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THE EFFECT OF ENERGY CONSERVATION ON ENVIRONMENTAL EMISSIONS: UTILITY, RESIDENTIAL, AND COMMERCIAL SECTORS

Paul D. Raskin and Richard A. Rosen

September 1977

Prepared by the
ENERGY SYSTEMS RESEARCH GROUP, INC.
ALBANY, NEW YORK
For the
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NATIONAL CENTER FOR ANALYSIS OF ENERGY SYSTEMS

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ABSTRACT

Environmental emissions in the utility, residential, and commercial sectors are estimated for four U.S. energy system scenarios and two future target years. Total utility emissions are estimated by specifying, for each scenario and year, total energy demands, fuel mixes, generating technologies, and air pollution control levels. In the residential and commercial sectors energy end-use requirements for space heating and cooling are determined and combined with end-use specific emission coefficients to calculate total emissions. The analyses show that emissions do not vary significantly among scenarios even though total energy use differs by as much as 45 quads. Low-energy demand scenario emissions increase relative to high-energy demand scenarios principally because of the relative increase in coal usage. Utility sector emissions are greater than residential and commercial sector emissions.

I. INTRODUCTION

In this study, environmental emissions in the utility, commercial, and residential sectors are evaluated for four energy system scenarios and two future target years. This study is an extension of an analogous study of the industrial sector,¹ also by Energy Systems Research Group, Inc., and is a contribution to the assessment by the BNL Office of Environmental Policy (OEP) of national environmental implications of possible transitions toward conservation in energy utilization patterns. The four scenarios are CONAES* scenario A, CONAES scenario B, the National Energy Plan scenario, and ERDA's scenario SF-2 (abbreviated A, B, NEP, and SF-2, respectively, throughout this report). The years selected for analysis are 1985 and 2000.

Section II focuses on emissions from the electric utility sector. For each scenario, total emissions are computed for ten air and water pollutants. This is done by specifying, for each scenario and year, total energy demands, fuel mixes, generating technology assumptions, and pollution control levels, and using these values, together with emission factor data, as the basis for the computation.

Section III is concerned with the commercial and residential sectors. Since, in the scenarios, energy flows are insufficiently disaggregated, it is first necessary to develop a consistent basis for separating energy demands by end-use in each sector. Then, emission matrices are developed for each end-use for five major air pollutants (water pollutants being negligible).

* National Academy of Sciences Committee on Nuclear and Alternative Energy Strategies.

II. UTILITY EMISSIONS

Four factors contribute to the dependence of utility sector emissions on explicit or implied scenario-specific assumptions: (1) the magnitude of demand for electricity, (2) the mix of fuels to central generating stations, (3) the breakdown of peaking versus base-load facilities, and (4) the degree of penetration of pollution abatement technology. Each of these factors plays a role in determining final emissions. The magnitude of demand for electricity varies widely over the scenarios analyzed because of differences in the assumptions about the growth rate of end-use demand and about improvements in energy conversion efficiency. The fractional breakdown of intermediate energy forms also varies over the scenarios. One key parameter here is the assumed impact of policies to induce accelerated growth in the use of coal in the utility sector. Disaggregated data on the fuel going to peak-power turbines on the one hand, and to base-load boilers on the other, is important because different emission characteristics are involved. Finally, emission control levels are sensitive to electric energy growth rates since standards affect new and existing facilities differentially.

The calculation of emissions involves the following major steps: (1) specification of scenario assumptions on electricity production disaggregated by fuel and generating technology, (2) designation of emission matrices that incorporate control assumptions and give emission levels for 10 pollutants (5 in air and 5 in water) and for electric power production systems using four types of fossil fuel, and (3) multiplication of the energy breakdowns and the emission matrices to obtain emission estimates.

The analysis in this study is restricted to fossil-fuel-fired electric plants. It does not include, e.g., radiation emissions from nuclear power plants or possible emissions from nonconventional sources such as solar electricity generation. Emissions associated with the cogeneration of electricity as an offshoot of industrial processes is treated in the companion study.¹

A. Energy Demands by Scenario

The energy requirements for each sector are reported quite differently for the ERDA and CONAES scenarios. For ERDA, all flows of energy to the sector are explicit in the Reference Energy Systems (RESS) for 1972, 1985, and 2000 (see Figures 1 to 4). These include separate flows for oil and gas to steam boilers, and for oil and gas to gas turbines for peaking power. Since the emissions from the two technologies differ, it is important to maintain this level of detail. The ERDA RESSs are also completely explicit about the individual contributions to be made by the new technologies using wood, solar, and geothermal energy for generating electricity. The totals for all energy sources are given in Table 1, which includes transmission losses and net electricity consumed by end users. The ERDA scenarios are characterized by a strong shift toward coal and nuclear fuels and away from oil and gas.

For the CONAES scenarios, much less information for the electric utility sector has been explicitly provided. The studies on the industrial sector¹ provided data on how much electricity that sector consumed. The gross electrical consumption of the residential and commercial sectors was available explicitly⁷ in CONAES Tables III-12 and III-29. Since one of

Figure 1. Reference energy system, year 1985-SF-2.

Figure 2. Reference energy system, year 2000 SF-2.

Figure 4. Reference energy system, year 2000 NEP.

Table 1

Electric Utility Sector Intermediate Energy Forms (IEFs)
for ERDA Scenarios in 1972, 1985, and 2000 (quads)

IEF	SF-2			NEP	
	1972	1985	2000	1985	2000
Coal	8.16	15.32	20.46	16.60	21.02
Oil	3.55	2.70	1.87	1.78	1.74
Gas	4.47	3.10	1.47	0.95	0.17
Hydro	2.89	3.80	4.30	3.13	3.59
Nuclear	0.58	7.98	28.49	7.60	18.71
Solar	0	0.02	0.35	0.03	0.35
Geothermal	0	0.17	3.00	0.15	2.18
Wood	0	0.10	0.60	0.10	0.60
Total	19.66	33.19	60.54	30.34	47.36

Table 2

Electric Utility Sector Energy Demands in CONAES Scenarios
for Year 2000 (quads)

Demand Sector	A	B
Industry* (purchased electricity)	6.70	7.30
Residential-commercial	16.00	20.50
Transportation	0.0	0.0
Total	22.70	27.80
Elec. output**	6.74	8.25

*See Table 22 of ref. 1.

**Assumes heat rate given by CONAES of 11,500 Btu/kW-hr.

Table 3

Internal Use of Energy by the Energy-Producing Industries,
Scenario B (MBtu/MMBtu produced)

	Coal	Oil	Gas	Uranium	Solar	Purch elec*	Total
Oil & gas extraction**		3				3	6
Oil refining	20	60				3	83
Coal mining**		2				2	4
Synthetic oil	500						500
Synthetic gas							
Utility electricity	1180	360	--	1390	75		3005

*Ignoring primary energy to produce purchased electricity.

**No debit for own production consumed.

the assumptions of this study was negligible use of electricity by the transportation sector, simple addition of the above totals (see Table 2) gave the total gross electricity demand. The fuel mix percentages for B were derived from CONAES Table V-4, reproduced here as Table 3. Since CONAES provided no explicit data for the utility sector for scenario A, the proportions were assumed to be the same as for scenario B.

The resulting proportions for the year 2000 are in terms of intermediate energy forms (IEFs) to the utility sector: coal 39.3%, oil 12.0%, gas 0%, nuclear and hydro 46.2%, and solar 2.5%. Applied to these fuel mixes are fuel resource to IEF losses of 3.5% for coal and 10% for oil, as in the ERDA scenarios. The resulting demands for IEFs and resources for 2000 are listed in Table 4. The sectoral energy consumptions assumed in this project can be cross-checked by comparing total energy consumption with the totals assumed in the CONAES study.⁷ The comparison given in Table 5 demonstrates that the disaggregations used here are generally consistent with the CONAES global assumptions.

Since the CONAES scenarios included no explicit assumption about the extent of gas turbine use for peaking, and since this use is important in calculating emissions, it was assumed that these scenarios, being strongly conservation oriented, incorporate intensive load-management and peak-leveling practices as well as shifts to alternative fuels. Thus, for future years, it was assumed that base year gas turbines were phased out at an annual retirement rate based on 30-year lifetimes. The total IEFs for all scenarios that contribute to fossil fuel utility sector emissions are summarized, by technology, in Table 6.

Table 4
Electric Utility Sector: Intermediate Energy Forms (IEFs)
and Energy Resources for the CONAES Scenarios in 2000 (quads)

IEF	1972	A 1985	B 1985	A 2000	B 2000
Coal	8.16	8.50	9.35	6.92	10.93
Oil	3.55	3.14	3.45	2.72	3.34
Gas	4.47	2.39	2.39	0	0
Hydro	2.91	3.80	3.80	4.30	4.30
Nuclear	0.58	2.02	2.59	6.19	8.53
Solar	0	0.26	0.325	0.57	0.70
Total	18.56	20.11	21.91	22.70	27.80

Table 5
CONAES Energy Resource Totals, 2000 (quads)

CONAES control totals*			This study	
Scenario A	Res. & Comm.	22.6	Res. & Comm.	7.0
	Trans.	12.0	Trans.	12.0
	Ind.	39.4	Ind.	31.8**
	Total	74.0	Utility	23.3
			Total	74.1
Scenario B	Res. & Comm.	28.7	Res. & Comm.	8.5
	Trans.	16.0	Trans.	16.0
	Ind.	42.9	Ind.	34.7**
	Total	87.6	Utility	28.6
			Total	87.8

*Utility consumption allotted to each sector separately.

**From ref. 1, with resource losses included at 8% rate.

Table 6
Intermediate Energy Forms Burned by Electric Utilities (quads)

		Boilers			Turbines		
		Coal	Oil	Nat.gas	Wood	Oil	Nat.gas
1972:	Base	8.16	3.27	4.30	0.	0.28	0.17
1985:	A	8.50	2.85	2.39	0	0.29	0
	B	9.35	3.16	2.39	0	0.29	0
	NEP	16.60	1.78	0.75	0.10	0.61	0.20
	SF-2	15.32	2.09	3.10	0.10	0.61	0
2000:	A	8.92	2.55	0	0	0.17	0
	B	10.93	3.17	0	0	0.17	0
	NEP	21.02	1.24	0	0.60	0.50	0.17
	SF-2	20.46	1.50	1.47	0.60	0.37	0

B. Emission Coefficients

Emission coefficients were developed for the fossil fuel utility sector for each scenario-year. The pollutants considered are listed in Table 7.

The starting point for the calculation of emission coefficients (in units of short tons of pollutant per 10^{12} Btu of fuel) are the air emission factors (Table 8), which give emissions for uncontrolled facilities in pounds of pollutant per physical unit of fuel. The average physical characteristics of the fuels in the utility sector included in this study are given in Table 9.

Once the level of emission control is specified, the emission factors and average fuel characteristic data can be combined to give the emission coefficients. Two sets of coefficients are developed as in ref. 3: an "uncontrolled" case and a "controlled" case. The array of emission coefficients for both air and water pollutants is given for the two cases in Tables 10 and 11. Control levels are those used by Hittman³ except where noted. The discrepancies are attributable either to use, in the previous work, of now outdated raw data from the earlier edition of the EPA report² or to computational errors.

The next step is to specify the fractional breakdown of controlled and uncontrolled plants. The scenario-specific emission coefficients will then be appropriately weighted averages of the emission matrices in Tables 10 and 11. The fractions of central electric plants that are uncontrolled are given as 0.775 for 1972 and 0 for 2000 by Beller.⁶ The fraction uncontrolled for 1985 was computed by linear extrapolation of the 1972 value to zero in 2000: if, for the ath scenario, total energy consumption in the utility

Table 7
Utility Pollutants Considered

Air:	Particulates (Part)
	Nitrogen oxides (NO _x)
	Sulfur oxides (SO _x)
	Hydrocarbons (HC)
	Carbon monoxide(CO)
Water:	Organics (Org)
	Dissolved solids (DS)
	Acids (Acid)
	Thermal (Th)
	Suspended solids(SS)

Table 8
Utility Emission Factors (lb/physical fuel unit) (from ref. 2)

	Fuel	Unit	Part*	NO _x	SO _x **	HC	CO
Boilers:	Coal	ton	16A	18	38S	0.3	1
	Oil	10 ³ gal	8	105	159S	2	3
	Nat. gas	10 ⁶ ft ³	10	700	0.6	1	17
	Wood	ton	10	10	1.5	35	30
Turbines:	Oil	10 ³ gal	5	67.8	140S	5.57	15.4
	Nat. gas	10 ⁶ ft ³	14	413	940S	42	115

*A = wt% of ash in coal.

**S = wt% sulfur.

Table 9
Average Fuel Characteristics, Utility Sector (from ref. 3)

Fuel	Unit	10 ⁶ Btu unit	Ash content, %	Sulfur content, %
Coal	ton	24.4	12.53	2.59
Res. oil	10 ³ gal	149		1.5
Dist. oil	10 ³ gal	138		0.218
Nat. gas	10 ⁶ ft ³	1031		0.00064
Wood	ton	10		

Table 10
Electric Utility Emission Coefficients, Uncontrolled Case
(short ton/10¹² Btu)

	Part	NO _x	SO _x	HC	CO	Org	DS	Acid	Th (10 ¹² Btu)	SS
Boiler:										
Coal	82.2	369	2020	6.15	20.5	2.71	58.1	25.7	0.528	6.84
Oil	27.2	357	811*	6.81	10.2**	0.0155	7.44	--	0.526	0.709
Nat. gas	4.85**	191	0.293	0.485**	8.25**	0.0155	3.40	--	0.526	0.709
Turbine:										
Oil	18.0	244	113	20.1	55.5	--	--	--	--	--
Nat. gas	6.80	201	0.293	20.4	56.0	--	--	--	--	--

*Includes all SO_x; the value for SO₂ alone is 801.

**Discrepancy with data in ref. 3.

Table 11
Electric Utility Emission Coefficients, Controlled Case (short ton/10¹² Btu)
Values are based on EPA emissions limitations (see ref. 4 for boilers and
ref. 5 for turbines). Uncontrolled values are used for the base year (BY)
because the new source performance standards for turbines (ref. 5) were not
given because they are negligible.

	Part	NO _x	SO _x	HC	CO	Org	DS
Boiler:							
Coal	20.6	350	202	6.15	20.5	0.00302	18.2
Oil	27.2	150	320	6.81	10.2	0.00302	
Nat. gas	4.85	100	0.293	0.485	8.25	0.00302	
Wood**	2.5	350	7.5	180	150	0.00302	
Turbine:							
Oil	18.0	244 (BY)	113 (BY)	20.1	55.5	--	
		73.2	70.0				
Nat. gas	6.80	201 (BY)	0.293	20.4	56.0	--	
		60.3					

sector is E^a , then the fraction uncontrolled, f^a , in 1985 is

$$f^a = (15/28)(0.775)E_{1972}/E^a.$$

The results are summarized in Table 12.

The appropriate emission matrix for each scenario can now be computed.

Let

e_{ij}^a = the emission of pollutant j in $\text{ton}/10^{12}\text{Btu}$ due to fuel/combustion process i in scenario a ,

u_{ij}^a - the corresponding "uncontrolled" matrix,

c_{ij}^a = the corresponding "controlled" matrix, and

f^a = the fraction "uncontrolled" in scenario a .

Then

$$e_{ij}^a = f^a u_{ij}^a + (1 - f^a) c_{ij}^a.$$

Since, for the year 2000, it has been assumed that all plants are at the "controlled" level, $f^a = 0$ and therefore $e_{ij}^a = c_{ij}^a$ for all scenarios in that year. This matrix is given in Table 11. The values of e_{ij}^a for the five other cases (base year and four 1985 scenarios) are presented in Tables 13 to 17.

C. Emission Intensities

The emission matrices give the quantity of each pollutant emitted per unit fuel input for both boiler and turbine electric generating technologies. The matrix for each scenario embodies the level of emission control. In this section, emissions per kilowatt-hour generated are calculated for all scenario-years under consideration. Let e_{ij}^a be the emissions matrix

Table 12
Fraction of Plans Uncontrolled, 1985

	A	B	NEP	SF-2
Energy consumption (quads)	14.03	15.9	20.04	21.22
Fraction	0.479	0.442	0.335	0.317

Table 13
Base Year Emissions Matrix (short ton/ 10^{12} Btu)
(No wood is burned in the base year)

	Part	NO _x	SO _x	HC	CO	Org	DS	Acid	Th (10^{12} Btu)	SS
Boiler:										
Coal	68.3	364	1610	6.15	20.5	2.10	49.1	19.9	0.409	5.30
Oil	27.2	310	700	6.81	10.2	0.0126	6.53	0	0.407	0.549
Nat. gas	4.85	170	0.293	0.485	8.25	0.0126	3.40	0	0.407	0.549
Turbine:										
Oil	18	244	113	20.1	55.5	0	0	0	0	0
Nat. gas	6.8	201	0.293	20.4	56	0	0	0	0	0

Table 14
Scenario A 1985 Emissions Matrix (short ton/ 10^{12} Btu)

	Part	NO _x	SO _x	HC	CO	Org	DS	Acid	Th** (10^{12} Btu)	SS
Boiler:										
Coal	50.1	359	1072	6.15	20.5	1.29	37.3	12.3	0.252	3.27
Oil	27.2	249	555	6.81	10.2	0.00899	5.33	0	0.251	0.339
Nat. gas	4.85	143	0.293	0.485	8.25	0.00899	3.40	0	0.251	0.339
Wood*	1.30	182	3.90	93.7	78.1	0.00157	9.48	0	0	0
Turbine:										
Oil	18	155	90.6	20.1	55.5	0	0	0	0	0
Nat. gas	6.8	127	0.293	20.4	56.0	0	0	0	0	0

*Wood burned is in controlled plants meeting New Source Performance Standards (NSPS).

**Thermal discharge limit in NSPS is zero.

Table 15

Scenario B 1985 Emissions Matrix (short ton/10¹²Btu)

	Part	NO _x	SO _x	HC	CO	Org	DS	Acid	Th (10 ¹² Btu)	SS
Boiler:										
Coal	47.8	358	1005	6.15	20.5	1.20	35.8	11.3	0.233	3.02
Oil	27.2	241	537	6.81	10.2	0.00853	5.18	0	0.232	0.313
Nat. gas	4.85	140	0.293	0.485	8.25	0.00853	3.40	0	0.232	0.313
Wood*	1.39	195	4.18	100	83.7	0.00168	10.1	0	0	0
Turbine:										
Oil	18.	148	89.0	20.1	55.5	0	0	0	0	0
Nat. gas	6.8	122	0.293	20.4	56	0	0	0	0	0

*See footnote to Table 14

Table 16

NEP 1985 Emissions Matrix (short ton/10¹²Btu)

	Part	NO _x	SO _x	HC	CO	Org	DS	Acid	Th (10 ¹² Btu)	SS
Boiler:										
Coal	41.2	356	811	6.15	20.5	0.909	31.5	8.60	0.176	2.29
Oil	27.2	219	484	6.81	10.2	0.00720	4.75	0	0.176	0.237
Nat. gas	4.85	139	0.293	0.485	8.25	0.00720	3.4	0	0.176	0.237
Wood*	1.66	232	4.98	119	99.7	0.00200	12.1	0	0	0
Turbine:										
Oil	18	139	84.4	20.1	55.5	0	0	0	0	0
Nat. gas	6.80	107	0.293	20.4	56	0	0	0	0	0

*See footnote to Table 14

Table 17

SF-2 1985 Emissions Matrix (short ton/10¹²Btu)

	Part	NO _x	SO _x	HC	CO	Org	DS	Acid	Th (10 ¹² Btu)	SS
Boiler:										
Coal	20.1	356	778	6.15	20.5	0.861	30.8	8.14	0.167	2.16
Oil	27.2	215	475	6.81	10.2	0.00697	4.68	0	0.166	0.224
Nat. gas	4.85	128	0.293	0.485	8.25	0.00697	3.40	0	0.166	0.224
Wood*	1.70	239	5.12	122	102	0.00206	12.4	0	0	0
Turbine:										
Oil	18.	127	83.5	20.1	55.5	0	0	0	0	0
Nat. gas	6.80	104	0.293	20.4	56	0	0	0	0	0

*See footnote to Table 14

for the ath scenario, defined earlier, and E_i^a be the fossil fuel breakdown of Table 6 (expressed in quads). Then, P_j^a , the emission intensity of pollutant j, is

$$P_j^a = 10^{-6} \left[\left(\sum_i E_i^a e_{ij}^a \right) / E^a \right] \times 11,500 \text{ (ton/10}^6 \text{ kW-hr)}$$

where $E^a = \sum_i E_i^a$, and a heat rate of 11,500 Btu/kW-hr has been assumed.

The data are presented in Table 18. Since the "controlled" emissions matrix applies to all scenarios in 2000, variations over scenarios in that year are due to fuel mix differences. For 1985, the variations are functions not only of fuel mix but also of emission matrix, which depends on the fraction of central station fossil-fuel-driven plants that are "controlled." In some cases these factors counteract each other. For example, in 1985, SF-2 has a lower particulate emission intensity than either A or B. This might seem surprising, since SF-2 incorporates a much more rapid shift to coal than do the CONAES scenarios; but this particulate-increasing factor is overridden by the high level of emissions control in SF-2 due to the assumption of rapid growth in electricity consumption.

D. Total Emissions

Total emissions are perhaps more revealing than emission intensities in weighing the environmental compatibility of the various scenarios. This is primarily because the large variation in fossil-fuel-derived electricity among the scenarios is due to different assumptions about end-use efficiencies and about the growth of nonconventional energy conversion technologies. None of the scenarios is based on quality of life curtailments. The scenarios embody differing concepts of the entire energy

Table 18

Emission Intensities by Scenario (short ton/10⁶ kW-hr)

Scenario	Part	NO _x	SO _x	HC	CO	Org	DS	Acid	Th* (10 ⁹ Btu)	SS	
BY		0.479	3.43	11.0	0.059	0.186	0.0122	0.310	0.116	4.57	0.034
1985:	A	0.426	3.40	8.79	0.064	0.196	0.0090	0.279	0.085	2.84	0.024
	B	0.416	3.40	8.42	0.065	0.197	0.0085	0.272	0.080	2.62	0.022
	NEP	0.430	3.74	8.25	0.082	0.241	0.0087	0.308	0.082	1.94	0.022
	SF-2	0.378	3.47	7.03	0.073	0.220	0.0072	0.268	0.068	1.86	0.019
2000:	A	0.253	3.47	2.60	0.075	0.217	3.42-5	0.169	--	--	--
	B	0.253	3.47	2.60	0.074	0.215	3.43-5	0.169	--	--	--
	NEP	0.234	3.81	2.28	0.127	0.280	3.37-5	0.194	--	--	--
	SF-2	0.225	3.66	2.19	0.119	0.264	3.42-5	0.185	--	--	--

*See Table 14

Table 19

Total Utility Emissions (10⁶ short ton/yr)

Scenario	Part	NO _x	SO _x	HC	CO	Org	DS	Acid	Th* (10 ⁹ Btu)	SS	
BY		0.674	4.83	15.5	0.0836	0.261	0.0172	0.439	0.163	6.42	0.0474
1985:	A	0.520	4.15	10.7	0.0787	0.240	0.0110	0.340	0.105	3.47	0.0296
	B	0.550	4.49	11.1	0.0860	0.260	0.0113	0.360	0.106	3.47	0.0300
	NEP	0.749	6.53	14.4	0.143	0.421	0.0151	0.536	0.143	3.38	0.0386
	SF-2	0.698	6.41	13.0	0.135	0.406	0.0132	0.494	0.125	3.43	0.0344
2000:	A	0.256	3.52	2.63	0.0756	0.219	3.46-5	0.171	--	--	--
	B	0.314	4.31	3.23	0.0922	0.267	4.26-5	0.210	--	--	--
	NEP	0.478	7.80	4.68	0.259	0.573	6.90-5	0.398	--	--	--
	SF-2	0.478	7.77	4.64	0.252	0.559	7.26-5	0.393	--	--	--

*See Table 14

system, from resources to final consumption. Total emissions are related to the entire mix of fuel, technology, and efficiency and are not directly related to life-style changes.

The variation over the scenarios for the emission intensities was less than 25%, but for total emissions it was as much as 100%. The total emission of pollutant j in the a th scenario can be written in terms of previously defined variables as

$$10^{-3} \sum_i E_i^a e_{ij}^a (10^6 \text{ ton/yr}).$$

The results are given in Table 19.

III. RESIDENTIAL AND COMMERCIAL EMISSIONS

A. Energy Demands by Scenario

Derivation of emissions in the residential-commercial sector involves specifying for each scenario the breakdown of fuel consumption by end use, designating the appropriate emissions matrix, mapping fuel and end use into specific pollutant, and multiplying energy consumption sectors by the emissions matrices to arrive at final emissions. Unlike the industrial and utility sectors, where energy consumption was either explicitly indicated or could be deduced in a straightforward manner, the scenarios under consideration are highly underspecified in terms of total energy breakdown by end use and fuel mix. Before computing emissions, one must extract from existing studies the necessary disaggregation in final demands. In order to derive the residential and commercial energy consumption figures by fuel and by end use for each scenario in future years, one must have an

equivalent breakdown for the base year 1972. This breakdown should include dividing fuel oil into distillate oil, residual oil, and liquid petroleum gas (LPG), since the emission coefficient for each fuel is different in the two different sectors. Since the ERDA and CONAES scenarios are based on base years and fuel mixes somewhat different from those used here, the fuel mix by end use and sector for 1972 had to be reconstructed.

The ERDA scenarios were extrapolated from the 1972 numbers in the BNL Sourcebook,⁶ and these values were used as long as they were reasonably consistent with other data. A new data source not available when the BNL Sourcebook was compiled is the National Energy Accounts⁸ (NEA). This gives controlled totals for each fuel for each sector, and these were used for the residential sector, which is the more precisely defined of the two sectors. The gas total from NEA was slightly modified to match the gas data by end use from the Sourcebook. For both oil (distillate, residual, and LPG) and gas the totals for the residential and commercial sectors combined were taken from the Sourcebook.

All residual oil assigned by NEA to both the residential and commercial sectors was assumed to be used for space heat only, although probably a small percentage of it is used for hot water taken from a large boiler. Coal was assumed to be used only for commercial space heat, as in the Sourcebook. The values for distillate oil going to commercial space heat and for LPG in the commercial sector were taken from Hittman's data³ for 1970, the only available information about these quantities. The amount of distillate oil going to residential space heat was taken from the Sourcebook; when added to Hirst's number⁹ for oil going to residential

hot water, this gave the NEA value for total residential distillate oil. Distillate oil going to commercial hot water was taken as the remainder. These results are summarized in Table 20. Note that here and throughout the study the data are disaggregated to three end uses: space heat (SH), water heat (WH) and cooking (C). In the residential and commercial sectors emissions are predominantly due to these uses, and those from other end uses are negligible. Emissions associated with the generation of electricity used for appliances and lighting have been charged to the utility sector, and those due to miscellaneous end uses (gas lights, natural-gas-driven air-conditioners, etc.) are small.³

From the base year fuel mix, the fraction of each fuel going to each sectoral end used was determined. These matrices are given in Table 21. Since the only information provided for future years in each scenario was the total oil or gas going to the joint residential and commercial sector, this matrix was used to obtain the fuel mix by end use for the future. Obviously, this involves the assumption that each fuel will be used for the same mix of end uses in the future as in 1972. No information was available by scenario regarding possible errors resulting from this assumption, and use of this assumption should not be taken to imply that for any given end use the fuel mix will remain the same.

Aggregated fuel breakdowns for each scenario are summarized in Table 22. The household and commercial floorspace assumptions underlying these projections are given in Table 23.* Assumptions on improvement of end-use efficiency for each scenario are presented in Table 24 in the form of

*These assumptions were not used in estimating residential-commercial energy use, but they are presented to show the relative importance of various measures aimed at conservation and improvement of end-use efficiency.

Table 20
Base Year Commercial-Residential Fuel Use Breakdowns (quads)

	Residential				Commercial				Grand total ^a
	SH	WH	Cook	Total	SH	WH	Cook	Total	
Coal ^b	0	0	0	0	0.32	0	0	0.32	0.32
Res. oil ^c	0.55 ^b	0	0	0.55	0.55	0	0	0.55 ^f	1.10
Dist. oil	3.09 ^b	0.27 ^d	0	3.36 ^c	0.57 ^e	0.20 ^f	0	0.77 ^f	4.13
Nat. gas ^b	3.82 ^f	1.18 ^b	0.30 ^b	5.30	1.56	0.44 ^e	0.13 ^e	2.13 ^e	7.43
LPG	0.07 ^f	0.12 ^b	0.06 ^b	0.25 ^c	0.08 ^e	0.02 ^e	0.01 ^e	0.11 ^e	0.36

^aGrand totals for coal, oil (residual, distillate, and LPG), and natural gas agree with data in ref. 6.

^bSee ref. 6.

^cSee ref. 8.

^dSee ref. 9.

^eSee ref. 3.

^fRemainder obtained by subtraction from row total or subtotal.

Table 21
Fractional Distributions of Fuel

	Residential			Commercial		
	SH	WH	Cook	SH	WH	Cook
Oil: Res	0.098	0	0	0.098	0	0
Dist	0.553	0.048	0	0.102	0.036	0
LPG	0.013	0.021	0.011	0.014	0.004	0.002
Nat. gas	0.514	0.158	0.040	0.209	0.059	0.017
Coal				1.0		

Table 22
Aggregate Fuel Mix by Scenario (quads)

Fuel	1972	A		B		NEP		SF-2	
		1985	2000	1985	2000	1985	2000	1985	2000
Oil	5.6	3.3	1.8	3.8	3.6	5.0	2.5	6.9	4.6
Nat. gas	7.4	6.4	4.8	6.6	4.3	7.8	6.7	8.1	7.2
Coal	0.3	0.2	0	0.3	0.3	0.11	0	0	0

Table 23
Household and Commercial Floorspace Assumptions

	1985				2000			
	A	B	NEP	SF-2	A	B	NEP	SF-2
Households (10 ⁶)								
Single-family	59.0	59.0	52.4	52.4	71.5	71.5	63.8	63.8
Multifamily	26.7	26.7	31.8	31.8	34.6	34.6	38.0	38.0
Total	85.7	85.7	84.2	84.2	106.1	106.1	101.8	101.8
Commercial (10 ⁹ ft ²)	32.3	32.3	32.9	32.9	40.5	40.5	43.5	43.5
Real GNP growth (%/yr)	2.15	2.15	3.1	3.1	2.15	2.15	3.1	3.1

Table 24
End-Use Energy Intensities* (1.0 in 1972)

	1985				2000			
	A	B	NEP	SF-2	A	B	NEP	SF-2
SH gas	0.88	0.85	0.83	0.91	0.67	0.70	0.64	0.81
SH oil	0.88	0.87	0.85	0.92	0.67	0.75	0.64	0.81
WH gas	0.70	0.73	0.87	0.96	0.65	0.70	0.84	0.96
WH oil	0.70	0.73	1.0	1.0	0.65	0.70	1.0	1.0
Cook gas	0.66	0.66	0.87	0.96	0.65	0.65	0.84	0.96

* Data from ref. 7 and BNL RES's. Intensity is a measure of total energy use in comparison with that in a base year.

relative energy intensities for relevant end uses, if available. Combining the fractional distribution of fuel (matrices in Table 21) with the aggregate fuel breakdowns (Table 22) leads to the disaggregated energy use distributions listed in Tables 25 and 26. These energy allotments are used below, in combination with the residential and commercial emission matrices, to evaluate emissions by pollutants, end use, and sector.

B. Emission Coefficients

Since water-borne emissions from energy use in the commercial and residential sectors are negligible, the analysis is limited to the five air pollutants listed in Table 7. The first step is to compute the emissions matrix for commercial and residential boilers. The Environmental Protection Agency² (EPA) has compiled emission factors as a function of physical unit of fuel input (see Tables 27 and 28). The ratings range from "a" (highest confidence) to "c" (average).

In order to develop matrices of emission as a function of energy input, one must specify the average fuel content for each resource. The values used in this study, along with average sulfur and ash content assumptions, are given in Table 29. With these values, conversion of the data in Tables 27 and 28 into boiler emission matrices, expressed as short tons of pollutant per 10^{12} Btu input, is straightforward. These matrices are given in Tables 30 and 31, and discrepancies with Hittman data³ are indicated. As in the utility sector, the discrepancies are presumably due either to computational errors or to Hittman's using earlier EPA emissions data. Note that the breakdown of coal fuel resource usage in the commercial sector of

Table 25
Commercial Sector Fuel Breakdown

		Coal	Res oil	Dist oil	Nat. gas	LPG
<u>BY</u>						
	SH	0.3	0.55	0.57	1.56	0.08
	WH	0	0	0.20	0.44	0.02
	Cook	0	0	0	0.13	0.07
<u>1985</u>						
A:	SH	0.2	0.32	0.34	1.33	0.05
	WH	0	0	0.12	0.38	0.01
	Cook	0	0	0	0.11	0.01
B:	SH	0.3	0.37	0.39	1.38	0.05
	WH	0	0	0.14	0.39	0.05
	Cook	0	0	0	0.11	0.01
NEP:	SH	0.11	0.49	0.51	1.63	0.05
	WH	0	0	0.18	0.46	0.02
	Cook	0	0	0	0.13	0.01
SF-2:	SH	0	0.68	0.70	1.69	0.07
	WH	0	0	0.25	0.48	0.02
	Cook	0	0	0	0.14	0.01
<u>2000</u>						
A:	SH	0	0.18	0.18	1.0	0.10
	WH	0	0	0.07	0.28	0.03
	Cook	0	0	0	0.08	0.01
B:	SH	0.3	0.36	0.36	0.90	0.03
	WH	0	0	0.14	0.25	0.01
	Cook	0	0	0	0.07	0
NEP:	SH	0	0.25	0.26	1.40	0.06
	WH	0	0	0.09	0.40	0.02
	Cook	0	0	0	0.11	0.01
SF-2:	SH	0	0.45	0.47	1.51	0.06
	WH	0	0	0.17	0.43	0.02
	Cook	0	0	0	0.12	0.01

Table 26
Residential Sector Fuel Breakdown

		Res oil	Dist oil	Nat. gas	LPG
<u>BY</u>					
	SH	0.55	3.09	3.80	0.07
	WH	0	0.27	1.17	0.12
	Cook	0	0	0.30	0.06
<u>1985</u>					
A:	SH	0.32	1.82	3.29	0.04
	WH	0	0.16	1.01	0.07
	Cook	0	0	0.26	0.04
B:	SH	0.37	2.10	3.39	0.05
	WH	0	0.18	1.04	0.08
	Cook	0	0	0.26	0.04
NEP:	SH	0.49	2.77	4.01	0.07
	WH	0	0.24	1.32	0.11
	Cook	0	0	0.31	0.06
SF-2:	SH	0.68	3.82	4.16	0.09
	WH	0	0.33	1.28	0.14
	Cook	0	0	0.32	0.08
<u>2000</u>					
A:	SH	0.18	1.00	2.47	0.02
	WH	0	0.09	0.76	0.04
	Cook	0	0	0.19	0.02
B:	SH	0.35	1.99	2.21	0.05
	WH	0	0.17	0.76	0.08
	Cook	0	0	0.19	0.04
NEP:	SH	0.25	1.38	3.34	0.03
	WH	0	0.12	1.06	0.05
	Cook	0	0	0.27	0.03
SF-2:	SH	0.45	2.54	3.70	0.06
	WH	0	0.22	1.14	0.10
	Cook	0	0	0.29	0.05

Table 27

Boiler Emission Factors, Commercial Sector
(lb/physical fuel unit) (from ref. 2)

Fuel	Unit	Part*	SO _x **	NO _x	HC	CO	Rating
Bit coal	ton	2A	38S	6	3	10	a
Anth coal	ton	2A	38S	6	0.2	10	b
Res oil	10 ³ gal	23	159S	60	3	4	a
Dist oil	10 ³ gal	15	144S	60	3	4	a
Nat. gas	10 ⁶ ft ³	10	0.6	120	8	20	a
LPG	10 ³ gal	1.9	0.09S	12	0.8	2.0	c

*A = wt% of ash in coal.

**S = wt% of sulfur for coal and oil, and grains/100 ft³ gas vapor for LPG.
Average sulfur content of natural gas is taken as 2000 grains/10⁶ std ft³.

Table 28

Boiler Emission Factors, Residential Sector
(lb/physical fuel unit) (from ref. 2)

Fuel	Unit	Part	NO _x	SO _x *	HC	CO	Rating
Res oil	10 ³ gal	23	12	159S	3	4	a
Dist oil	10 ³ gal	10	12	144S	3	5	a
Nat. gas	10 ⁶ ft ³	10	80	0.6	8	20	a
LPG	10 ³ gal	1.9	8	0.09S	0.8	2.0	c

*See footnote to Table 27.

Table 29

Average Fuel Characteristics in Commercial-Residential Sector (from ref. 3)

Fuel	Unit	10 ⁶ Btu/unit	Ash content, %	Sulfur content, %
Bit coal	ton	24.2	10	2.0
Anth coal	ton	25.4	12	0.6
Res oil	10 ³ gal	149	--	1.73
Dist oil	10 ³ gal	138	--	0.218
Nat. gal	10 ⁶ ft ³	1031	--	2000*
LPG	10 ³ gal	95.4	--	12**

*Grains/10⁶ std ft³. **Grains/100 ft³.

Table 30

Boiler Emission Matrix, Commercial Sector
(short ton/10¹² Btu)

Fuel	Part	NO _x	SO _x	HC	CO
Coal*	429	122	1270	46.3	204
Res oil	77.2	201	923**	10.1	13.5**
Dist oil	54.3	217	114	10.9	14.5**
Nat. gas	4.85**	58.2**	0.291	3.88	9.70
LPG	9.96	62.9**	5.66	4.19	10.5

*Assumes mix of 27% anthracite and 73% bituminous by fuel value (see ref. 10).

**Discrepancy with data in ref. 3.

Table 31

Boiler Emission Matrix, Residential Sector
(short ton/10¹² Btu)

Fuel	Part	NO _x	SO _x	HC	CO
Res oil	77.2	40*	923	10.1	13.5
Dist oil	36.2	43.5	114	10.9	18.1
Nat. gas	4.85**	38.8**	0.291**	3.88	9.70
LPG	9.96**	41.9**	5.66**	4.19**	10.5

*Nitrogen oxides emission for oil-fired residential boilers is not given separately in ref. 2. The value given here was derived from the proportion

$$\frac{\text{Residential residual oil NO}_x \text{ factor}}{\text{Commercial residual oil NO}_x \text{ factor}} = \frac{\text{Residential distillate oil NO}_x \text{ factor}}{\text{Commercial distillate oil NO}_x \text{ factor}}$$

**Discrepancy with data in ref. 3.

Table 32

Emission Matrix Correction Factors (from ref. 3)

	Part	NO _x	SO _x	HC	CO
Commercial:	WH	1.0	1.1	1.0	1.0
	C	1.0	0.6	1.0	1.0
Residential:	WH	1.0	0.6	1.0	1.0
	C	1.0	0.5	1.0	1.0

27% anthracite and 73% bituminous reported by the Bureau of Mines¹⁰ is assumed to persist through the time frame of the study.

The final step is to extend the boiler emission matrices applicable for space heating to the other end uses. The correction factors used are given in Table 32.

C. Emission by End Use

The evaluation of emissions associated with specific end uses is a straightforward exercise in matrix multiplication. The nomenclature and equations presented in Tables 33 and 34 provided the basis for a computer program to evaluate P_{kj}^a , emission as a function of end use and scenario. The results are presented in Tables 35 and 36.

Variations in emission levels among the scenarios are due to different assumptions about the aggregate amount of fuel consumed and the fuel mix for each end use. In some cases these effects counteract each other, for instance, the ERDA scenarios lead to less particulate emissions from space heating than do the CONAES scenario despite their higher fuel use levels because the CONAES scenarios assume more coal consumption in the commercial sector. The data in Tables 35 and 36 show that emissions vary widely and are sensitive functions of both the kinds and the total amounts of fuel assumed.

D. Total Emissions

Total emissions for each scenario are presented in Tables 37 and 38 for the commercial and residential sectors, and these have been summed to give the total commercial-residential sector emissions shown in Table 39.

Table 33

Computational Procedure for Commercial End-Use Emissions

Let:

e_{ij} = commercial sector emissions matrix (Table 30) in tons pollutant/ 10^{12} Btu

E_{ki}^a = consumption of fuel i (in quads/yr) by end-use k in scenario a (Table 25)

p_{kj}^a = emission (in 10^6 ton/yr) of pollutant j due to end-use k in scenario a

Then:

$$p_{jk}^a = 10^{-3} \sum_i E_{ki}^a e_{ij}$$

Definitions of Variables:

	i	j	k	a
1	Coal	Part	SH	Base year
2	Res oil	NO _x	WH	A 1985
3	Dist oil	SO _x	C	B1985
4	Nat. gas	HC	--	NEP 1985
5	LPG	CO	--	SF-2 1985
6	--	--	--	A 2000
7	--	--	--	B 2000
8	--	--	--	NEP 2000
9	--	--	--	SF-2 2000

Table 34

Computational Procedure for Residential End-Use Emissions

Let:

e_{ij} = residential sector emissions (Table 31) in tons pollutant/ 10^{12} Btu

E_{ki}^a = consumption of fuel i (in quads/yr) by end-use k in scenario a (Table 26)

p_{kj}^a = emission (in 10^6 ton/yr) of pollutant j due to end-use k in scenario a

Then:

$$p_{kj}^a = 10^{-3} \sum_i E_{ki}^a e_{ij}$$

Definitions of Variables:

	i	j	k	a
1	Res oil	Part	SH	Base year
2	Dist oil	NO _x	WH	A 1985
3	Nat. gas	SO _x	C	B 1985
4	LPG	HC	--	NEP 1985
5	--	CO	--	SF-2 1985
6	--	--	--	A 2000
7	--	--	--	B 2000
8	--	--	--	NEP 2000
9	--	--	--	SF-2 2000

Table 35

Emissions by End-Use, Commercial Sector (10⁶ short ton/yr)

		Part	NO _x	SO _x	HC	CO
<u>BY</u>						
	SH	2.10-1*	3.67-1	9.55-1	3.20-2	9.28-2
	WH	1.32-2	7.73-2	2.30-2	3.97-3	7.38-3
	C	7.30-4	4.92-3	9.44-5	5.46-4	1.37-3
<u>1985</u>						
A:	SH	1.36-1	2.43-1	5.89-1	2.16-2	6.34-2
	WH	8.46-3	5.37-2	1.38-2	2.82-3	5.53-3
	C	6.33-4	4.22-3	8.86-5	4.69-4	1.17-3
B:	SH	1.86-1	2.79-1	7.68-1	2.74-2	8.58-2
	WH	9.69-3	5.98-2	1.62-2	3.12-3	6.02-3
	C	6.33-4	4.22-3	8.86-5	4.69-4	1.17-3
NEP:	SH	1.21-1	3.22-1	6.51-1	2.22-2	5.30-2
	WH	1.22-2	7.38-2	2.08-2	3.83-3	7.28-3
	C	7.30-4	4.92-3	9.44-5	5.46-4	1.37-3
SF-2:	SH	9.97-2	3.93-1	7.08-1	2.14-2	3.68-2
	WH	1.62-2	9.25-2	2.88-2	4.71-3	8.60-3
	C	7.79-4	5.27-3	9.73-5	5.85-4	1.46-3
<u>2000</u>						
A:	SH	2.88-2	1.35-1	1.87-1	7.78-3	1.51-2
	WH	5.26-3	3.53-2	8.12-3	1.89-3	3.84-3
	C	3.88-4	2.79-3	2.33-5	3.10-4	7.76-4
B:	SH	1.81-1	2.43-1	7.55-1	2.52-2	8.06-2
	WH	9.01-3	5.08-2	1.61-2	2.58-3	4.67-3
	C	4.39-4	2.82-3	7.70-5	3.14-4	7.84-4
NEP:	SH	4.06-2	1.90-1	2.60-1	1.10-2	2.11-2
	WH	6.93-3	4.78-2	1.04-2	2.57-3	5.29-3
	C	6.33-4	4.21-3	8.86-5	4.69-4	1.17-3
SF-2:	SH	6.82-2	2.84-1	4.70-1	1.58-2	2.82-2
	WH	1.15-2	6.95-2	1.96-2	3.60-3	6.85-3
	C	6.82-4	4.57-3	9.15-5	5.08-4	1.27-3

*This is computer notation for 10⁻¹.

Table 36						
Emissions by End-Use, Residential Sector (10 ⁶ short ton/yr)						
	Part	NO _x	SO _x	HC	CO	
<u>BY</u>						
	SH	1.73-1*	3.06-1	8.61-1	5.43-2	1.01-1
	WH	1.66-2	3.73-2	3.18-2	7.99-3	1.75-2
	C	2.05-3	7.08-3	4.27-4	1.42-3	3.54-3
<u>1985</u>						
A:	SH	1.07-1	2.21-1	5.04-1	3.60-2	6.96-2
	WH	1.14-2	2.94-2	1.89-2	5.96-3	1.34-2
	C	1.66-3	5.88-3	3.02-4	1.18-3	2.94-3
B:	SH	1.22-1	2.40-1	5.82-1	4.00-2	7.64-2
	WH	1.24-2	3.09-2	2.13-2	6.33-3	1.42-2
	C	1.66-3	5.88-3	3.02-4	1.17-3	2.94-3
NEP:	SH	1.58-1	2.99-1	7.70-1	5.10-2	9.64-2
	WH	1.62-2	3.98-2	2.84-2	8.20-3	1.83-2
	C	2.10-3	7.27-3	4.30-4	1.45-3	3.64-3
SF-2:	SH	2.12-1	3.59-1	1.06	6.50-2	1.19-1
	WH	1.95-2	4.19-2	3.88-2	9.15-3	1.99-2
	C	2.35-3	7.88-3	5.46-4	1.58-3	3.94-3
<u>2000</u>						
A:	SH	6.23-2	1.47-1	2.81-1	2.24-2	4.47-3
	WH	7.34-3	2.10-2	1.07-2	4.10-3	9.42-3
	C	1.12-3	4.10-3	1.69-4	8.21-4	2.05-3
B:	SH	1.10-1	1.88-1	5.51-1	3.40-2	6-27-2
	WH	1.06-2	2.41-2	2.01-2	5.14-3	1.13-2
	C	1.32-3	4.52-3	2.82-4	9.05-4	2.26-3
NEP:	SH	8.62-2	2.05-1	3.89-1	3.10-2	6.20-2
	WH	9.98-3	2.91-2	1.43-2	5.63-3	1.30-2
	C	1.61-3	5.87-3	2.48-4	1.17-3	2.93-3
SF-2:	SH	1.45-1	2.75-1	7.06-1	4.68-2	8.86-2
	WH	1.45-2	3.48-2	2.60-2	7.24-3	1.61-2
	C	1.90-3	6.67-3	2.67-4	1.33-3	3.34-3

*See footnote to Table 25.

Table 37
Commercial Emission Totals (10⁶ short ton/yr)

		Part	NO _x	SO _x	HC	CO
BY		2.24-1*	4.49-1	9.78-1	3.66-2	1.01-1
1985:	A	1.45-1	3.01-1	6.03-1	2.49-2	7.02-2
	B	1.96-1	3.43-1	7.84-1	3.10-2	9.30-2
	NEP	1.34-1	4.01-1	6.72-1	2.66-2	6.16-2
	SF-2	1.17-1	4.91-1	7.37-1	2.68-2	4.68-2
2000:	A	3.45-2	1.73-1	1.95-1	9.99-3	1.97-2
	B	1.90-1	2.97-1	7.71-1	2.81-2	8.60-2
	NEP	4.82-2	2.43-1	2.72-1	1.40-2	2.76-2
	SF-2	8.03-2	3.58-1	4.89-1	1.99-2	3.63-2

*See footnote to Table 35.

Table 38
Residential Emission Totals (10⁶ short ton/yr)

	Part	NO _x	SO _x	HC	CO	
BY	1.92-1*	3.51-1	8.94-1	6.37-2	1.22-1	
1985:	A	1.20-1	2.57-1	5.23-1	4.31-2	8.60-2
	B	1.36-1	2.77-1	6.04-1	4.75-2	9.35-2
	NEP	1.77-1	3.46-1	7.98-1	6.06-2	1.18-1
	SF-2	2.34-1	4.08-1	1.10	7.58-2	1.43-1
2000:	A	7.07-2	1.73-1	2.92-1	2.73-2	5.62-2
	B	1.22-1	2.17-1	5.71-1	4.01-2	7.63-2
	NEP	9.78-2	2.40-1	4.04-1	3.78-2	7.79-2
	SF-2	1.61-1	3.16-1	7.33-1	5.54-2	1.08-1

*See footnote to Table 35.

Table 39
Total Commercial-Residential Emissions (10⁶ short ton/yr)

	Part	NO _x	SO _x	HC	CO	
BY	4.16-1*	8.00-1	1.87	1.00-1	2.23-1	
1985:	A	2.65-1	5.58-1	1.13	6.80-2	1.56-1
	B	3.32-1	6.20-1	1.39	7.85-2	1.87-1
	NEP	3.11-1	7.47-1	1.47	8.72-2	1.80-1
	SF-2	3.51-1	8.99-1	1.84	1.03-1	1.90-1
2000:	A	1.05-1	3.46-1	0.312	3.73-2	7.59-2
	B	3.12-1	5.14-1	1.34	6.82-2	1.62-1
	NEP	1.46-1	4.83-1	0.676	5.18-2	1.05-1
	SF-2	2.41-1	6.74-1	1.22	7.53-2	1.44-1

*See footnote to Table 35.

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* EPA = U.S. Environmental Protection Agency.