOE-funded research, TVA and the Federal power agencies (e.g., Bonneville Power Authority) could undertake improvements at their own facilities. About 4 percent of the electricity generated from fossil fuels comes from these Federal facilities (14).

The Federal Government, through the Federal Energy Regulatory Commission (FERC) has some, albeit indirect, ability to influence private utility operations through its authority over prices and conditions of wholesale power sales. Virtually all generating utilities sell power to other utilities at some point. If Congress feels that State PUCs are not identifying and enforcing efficiency improvements, it could direct FERC to include such considerations when regulating wholesale power sales.

For nuclear powerplants, the relevant goal is to increase the number of hours of operation, rather than efficiency of fuel use. The most promising option here is to establish a demonstration program to increase utilization from the current 65 percent (5,700 hours per year) to 75 percent (6,600 hours per year). In 1975, Japanese nuclear plants operated about 50 percent of the time. A 7-year improvement and upgrade program increased utilization to 75 percent (23), Western Europe averages 75 percent, as well. A coordinated demonstration program by DOE and the Nuclear Regulatory Commission might foster improvements to boost U.S. hours of operation above the average in a timely fashion. Key improvements would include preventive maintenance; installation of automated controls to improve reactor operation, thereby reducing the number of unscheduled shutdowns; and speedier refueling.

Switching ***to Lower Emitting Fuels—in*** addition to efficiency improvements, CO_2 emission rates from existing fossil-fuel-fired utilities can be lowered by switching to lower emitting fuels, For example, a typical Midwestern powerplant burning Illinois coal emits about 0.60 pounds of carbon per kWh of electricity generated (lbs C/kWh). By burning a mixture of 75 percent coal and 25 percent natural gas (or burning coal 9 months and gas 3 months per year) emissions will be lowered by 10 to 15 percent.

Such a goal can be achieved in several ways. A high enough carbon tax (discussed above) would encourage natural gas use by utilities. However, the effect of such a policy would depend on the relative price of coal and gas at each location. A carbon tax in the range of $75 to $150 per ton would make gas a more economic choice at many facilities, at least over the next decade.[24] If the tax were much lower, few utilities would find natural gas attractive; if it were much higher, demand for gas could be so great that prices would rise sharply.

A much more certain outcome would result from setting Co_2 emission limits. An emission rate limit of 0.55 lbs C/kWh would require atypical Midwestern coal plant burning Illinois coal to burn about 10 to 30 percent natural gas, depending on its efficiency. Plants burning western coals, for example from the Powder River basin, or Texas lignite might have to burn between 25 and 45 percent gas to meet this limit. Some efficient plants burning high-heat-value eastern and western coals might meet the standard with only a few to 10 percent natural gas, but almost all existing facilities would need to burn some gas to continue operation. At 0.55 lbs C/kWh, the most efficient ***new*** coal-burning technologies would just qualify (e.g., integrated coal gasification, combined cycle, or IGCC) by burning coal alone.

Because some facilities will have difficulty getting natural gas or converting their boilers to use gas, a marketable permit approach might be preferable. Utilities would receive permits for the amount of CO_2 that they are allowed to emit from their coa1-fired units; permits could be traded on the open market. Utilities would receive such permits based on their generation in an historic year (e.g., 1990) multiplied by an allowed emission rate (0.55 lbs C/kWh, using the example above). Some utilities would curtail coal use more than necessary to meet their limits and others less, but the overall impact on CO_2 emissions would be the same as setting uniform emission limits.

A variant on the above approach is to simply issue permits for a limited amount of coal use in existing facilities. Such an approach would be simpler to administer than emission permits, but does not give credit to more efficient coal plants or to lower CO_2-emmitting coals.

Measures That Apply to New Plants

Controlling Emission Rates FromNewFossil-Fuel-Fired Plants—Many of the policy options available to control emission rates from new fossil-fuel-fired plants are similar to those for existing plants, but greater opportunity exists for more stringent control. Earlier, we discussed three electricity demand sce-

‘A carbon tax of $75 to $150 per ton would approximately double or triple coal prices and increase natural gas prices by over 50 percent.

narios, a Base case and two lower demand scenarios, that assume "Moderate" and "Tough" conservation measures, respectively. Under the Base case scenario, we estimated that at least *some* new coal plants would have to be built (between 25 and 50 percent of all new plants) to meet demand. Under the two lower demand scenarios, we estimate that natural gas and renewable sources of energy are plentiful enough to meet demand through 2015, without the need for new coal plants. The choice of appropriate policy options will depend on whether the goal is to slow the rate of growth of new coal plant construction or to impose a *temporary moratorium* on new coal plants through 2015 to allow time to develop more efficient technologies. Under all of our scenarios, however, some fossil fuel sources will be needed to meet demand.

To limit construction of new coal plants a predetermined number of coal permits (or carbon permits specific to coal plants) could be auctioned each year to the highest bidder. If such a policy were adopted in combination with marketable permits for existing coal plants, permits could be freely traded among new and existing facilities.

Adoption of stringent CO_2 emission limits for new plants is one way of imposing a temporary moratorium on new coal plants. Two somewhat different strategies could be pursued. If the intent is to force development of ultra-efficient coal technologies, then a standard in the range of 0.35 to 0.40 lb C/kWh would be appropriate. Molten carbonate fuel cells, if successful, might be able to meet such emission rates using bituminous coals.

However, such a new source performance standard would do little to encourage improvement of other fuel technologies. Current combined cycle turbines burning distillate oil can meet such a standard, and similar technologies burning natural gas emit about 0.26 lb C/kWh. If the intent is to limit new fossil-fuel-fired generation to the cleanest sources only—advanced combined cycle turbines burning gas—then setting a new source performance standard at about 0.25 lb C/kWh would be more appropriate.

Measures To Encourage Use of Nonfossil Fuel Sources-Any of the general financial options discussed above, such as a carbon tax or fossil fuel energy tax, will serve to encourage use of nonfossil sources for electricity generation. The Solar Energy Research Institute and the National Laboratories

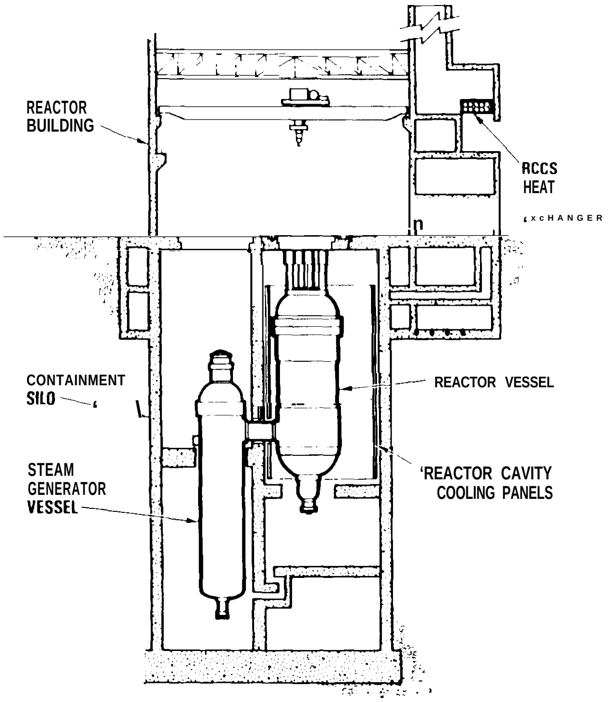


Photo credit: G.A. Technologies

Diagram of the Modular High Temperature Gas Reactor (MHTGR), one of several new nuclear reactors designed to be "passively safe." In the event of loss of coolant, fuel temperatures increase slowly enough to allow heat to be conducted to the surrounding earth, thereby avoiding massive failure and release of radiation.

recently evaluated the effect of a 2-cent/kWh subsidy for renewable sources of electricity (an increase of 25 to 30 percent over the base case cost for electricity) (59). They concluded that such a subsidy (or, conversely, a tax on fossil fuel) would double the penetration of renewable sources of electricity by 2010 as compared to a business-as-usual case and allow these sources to cost-effectively meet 40 percent of the new demand for electricity. Hydroelectric power, wind power, and biomass provide the bulk of the energy. A 2-cent/kWh subsidy is equivalent to a carbon tax of $75 per ton of carbon for coal and about $150 per ton of carbon for natural gas.

Although nuclear power might benefit somewhat from a carbon tax, the utility industry is unwilling to undertake construction under the current social and regulatory climate. New technologies are needed for a revival of nuclear power in this country, but utilities are not likely to order these technologies until they have been demonstrated in full-scale operation. Given the shape that the nuclear industry is currently in, the pace of such demonstrations is likely to be slow (if they happen at all). Appropriating funds to demonstrate new technologies is a promising way of giving nuclear power another chance at success.

A two-track program would offer the greatest flexibility. DOE could help fund full-scale demonstrations of both new ‘‘evolutionary’ light water reactors (LWR) and ‘revolutionary design changes such as a modular high temperature gas reactor (MHTGR). Demonstrations of the new technologies that started operation by 2000, if successful, might conceivably result in additional units on line by 2010. Evolutionary designs might be able to come on line more quickly than revolutionary ones, especially if one of the goals of the program is to develop standardized designs to minimize licensing time (68).

As noted earlier, research, development, and demonstration funds are needed to increase the role of renewable sources as well. SERI has estimated that if current funding for renewable research were increased to about $270 million per year (about two and a half times current levels), the penetration of renewable sources of electricity might double by the 2010-to-2020 timeframe (59). This has about the same effect as a 2-cent/kWh subsidy. The SERI forecast may overestimate the effectiveness of accelerated research in lowering the cost of renewable technologies, but it is clear that research and demonstration will help, particularly with respect to geothermal and wind sources.

***Measures To Hasten the Rate of Retirement of Existing* Facilities**-Under the Base case demand scenario, about 7 percent of the utility capacity operating in 1990 will retire by 2015. One final option for lowering emissions is to force older fossil-fuel-fried plants to retire earlier than their expected lifetime of 60 years. If all fossil-fuel-fired plants were forced to retire after 40 years of operation, about 35 percent of the existing capacity will be eliminated by 2010 and 50 percent by 2015. When combined with the measures discussed above for new plants, considerable reductions are possible. The 40-year time is arbitrary; it could be 30 or 35 years if desired, or longer if the costs for 40-year retirement are thought to be excessive.

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