

[COMMITTEE PRINT]

ENERGY PROGRAM

12

**TAX ON INDUSTRIAL USE OF
OIL AND NATURAL GAS**

PREPARED FOR THE
COMMITTEE ON WAYS AND MEANS
HOUSE OF REPRESENTATIVES
BY THE STAFF OF THE
JOINT COMMITTEE ON TAXATION



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I. INTRODUCTION

This pamphlet is the twelfth in a series prepared for use by the Committee on Ways and Means during its consideration of the tax proposals in the Administration's energy program.

This pamphlet deals with the proposed tax on industrial and utility use of oil and natural gas and the rebate of that tax for qualifying investments made by the industrial or utility user to convert to the use of coal or some fuel other than oil or natural gas.

The pamphlet is divided into several subparts. A background section outlines certain facts concerning the energy situation in the area under consideration. A section on present law follows. Next there is a discussion of the Administration proposal, followed by the energy-related legislative proposals considered in the 94th Congress. Alternative proposals offered by the members of the Ways and Means Committee are set forth in the next section. Finally, there is a discussion of possible areas for committee consideration.

In the 94th Congress, the major bill considered in connection with energy tax proposals was H.R. 6860. This bill was reported by the Ways and Means Committee and was amended on the House floor. Markup sessions on H.R. 6860 were held by the Finance Committee in July 1975, and tentative decisions were made in many areas, but the bill was not reported at that time. Many of the provisions approved by the Finance Committee were added to H.R. 10612, the Tax Reform Act of 1976, as Title XX, but all of the energy provisions were deleted in conference. In August 1976, the Finance Committee reported the provisions of Title XX (as passed previously by the Senate in H.R. 10612) as an amended version of H.R. 6860. This bill was never taken up on the Senate floor and the provisions expired with the adjournment of the 94th Congress.

Unless otherwise indicated, the provisions discussed below with respect to action in the 94th Congress reflect H.R. 6860 as approved by the Ways and Means Committee. Also, unless otherwise specifically indicated, references to the Finance Committee bill refer to Title XX of the Tax Reform Bill (as passed the Senate) and the Finance Committee reported version of H.R. 6860. Floor amendments are specifically noted.

II. BACKGROUND

Natural Gas

Consumption

Natural gas which comes from the well is "wet", which means that it contains both "dry" natural gas (i.e., the substance commonly thought of as natural gas) and natural gas liquids. This "wet" gas is processed by natural gas processing plants, which separate the wet gas into dry gas and natural gas liquids. Some natural gas liquids are further processed by petroleum refineries. Natural gas liquids are considered "petroleum products" (discussed in the next section).

Between 1950 and 1970, total consumption of "dry" gas grew at an extraordinarily rapid rate; it peaked in 1972 and has declined since then. Total natural gas resources are estimated to be approximately equal to 45 years worth of 1975 consumption. Proved reserves of natural gas, (i.e., those known reserves which can be economically extracted with existing technology at existing price levels), however, have declined sharply from 291 trillion cubic feet in 1970 to 216 trillion cubic feet in 1976.

Because companies will construct pipelines only if they are assured of gas supplies for many years, most natural gas is sold under long-term contracts which require producers to dedicate certain reserves to particular pipelines or to particular consumers. Many of these contracts fix the price of gas well below the world market price for other sources of fuel. As a result, gas producers have been depleting existing gas reserves at a very rapid rate in an attempt to satisfy current demands of gas consumers, but gas producers have been unwilling to develop new reserves and commit such reserves to long-term contracts, presumably in the expectation that gas prices will rise still further.

The result has been natural gas shortages which have resulted in curtailments of gas supplies to certain users. These were particularly severe in the cold winter in 1976-77, when gas shortages required layoffs in many industries.

TABLE 1.—Domestic consumption of petroleum products and natural gas, by major product and major consuming sector, 1976 (estimated)

[Quadrillion Btu]

	Household and commercial	Industrial	Transportation ¹	Electricity generation, utilities	Total domestic product demand
Petroleum products: ³					
Fuel and power:					
Liquefied gases ⁴	0.682	⁵ 0.281	0.108		1.071
Jet fuels.....			2.007	0.017	2.024
Gasoline.....			13.440		13.440
Kerosene.....	.269	.078			.347
Distillate fuel.....	3.144	.814	2.216	.419	6.630
Residual fuel.....	1.169	1.232	.798	3.043	6.279
Still gas.....		1.092			1.092
Petroleum coke.....		.386			.385
Total.....	5.264	3.883	18.569	3.479	31.268
Raw material: ⁶					
Plant condensate.....		.019			.019
Special naphthas.....		.157			.157
Lubes and waxes.....		.221	.164		.384
Petroleum coke.....		.157			.157
Asphalt and road oil.....	1.068				1.068

Petrochemical feedstock offtake:				
Liquefied refinery gas ⁷160			.160
Liquefied petroleum gas ^{7 8}720			.720
Naphtha.....	.402			.402
Still gas.....	.099			.099
Miscellaneous.....	.350			.350
Total	1.068	2.283	.164	3.515
Miscellaneous and unaccounted for.....				.155
Grand total, petroleum products	6.333	6.166	18.733	34.938
Natural gas: ⁹				
Fuels and power.....	¹⁰ 8.117	¹¹ 7.755	¹² .582	3.134
Raw materials (chemical).....		.628		.628
Grand total, natural gas	8.117	8.483	.582	20.216
Total petroleum and natural gas consumption	14.450	14.649	19.315	55.153

¹ Includes bunkers, military transportation, and all military use of distillate and residual fuel oils.

² Includes miscellaneous and unaccounted for users, not shown separately.

³ Includes liquefied refinery gas and natural gas liquids.

⁴ Includes liquefied refinery gases (made from petroleum) and liquefied petroleum gases (made from natural gas). Examples are propane and butane.

⁵ Includes secondary recovery of petroleum and agriculture uses.

⁶ Includes some fuel and power used by raw materials industries.

⁷ Includes ethane.

⁸ Includes LP gas for synthetic rubber.

⁹ Does not include use of 2.4 quads for production of liquefied petroleum gases.

¹⁰ Includes 0.247 quads delivered to municipalities and public authorities for heating, etc.

¹¹ Includes approximately 1.4 quads used as fuel in gasfields and natural gas processing plants.

¹² Consists of fuel used by natural gas pipelines.

Source: Bureau of Mines.

The 1976 consumption of dry natural gas is shown at the bottom of table 1. Residential and commercial customers (who would generally not be subject to tax under the Administration proposal because of the small users exemption) accounted for 40 percent of total consumption.

Electric utilities used 16 percent of the natural gas and industrial users consumed 38 percent. (This industrial figure includes 7 percent used as fuel by natural gas processing and in gas fields.) The remaining 3 percent was used in natural gas transportation as pipeline fuel.

Natural gas is used primarily as a fuel, but it also has some important subsidiary industrial uses as feedstocks and in irrigation pumping. In 1976, about 3 percent of total consumption was used as feedstocks in the chemical industry, principally for the production of fertilizers and plastics.

In industry, about 40 percent of the natural gas used as fuel is for boilers. The remainder is used in other types of combustors, such as kilns and furnances.

A tax aimed at industrial and utility users would affect about 47 percent of natural gas consumption. (This would exclude use as petrochemical feedstocks, and use as fuel in gas fields, natural gas processing plants, and in pipeline transportation.) The Administration proposes a small user exemption, but this would have a relatively modest effect on the impact of the tax because the proposed phaseout of the exemption would make the exemption inapplicable to most industrial and utility use of natural gas. However, most firms use too little gas to be liable for the Administration's proposed tax.

Users who could potentially convert to coal, however, account for less than 47 percent of consumption, because some industries use gas for process heating (for which use of coal is difficult) and in boilers too small or too new to make conversion economical in the foreseeable future. As shown in table 2, the principal industries which would be affected by such a tax are chemicals, petroleum refining, and primary metals.

About one-third of utility gas consumption and about one-quarter of industrial consumption is under "interruptible" contracts, which allow the distribution company to terminate service at times of heavy demand and short supply. Interruptible users normally convert to fuel oil when their natural gas supply is cut off. Generally interruptible customers pay less for their gas than those having firm contracts. The advantage to the distributor is that interruptible customers generally use gas on a year round basis (whereas residential customers, for example, generally use little or no gas during warm weather periods) and thus keep the pipeline operating at reasonably full capacity throughout the year.

TABLE 2.—Distribution of industrial consumption of natural gas and petroleum products, 1974, by industry ¹

[In percent]

Industry	Natural gas	Petroleum products
Food products.....	4.5	2.2
Paper products.....	4.6	4.9
Chemicals.....	15.2	41.2
Petroleum refining.....	10.6	28.7
Nonmetallic products.....	7.2	1.7
Primary metals industries.....	10.8	6.1
Other.....	² 47.1	15.2
Total.....	100.0	100.0

¹ Includes both fuel and raw material uses.² Includes 15.3 percent used as fuel in gas fields and by natural gas processing plants.

Source: Bureau of Mines.

Effect of pricing policies

The price of natural gas sold in interstate commerce is regulated by the Federal Power Commission (FPC). In mid-1976, the average wellhead price of natural gas sold to major interstate pipelines was 44 cents per thousand cubic feet (mcf). These pipelines purchased about one-half of the gas produced in the United States. The price ceiling for interstate natural gas is now \$1.45 per mcf, but the average price at which interstate gas is sold is considerably less than this because many prices are set by old long-term contracts.

The price of gas sold within the producing States is considerably higher than \$1.45, and in some cases exceeds \$2.00, so that producers dedicate relatively little new gas to interstate commerce. The principal exception is offshore gas, which is subject to FPC regulation no matter where it is sold.

The distortions resulting from the existing methods of pricing natural gas can be seen by comparing gas and oil prices. Comparisons between different energy sources can most easily be made in terms of Btus, or British thermal units. A Btu is the amount of energy required to raise the temperature of one pound of water by one degree Fahrenheit. A barrel of crude oil, the equivalent of 42 gallons, contains, on the average, about 5.8 million Btus. (The Btu content of oil varies from barrel to barrel, however, depending on the quality of the oil.) Natural gas contains about 1 million Btu per thousand cubic feet, or mcf. Coal contains about 23 million Btu per short ton.

In November 1976, the average price of gas sold to residences was \$1.97 per mcf. Since one barrel of distillate fuel oil contains 5.8 times as much energy as one mcf of gas, this natural gas price is equivalent to a price of \$11.43 per barrel for distillate fuel oil. That month, the

price of heating oil was \$17.50 per barrel, so that residential gas prices were only two-thirds of heating oil prices and incentives for gas conservation were correspondingly weaker.

In July 1976, the price of gas sold by the major interstate pipelines to industrial users averaged \$.943 per mcf, which is equivalent to a price of \$5.79 per barrel for residual fuel oil, but residual fuel oil itself sold for an average price of \$10.74 per barrel. Thus, those companies lucky enough to be customers of an interstate pipeline incur half the energy cost of their competitors who must rely on fuel oil.

Future production of natural gas from conventional sources is not likely to increase significantly above current levels if prices remain in the vicinity of their present levels. Most analysts agree that if serious technological and environmental problems could be overcome and prices were to reach approximately \$5 per mcf (after adjusting for inflation), approximately double the current world oil price equivalent, then substantial supplies of gas might become available from such sources as synthetic natural gas, coal seam methane, Devonian shale, and geopressured gas.

Petroleum Products

Petroleum products are derived from crude petroleum and from natural gas liquids. Crude petroleum products consist primarily of distillate and residual oil. Natural gas liquids include natural gasoline, propane, butane and ethane. Natural gas liquids supply about 10 percent of the U.S. demand for refined petroleum products.

As shown in table 1, a tax on industrial and utility use of petroleum products would not affect the majority of petroleum products. Approximately 54 percent of these products are used for transportation (commercial, governmental, and individual).

Household and commercial users account for 18 percent. These users rely primarily on residual and distillate fuel oils, liquefied gases, and kerosene for heating purposes. Asphalt and road oil are also allocated to this sector.

Industrial and electrical utilities users account for 28 percent of petroleum products use. This is divided into 21 percent for fuel uses, 5 percent for petrochemical feedstock uses, and 2 percent for other raw material uses. Approximately 40 percent of industrial use of petroleum products for fuel is for boilers; the remainder is for other types of combustors.

Under the Administration proposal, some products used as raw materials, including lubricants, wax, coke and plant condensate (used as refinery input), which together account for one percent of total demand, would be exempted from the tax. Thus, assuming that the tax would not affect the commercial sector, about 27 percent of total consumption of petroleum products could be taxed by an industrial and utility use tax (22 percent if petrochemical feedstocks were not part of the tax base). As shown in table 2, the chemical and petroleum refining industries would be the largest payers of the tax.

Prices for the natural gas liquids other than ethane and for gasoline are currently subject to controls, although the Administration proposes to remove gasoline prices from controls later in 1977.

Oil Imports

Petroleum is the most significant single energy source in the United States. In 1976, it accounted for 47 percent of U.S. energy consumption and for more than 95 percent of energy consumed in transportation. The total amount of oil consumed in the United States doubled between 1950 and 1970; except for a slight decline at the bottom of the 1974 recession, U.S. oil consumption has continued to rise.

Domestic oil production has declined steadily since 1970 when production peaked at approximately 4.1 billion barrels.¹ By 1976, domestic production declined to approximately 3.6 billion barrels.²

The inevitable result of rapidly increasing oil consumption and declining domestic production has been a significant growth in oil imports. Until 1965, the United States was self-sufficient in oil because its spare (unused) production capacity for crude petroleum exceeded its oil imports. However, since 1972, domestic production has proceeded at full capacity and imports have risen steadily. In 1976, oil imports amounted to 7.3 million barrels per day (mbd), or 42 percent of consumption.

The United States imports oil principally from Venezuela, Arab countries, Canada, Iran, and Indonesia. In 1975, the United States was dependent on Arab suppliers for 13 percent of its consumption. This dependence on Arab suppliers clearly increased in 1976.

Without any change in policies, there is likely to be a significant increase in our dependence on imported oil in future years. The Federal Energy Administration estimates that under current energy policies, oil imports will be 48 percent of consumption in 1980, 50 percent of consumption in 1985, and 58 percent of consumption in 1990. These FEA estimates are consistent with independent private forecasts.

Moreover, many U.S. allies, including Japan, Germany, France, and the United Kingdom, have relied on imports for more than 95 percent of their oil needs in recent years. These countries have relied on Arab suppliers for one-half to three-quarters of their total oil consumption. Except for the United Kingdom, which may become self-sufficient as a result of North Sea oil production, these countries will continue to rely heavily on imports in the future.

Availability of Alternate Fuel Sources

Coal

One likely effect of a tax on utility and industrial use of petroleum products and natural gas would be to increase the use of coal.

Coal is the most abundant fossil fuel available in the United States. The known reserves are sufficient to meet domestic needs for several centuries. This abundance is especially important now in view of the prospect for substantial price increases for petroleum, natural gas and their products and the prospect that proved oil and gas reserves will not keep pace with future oil and gas consumption. Coal is most important immediately because of its suitability as a fuel substitute for oil and gas and because coal is potentially a source for synthetic

¹ Estimate of production of crude petroleum includes natural gas liquids.

² Staff estimate based on data for part of year.

oil and gas. Its drawbacks are its adverse environmental impact and the relatively high cost of its extraction, transportation and use.

Coal reserves

Domestic coal reserves are approximately 437 billion tons and are found in 30 States. Slightly more than half the reserves, 234 billion tons or 54 percent, are located in western states. About two-thirds of the total is found in 5 states—Montana, Illinois, Wyoming, West Virginia and Pennsylvania, in order of size of reserve.

About 46 percent, or 200 billion tons, has a sulfur content below 1 percent, which is below the level deemed satisfactory to avoid air pollution. Almost all of the coal reserves in Montana and 60 percent of those in Wyoming are in this category. Almost the same amount of coal reserves, 186 billion tons, has a high sulfur content.

About 300 billion tons, or 69 percent of all coal reserves, can only be recovered through relatively high cost underground mining techniques; the remainder may be recovered by surface mining.

Production, consumption, and transportation

Domestic production of coal in 1977 is estimated at 700 million tons, an increase of more than 5 percent over 1976 production. Production has increased by 155 million tons, or 28 percent, since 1968, with two-thirds of the increased production levels occurring after 1973. Electric utilities have long been the major consumer of coal, and during this period since 1968, their share of coal consumption increased from 54 to 68 percent. The increased share reflects increased generation of electrical energy and some shifts from use of oil and natural gas to coal as boiler fuel.

Coal production generally is described as being demand limited, that is, the level of production is determined by the demand for it, as illustrated by the increases in production and consumption since 1968. Consumers of large amounts of coal, primarily electric utilities and some industrial firms, tend to sign contracts directly with mine owners for all or a specific portion of the mine's output. Financing is readily available once these contracts are signed. Several years of lead-time are necessary between the decision to open a mine and the start of production. The interval between the decision to open a new coal mine and shipment of the initial load of consumable coal usually is long enough to provide for transportation of the coal, including the manufacture of additional carriers needed, and construction of new railroad roadbeds.

Coal is transported from the mine to the consumer primarily by train. In 1974, railroads carried 66 percent of the coal that moved between mines and consumers. Water transportation and trucks, respectively, carried 11 percent of the total. The rest was carried in miscellaneous forms, including a small amount by slurry pipelines.

The existing railroad lines may be extensive enough to carry the coal where it is needed. If they are not and new railroad lines must be put in place, this could cause some delay in the delivery of coal by rail to those areas where it is needed. Flexibility exists with respect to freight cars, because more efficient use of the cars, especially shorter turn-around time, could offset a temporary shortage in the number of cars. The condition of roadbeds in some sections in the country is being cor-

rected under a program which was begun in April 1977 under the Railroad Revitalization and Regulatory Reform Act of 1976.

Coal slurry pipelines can move coal efficiently between fixed terminals over a fixed route. The pipeline moves a water and coal mixture, and by its nature places relatively large, additional demand on the water supply in the area where the coal is mined. Problems with the use of slurry pipelines may arise in those areas where there is not a copious flow of water. The pipelines require substantial initial capital costs, but the operating costs are relatively low. Currently construction of the pipelines has been delayed because legal complications have arisen over the rights-of-way.

Expansion of mining capacity

The proposed national energy program, as presented by the Administration, calls for continued, substantial increases in coal consumption by industry and electric utilities that will result from continuation of the pattern that began after 1973—a substantial shift from oil and natural gas to coal, nuclear fuel or other sources. In part, the ability of the coal industry to provide sufficient output is demonstrated by the production increases in the past several years. Even more rapid increases may be necessary in the future as the electric utility industry is shifted from reliance on oil and gas.

As indicated above, coal production in 1977 is estimated to be 700 million tons, an increase of 35 million tons (or 5 percent) over 1976. Projections made in 1976 as a result of surveys by the National Coal Association and FEA indicate current plans to expand coal production capacity over 1976 levels by about two-thirds by 1985. These expansion plans were developed on the assumption that difficulties (if any) with the size of the available labor force and transportation systems would not seriously restrict deliveries of coal to consumers.

Coal prices and profit

Coal prices, per million Btu, are approximately 50 percent below the equivalent oil price and 10 to 20 percent above the equivalent gas price. Coal prices are unregulated and basically responsive to the demand for coal.

Electric utilities, the dominant consumers of coal, tend to sign long-term contracts for a mine's total output. The contract price usually reflects the current market price when the contract is signed, with provisions for a pass-through of higher operating costs and occasionally some protection of profit margins. Spot prices of coal, the type used primarily as boiler fuel, ranged between \$10 and \$20 a ton in mid-1976 and have risen since then. A rising trend should continue through 1977 as consumers build inventories as a hedge against a coal strike late in 1977. Subsequent prices could be affected strongly by prices of oil and gas, including any new oil and gas taxes, which consumers will be paying.

Ownership of coal

Generally, domestic coal mines are owned by corporations primarily involved in other economic activities. There is only one coal company (North American Coal) among the 10 largest steam coal producers in 1975; two of the 10 were electric utility systems (American Electric Power and Pacific Power and Light).

Among the 150 largest holders of coal reserves, seventy of the companies are primarily coal producers, but 44 of them produced nothing or less than 100,000 tons in 1975. Oil and gas companies and electric utilities were the next two largest types of holders of coal reserves. Thirty-nine of the companies produced 2 million or more tons; 8 were coal companies, 9 were in oil and gas, and 6 in each of electric utilities and steel. The 9 oil and gas companies held the largest reserves—28 billion tons; the 8 coal companies and 3 companies in metals other than steel each held reserves of 10 billion tons, and electric utility and steel companies held between 5 and 6 million tons each.

Costs of conversion

It is estimated that in 1975 dollars, it costs about \$525 million to build a 1,000-megawatt coal-fired plant, including the scrubbers necessary to remove sulfur from the exhaust gases. This comes to a cost of about \$525 per kilowatt. A 1,000-megawatt plant is adequate to meet the energy needs of a city of approximately 1 million people.

There is, however, considerable regional variation in these construction costs. For example, the cost of construction in the Southeast is about 9 percent below the national average and the cost in New England is about 11 percent above the national average.

In the case of a public utility, it takes approximately 8 years to site and construct a coal-fueled facility. However, somewhat shorter conversion times, ranging from perhaps 2 to 3 years, are possible in the case of industrial conversion to the use of coal.

Nuclear energy

Since the 1950's, the United States has encouraged the use of nuclear energy as a long-term replacement for fossil fuels to generate electricity. Through the Atomic Energy Commission and its successors, the Nuclear Regulatory Commission and ERDA, research and development on nuclear power has continued for 25 years. The United States is now in its 18th year of commercial nuclear power production.

In the current nuclear power plant, the nuclear fuel core replaces fossil fuel in the generation of steam which in turn drives turbines which generate electricity. A nuclear fuel core contains uranium fuel which has been enriched in its fissionable Uranium-235 (U-235)³ content. When U-235 is bombarded by neutrons, the uranium atoms split ("fission") and release energy in the form of heat plus additional neutrons which sustain the nuclear reaction. The heat is transferred to the primary coolant, which can be boiling water, pressurized subcooled water, gas or liquid metal. This heated substance is used to produce steam, which turns a turbine generator which in turn produces electricity.

Types of reactors

There are three main types of reactors in use or being funded in the United States: (1) light water reactors, (2) gas cooled reactors, and (3) the developing liquid-metal fast breeder reactors.

(1) *Light water reactors.*—Light water reactors are fueled by enriched uranium dioxide (UO₂). Their name derives from the fact that

³ The term U-235 means uranium with an atomic weight of 235. The number 235 refers to the number of neutrons and protons in the atom.

ordinary water is used to cool the core, and in so doing generates steam which drives a turbine generator. The water may be either boiling or pressurized in its uses as a coolant.

(2) *Gas cooled reactors.*—Gas cooled reactors are fueled by U-235 in the initial reactor core and thorium-232, which is converted to uranium-233, in subsequent cores. High pressure helium gas is used as the coolant. Because of the high pressure and temperature steam provided by these reactors; the gas cooled reactor has a net thermal operating efficiency of nearly 40 percent. There is only one such reactor in the United States.

(3) *Liquid metal fast breeder reactor.*—This type of reactor produces more nuclear fuel than it consumes. A fast breeder reactor converts nonfissionable (and abundant) U-238 to fissionable plutonium-239. For the past 20 years, the government has been conducting, research and development on the breeder concept.

Use of nuclear fuel in electricity generation

The importance of nuclear power for domestic electricity supply has grown markedly in the past several years. In 1973, nuclear-fueled electricity constituted 4.5 percent of domestic electricity supply. In 1974, it rose to 6 percent; in 1975 it averaged 9.0 percent, and it averaged 9.3 percent in 1976. In January 1977, a period of unusually cold weather and high electricity demand, nuclear power plants generated 11.3 percent of all U.S. electricity.

In the past 4 years, concern over growth in electrical demand, waste disposal, safety, reprocessing, capital costs, and uncertainties over the price and availability of uranium have led utilities to delay their orders for new reactors. In 1973, 34 reactors were ordered, in 1974, 26 reactors were ordered, in 1975, 4 reactors were ordered, and in 1976, 1 reactor was ordered.

Operational safety

While many have serious concerns about the possibility of a nuclear accident, the operational safety record of nuclear plants in the United States thus far has been excellent. According to information supplied by the U.S. Nuclear Regulatory Commission, through May 31, 1977, U.S. nuclear plants have produced 326 reactor years of operation without any radiation accident resulting in a known death among plant personnel or among the general public.

In 1968, the former Atomic Energy Commission (AEC) adopted a plan for the collection of radiation exposure records for persons working with radioactive materials or in radioactive environments. For the period 1968-1975, only 22 out of a more than 400,000 recorded annual exposures exceeded those permitted under Federal safety regulations, under carefully monitored circumstances. There has been only one such instance during each of the last three years.

Plutonium

Plutonium is a byproduct of both the light water reactor and the liquid metal breeder reactor. Because plutonium is used to make nuclear weapons (30 pounds of plutonium—about half the annual byproduct of a current light water reactor—is sufficient to make a substantial nuclear weapon), there is serious concern that the security of

the nuclear fuel cycle be maintained. Because the liquid metal breeder reactor generates more plutonium than it consumes, the use of this technology, as compared to conventional light water reactor technology, substantially compounds the security problem. In April of this year, the Administration reversed previous policy and proposed to stop commercialization of the Clinch River breeder but proposed to continue work on research and development of non-plutonium breeder reactors. However, this decision is being actively reviewed by congressional committees.

Waste management

Any nuclear technology creates radiation hazards and problems of waste management. Because radioactive decay is extremely slow, such materials must be stored for long periods of time. While a variety of technologies are available to do this, many, such as underground storage, require continuous surveillance, since there is a constant risk of ground water contamination. To a large extent, public criticism of nuclear power has shifted from reactor safety to radioactive waste.

Currently, ERDA is conducting field investigations and analyses in 36 States to determine the suitability of underground structures for waste disposal. The Environmental Protection Agency and Council on Environmental Quality have repeatedly expressed concern about waste management problems. The President has directed that a review be made of the waste management program.

Availability of uranium

The recent quadrupling in the price of yellowcake (the trade name for uranium ore, needed in the production of reactor fuel) coupled with an Administration decision to defer commercialization of the liquid metal breeder reactor (which is capable of producing nuclear fuel) means that there will be higher prices for uranium.

Estimates of U.S. uranium reserves vary considerably. Table 3 contains July, 1976, ERDA estimates of domestic uranium oxide reserves. The forward cost represents the cost of producing additional yellowcake with existing facilities. An average thousand megawatt reactor uses 6,000 tons of yellowcake over its 30-year life, or 200 tons a year. Current total annual reactor consumption is 17,200 tons a year. Known reserves represent 17 years supply of yellowcake at estimated 1987 consumption rates. If probable reserves are added to known reserves at the \$30 forward cost, there are 41 years of supply. These supply figures, of course, assume a constant consumption level.

TABLE 3.—Reserves of uranium oxide yellowcake
[In thousands of tons]

Forward cost ¹ (1975 dollars a pound)	Potential resources				Total
	Reserves	Probable	Possible	Specula- tive	
\$10-----	270	440	420	145	1,275
\$15-----	430	655	675	290	2,050
\$30-----	640	1,060	1,270	590	3,560
	² 140				140
Total supply-----	780	1,060	1,270	590	3,700
Cumulative number years' supply ³ -----	17.3	40.9	69.1	82.2	82.2

¹ Forward costs are those costs incurred after the geological investigation, land acquisition, and exploration have been completed, and therefore do not represent prices at which uranium oxide will be marketed.

² By-product of phosphate and copper production that becomes available independent of forward costs.

³ Assumes 45,000 tons a year consumption, estimated for 1987.

Source: ERDA, July 1976.

Costs of conversion

It is estimated that in 1977 dollars, it costs about \$620 million to build a 1,000-megawatt nuclear power plant. This comes to a cost of about \$620 dollars per kilowatt. A 1,000-megawatt plant is adequate to supply the energy needs of a city of about 1 million people. As in the case of coal plants, however, there is considerable regional variation in cost.

The leadtime required for siting, licensing, and construction of a nuclear facility is approximately 8 to 11 years, although the Administration intends to speed up the licensing process, which may cut this period to some extent.

III. PRESENT LAW

Under present law, natural gas prices for gas which is sold in interstate commerce are regulated by the Federal Power Commission. Gas which is sold intrastate is not subject to Federal price control.

Historically, the price of natural gas sold in interstate commerce was controlled at levels ranging from about 14 cents per thousand cubic feet ("mcf") to 34 cents per mcf, depending on the area of the country where the gas was produced and sold. Thus, all interstate gas was sold at levels substantially below those prices charged for an equivalent amount of energy in the form of oil (even in periods when oil prices were far below current levels). Beginning in 1974, prices for gas which is newly committed to interstate commerce have been standardized on a national basis and have increased substantially, so that gas newly dedicated to interstate commerce is now selling at a rate of approximately \$1.45 per mcf. However, much gas is selling at prices below this rate under old contracts which were entered before the recent round of price increases.

The FPC has authority to permit "spot sales" of interstate gas at higher than controlled prices during limited periods of emergency. In addition, in The Emergency Natural Gas Act of 1977, Congress authorized the President to permit sales of gas at uncontrolled prices to prevent local natural gas emergencies, but this authority expires July 1, 1977, unless it is extended.

The price paid by consumers for natural gas which is delivered to their homes and businesses is regulated at the State level by public utility commissions. Generally, current pricing policies favor bulk industrial users of natural gas. However, these customers are usually "interruptible," which means that in time of shortage, their gas is shut off first.

Under the Energy Supply and Environmental Coordination Act of 1974, the Federal Energy Administration may prohibit new or existing utility power plants or major industrial fuel burning installations from burning petroleum or natural gas if certain findings are made. For existing plants, the FEA must show that the plant has the practical capability to burn coal, that coal and transportation facilities are available, that coal burning would not cause adverse environmental effects, and that, in the case of a power plant, a conversion will not impair the reliability of electric service. For new plants, the FEA may order that coal be used unless the reliability or adequacy of service is likely to be impaired or an adequate and reliable supply of coal is not expected to be available.

IV. ADMINISTRATION PROPOSAL

Under the Administration proposal, a tax would be imposed on industrial and utility use of oil and natural gas (with certain exceptions), and a rebate of the users' tax would be provided for investments in alternative energy property.

A. Oil Consumption Tax

In the case of petroleum and petroleum products, industrial users would be subject to a tax determined in accordance with the following schedule (subject to an inflation adjustment):

Year of use:	Tax (per barrel)
1979	\$0.90
1980	1.80
1981	1.80
1982	2.10
1983	2.40
1984	2.70
1985 and thereafter	3.00

NOTE: Under the Administration's bill, the tax would actually be imposed on a basis of the Btu content of the oil or natural gas. Natural gas contains about one million Btu's per thousand cubic feet; refined oil products, on the average, contains about 6 million Btu's per barrel.

An exemption from tax based on combined use of oil and natural gas would be provided for small industrial users who use less than approximately 85,000 barrels of oil or the equivalent amount of natural gas annually. This exemption is the equivalent of about \$100,000 per month worth of oil at current world prices. The exemption would be phased out so that no exemption would be allowed for those who use more than approximately 250,000 barrels annually.

Electric utilities would be subject to a flat tax beginning in 1983 of \$1.50 per barrel subject to the inflation adjustment.

Under the Administration's proposal, the petroleum taxed would include crude oil, refined petroleum products and natural gas liquids (other than lubricating oils, greases, waxes, petroleum coke, pitch, asphalt and related products) as described in regulations issued by the Secretary of the Treasury. The Secretary would establish standard Btu contents for various types and grades of petroleum.

B. Gas Consumption Tax

In the case of natural gas (including liquified gases), industrial users would be subject to a tax which—when fully phased in—would have the effect of making natural gas cost equivalent per Btu to the cost of Number 2 distillate oil (not including the oil consumption tax). For industrial users, the tax would first be imposed in 1979. For that year, the tax, when added to the user's cost of the natural gas,

would bring the total effective cost to a level of \$1.05 per million Btu's (that is, per thousand cubic feet or "mcf" of natural gas) below the price of the same amount of energy in the form of oil (the "Btu equivalency price"). In subsequent years, the effective cost differential would decrease in accordance with the following schedule (subject to inflation adjustment):

Year of use:	Cost differential (per million Btu's)
1979	\$1.05
1980	.40
1981	.35
1982	.25
1983	.20
1984	.15
1985 and thereafter	0

The "Btu equivalency price" would be determined annually by the Administrator of the Federal Energy Administration. It would be the average regional price (exclusive of the oil consumption tax) of all No. 2 distillate oil sold for use in the region for the calendar year.

There is a small users exemption, similar to that provided for the oil consumption tax, for industrial use of natural gas.

A similar tax would be imposed on electric utilities, except that the tax would be first imposed in 1983 and would be imposed in accordance with the following schedule:

Years of use:	Cost differential (per million Btu's)
1983, 1984, 1985	\$0.50
1986, 1987	.25
1988 and thereafter	0

The oil and natural gas consumption taxes would generally apply to use as fuel or feedstocks. The taxes would not apply to gasoline and lubricating oil or to fuel supplies for vessels or commercial aircraft. The oil and gas consumption taxes also would not apply to use in any aircraft, rail or water transportation; farming, drying of grains and feed grasses or irrigation pumping, production of anhydrous ammonia or ammonia liquor (except use of natural gas as a fuel), production of refined petroleum products (other than use as a fuel), natural gas reinjected for repressuring or cycling use, and natural gas used at the point of consumption which is not practically marketable.

C. Industrial Oil and Gas Rebate

Under the Administration's proposal, industrial users (other than electric utilities) may elect either to take a rebate of 100 percent of their investment in alternative energy property against the oil or gas consumption tax, or to obtain the additional energy investment tax credit against their income tax. (See pamphlet 9, "Business Energy Tax Credits for Conservation and Conversion.") The election must be made at the time a taxpayer first claims a rebate for the expenditures for alternative energy property against oil and gas consumption taxes. Once made, the election cannot be revoked. The election applies to each investment for all taxable years.

The amount rebated against the oil or gas consumption taxes may not exceed the tax imposed for the calendar year. Any excess expenses for alternative energy property for the year not allowed as a rebate against tax for the current year may be carried over to the next calendar year and treated as an investment in alternative energy property for the following year. Thus, under the proposal, amounts may be carried over from year to year to offset future years' oil or gas consumption tax liability.

Under the proposal, alternative energy property includes coal-fired boilers; boilers whose primary fuels will not be petroleum or natural gas; facilities for the conversion of coal into synthetic gas which has a heat content of 500 Btu's per standard cubic foot or less ("low Btu gas"); equipment for the burning of coal in combustors other than boilers (limited to equipment used to supply coal to a burner and the burner itself); pollution control equipment required by Federal, State or local government regulation to be installed on the equipment previously described (except equipment required to be installed under regulations in effect on April 20, 1977, relating to combustors currently using coal); and equipment used for the unloading, transfer, storage, reclaiming from storage or preparation (including washing, crushing, drying, and weighing at the point of use) of coal for use in the above facilities, and at facilities where coal is used as a feedstock for the manufacture of chemicals or other products, except coke. This property qualifies for the rebate whether or not it replaces existing oil- or gas-fired equipment.

Under the proposal, the costs for which a rebate is allowed include the costs of engineering, designing, purchasing, manufacturing for its own use, transporting, assembling, or installing prior to the commencement of construction of the alternate energy property. Alternative energy property expenses do not include the costs of buildings and other structures, or the costs of preparing plans or designs not otherwise specifically allowed, or the costs of preparing a site for construction (including demolition and grading).

The provision further provides that no deduction against income taxes is to be allowed for oil and gas consumption taxes to the extent that they are offset by the rebate for alternative energy property expenditures. In addition, there is no requirement that the basis of alternative energy property be adjusted to the extent that the cost of such property is treated as a rebate against the tax.

D. Utility Oil and Gas Rebate

The Administration's proposal allows electric utilities to elect a rebate against their oil and gas consumption taxes for qualified replacement investments made after April 20, 1977. The rebate is similar to the industrial oil and gas conservation rebate except that unlike the industrial rebate, the utility rebate applies only to conversion of existing oil- and gas-fired facilities to alternative sources of fuel and the replacement of existing oil- or gas-fired capacity with facilities that

use coal or other fuels. Unlike industrial users, however, utilities could obtain credit for generators.

Qualifying replacement investments include amounts paid or incurred for engineering, designing, purchasing, transporting, assembling, and installing electrical generating property with a capacity for using coal or other fuel to replace electrical generating property with a capacity for using petroleum or natural gas. The Secretary of the Treasury will prescribe regulations further describing qualified replacement investments after consultation with the Administrator of the Federal Energy Administration.

In the case of utilities, the credit would also be available for replacement of oil- or gas-fired capacity with nuclear capacity.

Revenue Effect

Table 4 shows the Administration's estimates of collections from the oil and natural gas consumption taxes. The estimates assume that the tax schedule for use of petroleum products is adjusted for inflation since 1975. Thus, the tax rate in 1979 is estimated to be \$1.12 per barrel. The gross receipts are lowered both by the rebate for qualified investment and because the taxpaying users will pay lower business income taxes due to their likely inability to pass through the entire cost of the user taxes to the consumers of their products. The gross revenue collected by the tax rises rapidly in the first few years as the tax is phased in; from a 1979 level of \$2.7 billion, gross collections reach \$21.6 billion by 1985. Net collections increase from \$1.4 billion in 1979 to \$12.0 billion in 1985.

TABLE 4.—*Estimated revenue from oil and natural gas consumption taxes*
 [In millions of dollars]

	Fiscal year—							
	1979	1980	1981	1982	1983	1984	1985	1979-85
Tax without rebate for qualified investment.....	2,745	7,555	10,499	12,467	16,467	19,235	21,566	90,534
Qualified investment rebate.....	-1,201	-3,675	-5,736	-6,880	-8,974	-9,700	-8,040	-44,206
Reduced industry income tax ¹	-141	-436	-594	-669	-878	-1,134	-1,563	-5,415
Net effect on receipts.....	1,403	3,444	4,169	4,918	6,615	8,401	11,963	40,913

¹ Results from less than full pass-through of tax to prices.

Source: Office of the Secretary of the Treasury.

Energy Savings Estimate

The Administration estimates that by 1985 the oil and gas consumption tax and rebate will reduce demand for oil by about 2.7 quadrillion Btu (quads) per year and will reduce demand for gas by about 3.4 quads.¹ Of the oil savings, approximately half would be from industry and half from utilities; of the gas savings, approximately three-quarters would be from industry and one-quarter from utilities. Almost all of this oil and gas saving would result in increased coal consumption, since total energy demand would be reduced only 0.8 quads by the tax.

E. Non-Tax Aspects of Administration Proposal

1. Natural gas prices

The present interstate-intrastate distinction for price controls would be eliminated for all new contracts. Gas selling under existing intrastate contracts would be brought under controls as those contracts expire.

Under the proposal, new gas (that is, gas found more than two and a half miles, or more than 1,000 feet deeper than gas from any producing well in existence on April 20, 1977, or from an offshore lease entered after that date) would be entitled to receive the BTU equivalent price of domestic crude oil, determined on a nationally weighted average refiner acquisition basis. This would be about \$1.75 per thousand cubic feet at the beginning of 1978. Intrastate gas made available on the interstate market at the expiration of existing contracts would also be eligible for the \$1.75 price.

Old interstate gas sold under existing contracts would continue to be regulated at current levels (subject to inflation adjustments) and subject to high-incentive pricing for specific categories of high-cost gas. Gas made available from old interstate reservoirs at the expiration of existing interstate contracts would be regulated at a price not to exceed \$1.45 per mcf, subject to an inflation adjustment.

High-cost gas would be allocated to industrial users.

Federal jurisdiction would be applied to synthetic natural gas facilities to guarantee them a reasonable rate of return.

The Emergency Natural Gas Act of 1977 would be extended for three years to authorize the President to allocate scarce supplies of gas.

2. Utility rate reform

State Public Utility Commissions would have to require their regulated electric utilities to phase out and eliminate promotional, declining block, and other rates for electricity that do not reflect costs. Electric utilities would be required to offer each customer either time-of-day rates or a load management system and rates reflecting the savings from this system. Electric utilities would be required to offer lower

¹ One quad per year is approximately equal to 500,000 barrels of oil per day and to approximately one trillion cubic feet (Tcf) of natural gas.

rates to customers who are willing to have their power interrupted at times of highest peak demand. Also master metering of electricity would generally be prohibited in new structures.

State Public Utility Commissions would require gas utilities to eliminate declining block rates and to implement such rules as the FEA may prescribe with respect to master metering, summer-winter rate differentials, and interruptible rates. In addition, the Federal Power Commission would be authorized to require interconnection and power pooling between utilities even if they are not presently under FPC jurisdiction, and to require the transmission of power between two noncontiguous utilities across a third utility's system.

3. Coal conversion regulatory policy

Under the Administration proposal, no new electric power plant may use natural gas or petroleum as a fuel. Exceptions may be granted by the Administrator of the FEA where coal is not expected to be available, where environmental factors preclude the use of coal, for peak load power plants, and to prevent impairment of reliability of service.

No existing electric power plant may use natural gas as a fuel after 1989 and no electric power plant currently using petroleum as a fuel may shift to natural gas without an exception or an exemption. The Administrator of the FEA may preclude the use of oil or natural gas prior to 1990 in existing power plants. Temporary exceptions and permanent exemptions may be granted for economic and environmental reasons.

In addition, no new major fuel-burning boiler may use natural gas or petroleum as a fuel, and the Administrator of the FEA may prohibit the use of natural gas or petroleum in non-boiler combustors, such as cement and lime kilns, furnaces, and process heaters. Temporary exceptions may be provided where economic and environmental reasons warrant.

The Administrator of the FEA may identify categories of existing major fuel burning installations with the capability to use coal and prohibit such installation from using natural gas or petroleum as a fuel. Also, the use of gas in facilities without a capability to use coal could be prohibited.

Any industrial firm or utility prohibited from using natural gas would be allowed to sell its contract to purchase gas at a price that would compensate it for shifting to petroleum on an interim basis or to coal on a longer-term basis.

V. ACTION IN THE 94TH CONGRESS

The House version of H.R. 6860 in 1975 imposed an excise tax on oil and natural gas used in business as a fuel (the tax, therefore, excluded use of oil or natural gas as a petrochemical feed stock). The tax on oil would have been phased in between 1977 and 1982 and would have reached \$1 per barrel. The tax on natural gas would have been phased in between 1977 and 1980 and would have reached 18 cents per thousand cubic feet.

Exemptions were provided for use in a vehicle, vessel or aircraft, residential facilities, on farms, in mining, and, until 1982, for use in existing electrical generating facilities. Use by tax-exempt organizations was also exempted.

The Administrator of the FEA was to report to Congress identifying (1) the industries or industrial processes for which there is no economically feasible alternative to the use of petroleum or petroleum products, (2) areas where conversion to other fuels is not feasible because of Federal, State, or local laws on pollution, and (3) other uses which he believes should be exempted from this tax for other reasons.

On the House floor, additional exemptions for the textile and glass manufacturing industries were added.

The Finance Committee tentatively approved the provision during markup sessions after adding four more exemptions, but it did not include the provision in any reported bill.

The following is the tax schedule agreed to by both committees:

	Tax per barrel of oil	Tax per thousand cubic feet of natural gas
Year of use:		
1977.....	\$0. 17	0. 04
1978.....	. 33	. 08
1979.....	. 50	. 12
1980.....	. 67	. 18
1981.....	. 83	. 18
1982 and thereafter.....	1. 00	. 18

VI. ALTERNATIVE PROPOSALS

A. Members' Proposals

Mr. Waggonner

The industrial and utility use taxes on oil and natural gas would be deleted (at least for users paying the full fair market value for petroleum, petroleum products or natural gas); alternatively, the taxes would be delayed until 1985 with the natural gas users tax phased in through 1990.

If some form of user's tax is provided, the following exemptions for fuel uses would be allowed: the business use of fuel in the extraction of minerals; glass manufacturing processes; agricultural products, processing and distribution (including farming purposes, crop or seed drying, food and fiber processing and distribution, and fertilizer and chemical production); chemical and petrochemical feedstocks; and other priority users such as manufacturers of oil pipes. In addition the tax would only apply to large users where conversion is technologically feasible and any tax would be rebated to fuel users who produce energy generating raw materials.

The user tax rebate for utilities would apply to facilities that phase out oil and gas fuel generation and to utility construction costs which are included in the rate base after 1978. In addition, the user tax would be rebated on the basis of consolidated tax returns.

Mr. Pickle

Utilities which are federal, state or municipal entities would be exempt from the utility users tax at least until 1985.

Utilities would be able to elect to credit their alternative energy investments against the user tax (instead of the income tax). Alternative energy property would include coal fired boilers, or other boilers whose primary fuel was not oil or natural gas; facilities for converting coal into natural gas; other coal conversion equipment, including equipment relating to the processing and handling of coal, nuclear or any other type of non-oil or non-natural gas base generating unit which results in the utility having to rely less on oil or natural gas base generation whether it is a conversion or new equipment; and pollution control equipment relating to coal. Utilities would be eligible for the credit on all alternative energy investments made since September 30, 1973.

Mr. Rangel

Utilities using oil burning generators under EPA clean-air exemptions would be exempted from the utility users' tax.

Mr. Jones

The industrial and utility users taxes on oil and gas would be deleted.

Mr. Tucker

The utility users tax would include an exemption for the use of oil or gas-fired generators to provide peakload or standby power needs.

A credit would be provided against the industrial oil and gas users tax for State taxes on oil and gas.

Mr. Archer

The oil and gas industrial and utility users taxes would be deleted. Alternatively, the tax would not be imposed where it is impossible or unfeasible to convert to other fuels or where a utility is phasing out its use of oil or natural gas as a boiler fuel under a Department of Energy approved plan. In any case, no users tax would be imposed on utilities before 1990, the target date for conversion of utilities.

Qualified replacement equipment eligible for the utility conservation rebate would include investments in nonpetroleum generation equipment which ultimately replaces or phases out oil or gas generating equipment. In addition, the rebate would not be elective.

The utility conservation rebate would be allowed up to the amount of taxes paid by all members of a controlled group.

B. Other Proposals

The tax on industrial use could be limited to the use of oil and gas as a fuel, which would exclude petrochemicals.

The 100-percent rebate could be deleted since the property qualifying for the rebate would generally be eligible for the special business energy income tax credits where such credits were deemed appropriate. In addition, incentives for conversion could be provided by permitting rapid amortization.

In return for the deletion of the rebate, the tax on oil could be scaled down to some extent, perhaps to \$1 or \$2 per barrel.

For natural gas, the tax rate could be keyed to the price of oil as in the Administration's proposal, but the price of fuel oil could include any users tax on that fuel oil. Also, the tax could be reduced from 100 percent of the price differential between natural gas and oil to 80 or 90 percent of that differential. (Otherwise, there is no incentive for purchasers of gas not to renegotiate contracts at higher prices in order to obtain reduced tax rates.) Alternatively, the tax on natural gas could be at a flat rate which is set high enough to make the cost of natural gas and oil fairly comparable for industrial and utility users.

The small and medium size users exemption could be eliminated. Instead, the specific classes of users such as office buildings, apartments and hospitals could be exempted.

If the committee decides to adopt the rebate approach proposed by the Administration, the rebate might be confined to situations where industrial users (as well as utilities) replace existing oil and gas boilers with alternative energy property. Also, the basis for depreciating qualifying property could be reduced by 50 percent of the amount of the rebate. (The 50-percent figure is to account for the fact that the rebate is included in taxable income.) Also, the existing 10-percent investment credit could be denied to such property.

The tax rate and phase-in could be the same for utilities as for other industries.

VII. AREAS FOR COMMITTEE CONSIDERATION

General considerations

Higher prices for natural gas and petroleum products would encourage conservation in three ways: (1) encouraging the substitution of coal and nuclear energy sources for petroleum products and natural gas, (2) encouraging the use of less energy-intensive and more energy-efficient methods of production, and (3) raising the price of the final product and discouraging the consumption, and therefore production, of energy-intensive goods. A tax on industrial use of oil and natural gas would be likely to reduce energy consumption in all three ways. A credit for coal-burning equipment would reinforce conversion but would not necessarily lead to a reduction in overall energy use.

The potential for conservation in the industrial sector is indicated by changes in industrial energy use from 1973 to 1976, a period of rapidly rising energy prices. Although industrial production has the same in both years, energy consumption declined by 6.1 percent.

Future consumption of petroleum products and natural gas combined by utilities is likely to decline even without any change in prices or increase in taxes. Under the Administration proposal, no new utility boilers, and no new industrial boilers above 10 megawatts, may be oil or gas fired. In addition, certain industrial users of oil or natural gas may be required to convert to coal or some other fuel by the FEA, and all utilities will be required to convert by 1990. However, there may be certain exceptions to the foregoing rules for environmental or hardship reasons. Generally these exceptions will be temporary.

Even apart from these regulatory obstacles (to which there could always be exceptions) electric utilities currently plan no new oil or gas-fired plants to meet their base load demand. (Baseload plants are those operated at 70 percent or more of capacity.) Even though the capital cost per kilowatt of capacity of a coal-fired boiler (and necessary scrubber) or nuclear plant is considerably greater than that for oil and gas-fired plants, the lower cost of coal and nuclear fuel per Btu more than makes up for this difference (at least at current price levels). Since the useful life of steam boilers for base-load purposes is approximately 30 years, hardly any base-load electricity will be generated from natural gas or petroleum products after the turn of the century. (Intermediate and peakload units might still use oil, however.) On the other hand, about half of the existing oil or gas-fired plants are 10 years old or less, and rapid conversion of these plants is not likely to occur, even in the face of strong tax incentives.

Industrial firms, however, have much smaller boilers and continue to find oil and natural gas more economical than coal. Large industrial users (30 megawatts or more per boiler) now select coal about half the time for new plants, but coal currently supplies only about 10 percent of all industrial boiler fuel. About two-thirds of all boilers in industry

are gas-fired, although gas-fired units currently account for only about one-third of new sales of units used to generate electricity. Oil-fired units comprise almost one-half of new sales, while coal and miscellaneous sources power the remainder.

The enactment of the crude oil equalization tax should speed up the process of conversion, particularly for oil burning utilities. If utilities must pay world prices for petroleum products, then they are likely to substitute new coal or nuclear plants for existing oil facilities even before this conversion is required by law (generally 1990). The oil and natural gas users tax would provide a further incentive in this regard.

Issues concerning the tax

One of the basic questions which the committee must consider in this area is whether it would prefer to adopt the general approach of the Administration proposal, or the general approach which was followed in H.R. 6860. The most important differences are as follows:

(1) Under the Administration proposal, the rate schedule is considerably higher than that imposed under H.R. 6860.

(2) Under the Administration proposal, the tax on natural gas varies with the price paid for that gas by the industrial user (the lower the price, the higher the tax). Under the proposal, when the tax is fully phased in, all large users of natural gas will face the same cost. Under H.R. 6860, the tax on natural gas was imposed at a flat rate. Thus, those users who have contracted for gas at relatively low prices would have continued to receive an advantage relative to other fuel users.

(3) Under the Administration proposal, the tax rate and the phase in schedule for the tax are favorable to utilities. Under H.R. 6860, the tax rate was the same for both industrial users and utilities (although utilities were given a delayed effective date).

(4) Under the Administration proposal, exemption from the tax and the tax rate depend on total energy use by a group of firms under common ownership. Under H.R. 6860, exemption would have been given for specific uses or industries.

Tax rate and structure

Under the Administration's proposal, the structure of the tax on natural gas is intended to equalize the cost of natural gas to all industrial and utility users, regardless of the price they are currently paying under contracts with their suppliers. Thus, a business or utility which is currently paying a relatively low price for natural gas would be subject to a relatively high tax, while a business or utility which is currently paying a relatively high price would be subject to a relatively small tax.

This approach has the advantage (in terms of conservation) of bringing the cost of natural gas up rapidly for all industrial and utility consumers. However, some would argue that this approach is inequitable to beneficiaries of existing low-cost natural gas contracts.

Another problem with the Administration proposal is that certain firms now pay relatively low prices for natural gas because they are "interruptible." The existence of some interruptible customers benefits the gas distribution system by allowing the pipeline to operate

on a year-round basis and by providing an easy means for determining whose gas will be shut off in times of shortage. If the natural gas users tax is structured in such a way that all users will pay the same after-tax price for gas, no one will have an incentive to purchase gas on an interruptible basis.¹

For these reasons, the committee may wish to consider an oil and natural gas users tax which is based on a flat rate, rather than the approach suggested in the Administration proposal. This flat rate approach was adopted by the committee in H.R. 6860.

One possible tax schedule might be as follows:

Year of use	Tax per barrel of oil	Tax per thousand cubic ft. of natural gas
1979.....	\$0.30	\$0.15
1980.....	.60	.25
1981.....	.90	.35
1982.....	1.20	.45
1983.....	1.50	.55
1984.....	1.75	.65
1985 and thereafter.....	2.00	.75

There are, of course, a number of possible rate schedules. The above tax on industrial and utility use of oil is somewhat higher than that adopted by the committee in H.R. 6860. The tax on natural gas is substantially higher (though generally lower than the tax proposed by the Administration) and is more than the Btu equivalent tax on the use of oil. Following this approach would have the effect of partially equalizing the cost of oil and natural gas for industrial or utility use, but would not go as far as the Administration proposal in this regard.²

The committee may also wish to consider whether the tax rates on the consumption tax should be tied to the rate of inflation.

¹ An additional technical problem with the Administration approach is that utilities and industrial users of natural gas may have little incentive not to renegotiate their contracts with current suppliers to provide for upward price adjustments. If the committee should decide to adopt the Administration proposal in this regard, it may therefore be necessary to provide some mechanism to discourage renegotiation.

The committee might provide, for example, that the tax would be based on prices under contracts as in effect on April 20, 1977. It might also be provided, however, that the contracts could be renegotiated under certain specified conditions. Another alternative which avoids the complexity associated with basing the tax on preexisting contracts would be to provide that the tax rate would equal 80 or 90 percent of the difference between the actual selling price of the gas and the Btu equivalent price of distillate fuel oil rather than 100 percent.

² As a safety valve, the committee might wish to provide that if the proposed tax on the industrial and utility use of gas raised the price of natural gas above the price of an equivalent amount of oil (including the oil users tax), then the gas tax would be capped at this level. However, at the rates suggested in the above table, it is unlikely that this would occur, because natural gas is selling far below the price of an equivalent amount of oil in most cases.

Utility preference

Under the Administration proposal, utilities are favored over industrial users of oil in terms of the rate schedule, and are favored over industrial users of oil and natural gas in connection with the phase in period. There are several arguments for and against the proposition that utilities should be treated somewhat favorably. First, it is argued that the leadtime to convert from oil and natural gas to some other fuel is substantially longer for a utility than for most industrial users. Further, it is argued that if the cost of fuel is increased for utilities, this cost will be passed along to the customers in the form of higher rates, although this may be true for industrial users as well. Of course, in order to do this the utilities may have to receive the permission of local regulatory agencies. If the utilities do increase their charges to customers, however, this will not necessarily be undesirable to the extent that this encourages conservation without causing undue hardship. However, the distinction between utilities and other industrial users would be particularly complex for industrial users which generate their own electricity and sell some of it, and also in cases of joint ventures between utilities and other businesses. Separate records would have to be kept for products used to generate sold electricity and for products used for other industrial purposes. Finally, special treatment of utilities relative to other industries can lead to economic inefficiency because utilities would not be subject to the same market discipline as other businesses.

Exemptions

Another issue that the committee may wish to consider with respect to the Administration proposal is the proposed exemption for small users. Because the rate in effect depends on the total energy use by an entire group of companies under common ownership, differences among users' forms of business organization could cause similar uses of petroleum products and natural gas to be taxed at different rates. In addition, the phaseout of this exemption leads to a tax rate as high as \$7 per barrel for oil and several dollars per mcf of gas in the phaseout range. These high marginal rates could encourage uneconomical conversion or force firms to scale down the size of their operations. Another approach, which the committee adopted in H.R. 6860, would be to state specifically in the statute the type of businesses and industries which would be subject to the tax. H.R. 6860 applied only to use of oil and gas as fuel, which meant that the use of petroleum for petrochemical feedstocks was not subject to tax. Also, the committee provided exemptions for certain specific business uses. The committee also provided that the Administrator of the FEA was to make a survey of those businesses which would not, as a practical matter, be able to convert to any fuel other than oil or natural gas. A report was to be filed with the committee, within one year, and after receiving the report the committee was to have decided whether any particular business exemption from the tax would have been continued.

Issues concerning the rebate

Under the Administration's rebate proposal, industrial and utility users who converted to coal and other fuel would be entitled to a 100

percent credit against their users tax for the current year and would be entitled to carry over any unused investment to apply against users tax for future years. This approach may be questioned on several grounds. In certain cases, this approach would encourage relatively slow conversion from oil or natural gas to coal or some other fuel. If conversion were too rapid and the use of oil or natural gas were completely eliminated, thus allowing the user to avoid paying consumption taxes, the industrial user might find itself in a position where it had conversion investment which could no longer be carried forward and offset against future years' users taxes.

Another problem is that the 100-percent rebate, together with depreciation and the regular investment credit, which is available for most conversion property, creates a situation in which the government, through tax deductions and credits, is providing more than 100 percent of the cost of investments in coal-burning equipment. This would encourage wasteful spending.

Another problem with the Administration proposal is that the amount of incentive provided for a business or utility to invest in alternative energy property is largely a matter of chance. If the business or utility purchases natural gas at a relatively low price, the relatively high tax is imposed. These taxes are then available for credits if the business or utility makes a qualifying investment. However, if the business or utility is presently paying a high price for its natural gas, it will pay a relatively lower user tax, which also means that a relatively small credit will be available if the business or utility makes qualifying investments. Since all business and utilities will pay the same total cost for their gas (i.e., price plus the users tax) it could well be argued that this proposal is unfair and will place certain utilities and businesses at a serious competitive disadvantage. (This would not be a problem, however, if the committee were to adopt a flat rate of tax.)

Many of these problems with the rebate are compounded by the fact that, under the Administration proposal, the business or utility is required to make a one-time only election to take this rebate, or the business energy tax credits, for conversion investments.

A more fundamental question concerning the Administration's proposal is whether the combination of the tax and rebate facilitates the formation of capital for conversion purposes. Those who support the existing investment credit do so, among other grounds, on the theory that the investment credit makes available funds (currently 10 percent of the investment) which might not otherwise be available to the business. However, the users tax would take funds away from a business or utility, except to the extent that the utility is successful in persuading State public utility commissions to include the amount of the tax in the utility rate base (or that the business is successful in passing the increased cost along to customers). The Administration's rebate proposal would alleviate this, but will not make available to the utility any funds in addition to that already available under present law.

One alternative which the committee might consider would be to provide income tax credits for coal conversion rather than credits

against the users tax (and perhaps reduce the rate of the users tax to some extent). Under this approach, it might be possible to provide for an additional credit of, for example, 10 or 15 percent for industrial or utility conversion which occurred in 1978, 1979 or 1980. The additional credit might then be phased down to 5 or 10 percent in 1981, and could be further phased down at the rate of 2 percent per year so that no additional credit would be available for conversion which began in 1986 and thereafter. (This property could continue to be eligible for the existing investment credit.)

Under present law, utilities are allowed to take the investment credit for up to 90 percent of their tax liabilities in 1977. This rate is phased down by 10 percent a year, so that utilities will be subject to the regular 50 percent limit which applies for most other businesses by 1981. If the Committee should decide to provide an incentive for conservation in the form of a credit, it might also wish to consider a provision allowing utilities and other businesses to offset the credit for qualified energy investment against 100 percent of their tax liability.

As an alternative (or possibly in addition to) the business credits, the committee may wish to consider rapid amortization of conversion property. It could be provided that the taxpayer would have to elect between rapid amortization and the business credits. Alternatively, the committee may wish to provide that that taxpayers electing rapid amortization could only receive some fraction (perhaps 50 percent) of the credits which would otherwise be available.

Under the Administration proposal, the credit for industrial users other than utilities applies not just to conversion investments but also to investments in coal-fired boilers which do not replace existing oil or gas-fired boilers. (Utilities, on the other hand, could take advantage of the rebate only if they replaced existing capacity.) The committee may want to limit additional credit solely to conversion investments in order to ensure that a credit is allowed only when there will be a reduction in oil or gas use.

Also, if the committee decides to allow a credit for utility conversion to nuclear fuel it will be necessary to consider the type of items which should be included in the credit base. Qualified equipment might include pressure vessels, steam generators, pressurizers, reactor feed pumps, valves, piping and tanks, instrumentation and controls, control rod drive mechanisms, containment structures and turbine generators. Further, one of the principal problems in connection with nuclear energy is the disposal of nuclear waste. The committee might wish to consider whether the credit base should include nuclear waste disposal facilities.