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Projected Impacts of Alternative New Source Performance Standards for Small Industrial-Commercial-Institutional Fossil Fuel-Fired Boilers

NSPS

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PROJECTED IMPACTS OF ALTERNATIVE NEW SOURCE PERFORMANCE STANDARDS FOR SMALL INDUSTRIAL-COMMERCIAL-INSTITUTIONAL FOSSIL FUEL-FIRED BOILERS

Emission Standards Division

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Office of Air and Radiation
Office of Air Quality Planning and Standards
Research Triangle Park, N.C. 27711

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1. INTRODUCTION

This report presents projected environmental, cost, and energy impacts of alternative air emission standards for new small (<29 MW, <100 MMBtu/hr) industrial-commercial-institutional fossil fuel-fired boilers. These draft standards would revise the emission regulations that currently exist in Subpart D of 40 CFR Part 60. The effects of alternative sulfur dioxide (SO_2) and particulate matter (PM) emission standards are assessed in this report. The methodology used to examine environmental, cost, and fossil fuel results projected under current and alternative air emission regulations also is discussed.

For individual boilers, air emission regulations can play a significant role in determining boiler fuel choice and the levels of air emissions. Air emission regulations can result in measurable national and regional environmental, cost, and energy impacts, including changes in the types of fossil fuels combusted and changes in the level of air pollutant emissions generated by new small fossil fuel-fired boilers.

This analysis examines projected impacts in the fifth year following proposal of standards. The analysis of alternative regulations is designed to highlight potential environmental, cost, and energy impacts. These impacts are measured in terms of the projected change under current versus alternative air emission regulations. The analysis of environmental impacts focuses on expected reductions in levels of air emissions. Cost impacts are evaluated in terms of incremental changes in the total annualized costs for boiler and pollution control equipment capital, operating, and fuel costs. Energy impacts are evaluated in terms of shifts in the demand between fuel types (e.g., coal or residual fuel oil versus natural gas).

This report addresses only fossil fuel (coal, oil and natural gas) consumption in small (<29 MW, <100 MMBtu/hr) new boilers. It does not analyze non-fossil fuel-fired steam generating units (i.e., wood or municipal solid waste combustion).

The balance of this report is presented in three parts. Section 2 presents the approach employed to analyze the alternative standards and describes key assumptions and inputs. The potential national environmental, cost and energy impacts for the alternative standards are also summarized in Section 2. The methodology and results of the economic impact analyses for the commercial/institutional sector are presented in Section 3. The industrial sector economic impact analyses are summarized in Section 4.

2. EMISSIONS, COST AND ENERGY IMPACTS OF ALTERNATIVE NSPS

The methodology and results of the projections of national SO_2 and PM emissions reductions, total pollution control costs and energy impacts of alternative NSPS for new small (<29 MW, <100 MMBtu/hr) industrial-commercial-institutional boilers in the fifth year after proposal are summarized in this section.

2.1 METHODOLOGY

2.1.1 Scope

This analysis addresses only fossil fuel (coal, fuel oil and natural gas) combustion in new small boilers. It does not include emissions from the combustion of fuels like wood or municipal solid waste.

Alternative NSPS for SO_2 and PM emissions control from the combustion of coal and fuel oil are assessed. NO_x emissions control is not analyzed in this report.

The projected number, sizes and types of new industrial-commercial-institutional boilers <29 MW (<100 MMBtu/hr) and constructed over the next five years are based on recent sales levels. These sales estimates are not available by type of purchaser (industrial versus commercial/institutional). As a result, the results are estimated for the total industrial-commercial-institutional sector.

The projected fuel mix by boiler type, size and alternative air emission regulation is based on recent sales data and exogenous assumptions. These estimates are not based on a life-cycle analysis of the least-cost fuel type/pollution control compliance option and they are not based on a statistical analysis of historical sales data.

The boiler types are cast iron, firetube, firebox and watertube units. The boiler size classes are:

- <1 MW (<3 MMBtu/hr)
- 1-3 MW (3-10 MMBtu/hr)
- 3-9 MW (10-30 MMBtu/hr)
- 9-29 MW (30-100 MMBtu/hr)

The SO_2 emissions control options are compliance low sulfur fuel types. The PM emissions control options for coal combustion are dual mechanical collectors and fabric filters.

The national impacts are measured in terms of the projected change under current versus alternative national air emissions regulations. The analysis of environmental impacts focuses on projected decreases in SO_2 and PM emissions in the fifth year after the proposal of the NSPS. Cost impacts are evaluated in terms of increases in the total annualized costs for new boiler and pollution control equipment capital, operating and maintenance and fuel costs. Energy impacts are assessed in terms of potential shifts in the demand between fuel types in small new boilers in the next five years.

2.1.2 Analytical Approach

The estimates of baseline SO_2 and PM emissions under current air emissions standards are based on recent sales data by boiler size and fuel type and assumptions about representative air emissions rates and annual capacity utilization rates. American Boiler Manufacturers Association (ABMA) data for 1987 firebox, firetube and watertube boiler sales and recent Hydronics Institute cast iron boiler sales data were multiplied times five to project the total capacity of new small industrial-commercial-institutional boilers constructed by the fifth year after proposal of NSPS. This assumes that recent sales levels will not change over the next five years.*

The sales data are national; therefore, only national projections are presented in this report.

It is assumed that all new small boilers have a 26% capacity factor with the concurrence of the American Boiler Manufacturers Association. These boilers have relatively low annual capacity utilization rates due to the seasonal nature of space heating requirements. PEDCo Environmental, Inc. reviewed commercial boiler data from Indiana, New York and Ohio. For 324 coal boilers with an average size of 15 MW (50 MMBtu/hr), the average capacity factor was 23.6 percent. For 5,615 oil/gas boilers with an average size of 4 MW (13 MMBtu/hr), the average capacity factor was only 10.4 percent.[1] Some

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* Historical boiler sales data are summarized in Appendix B.

industrial boilers may have higher capacity utilization rates because they are used to provide process steam as well as space heating.

In this analysis, the fuel costs are estimated based on projected regional delivered fuel prices over a fifteen-year period beginning in 1992. Given that the standard is proposed in 1989 and this analysis focuses on projecting fifth year impacts, 1992 is the mid-point of this five-year period. These fuel prices have been annualized using a ten percent discount rate.

Naturally, there is uncertainty related to energy market conditions over the next twenty years. EEA developed two forecasts of fuel prices in order to evaluate the sensitivity of the projected impacts of alternative air emissions standards to this exogenous assumption, fuel prices.

Two crude oil price forecasts (reference the Low Oil Price Scenario and the High Oil Price Scenario in Table 2-1) were developed by EEA in 1986 with the U.S. Department of Energy (Office of Policy, Planning and Analysis) WOIL forecasting model. Table 2-1 compares EEA's two 1986 forecasts with other recent projections. EEA estimated regional commercial and industrial distillate and residual fuel oil and natural gas prices for the Low Oil Price Scenario and the High Oil Price Scenario in Table 2-1 .[2,3] The Low Oil Price Scenario and the High Oil Price Scenario fuel prices have been used in this national impacts analysis.

The alternative air emissions standards are summarized in Table 2-2. These regulations are preliminary options; they are not an exhaustive, complete compilation of possible combinations of SO_2 and PM emissions standards. It was assumed that flue gas desulfurization (FGD) systems are relatively expensive for these small boiler sizes and low annual capacity utilization rates. Therefore, the SO_2 emissions control compliance strategy is selecting low sulfur coal or oil types in response to the alternative NSPS or choosing natural gas. The cost impacts reflect the associated increased fuel costs and monitoring and testing costs.

2.2 BASELINE AIR EMISSIONS AND FUEL MIX FORECASTS

The baseline air emissions and fuel mix forecasts are based on recent new boiler sales data. These estimates are multiplied times five to project national impacts in the fifth year after proposal of NSPS. ABMA expects

TABLE 2-1. CRUDE OIL PRICE PROJECTIONS[a]
(1985 $/bbl)

Year	Low Oil Price Scenario[b]	High Oil Price Scenario[b]	GRI[c]	DOE/EIA[d]	DOE/EIA[e]
1985 actual	27	27	27	27	27
1986 actual	14	14	14	14	14
1990	14	24	19	13-19	12-17
1995	20	27	22	17-26	15-22
2000	25	31	25	23-38	20-32
2005	31	37	32	N.A.	N.A.

[a] Average U.S. refiner acquisition cost of crude oil.

[b] Energy and Environmental Analysis, Inc. 1986. Reference 2.

[c] Gas Research Institute. 1988. Reference 7.

[d] U.S. Department of Energy, Energy Information Administration. 1988. Reference 8.

[e] U.S. Department of Energy, Energy Information Administration. 1989. Reference 9.

TABLE 2-2. ALTERNATIVE NSPS

Fuel type	Emissions ceiling ng/J (lb/MMBtu) SO_2	PM
Fuel oil	688 (1.6)	43 (0.1)
	344 (0.8)	
	215 (0.5)	
	129 (0.3)	
Coal	516 (1.2)[a]	129 (0.3)
		21 (0.05)

[a] 30-day rolling average.

short-term industrial-commercial-institutional boiler sales to remain relatively constant at recent levels.

New boiler sales data do not distinguish residual (heavy) fuel oil versus distillate (light) fuel oil. ABMA used their own burner sales data to estimate this distribution for firebox, firetube and watertube boilers. Oil-fired cast iron boilers were assumed to burn only distillate fuel oil.

Table 2-3 summarizes ABMA's 1987 data for small new residual fuel oil boiler sales. ABMA estimated that there were no residual fuel (heavy) oil boiler sales for new low pressure steam or hot water boilers <1000 HP in 1987. The average boiler size for the new high pressure steam watertube/firebox/firetube boilers <1000 HP in 1987 was about 2 MW (7 MMBtu/hr). The average boiler size for the stationary watertube boilers 10,000-80,000 pounds of steam/hour (PPH) in 1987 was about 16 MW (55 MMBtu/hr).

The actual locations of these boiler sales is not known and, as a result, the distribution of local air emissions regulations for these small new boiler sales is not known. It is assumed that the average baseline emissions rates for the new high pressure steam watertube/firebox/ firetube boilers <1000 HP with no alternate fuel was 709 ng SO_2/J (1.65 lb SO_2/MMBtu) and 56 ng PM/J (0.13 lb PM/MMBtu). These estimates were reduced for the oil/gas combination boilers. The average baseline emission rates for the larger stationary watertube boilers were assumed to be 1,096 ng SO_2/J (2.55 lb SO_2/MMBtu) and 99 ng PM/J (0.23 lb PM/MMBtu); these estimates were also reduced for the oil/gas combination boilers. These estimates may overstate average "baseline" emissions to the extent that some of these new small boilers may be located in urban areas with very low sulfur local air emissions standards.

Table 2-4 presents an estimate of the distribution of new small residual fuel oil boiler sales by size class. Recall that this estimate represents the data in Table 2-3 for 1987 times five years. This size boiler distribution is an EEA estimate; the 1987 sales levels in these boiler size categories were not provided by ABMA.

Table 2-5 summarizes ABMA's estimates of new small (<29 MW, <100 MMBtu/hr) coal boiler sales in 1987. ABMA estimated 44 new coal boilers <1000

TABLE 2-3. RESIDUAL FUEL OIL BOILER SALES IN 1987[a]

	Number of boilers[b]	SO_2 emissions[b] metric tons	SO_2 emissions[b] (short tons)	PM emissions metric tons	PM emissions (short tons)
High pressure steam watertube/firebox/firetube <1000 HP (<40 MMBtu/hr)					
oil with no alternate fuel	84	868	(957)	83	(91)
oil/gas combination	144	864	(952)	74	(82)
Stationary watertube boilers 10,000-80,000 PPH (12-100 MMBtu/hr)					
oil with no alternate fuel	8	1,068	(1,177)	87	(96)
oil with gas/alternate fuel	35	2,812	(3,100)	291	(321)
gas with oil/alternate fuel	30	1,374	(1,515)	121	(133)
Total	301	6,986	(7,701)	656	(723)

[a] American Boiler Manufacturers Association data categories.

[b] Reference 4.

TABLE 2-4. BASELINE RESIDUAL FUEL OIL BOILERS[a]

	Boiler Size, MW (MMBtu/hr)			
	1-3 (3-10)	3-9 (10-30)	9-29 (30-100)	1-29 (3-100)
Number of boilers	1,020	205	280	1,505
SO_2 emissions[b]				
metric tons, Mg	5,801	6,169	22,961	34,931
(short tons)	(6,395)	(6,800)	(25,310)	(38,505)
PM emissions[b]				
metric tons, Mg	485	694	2,100	3,279
(short tons)	(535)	(765)	(2,315)	(3,615)

[a] Boiler sales over a five-year period. Reference 6.

[b] In the fifth year assuming current air emissions regulations.

TABLE 2-5. COAL BOILER SALES IN 1987

Number of boilers	50[a]
SO_2 emissions	
metric tons, Mg	3,620[a]
(short tons)	(3,990)[a]
PM emissions	
metric tons, Mg	509[b]
(short tons)	(561)[b]

[a] American Boiler Manufacturers Association. Reference 4.

[b] Reference 5.

HP with an average size of 4 MW (15 MMBtu/hr) and 6 new stationary coal boilers <29 MW (<100 MMBtu/hr) with an average size of 17 MW (60 MMBtu/hr) in 1987.

The average baseline emission rates for these new coal boilers are assumed to be 1,526 ng SO_2/J (3.55 lb SO_2/MMBtu). For the small coal boilers <1000 HP, the baseline emission rate estimate is 193 ng PM/J (0.45 lb PM/MMBtu); 258 ng PM/J (0.6 lb PM/MMBtu) is assumed for the larger stationary coal boilers.

Table 2-6 presents an estimate of the size distribution of new small coal boilers by size class after five years of sales. This boiler size distribution is an EPA estimate; the 1987 sales levels in these boiler size categories were not provided by ABMA.

Distillate fuel oil boilers are also sources of SO_2 and PM emissions. Table 2-7 summarizes the baseline estimates for this fuel type. The average emissions estimates are 129 ng SO_2/J (0.3 lb SO_2/MMBtu) and 4 ng PM/J (0.01 lb PM/MMBtu).

Cast iron boiler sales data were provided to EPA by the Hydronics Institute (see Appendix B). EEA estimated residential versus commercial/institutional cast iron boiler sales. Distillate versus residual fuel oil cast iron boiler sales data were not available. It was assumed that oil-fired cast iron boiler sales were distillate fuel oil units. Table 2-7 includes oil-fired commercial/institutional cast iron boilers, oil-fired low pressure steam and hot water watertube/firetube/firebox light oil boilers <1000 HP and light oil stationary watertube boilers <29 MW (<100 MMBtu/hr).

Baseline estimates for new small natural gas boilers are summarized in Table 2-8. Table 2-8 includes commercial/institutional cast iron boilers as well as watertube/firetube/firebox units <1000 HP and stationary watertube units <29 MW (<100 MMBtu/hr). The average emission rates estimates are 0.26 ng SO_2/J (0.0006 lb SO_2/MMBtu) and 4 ng PM/J (0.01 lb PM/MMBtu).

The baseline fuel mix is shown in Table 2-9. Natural gas and distillate fuel oil are the predominant fuel types for new units <9 MW (<30 MMBtu/hr).

The baseline SO_2 and PM emissions estimates by fuel type and boiler size class are summarized in Tables 2-10 and 2-11, respectively.

TABLE 2-6. BASELINE COAL BOILERS[a]

	Boiler Size, MW (MMBtu/hr)			
	1-3 (3-10)	3-9 (10-30)	9-29 (30-100)	1-29 (3-100)
Number of boilers	145	85	20	250
SO_2 emissions[b]				
metric tons, Mg	5,014	7,215	5,869	18,098
(short tons)	(5,527)	(7,953)	(6,470)	(19,950)
PM emissions[b]				
metric tons, Mg	636	915	993	2,545
(short tons)	(701)	(1,009)	(1,095)	(2,805)

[a] Boiler sales over a five-year period.

[b] In the fifth year assuming current air emissions regulations.

TABLE 2-7. BASELINE DISTILLATE FUEL OIL BOILERS[a]

	Boiler Size, MW (MMBtu/hr)				
	<1 (<3)	1-3 (3-10)	3-9 (10-30)	9-29 (30-100)	<29 (<100)
Number of boilers	60,575	5,690	375	55	121,835
SO_2 emissions[b]					
metric tons, Mg	18,774	7,607	2,286	767	29,434
(short tons)	(20,695)	(8,385)	(2,520)	(845)	(32,445)
PM emissions[b]					
metric tons, Mg	626	295	100	36	1,057
(short tons)	(690)	(325)	(110)	(40)	(1,165)

[a] Boiler sales over a five-year period. References 5 and 6. Excludes estimates of residential boilers.

[b] In the fifth year assuming current air emissions regulations.

TABLE 2-8. BASELINE NATURAL GAS BOILERS[a]

	Boiler Size, MW (MMBtu/hr)				
	<1 (<3)	1-3 (3-10)	3-9 (10-30)	9-29 (30-100)	<29 (<100)
Number of boilers	62,325	7,400	580	115	70,420
SO_2 emissions[b]					
metric tons, Mg	39	23	8	5	74
(short tons)	(43)	(25)	(9)	(5)	(82)
PM emissions[b]					
metric tons, Mg	644	381	145	77	1,247
(short tons)	(710)	(420)	(160)	(85)	(1,375)

[a] Boiler sales over a five-year period. References 5 and 6. Excludes estimates of residential boilers.

[b] In the fifth year assuming current air emissions regulations.

TABLE 2-9. BASELINE FUEL MIX[a]

Fuel Type	Boiler Size, MW (MMBtu/hr) <1 (<3)	1-3 (3-10)	3-9 (10-30)	9-29 (30-100)	<29 (<100)
Natural gas[b]	62,325	7,400	580	115	70,420
Distillate fuel oil[c]	60,575	5,690	375	55	66,695
Residual fuel oil[c]	0	1,020	205	280	1,505
Coal	0	145	85	20	250
Total	122,900	14,255	1,245	470	138,870

[a] Boiler sales over a five-year period; total number of boilers from Tables 2-4 through 2-8.

[b] Single-fuel units.

[c] Single-fuel and oil/gas units.

TABLE 2-10. BASELINE SO_2 EMISSIONS[a]

Fuel Type	<1 (<3)	1-3 (3-10)	3-9 (10-30)	9-29 (30-100)	<29 (<100)
	Boiler Size, MW (MMBtu/hr)				
			(metric tons, Mg)		
Natural gas	39	23	8	5	74
Distillate fuel oil	18,774	7,607	2,286	767	29,434
Residual fuel oil	0	5,801	6,169	22,961	34,931
Coal	0	5,014	7,215	5,869	18,098
Total	18,813	18,445	15,678	29,601	82,537
			(short tons)		
Natural gas	43	25	9	5	82
Distillate fuel oil	20,695	8,385	2,520	845	32,445
Residual fuel oil	0	6,395	6,800	25,310	38,505
Coal	0	5,527	7,953	6,470	19,950
Total	20,738	20,332	17,282	32,630	90,982

[a] In the fifth year assuming current air emissions regulations. Excludes estimates from residential boilers. Reference Tables 2-4 through 2-8.

TABLE 2-11. BASELINE PM EMISSIONS[a]

Fuel Type	<1 (<3)	1-3 (3-10)	3-9 (10-30)	9-29 (30-100)	<29 (<100)
	Boiler Size, MW (MMBtu/hr)				
	(metric tons, Mg)				
Natural gas	644	381	145	77	1,247
Distillate fuel oil	626	294	100	36	1,057
Residual fuel oil	0	485	694	2,100	3,279
Coal	0	636	915	993	2,545
Total	1,270	1,797	1,854	3,207	8,128
	(short tons)				
Natural gas	710	420	160	85	1,375
Distillate fuel oil	690	325	110	40	1,165
Residual fuel oil	0	535	765	2,315	3,615
Coal	0	701	1,009	1,095	2,805
Total	1,400	1,981	2,044	3,535	8,960

[a] In the fifth year assuming current air emissions regulations. Excludes estimates from residential boilers. Reference Tables 2-4 through 2-8.

2.3 NATIONAL IMPACTS

This section presents projections of national air emissions reductions and increases in total annualized pollution control costs from alternative SO_2 and PM NSPS for new small (<29 MW, <100 MMBtu/hr) industrial-commercial-institutional boilers in the fifth year after proposal of NSPS. Results are presented assuming that the fuel mix under the alternative NSPS assumptions is identical to the baseline estimates in Section 2.2 and also assuming that the fuel mix under the alternative NSPS assumptions is different than the baseline estimates. Results are presented for the Low Oil Price Scenario and the High Oil Price Scenario.

2.3.1 Alternative NSPS Fuel Mix is the Same as the Baseline Fuel Mix

2.3.1.1 Residual Fuel Oil: Low Oil Prices

Table 2-12 presents projected residual fuel oil boilers SO_2 emissions reductions by boiler size class. It was assumed that small residual fuel oil watertube/firetube/firebox boilers burned medium sulfur oil in the baseline; therefore, there is very little projected SO_2 emission reduction for a 688 ng SO_2/J (1.6 lb SO_2/MMBtu) emission regulation for sizes <3 MW (<10 MMBtu/hr). The baseline residual fuel oil boiler SO_2 emissions estimate is 34,931 metric tons (38,505 short tons), see Table 2-4. A 688 ng SO_2/J (1.6 lb SO_2/MMBtu) standard is expected to reduce new small residual fuel oil boiler baseline SO_2 emissions by 28 percent. A 344 ng SO_2/J (0.8 lb SO_2/MMBtu) control level is forecasted to reduce new small residual fuel oil boiler baseline SO_2 emissions by 36 percent. A 215 ng SO_2/J (0.5 lb SO_2/MMBtu) regulation is projected to reduce baseline SO_2 emissions by 78 percent. A 129 ng SO_2/J (0.3 lb SO_2/MMBtu) limit will reduce baseline SO_2 emissions by 87 percent.

Lower sulfur residual fuel oil types are also expected to reduce PM emissions without the addition of any particulate matter emissions control equipment. Table 2-13 summarizes these expected PM emissions reductions.

The annualized cost impacts without monitoring and testing costs represent the fuel price increases associated with purchasing low sulfur residual fuel oil types. It is assumed that the fuel price increase (1985 dollars) for the stationary watertube boilers burning high sulfur residual

TABLE 2-12. PROJECTED RESIDUAL FUEL OIL BOILER SO_2 EMISSIONS REDUCTIONS[a]

Alternative SO_2 control level ng/J	(lb/MMBtu)	Boiler size, MW (MMBtu/hr) 1-3 (3-10)	3-9 (10-30)	9-29 (30-100)	1-29 (3-100)
		(metric tons, Mg)			
688	(1.6)	176	1,320	8,554	10,050
344	(0.8)	2,989	3,745	15,757	22,491
215	(0.5)	4,043	4,654	18,458	27,156
129	(0.3)	4,747	5,260	20,259	30,266
		(short tons)			
688	(1.6)	194	1,455	9,429	11,078
344	(0.8)	3,295	4,128	17,370	24,793
215	(0.5)	4,457	5,130	20,347	29,934
129	(0.3)	5,233	5,798	22,332	33,363

[a] In the fifth year following proposal of NSPS; reductions from baseline estimates presented in Table 2-4; alternative NSPS fuel mix is assumed to be the same as the baseline fuel mix.

TABLE 2-13. PROJECTED RESIDUAL FUEL OIL BOILER PM EMISSIONS REDUCTIONS[a]

Alternative SO_2 control level ng/J	(lb/MMBtu)	Boiler size, MW (MMBtu/hr) 1-3 (3-10)	3-9 (10-30)	9-29 (30-100)	1-29 (3-100)
		(metric tons, Mg)			
688	(1.6)	0	130	901	1,031
344	(0.8)	176	281	1,351	1,808
215	(0.5)	246	342	1,531	2,119
129	(0.3)	317	403	1,711	2,430
		(short tons)			
688	(1.6)	0	143	993	1,136
344	(0.8)	194	310	1,489	1,993
215	(0.5)	271	377	1,688	2,336
129	(0.3)	349	444	1,886	2,679

[a] In the fifth year following proposal of NSPS; alternative NSPS fuel mix is assumed to be the same as the baseline fuel mix.

fuel oil in the baseline is \$0.63/GJ (\$0.66/MMBtu) to comply with the 129 ng SO_2/J (0.3 lb SO_2/MMBtu) limit.[3] It is assumed that the fuel price increase is \$0.44/GJ (\$0.46/MMBtu) for the smaller watertube/firetube/firebox boilers burning medium sulfur residual fuel oil in the baseline.[3] Slightly smaller fuel price premiums were used for the 215 ng SO_2/J (0.5 lb SO_2/MMBtu) scenario. For the 344 ng SO_2/J (0.8 lb SO_2/MMBtu) control level, it is assumed that the fuel price increase is \$0.47/GJ (\$0.50/MMBtu) for the stationary watertube boilers and \$0.28/GJ (\$0.30/MMBtu) for the smaller watertube/firetube/firebox boilers.

The annualized cost impacts for the Low Oil Price Scenario range from \$4 million to \$22 million (1985 dollars). Table 2-14 presents estimates by boiler size class.

Cost-effectiveness is the annualized pollution control cost increase divided by the expected annual emissions reduction. It is assumed that the PM emissions reductions are incidental and that the total annualized pollution control cost increases can be compared with the expected SO_2 emissions reductions. If the total annualized pollution control cost increases were divided between the SO_2 and PM emissions reductions, then the SO_2 emissions control cost-effectiveness ratios in Tables 2-15 and 2-16 would be reduced.

Cost-effectiveness ratios can be calculated as average or incremental. "Average" is calculated by comparisons with the baseline. "Incremental" ratios can be derived by comparing the results for the 215 ng SO_2/J (0.5 lb SO_2/MMBtu) limit with the 688 ng SO_2/J (1.6 lb SO_2/MMBtu) standard and by comparing the estimates for the 129 ng SO_2/J (0.3 lb SO_2/MMBtu) regulation with the 215 ng SO_2/J (0.5 lb SO_2/MMBtu) scenario. Tables 2-15 and 2-16 show the average and incremental SO_2 emissions control cost-effectiveness ratios for residual fuel oil boilers by boiler size category.

2.3.1.2 Residual Fuel Oil: High Oil Prices

It is assumed that the fuel price increase (1985 dollars) for the stationary watertube boilers burning high sulfur residual fuel oil in the baseline is \$0.55/GJ (\$0.58/MMBtu) to comply with the 344 ng SO_2/J (0.8 lb SO_2/MMBtu) limit; for this group of boilers, the fuel price increase is

TABLE 2-14. PROJECTED ANNUALIZED COST INCREASES
FOR RESIDUAL FUEL OIL BOILERS[a]
(000 $1985)

Alternative SO_2 control level ng/J	(lb/MMBtu)	Boiler size, MW (MMBtu/hr) 1-3 (3-10)	3-9 (10-30)	9-29 (30-100)	1-29 (3-100)
		Without monitoring and testing costs			
688	(1.6)	0	575	3,970	4,545
344	(0.8)	2,326	2,577	9,926	14,829
215	(0.5)	3,101	3,245	11,911	18,257
129	(0.3)	3,566	3,646	13,102	20,314
		With monitoring and testing costs[b]			
688	(1.6)	1,020	780	4,250	6,050
344	(0.8)	3,346	2,782	10,206	16,334
215	(0.5)	4,121	3,450	12,191	19,762
129	(0.3)	4,586	3,851	13,382	21,819

[a] In the fifth year following proposal of NSPS; alternative NSPS fuel mix is assumed to be the same as the baseline fuel mix; Low Oil Price Scenario.

[b] Assumed to be $1,000 per year per boiler. These estimates do not include the aggregate monitoring and testing costs for distillate fuel oil boilers.

TABLE 2-15. PROJECTED RESIDUAL FUEL OIL BOILER AVERAGE SO_2 EMISSIONS CONTROL COST-EFFECTIVENESS RATIOS[a]

Alternative SO_2 control level ng/J	(lb/MMBtu)	Boiler size, MW (MMBtu/hr) 1-3 (3-10)	3-9 (10-30)	9-29 (30-100)	1-29 (3-100)
			(1985 $/Mg)		
688	(1.6)	---	591	497	602
344	(0.8)	1,119	743	648	726
215	(0.5)	1,019	741	660	728
129	(0.3)	966	732	661	721
			(1985 $/short ton)		
688	(1.6)	---	536	451	546
344	(0.8)	1,015	674	588	659
215	(0.5)	925	672	599	660
129	(0.3)	876	664	599	654

[a] Comparisons with the baseline; with monitoring and testing costs; alternative NSPS fuel mix is assumed to be the same as the baseline fuel mix; Low Oil Price Scenario.

TABLE 2-16. PROJECTED RESIDUAL FUEL OIL BOILER INCREMENTAL SO_2 EMISSIONS CONTROL COST-EFFECTIVENESS RATIOS[a]

Alternative SO_2 control level ng/J	(lb/MMBtu)	Boiler size, MW (MMBtu/hr) 1-3 (3-10)	3-9 (10-30)	9-29 (30-100)	1-29 (3-100)
		(1985 \$/Mg)			
688	(1.6)[b]	--	632	497	618
344	(0.8)[c]	827	827	827	827
215	(0.5)[d]	735	735	735	735
129	(0.3)[e]	661	661	661	661
		(1985 \$/short ton)			
688	(1.6)[b]	---	574	451	561
344	(0.8)[c]	750	750	750	750
215	(0.5)[d]	667	667	667	667
129	(0.3)[e]	600	600	600	600

[a] With monitoring and testing costs; alternative NSPS fuel mix is assumed to be the same as the baseline fuel mix; Low Oil Price Scenario.

[b] Compared with the baseline.

[c] Compared with the results for 688 ng/J (1.6 lb/MMBtu).

[d] Compared with the results for 344 ng/J (0.8 lb/MMBtu).

[e] Compared with the estimates for 215 ng/J (0.5 lb/MMBtu).

\$0.73/GJ (\$0.77/MMBtu) to comply with the 129 ng SO_2/J (0.3 lb SO_2/MMBtu) regulation.[3] It is assumed that the fuel price increase is \$0.34/GJ (\$0.36/MMBtu) for the smaller watertube/firetube/firebox boilers to comply with the 344 ng SO_2/J (0.8 lb SO_2/MMBtu) standard and \$0.52/GJ (\$0.55/MMBtu) to comply with the 129 ng SO_2/J (0.3 lb SO_2/MMBtu) level.[3]

The annualized cost impacts for the High Oil Price Scenario range from \$5 million to \$24 million (1985 dollars). Table 2-17 summarizes the estimates by boiler size class. Average and incremental residual fuel oil boiler SO_2 emissions control cost-effectiveness ratios are shown in Tables 2-18 and 2-19, respectively.

2.3.1.3 Coal

Table 2-20 summarizes the projected emission reductions for coal boilers by boiler size category. It was assumed that the average annual SO_2 emission rate is 430 ng SO_2/J (1.0 lb SO_2/MMBtu) under the alternative regulation.

Variability in SO_2 emission rates exists when burning coal without a scrubber. This variability is due to many factors, including the lack of uniformity in coal seams (geological or natural factors), as well as coal mining, processing, cleaning, transportation and storage practices which may result in some degree of "blending" or mixing.

EPA has adopted a continuous 30-day rolling average period (recomputed daily) for drafting SO_2 NSPS for coal boiler combustion sources. EPA believes that this is long enough to minimize variability (variability declines as the averaging period increases), in order to yield results that are representative of real performance, but also permits timely enforcement (i.e., daily) of compliance with standards.

EPA has estimated a ratio of about 1.20 between the maximum expected daily average SO_2 emission rate (computed from 30 days of data) and the long-term (i.e., annual) average emission rate. Therefore, a coal type with an average annual sulfur content of 430 ng SO_2/J (1.0 lb SO_2/MMBtu) is expected to comply with the alternative regulation.

TABLE 2-17. PROJECTED ANNUALIZED COST INCREASES FOR RESIDUAL FUEL OIL BOILERS[a] (000 $1985)

Alternative SO_2 control level ng/J	(lb/MMBtu)	Boiler size, MW (MMBtu/hr) 1-3 (3-10)	3-9 (10-30)	9-29 (30-100)	1-29 (3-100)
		Without monitoring and testing costs			
688	(1.6)	0	630	4,367	4,997
344	(0.8)	2,791	3,035	11,514	17,340
215	(0.5)	3,643	3,770	13,697	21,110
129	(0.3)	4,264	4,190	14,491	22,945
		With monitoring and testing costs[b]			
688	(1.6)	1,020	835	4,647	6,502
344	(0.8)	3,811	3,240	11,794	18,845
215	(0.5)	4,663	3,975	13,977	22,615
129	(0.3)	5,284	4,395	14,771	24,450

[a] In the fifth year following proposal of NSPS; alternative NSPS fuel mix is assumed to be the same as the baseline fuel mix; High Oil Price Scenario.

[b] Assumed to be $1,000 per year per boiler. These estimates do not include the aggregate monitoring and testing costs for distillate fuel oil boilers.

TABLE 2-18. PROJECTED RESIDUAL FUEL OIL BOILER AVERAGE SO_2 EMISSIONS CONTROL COST-EFFECTIVENESS RATIOS[a]

Alternative SO_2 control level ng/J	(lb/MMBtu)	Boiler size, MW (MMBtu/hr) 1-3 (3-10)	3-9 (10-30)	9-29 (30-100)	1-29 (3-100)
			(1985 \$/Mg)		
688	(1.6)	5,796	633	543	647
344	(0.8)	1,275	865	748	838
215	(0.5)	1,153	856	757	833
129	(0.3)	1,113	836	729	808
			(1985 \$/short ton)		
688	(1.6)	5,258	574	493	587
344	(0.8)	1,157	785	679	760
215	(0.5)	1,046	775	687	755
129	(0.3)	1,010	758	661	733

[a] Comparisons with the baseline; with monitoring and testing costs; alternative NSPS fuel mix is assumed to be the same as the baseline fuel mix; High Oil Price Scenario; reference Tables 2-12 and 2-17.

TABLE 2-19. PROJECTED RESIDUAL FUEL OIL BOILER INCREMENTAL SO_2 EMISSIONS CONTROL COST-EFFECTIVENESS RATIOS[a]

Alternative SO_2 control level ng/J	(lb/MMBtu)	Boiler size, MW (MMBtu/hr) 1-3 (3-10)	3-9 (10-30)	9-29 (30-100)	1-29 (3-100)
		(1985 $/Mg)			
688	(1.6)[b]	5,796	633	543	647
344	(0.8)[c]	992	992	992	992
215	(0.5)[d]	808	808	808	808
129	(0.3)[e]	882	693	441	590
		(1985 $/short ton)			
688	(1.6)[b]	5,258	574	493	587
344	(0.8)[c]	900	900	900	900
215	(0.5)[d]	733	733	733	733
129	(0.3)[e]	800	629	400	535

[a] With monitoring and testing costs; High Oil Price Scenario; reference Tables 2-12 and 2-17.

[b] Compared with the baseline.

[c] Compared with the results for 688 ng/J (1.6 lb/MMBtu).

[d] Compared with the results for 344 ng/J (0.8 lb/MMBtu).

[e] Compared with the estimates for 215 ng/J (0.5 lb/MMBtu).

TABLE 2-20. PROJECTED COAL BOILER EMISSIONS REDUCTIONS[a]

Alternative control level ng/J	(lb/MMBtu)	Boiler size, MW (MMBtu/hr) 1-3 (3-10)	3-9 (10-30)	9-29 (30-100)	1-29 (3-100)
			SO_2		
516[b]	(1.2)[b]	3,602	5,184	4,214	13,000
		(3,971)	(5,714)	(4,645)	(14,330)
			PM		
129	(0.3)	212	305	496	1,013
		(234)	(336)	(547)	(1,117)
21	(0.05)	560	819	911	2,290
		(617)	(903)	(1,004)	(2,524)

[a] In the fifth year following proposal of NSPS; reductions from baseline estimates presented in Table 2-6; alternative NSPS fuel mix is assumed to be the same as the baseline fuel mix.

[b] 30-day rolling average.

Table 2-21 shows the projected annualized pollution control cost increases for coal boilers by boiler size class. The SO_2 emissions control costs without monitoring and testing are based on a fuel price increase of \$0.31/GJ (\$0.33/MMBtu), 1985 dollars.[3] The SO_2 emissions control monitoring and testing costs are assumed to be \$31,000 per year per boiler.*

The PM emissions control costs for the 129 ng PM/J (0.3 lb PM/MMBtu) standard is based on the annualized capital and O&M costs for a double mechanical collector; a fabric filter is the applicable control equipment type for the 21 ng PM/J (0.05 lb PM/MMBtu) regulation. The PM emissions control monitoring and testing costs are assumed to be \$16,000 per year per boiler.* The coal boiler emissions control cost-effectiveness ratios are summarized in Table 2-22.

2.3.1.4 Distillate Fuel Oil

Significant SO_2 and PM emissions reductions from distillate fuel oil combustion are not expected. The baseline average emissions estimates are 129 ng SO_2/J (0.3 lb SO_2/MMBtu) and 4 ng PM/J (0.01 lb PM/MMBtu).

2.3.2 Alternative NSPS Fuel Mix is Different than the Baseline Fuel Mix

Very low sulfur residual fuel oil may not be readily available in all areas of the country with access to medium or high sulfur residual fuel oil supplies. In order to comply with the alternative SO_2 emission limits where very low sulfur residual fuel oil is not available, flue gas desulfurization (FGD) systems could be installed or other compliance fuels (e.g., distillate fuel oil or natural gas) could be purchased.

The national projections of the annualized cost increases and emissions reductions associated with alternative NSPS will be different (than the estimates presented in Section 2.3.1) if the compliance strategies are a mix of very low sulfur residual fuel oil and other alternatives. For sensitivity analyses purposes, it was assumed that half of the residual fuel oil demand in the baseline would select compliance very low sulfur residual fuel oil and half would choose distillate fuel oil under the alternative NSPS.

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* These monitoring and testing cost estimates do not necessarily reflect the average costs associated with the proposed standards.

TABLE 2-21. PROJECTED ANNUALIZED COST INCREASES FOR COAL BOILERS[a] (000 $1985)

Alternative control level ng/J	(lb/MMBtu)	Monitoring and testing	Boiler size, MW (MMBtu/hr) 1-3 (3-10)	3-9 (10-30)	9-29 (30-100)	1-29 (3-100)
				SO_2		
516[b]	(1.2)[b]	No	1,027	1,478	1,202	3,707
		Yes	5,522	4,113	1,822	11,457
				PM		
129	(0.3)	No	2,755	1,870	645	5,270
		Yes	5,075	3,230	965	9,270
21	(0.05)	No	5,945	5,860	2,830	14,725
		Yes	8,265	7,310	3,150	18,725

[a] In the fifth year following proposal of NSPS; alternative NSPS fuel mix is assumed to be the same as the baseline fuel mix.

[b] 30-day rolling average.

TABLE 2-22. PROJECTED COAL BOILER EMISSIONS CONTROL COST-EFFECTIVENESS RATIOS[a]
1985 \$/Mg (1985 \$/short ton)

Alternative control level ng/J	(lb/MMBtu)	Type	Boiler size, MW (MMBtu/hr) 1-3 (3-10)	3-9 (10-30)	9-29 (30-100)	1-29 (3-100)
				SO_2		
516[b]	(1.2)[b]	Average	1,533 (1,391)	793 (720)	432 (392)	881 (800)
				PM		
129	(0.3)	Average	23,940 (21,690)	10,590 (9,610)	1,950 (1,760)	9,150 (8,300)
21	(0.05)	Average	14,760 (13,400)	8,930 (8,100)	3,460 (3,140)	8,180 (7,420)
21	(0.05)	Incremental[c]	9,170 (8,330)	7,940 (7,200)	5,270 (4,780)	7,400 (6,720)

[a] With monitoring and testing costs.

[b] 30-day rolling average.

[c] Compared with the results for 129 ng PM/J (0.3 lb PM/MMBtu).

The average emissions estimates for distillate fuel oil are 129 ng SO_2/J (0.3 lb SO_2/MMBtu) and 4 ng PM/J (0.01 lb PM/MMBtu).

Tables 2-23 and 2-24 summarize the projected emissions reductions. Compared with the projections in Tables 2-12 and 2-13, these estimates are not substantially different.

2.3.2.1 Low Oil Price Scenario

The baseline projection of new small residual fuel oil boilers is not available by location or by economic sector (industrial versus commercial/institutional). The fuel price differences between residual and distillate fuel oils may vary by location and economic sector. As a result, two estimates (Tables 2-25 and 2-26) of the projected annualized cost increases have been prepared. The cost assumptions in Table 2-25 reflect Midwest industrial distillate fuel oil prices, whereas the cost assumptions in Table 2-26 are illustrative of higher East Coast commercial distillate fuel oil prices.[3]

The monitoring and testing costs are assumed to be applicable to distillate fuel oil boilers for the 129 ng SO_2/J (0.3 lb SO_2/MMBtu) regulation, but not for the 215 ng SO_2/J (0.5 lb SO_2/MMBtu) standard. Distillate fuel oil is assumed to be a compliance fuel for the 215 ng SO_2/J (0.5 lb SO_2/MMBtu) emission limit without the expense of fuel sampling or certification.

The projected SO_2 emissions control cost-effectiveness ratios in Tables 2-27 and 2-28 reflect monitoring and testing costs, fuel price increases and SO_2 emissions reductions for the baseline residual fuel oil boilers as well as the monitoring and testing costs (without any expected SO_2 emissions reductions) for the baseline distillate fuel oil boilers. It is assumed that the PM emissions reductions are incidental and that the total annualized pollution control cost increases can be compared with the expected SO_2 emissions reductions. If the total annualized pollution control cost increases were divided between the SO_2 and PM emissions reductions, then the SO_2 emissions control cost-effectiveness ratios in Tables 2-27 and 2-28 would be reduced.

2.3.2.2 High Oil Price Scenario

As above, two estimates of the projected annualized cost increases have been developed; Table 2-29 reflects Midwest industrial distillate fuel oil

TABLE 2-23. PROJECTED RESIDUAL FUEL OIL BOILER SO_2 EMISSIONS REDUCTIONS[a]

Alternative SO_2 control level ng/J	(lb/MMBtu)	Boiler size, MW (MMBtu/hr) 1-3 (3-10)	3-9 (10-30)	9-29 (30-100)	1-29 (3-100)
		(metric tons, Mg)			
344	(0.8)	3,868	4,502	18,009	26,379
215	(0.5)	4,394	4,956	19,358	28,709
129	(0.3)	4,745	5,259	20,258	30,263
		(short tons)			
344	(0.8)	4,264	4,963	19,851	29,078
215	(0.5)	4,844	5,463	21,339	31,646
129	(0.3)	5,231	5,797	22,331	33,359

[a] In the fifth year following proposal of NSPS; reductions from baseline estimates in Table 2-4; alternative NSPS fuel mix is assumed to have less residual fuel oil and more distillate fuel oil than the baseline fuel mix.

TABLE 2-24. PROJECTED RESIDUAL FUEL OIL BOILER PM EMISSIONS REDUCTIONS[a]

Alternative SO_2 control level ng/J	(lb/MMBtu)	Boiler size, MW (MMBtu/hr) 1-3 (3-10)	3-9 (10-30)	9-29 (30-100)	1-29 (3-100)
			(metric tons, Mg)		
344	(0.8)	291	381	1,646	2,318
215	(0.5)	327	411	1,736	2,473
129	(0.3)	361	442	1,826	2,629
			(short tons)		
344	(0.8)	321	420	1,814	2,555
215	(0.5)	360	453	1,914	2,727
129	(0.3)	398	487	2,013	2,898

[a] In the fifth year following proposal of NSPS; alternative NSPS fuel mix is assumed to have less residual fuel oil and more distillate fuel oil than the baseline fuel mix.

TABLE 2-25. PROJECTED ANNUALIZED COST INCREASES FOR OIL BOILERS[a] (000 $1985)

Alternative SO_2 control level ng/J	(lb/MMBtu)	Boiler size, MW (MMBtu/hr) 1-3 (3-10)	3-9 (10-30)	9-29 (30-100)	1-29 (3-100)
		Without monitoring and testing costs			
344	(0.8)	4,884	4,781	16,476	26,141
215	(0.5)	5,271	5,115	17,468	27,854
129	(0.3)	5,504	5,315	18,064	28,883
		With monitoring and testing costs			
344	(0.8)	5,394[b]	4,883[b]	16,616[b]	26,893[b]
215	(0.5)	5,781[b]	5,217[b]	17,608[b]	28,606[b]
129	(0.3)	12,214[c]	5,895[c]	18,399[c]	36,508[c]

[a] In the fifth year following proposal of NSPS; alternative NSPS fuel mix is assumed to have less residual fuel oil and more distillate fuel oil than the baseline fuel mix; Low Oil Price Scenario.

[b] $1,000 per year per residual fuel oil boiler.

[c] $1,000 per year per residual and distillate fuel oil boiler.

TABLE 2-26. PROJECTED ANNUALIZED COST INCREASES FOR OIL BOILERS[a] (000 $1985)

Alternative SO_2 control level ng/J	(lb/MMBtu)	Boiler size, MW (MMBtu/hr) 1-3 (3-10)	3-9 (10-30)	9-29 (30-100)	1-29 (3-100)
		Without monitoring and testing costs			
344	(0.8)	7,711	7,220	23,722	38,653
215	(0.5)	8,101	7,554	24,714	40,369
129	(0.3)	8,331	7,757	25,310	41,398
		With monitoring and testing costs			
344	(0.8)	8,221[b]	7,322[b]	23,862[b]	39,405[b]
215	(0.5)	8,611[b]	7,656[b]	24,854[b]	41,121[b]
129	(0.3)	15,041[c]	8,337[c]	25,645[c]	49,023[c]

[a] In the fifth year following proposal of NSPS; alternative NSPS fuel mix is assumed to have less residual fuel oil and more distillate fuel oil than the baseline fuel mix; Low Oil Price Scenario.

[b] $1,000 per year per residual fuel oil boiler.

[c] $1,000 per year per residual and distillate fuel oil boiler.

TABLE 2-27. PROJECTED OIL BOILER SO_2 EMISSIONS CONTROL AVERAGE COST-EFFECTIVENESS RATIOS[a]

Alternative SO_2 control level ng/J	(lb/MMBtu)	Boiler Size, MW (MMBtu/hr) 1-3 (3-10)	3-9 (10-30)	9-29 (30-100)	1-29 (3-100)
		(1985 \$/Mg)			
344	(0.8)	1,394-2,125	1,084-1,626	923-1,325	1,019-1,494
215	(0.5)	1,316-1,959	1,053-1,545	909-1,284	996-1,432
129	(0.3)	2,574-3,169	1,121-1,585	908-1,265	1,206-1,620
		(1985 \$/short ton)			
344	(0.8)	1,265-1,928	984-1,475	837-1,202	925-1,355
215	(0.5)	1,193-1,777	955-1,401	825-1,164	904-1,299
129	(0.3)	2,335-2,875	1,017-1,438	824-1,148	1,095-1,470

[a] With monitoring and testing costs; alternative NSPS fuel mix is assumed to have less residual fuel oil and more distillate fuel oil than the baseline fuel mix; Low Oil Price Scenario.

TABLE 2-28. PROJECTED OIL BOILER SO_2 EMISSIONS CONTROL INCREMENTAL COST-EFFECTIVENESS RATIOS[a]

Alternative SO_2 control level ng/J	(lb/MMBtu)	Boiler size, MW (MMBtu/hr) 1-3 (3-10)	3-9 (10-30)	9-29 (30-100)	1-29 (3-100)
		(1985 $/Mg)			
215	(0.5)[b]	735	735	735	735
129	(0.3)[c]	18,324	2,243	879	5,085
		(1985 $/short ton)			
215	(0.5)[b]	667	667	667	667
129	(0.3)[c]	16,623	2,034	797	4,613

[a] With monitoring and testing costs; alternative NSPS fuel mix is assumed to have less residual fuel oil and more distillate fuel oil than the baseline fuel mix; Low Oil Price Scenario.

[b] Compared with the results for 344 ng/J (0.8 lb/MMBtu).

[c] Compared with the estimates for 215 ng/J (0.5 lb/MMBtu).

TABLE 2-29. PROJECTED ANNUALIZED COST INCREASES FOR OIL BOILERS[a] (000 $1985)

Alternative SO_2 control level ng/J	(lb/MMBtu)	Boiler size, MW (MMBtu/hr) 1-3 (3-10)	3-9 (10-30)	9-29 (30-100)	1-29 (3-100)
		Without monitoring and testing costs			
344	(0.8)	6,279	6,041	20,446	32,766
215	(0.5)	6,705	6,408	21,537	34,650
129	(0.3)	7,016	6,675	22,331	36,022
		With monitoring and testing costs			
344	(0.8)	6,789[b]	6,143[b]	20,586[b]	33,518[b]
215	(0.5)	7,215[b]	6,510[b]	21,677[b]	35,402[b]
129	(0.3)	13,726[c]	7,255[c]	22,666[c]	43,647[c]

[a] In the fifth year following proposal of NSPS; alternative NSPS fuel mix is assumed to have less residual fuel oil and more distillate fuel oil than the baseline fuel mix; High Oil Price Scenario.

[b] $1,000 per year per residual fuel oil boiler.

[c] $1,000 per year per residual and distillate fuel oil boiler.

prices and Table 2-30 is based on higher East Coast commercial distillate fuel oil prices.[3]

The monitoring and testing costs are assumed to be applicable to distillate fuel oil boilers for the 129 ng SO_2/J (0.3 lb SO_2/MMBtu) regulation, but not for the 215 ng SO_2/J (0.5 lb SO_2/MMBtu) standard. Distillate fuel oil is assumed to be a compliance fuel for the 215 ng SO_2/J (0.5 lb SO_2/MMBtu) emission limit without the expense of fuel sampling or certification.

The projected SO_2 emission control cost-effectiveness ratios in Tables 2-31 and 2-32 reflect monitoring and testing costs, fuel price increases and SO_2 emission reductions for the baseline residual fuel oil boilers as well as the monitoring and testing costs (without any expected SO_2 emissions reductions) for the baseline distillate fuel oil boilers. It is assumed that the PM emissions reductions are incidental and that the total annualized pollution control cost increases can be compared with the expected SO_2 emissions reductions. If the total annualized pollution control cost increases were divided between the SO_2 and PM emissions reductions, then the SO_2 emissions control cost-effectiveness ratios in Tables 2-31 and 2-32 would be reduced.

2.3.3 Summary of Projected Emissions Reductions

Tables 2-33 and 2-34 summarize the expected SO_2 and PM emissions reductions in the fifth year following proposal of NSPS. These forecasts may be understated if residual fuel oil and coal boiler sales increase above recent levels.

TABLE 2-30. PROJECTED ANNUALIZED COST INCREASES FOR OIL BOILERS[a] (000 $1985)

Alternative SO_2 control level ng/J	(lb/MMBtu)	Boiler size, MW (MMBtu/hr) 1-3 (3-10)	3-9 (10-30)	9-29 (30-100)	1-29 (3-100)
		Without monitoring and testing costs			
344	(0.8)	9,222	8,580	27,990	45,792
215	(0.5)	9,649	8,948	29,082	47,679
129	(0.3)	9,959	9,215	29,876	49,050
		With monitoring and testing costs			
344	(0.8)	9,732[b]	8,682[b]	28,130[b]	46,544[b]
215	(0.5)	10,159[b]	9,050[b]	29,222[b]	48,431[b]
129	(0.3)	16,669[c]	9,795[c]	30,211[c]	56,675[c]

[a] In the fifth year following proposal of NSPS; alternative NSPS fuel mix is assumed to have less residual fuel oil and more distillate fuel oil than the baseline fuel mix; High Oil Price Scenario.

[b] $1,000 per year per residual fuel oil boiler.

[c] $1,000 per year per residual and distillate fuel oil boiler.

TABLE 2-31. PROJECTED OIL BOILER SO_2 EMISSIONS CONTROL AVERAGE COST-EFFECTIVENESS RATIOS[a]

Alternative SO_2 control level ng/J	(lb/MMBtu)	Boiler Size, MW (MMBtu/hr) 1-3 (3-10)	3-9 (10-30)	9-29 (30-100)	1-29 (3-100)
			(1985 \$/Mg)		
344	(0.8)	1,755-2,516	1,365-1,928	1,143-1,562	1,271-1,764
215	(0.5)	1,642-2,312	1,314-1,826	1,120-1,510	1,233-1,687
129	(0.3)	2,893-3,513	1,380-1,863	1,119-1,491	1,442-1,873
			(1985 \$/short ton)		
344	(0.8)	1,592-2,282	1,238-1,749	1,037-1,417	1,153-1,601
215	(0.5)	1,489-2,097	1,192-1,657	1,016-1,369	1,119-1,530
129	(0.3)	2,624-3,187	1,252-1,690	1,015-1,353	1,308-1,699

[a] With monitoring and testing costs; alternative NSPS fuel mix is assumed to have less residual fuel oil and more distillate fuel oil than the baseline fuel mix; High Oil Price Scenario.

TABLE 2-32. PROJECTED OIL BOILER SO_2 EMISSIONS CONTROL INCREMENTAL COST-EFFECTIVENESS RATIOS[a]

Alternative SO_2 control level ng/J	(lb/MMBtu)	Boiler size, MW (MMBtu/hr) 1-3 (3-10)	3-9 (10-30)	9-29 (30-100)	1-29 (3-100)
		(1985 $/Mg)			
215	(0.5)[b]	809	809	809	809
129	(0.3)[c]	18,547	2,459	1,099	5,305
		(1985 $/short ton)			
215	(0.5)[b]	734	734	734	734
129	(0.3)[c]	16,822	2,231	997	4,813

[a] With monitoring and testing costs; alternative NSPS fuel mix is assumed to have less residual fuel oil and more distillate fuel oil than the baseline fuel mix; High Oil Price Scenario.

[b] Compared with the results for 344 ng/J (0.8 lb/MMBtu).

[c] Compared with the estimates for 215 ng/J (0.5 lb/MMBtu).

TABLE 2-33. SUMMARY OF EXPECTED SO_2 EMISSIONS REDUCTIONS[a]

Fuel type	Alternative SO_2 control level ng/J	(lb/MMBtu)	Boiler size, MW (MMBtu/hr) 1-3 (3-10)	3-9 (10-30)	9-29 (30-100)	1-29 (3-100)
			(10^3 metric tons)			
Residual fuel oil	688	(1.6)	0.2	1.3	8.6	10.1
	344	(0.8)	2.9-3.9	3.7-4.5	15.8-18.0	22.5-26.4
	215	(0.5)	4.0-4.4	4.7-5.0	18.4-19.4	27.2-28.7
	129	(0.3)	4.7	5.2	20.3	30.3
Coal	516	(1.2)[b]	3.6	5.2	4.2	13.0
			(10^3 short tons)			
Residual fuel oil	688	(1.6)	0.2	1.5	9.4	11.1
	344	(0.8)	3.3-4.3	4.1-5.0	17.4-19.9	24.8-29.1
	215	(0.5)	4.4-4.8	5.1-5.5	20.3-21.3	29.9-31.6
	129	(0.3)	5.2	5.8	22.3	33.4
Coal	516	(1.2)[b]	4.0	5.7	4.6	14.3

[a] In the fifth year following proposal of NSPS; reductions from baseline estimate.

[b] 30-day rolling average.

TABLE 2-34. SUMMARY OF EXPECTED PM EMISSIONS REDUCTIONS[a]

Fuel type	Alternative control level ng/J	(lb/MMBtu)	Boiler size, MW (MMBtu/hr) 1-3 (3-10)	3-9 (10-30)	9-29 (30-100)	1-29 (3-100)
	SO_2		(10^3 metric tons)			
Residual fuel oil	688	(1.6)	0	0.1	0.9	1.0
	344	(0.8)	0.2-0.3	0.3-0.4	1.4-1.6	1.8-2.3
	215	(0.5)	0.2-0.3	0.3-0.4	1.5-1.7	2.1-2.5
	129	(0.3)	0.3-0.4	0.4	1.7-1.8	2.4-2.6
	PM					
Coal	129	(0.3)	0.2	0.3	0.5	1.0
	21	(0.05)	0.6	0.8	0.9	2.3
	SO_2		(10^3 short tons)			
Residual fuel oil	688	(1.6)	0	0.1	1.0	1.1
	344	(0.8)	0.2-0.3	0.3-0.4	1.5-1.8	2.0-2.6
	215	(0.5)	0.3-0.4	0.4-0.5	1.7-1.9	2.3-2.7
	129	(0.3)	0.3-0.4	0.4-0.5	1.9-2.0	2.7-2.9
	PM					
Coal	129	(0.3)	0.2	0.3	0.5	1.1
	21	(0.05)	0.6	0.9	1.0	2.5

[a] In the fifth year following proposal of NSPS; reductions from baseline estimate.

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3. ECONOMIC IMPACTS: COMMERCIAL/INSTITUTIONAL SECTOR

3.1 INTRODUCTION

The assessment of the potential economic impact of a NSPS on commercial/institutional (C/I) boilers was organized two ways. One set of analyses focused on the impact of new regulations on "generic" buildings where boilers are used only for space and hot water heating -- the predominant use of boilers in commercial/institutional buildings. Here the impacts of potential regulatory costs are related to the operating budgets and rental rates of commercial buildings. A second set of analyses focused on selected commercial sectors where economic impacts might be more severe than for "generic" buildings. For example, applications such as laundries or hospitals, where steam is used for specialized purposes other than space heating, could lead to more significant economic impacts for those sectors.

This analysis is focused on the impacts of "model plants" intended to be representative of various situations where boilers are used in the C/I sector. In most instances, the model plant is actually one building where boilers provide various energy services, depending on the activities of the building occupants. An example of this situation is a building where boilers are used exclusively for space and hot water heating. In some commercial sector applications, such as hotel chains or large commercial laundries, one firm may own several buildings or "model plants." In these cases, we have tried to focus on the specific building or boiler installation as our model unit for analysis. We have done so because a business with multiple plants will consider the economic viability of each of its plants.

An important aspect of the economic analysis for C/I boilers is that it should be viewed as a "worst case" analysis intended to identify the limits of possible adverse consequences of a NSPS. The reasons why this should be viewed as a "worst case" analysis are:

- Only very stringent regulatory scenarios are considered such as very low sulfur residual oil or installation of flue gas desulfurization equipment.
- These stringent regulations are applied to <u>all</u> boiler sizes in the model building analyses, ignoring the effect of a boiler size cutoff; the proposed NSPS may not be applicable to all of these boiler sizes.

- In buildings with more than one boiler installed, we have assumed that all boilers in the building would be subject to the NSPS. In fact, most new boilers would be replacements in existing buildings* and not all of the existing boilers would necessarily be replaced at the same time.
- We have made no allowance for the fact that several urban areas already have regulations. In effect, the baseline for considering impacts of the NSPS implies no (or very lax) regulatory controls are currently in place.
- The analysis assumes that the boilers are firing a dirty fuel (e.g. residual oil) rather than natural gas. The impacts presented here would be applicable only when such dirty fuels are fired. In fact, natural gas is currently the predominant fuel choice in C/I boilers.*

All of these considerations tend to overstate the likely economic impacts of any NSPS, emphasizing that this is a "worst case" type of analysis.

3.2 SELECTED SECTORS

3.2.1 Approach

The goals in this phase of the study are threefold: 1) identify those boiler applications which would likely incur economic impacts from a New Source Performance Standard for small boilers used in commercial/institutional buildings; 2) select from each sector several "example" firms for which sufficient data on boiler use and establishment sales could be obtained; and 3) examine pollution control cost impacts for each selected firm/sector.

Several factors were considered in selecting specific end uses. One factor was to try to identify applications which use boilers for other purposes beside space heating, such as cooking, baking, sterilization. To the extent that energy usage is more intensive (Btus per dollar of sales), economic impacts would tend to be greater. Another consideration might be an application which tends to have a low ratio of business sales/revenue per square foot of building space. In such instances, increases of building operating costs would tend to have a more significant effect on price increases needed to sustain profitability. Motels or hotels and some labor service activities could be examples where building operating costs are a more

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* See Appendix A

significant element in the total costs of the firm. Still another factor would be to consider public entities, such as schools, which are widespread and where the economic impacts take the form of increases in local government budgets.

Important examples of commercial/institutional establishments that use boilers for applications other than space heating include laundries, hospitals and some hotels. These three groups have been included in this analysis because they have daily special steam demand requirements that are distinct from the seasonal space heating requirements in generic buildings.

Colleges and universities have also been included in this selected sectors analysis. This group uses relatively large boilers in central heating facilities and sends steam or hot water through underground pipes to most or all of the numerous buildings on campus. This group is distinct from the generic buildings discussed in Section 3.3 because the typical college/university boiler sizes are substantially larger than the typical boilers in commercial "generic" buildings.

Elementary and secondary schools are another "selected sector." Elementary and secondary schools use boilers for seasonal space heating purposes like generic buildings. They are analyzed in this section (as opposed to Generic Buildings, Section 3.3) because comparing pollution control costs to building rental rates is not appropriate for this group.

3.2.2 Data Sources and Descriptions of Selected Sectors

Data on the boiler configuration and total annual costs/revenues per establishment for large and small firms within each selected sector have been gathered through telephone contacts and reviews of published company financial statements. (In performing this part of the analysis, effort has focused on publicly-owned companies due to government rules limiting contacts with individual firms). Specifically, the following information has been obtained:

Number and size of boilers per establishment
Annual hours of operation per boiler
Boiler fuel type
Annual boiler fuel use and expenditures

Building (or establishment) size (sq. feet)

Annual total revenues (or total expenditures) per establishment

In some instances data on annual boiler fuel use, annual boiler fuel expenditures and/or establishment-specific total annual revenues were unavailable. Therefore, estimates of these data were made using the following procedures:

- Annual Boiler Fuel Consumption
  Data are collected on: 1) boiler heat input (in MMBtu/hr), 2) average daily number of hours of boiler operation, and 3) average number of days per year of boiler use for establishments in each selected sector. The product of these three variables yields an estimate of total boiler fuel consumption for an establishment.
- Annual Boiler Fuel Expenditures
  Where data on total annual boiler fuel expenditures are not forthcoming, information has been obtained on the average mix of fuels used in the boiler and average annual fuel prices per MMBtu. These data have been used in conjunction with the boiler fuel use estimates to calculate total fuel expenditures.
- Annual Total Revenues (or Expenditures) per Establishment
  As noted earlier, information on establishment-specific total sales (or total costs) is a key requirement for evaluating economic impact. This also is the information most difficult to obtain from individual companies and institutions. Therefore, estimates have been made using a variety of approaches and other data as follows:

  Elementary and Secondary Schools:

  Total Cost per School = (pupils/school) * (cost/pupil)

  Hospitals

  Total Cost per Hospital = (beds/hospital) * (cost/bed)

  Hotels

  Total Sales = (rooms/hotel) * (average occupancy rate) * (average daily room rate) * 365 days/year

  Laundries Total Sales per facility = (total company sales) * (facility sq. ft)/ (total sq. ft of all company facilities)

Elementary and Secondary Schools

Boiler configuration data for 100 boilers in elementary and secondary schools in Illinois, provided by the Illinois Environmental Protection Agency, show that all of the boiler sizes are smaller than 4 MW (15 MMBtu/hr) and most of these boilers are smaller than 3 MW (10 MMBtu/hr).

Table 3-1 presents a range of data on the boiler configurations of four typical elementary and four secondary schools located in urban mid-Atlantic cities. The boilers range from 125 hp to 150 hp and are used primarily for space heating during the winter. As shown in Table 3-1, the boilers provide heat for buildings ranging in size from about 47,000 to 200,000 square feet. The fuel used to fire the boilers constitutes a relatively small percentage of the total school budget -- 0.4-1.7 percent.

Hospitals

Generally, boilers used in hospitals provide steam for the preheat coils in air handling units, and for heat exchangers which provide hot water for perimeter heating (fan coils and convectors), zone control heating, domestic hot water, humidification and sterilization. Boiler configuration data for 73 boilers in hospitals in Illinois (provided by the Illinois Environmental Protection Agency), 76 boilers in hospitals in Minnesota (provided by the Minnesota Pollution Control Agency) and 92 boilers in hospitals in Boston (provided by the Commonwealth of Massachusetts, Department of Environmental Quality Engineering, Division of Air Quality Control) indicate that most of the boilers are smaller than 9 MW (30 MMBtu/hr).

Table 3-2 provides statistics on the boiler configurations of three hospitals ranging in size from 365,000 square feet to 760,000 square feet. All of these hospitals are equipped with multiple boilers. Typically, one boiler is used only as a back-up. The others are used for various lengths of time throughout the year depending on need. As shown in Table 3-2, the boilers are sized between 5 and 14.2 MW (17 MMBtu/hr and 48.5 MMBtu/hr). Depending on the extent to which the boilers are operated, annual fuel consumption ranges from 44.3 TJ (42,000 MMBtu) to 180.4 TJ (171,000 MMBtu). Although hospitals are more energy-intensive, the annual cost of fueling a boiler is a relatively insignificant portion of the total annual costs of operating a hospital: 0.3 -1.4 percent. The relatively low share of fuel costs in hospital budgets is due to the high costs of highly-trained doctors and auxiliary personnel plus increasingly expensive medical equipment.

TABLE 3-1. ELEMENTARY AND SECONDARY SCHOOLS

	Junior High School[a]	Elementary School[a]
Boiler Configuration	3 steam boilers 125 hp each (5 MMBtu/hr each)	2 steam boilers 150 hp each (6 MMBtu/hr each)
Building Size	125,000 - 185,000 sq. ft.	47,000 - 104,000 sq. ft.
Annual Fossil Fuel Use (MMBtu)	5,606 - 7,984	3,177 - 5,872
Boiler Fuel Costs (x 1000)	$22.9 - 32.6	$13.0 - 35.9
Enrollment (No. of pupils)	455 - 1,450	460-670
Annual Building Operating Costs[b] (x1,000)	$1,727 - 5,504	$1,746 - 2,543
Boiler Fuel as % of Total Costs	0.4 - 1.7	0.5 - 1.7

[a] Range for four schools.

[b] $3,796/pupil times the total number of pupils.

TABLE 3-2. HOSPITALS

	Hospital A	Hospital B	Hospital C
Boiler Configuration	B1: 29.1 MMBtu/hr B2: 29.1 MMBtu/hr	B1: 16.7 MMBtu/hr B2: 25.1 MMBtu/hr B3: 25.1 MMBtu/hr	B1: 48.5 MMBtu/hr B2: 48.5 MMBtu/hr B3: 29.1 MMBtu/hr
Building Size	460,000 sq. ft	365,000 sq. ft	760,000 sq. ft
Annual Fossil Fuel Use (MMBtu)	42,048	170,820	121,300
Boiler Fuel Costs (x 1000)	$204	$827	$642
Annual Building Operating Costs (x1,000)	$76,303	$59,818	$136,696
Boiler Fuel as % of Total Costs	0.3	1.4	0.5

Laundries

Commercial laundries require substantial quantities of steam for washing, drying and finishing operations. Wash water heating is probably the major source of boiler load in a commercial laundry. Boiler configuration data for 15 boilers in laundries in Illinois, 4 boilers in laundries in Minnesota and 18 boilers in laundries in Boston show that all of the boiler sizes are smaller than 15 MW (50 MMBtu/hr) and most are smaller than 6 MW (20 MMBtu/hr). Commercial laundry boilers are characterized by relatively high capacity utilization rates: about 55 percent.

The boilers in Table 3-3 range in size from 2.9 - 7.3 MW (10.0 to 25.1 MMBtu/hr). Many laundry establishments are equipped with at least one back-up boiler although, as noted in the table, some are only single-boiler operations.

Since boilers are used relatively intensively in laundry operations, one would expect that the cost of fueling a boiler might be a significant fraction of total establishment sales. Given the estimates of total annual boiler fuel expenditures obtained from three laundry plants (shown in Table 3-3), this appears not to be the case. Using these data, boiler fuel costs range from 1.8 to 2.7 percent of total plant revenues. However, the total boiler fuel expenditures reported by the laundry plants listed in Table 3-3 imply fuel prices which were only 50 percent of the national average price for natural gas in 1986. Using the latter price, as more representative of most laundries, and the estimates of annual boiler fuel use in Table 3-3, boiler fuel costs range from 4.2 percent to 8.3 percent of total plant revenues.

Hotels

Boiler applications in hotels vary broadly. In some hotels boilers are used to provide steam for general space and hot water heating in guest rooms as well as driving turbines for summer cooling, running water pumps, laundry, heated swimming pool and restaurant facilities on the premises. In other hotels, boilers are used only for very specific applications and are therefore very small. For example, a medium-sized hotel in Washington, D.C. relies on a 80 kW (0.3 MMBtu/hr) boiler to provide steam for an on-site laundry facility that is operated 14 hours/day and 6 days per week. Boiler configuration data

TABLE 3-3. LAUNDRIES

	Laundry A		
	Plant 1	Plant 2	Laundry B
Boiler Configuration	B1: 23.4 MMBtu/hr B2: 16.7 MMBtu/hr	B1: 10.0 MMBtu/hr B2: 10.0 MMBtu/hr	B1: 25.1 MMBtu/hr
Building Size	75,000 sq. ft	65,000 sq. ft	N.A.
Annual Fossil Fuel Use (MMBtu)	109,500	47,400	125,750
Annual Plant Sales (x1,000)	$11,100	$5,600	$7,500
Boiler Fuel as % of Total Sales	2.7 - 4.9	2.7 - 4.2	1.8 - 8.3

for 21 boilers in hotels in Boston indicate that all boilers are smaller than 7 MW (25 MMBtu/hr).

Boiler configuration data for a large and a small hotel are presented in Table 3-4. Both hotels rely on boilers primarily to supply space and hot water heating for guest rooms, laundry and kitchen facilities particularly during the winter. As shown in the table, the annual boiler fuel consumption varies widely between the two hotels -- a reflection of different building and boiler sizes and different degrees of boiler usage. Despite the difference in the absolute values for boiler fuel consumption and hotel revenues, boiler fuel costs are roughly the same percentage of total sales (1.6-2.0 percent) for both the large and the small hotel.

Colleges and Universities.

Boiler configuration data for 72 boilers in colleges/universities in Illinois, 90 boilers in colleges/universities in Minnesota and 86 boilers in colleges/universities in Boston show that boiler sizes range from very small (<1 MW, <5 MMBtu/hr) to large (>29 MW, >100 MMBtu/hr).

Boiler configuration data for a large university and a small college are presented in Table 3-5. In both cases, boilers are used to provide steam for hot water and space heating for a number of buildings at various times throughout the year. Generally, the boilers are operated one at a time except during peak periods (i.e., winter) when additional capacity is needed.

With respect to the large university shown in Table 3-5, two of the boilers are sized above the 29 MW (100 MMBtu/hr) level (currently defined as the cut-off for "small" boilers). The other two boilers are only slightly below the cut-off point. For this reason, this example has not been included in the cost impact analysis presented below. However, it is interesting to note that the proportion of total operating costs contributed by annual boiler fuel expenditures is very low (1.4 percent) and essentially similar to that of the small college listed in Table 3-5.

3.2.3 Worst Case Economic Impacts

Boiler fuel expenditures as a percentage of total revenues per establishment provide an indication of the overall importance of steam in relation to total sales (or budgets) for selected commercial/institutional

TABLE 3-4. HOTELS

	Large Hotel	Small Hotel
Boiler Configuration	B1: 8.35 MMBtu/hr B2: 11.70 MMBtu/hr	5 steam boilers 0.7 MMBtu/hr each
Building Size	685 rooms	227 rooms
Annual Fossil Fuel Use (MMBtu)	72,010	8,486
Boiler Fuel Costs (x 1000)	$294	$53
Annual Building Revenues (x1,000)	$14,883	$3,430
Boiler Fuel as % of Total Revenues	2.0	1.6

TABLE 3-5. COLLEGES AND UNIVERSITIES

	Large University	Small College
Boiler Configuration	B1: 145 MMBtu/hr B2: 121 MMBtu/hr B3: 97 MMBtu/hr B4: 85 MMBtu/hr	B1: 24 MMBtu/hr B2: 29 MMBtu/hr B3: 10 MMBtu/hr
Annual Fossil Fuel Use (MMBtu)	922,000	107,383
Boiler Fuel Costs (x 1000)	$4,000	$444
Annual Building Operating Costs (x1,000)	$293,291	$29,585
Boiler Fuel as % of Total Costs	1.4	1.5

sectors. To evaluate the economic impacts of a NSPS, it also is essential to examine the ability of a firm to pay for the costs of pollution control. In this respect, a useful measure is the annualized cost of pollution control as a percentage of total annual revenues per establishment.

The objective is to use relatively high (not necessarily the most likely) compliance costs estimates in order to delimit the magnitude of possible adverse economic impacts. The "worst case" cost impact is calculated by assuming full pass-through of compliance costs. Most commercial/institutional buildings do not use boilers (see Tables A-1 and A-2) and, therefore, will not be subject to any economic impacts due to a NSPS.

A "worst case" cost estimate for coal combustion would be patterned after the promulgated PM and NO_x NSPS for large (>29 MW, >100 MMBtu/hr) industrial-commercial-institutional boilers (51 FR 42768) and the promulgated SO_2 NSPS for large industrial-commercial-institutional boilers (52 FR 47827). It would include a sodium scrubber (other feasible and demonstrated, but more expensive alternatives are dual alkali and lime spray drying FGD systems), a SO_2 monitor at the FGD inlet, a SO_2 monitor at the FGD outlet, a PM emissions control device (an electrostatic precipitator or a fabric filter--because the wet FGD system may not, in and of itself, remove enough of the PM emissions), an opacity monitor, a low excess air system to control NO_x emissions, a NO_x monitor, and an O_2/CO_2 outlet diluent monitor. However, relatively few coal-fired boilers smaller than 29 MW (100 MMBtu/hr) have been used in the commercial/institutional sector. Even fewer coal-fired boilers may be ordered in the next five years because of the drop in oil prices since early 1986.

Most of the boilers in the commercial/institutional sector fire natural gas (see Table A-1). Natural gas is not subject to the proposed SO_2 and PM emissions standards. Therefore, adverse economic impacts are not expected for new small package boilers firing natural gas.

Given that coal is not a representative new small boiler fuel type in the commercial-institutional sector and that adverse economic impacts are not expected from new small boilers firing natural gas, this analysis has focused on distillate and residual fuel oil combustion compliance options.

An expensive control compliance option would be to require a scrubber for fuel oil combustion in new small boilers. EPA has determined that sodium scrubbing systems, a conventional wet flue gas desulfurization (FGD) system, have been widely applied to small oil-fired steam-generating units and are considered demonstrated for purposes of developing NSPS.[1]

EPA has prepared estimates of the annualized capital and operating costs for various sizes of scrubbers.[2] In applying these costs, some assumptions concerning boiler operation in multiple boiler establishments are necessary. Specifically, in sizing the scrubbers it is assumed that multiple boiler establishments: 1) operate boilers one at a time; 2) use the largest boiler most of the time; and 3) employ the other boilers as back-up units. These assumptions reflect the standard boiler operating procedures stated by most of the respondents who provided data for this analysis. The assumption of single boiler operation in multiple boiler establishments also is verified by the relatively low boiler capacity utilization rates characteristic of most of the selected sectors.

Table 3-6 incorporates the selected sector data from Section 3.2.2 with information on the annualized capital and operating costs for various sizes of scrubbers. Boiler fuel expenditures account for from 0.5 percent to as much as 8 percent of the total annual revenues of a commercial/institutional establishment. The incremental costs of pollution control are under 5 percent of total annual revenues for each of the selected sectors. The results suggest that this very stringent control requirement could lead to potential increases of 2-4 percent in the prices of (or budgets for) some laundries, hotels and schools.

The impacts of this very stringent control scenario did not include the costs of monitoring and testing, which can be a significant expense.[3] Table 3-7 summarizes EPA estimates for these parameters. The cost estimates in Table 3-7 do not necessarily reflect the average expenses associated with the proposed standards. Table 3-8 shows the impacts of including monitoring and testing costs. The result indicates potential price increases (or budget increases for schools) of from 3 to 8 percent for some laundries, hotels and schools.

TABLE 3-6. SELECTED SECTORS ECONOMIC IMPACTS: FGD
(Without Monitoring and Testing Costs)

Sector	Annual Revenues (x 1,000 $)	Scrubber Size (MMBtu/hr)	Annualized Scrubber Cost[a] (x 1,000 $)	Boiler Fuel Cost Percent[b]	Pollution Control Percent[c]
Laundry A:					
Plant 1	11,100	23.4	120.4	2.7-4.9	1.1
Plant 2	5,600	10.0	93.1	2.7-4.2	1.7
Laundry B	7,500	25.2	120.4	1.8-8.3	1.6
Hospital A	76,303	29.1	140	0.3	0.2
Hospital B	59,818	50[d]	200	1.4	0.3
Hospital C	136,696	100[d]	285	0.5	0.2
Large Hotel	14,883	20[d]	120.4	2.0	0.8
Small Hotel	3,430	5[e]	70	1.6	2.0
Small College	29,585	53[d]	200	1.5	0.7
Jr. High	1,727-5,504	5	70	0.4-1.7	1.3-4.1
Elem. School	1,746-2,543	6	70	0.5-1.7	2.8-4.0

[a] Rough extrapolation of estimates in Reference 1 converted to 1985 dollars; assumes low annual capacity utilization rate and a 0.13147 capital recovery factor (10 percent interest and 15 years); excludes monitoring and testing.

[b] Boiler fuel costs divided by annual revenues (see Tables 3-1 through 3-5).

[c] Annualized scrubber cost divided by annual revenues.

[d] Two largest boilers

[e] Sum of all five boilers

TABLE 3-7. MONITORING AND TESTING COST ESTIMATES[a] (000$)

	Capital	Annual O&M	Annualized[b]
Opacity monitor	59	8	16
SO_2/diluent monitor	55	46	53
PM/SO_2 test	8	0	1
Total	122	54	70

[a] Reference 3.

[b] Annual O&M plus (0.13147 times capital cost); this capital recovery factor is based on a 10 percent interest rate and 15 years.

TABLE 3-8. SELECTED SECTORS ECONOMIC IMPACTS: FGD
(With Monitoring and Testing Costs)

Sector	Annual Revenues (x 1,000 $)	Scrubber Size (MMBtu/hr)	Annualized Scrubber and Monitoring Cost[a] (x 1,000 $)	Boiler Fuel Cost Percent[b]	Pollution Control Percent[c]
Laundry A:					
Plant 1	11,100	23.4	190.4	2.7-4.9	1.7
Plant 2	5,600	10.0	163.1	2.7-4.2	2.9
Laundry B	7,500	25.2	190.4	1.8-8.3	2.5
Hospital A	76,303	29.1	210	0.3	0.3
Hospital B	59,818	50[d]	270	1.4	0.5
Hospital C	136,696	100[d]	355	0.5	0.3
Large Hotel	14,883	20[d]	190.4	2.1	1.3
Small Hotel	3,430	5[e]	140	1.6	4.1
Small College	29,585	53[d]	270	1.5	0.9
Jr. High	1,727-5,504	5	140	0.4-1.7	2.5-8.1
Elem. School	1,746-2,543	6	140	0.5-1.8	5.5-8.0

[a] Includes annualized scrubber costs from Table 3-6 and annualized monitoring and testing costs from Table 3-7.

[b] Boiler fuel costs divided by annual revenues (see Tables 3-1 through 3-5).

[c] Annualized scrubber and monitoring and testing costs divided by annual revenues.

[d] Two largest boilers

[e] Sum of all five boilers

The significant impacts due to this stringent control scenario requiring scrubbers and monitoring requirements occur due to the very high capital costs assumed for scrubbers on these smaller sized boilers, and expensive monitoring requirements which significantly increase the costs of using boilers. The most severe impact would be experienced in places like schools which utilize very small boilers only for space heating purposes.

A less expensive but still stringent SO_2 emissions control standard would be a very low sulfur fuel regulation. This regulation may require fuel sampling and/or initial PM/SO_2 tests. This is assumed to cost $1,000 per year. The fuel price increase is estimated to be no larger than $0.73/GJ or $0.77/MMBtu (1985 dollars). This estimate is based on the projected difference in commercial residual fuel oil prices between high (3.0 percent) sulfur and very low (0.3 percent) sulfur.[4,5] Table 3-9 summarizes the potential price impacts of a very low sulfur fuel requirement (0.3 percent sulfur) on boilers firing residual fuel oil. In this regulatory scenario (with monitoring and testing costs), some laundries could experience price (or budget) increases of about 1 percent.

3.3 GENERIC BUILDINGS

3.3.1 Scope

The generic buildings analysis addresses the potential impact of a revised NSPS in buildings where the primary use of the boiler is space heating. Representational boiler configurations for five different building size ranges were developed from a small sample of actual configurations in different cities. In order to capture the effects of regional (climatic) differences, the data collection and analysis were performed separately for an area in the northern and an area in the southern United States.

Generic buildings use boilers primarily for space heating, although a small portion of boiler energy use may be for water heating. The list of generic buildings excludes buildings with a significant additional process requirement for steam. Offices, assembly halls, religious institutions and

TABLE 3-9. SELECTED SECTORS ECONOMIC IMPACTS: VERY LOW SULFUR REGULATION (With Monitoring and Testing Costs)

Sector	Annual Revenues (x 1,000 $)	Annual Fossil Fuel Consumption (MMBtu/yr)	Annual Pollution Control Cost[a] (x 1,000 $)	Pollution Control Percent[b]
Laundry A:				
Plant 1	11,100	109,500	85	0.8
Plant 2	5,600	47,400	37	0.7
Laundry B	7,500	125,750	98	1.3
Hospital A	76,303	42,048	33	0.1
Hospital B	59,818	170,820	133	0.2
Hospital C	136,696	121,300	94	0.1
Large Hotel	14,883	72,010	56	0.4
Small Hotel	3,430	8,486	8	0.2
Small College	29,585	107,383	84	0.3
Jr. High	1,727-5,504	5,606-7,984	5-7	0.1-0.4
Elem. School	1,746-2,543	3,177-5,872	3-6	0.1-0.3

[a] (Annual fossil fuel consumption times $0.77/MMBtu) plus $1,000.

[b] Annual pollution control costs divided by annual revenues.

retail space use boilers primarily for space heating and are included in this analysis.*

Data from two regional areas are studied separately in order to understand how boiler configurations vary with climatic area. Boston, Massachusetts was selected as the northern study area. Boiler use in a southern area is represented in this study by data from Washington, D.C. The generic buildings economic impact analysis provides estimates of potential cost impacts of specific alternative air emissions standards for new commercial/ institutional boilers in five building size classes and two regions. The cost impacts are measured by comparing the annualized pollution control costs of regulatory scenarios to estimates of the annual building operating budget. The annual building operating budget is estimated to be the building size (in square feet) times the rental rate (dollars per square foot). This analysis assumes full cost pass-through of the total annualized pollution control costs.

This approach measures the potential increase in building rental rates to tenants as a consequence of worst case NSPS control scenarios. The economic impact on the tenant would obviously depend on the nature of the business activity of each tenant. Tenants whose business implies a very high ratio of sales per square foot of floor space rented (grocery store, Wall Street brokers) would tend to see very little impact on profit margins since building control costs would be such a small percentage of sales. Other tenants with a relatively low ratio of sales per square foot of space would tend to experience relatively greater impacts on their cost structure. Essentially, the objective in focusing on the impact of the NSPS on building rental rates is intended to provide an indicator which any building tenant can relate to in assessing whether they might be significantly affected by a NSPS.

3.3.2 Approach

A different data collection strategy is necessary for each city because data availability in Boston is different from data availability in Washington, D.C. The Boston data on boiler use were provided by the Division of Air Quality Control, Department of Environmental Quality Engineering of the

* Schools were included in the selected sectors analysis in Section 3.2.

Commonwealth of Massachusetts. This office tracks the generation of air pollution by source, frequency of use, and fuel type. Information is available on the number, size, frequency of use, address and purpose of establishment for boilers within the Boston city limits. Building size data were not available from this data source. In addition, data were acquired on commercial building vacancies, rental rates and building sizes from three real estate agencies.[6,7,8] These rental data were matched with the boiler information to develop a data set on boiler use in generic buildings in Boston.

In Washington, D.C. data were collected from the D.C. Boiler Inspector's Office. From these records of boiler registration and safety inspection, data on address, number of boilers and boiler size were gathered. From the D.C. Tax Assessor's Office information was collected on building address, type of occupant, and building size. These two data sources were matched by building address to create a data set on boiler use in generic buildings in Washington, D.C.

Boston Data

Collection and compilation of data on boiler use in Boston, Massachusetts resulted in the set of 21 data points shown in Table 3-10. These are all office buildings. From these data we see that boiler size ranges from 1-4 MW (3 to 13 MMBtu/hr) in generic buildings and that there is only one building with a boiler larger than 3 MW (10 MMBtu/hr). Small buildings tend to have fewer boilers than larger buildings. In most Boston buildings with multiple boilers, the average annual capacity utilization rate is low. This suggests that the additional boilers serve as backup and not as primary boilers.

Based on these data, the typical configurations shown in Table 3-11 were developed. In these configurations, all additional boilers in a building are considered to be the same size as the first. The number and size of these boilers were calculated from the average number and size in each building size range.

Washington, D.C. Data

Collection and compilation of data on boiler use in Washington, D.C. resulted in the set of 12 data points shown in Table 3-12. These are mostly office and apartment buildings; there are a few churches and small retail

TABLE 3-10. GENERIC BUILDINGS BOILER CONFIGURATION DATA FOR BOSTON, MASSACHUSETTS

Building Size (1000 sq.ft.)	Boiler 1 (MMBtu/hr)	Boiler 2 (MMBtu/hr)	Boiler 3 (MMBtu/hr)	Boiler 4 (MMBtu/hr)
22	3			
30	3			
32	3			
50	6	10	10	
60	6	4	4	
64	4			
66	6	6		
72	8			
72	6			
82	4	4		
90	9			
100	4	4		
110	5	5		
110	3			
120	6	6		
150	4	4	4	4
196	13	12		
200	9	9		
280	10	7		
333	7	7		
580	7	7		

TABLE 3-11. GENERIC BUILDINGS TYPICAL BOILER CONFIGURATIONS FOR BOSTON, MASSACHUSETTS[a]

Building Size Range (1000 sq.ft.)	Total Number of Boilers	Boiler Size of Each (MMBtu/hr)
1-25	1	3
26-50	1	5
51-100	2	5
101-200	2	6
201+	2	7

[a] Derived from Table 3-10.

TABLE 3-12. GENERIC BUILDINGS BOILER CONFIGURATION DATA FOR WASHINGTON, D.C.

Building Size (1000 sq.ft.)	Boiler 1 (MMBtu/hr)	Boiler 2 (MMBtu/hr)	Boiler 3 (MMBtu/hr)	Boiler 4 (MMBtu/hr)
22	1			
34	3			
81	2	2		
129	3	3		
139	5			
186	5	4		
202	6	6		
245	6	6		
285	6	6	6	
287	7	4		
345	12	8	8	
875	13	13		

stores. Specific average capacity utilization rates for each building are unavailable. These data show that boiler size ranges from 0.3 to 4 MW (1 to 13 MMBtu/hr). Only two buildings have boilers larger than 3 MW (10 MMBtu/hr) and these buildings are both over 300,000 square feet. As with the Boston data, small buildings tend to have smaller and fewer boilers than large buildings.

Table 3-13 shows the typical boiler configurations drawn from the Washington data. It was assumed that all boilers in any given building are the same size. The original data are subdivided into the defined building size ranges. Typical configurations are drawn from simple averages of the number and size of boilers in each building size range.

Boston and Washington Configurations Compared

Boston and Washington show similar boiler use patterns. Both Boston and Washington have an identical number of boilers in each building size range. The Washington buildings, in general, tend to have slightly smaller boilers than the Boston buildings (see Table 3-14). This assumption is consistent with Washington's relatively warmer climate.

Table 3-15 presents estimates of annual fossil fuel consumption in boilers in generic buildings. Actually, there is considerable variability in energy consumption per square foot in commercial buildings due to building design characteristics, HVAC equipment differences and energy conservation measures. In general, there are economies of scale - energy consumption per square foot decreases as building size increases.

Table 3-16 summarizes other comparable estimates of annual fossil fuel consumption in commercial buildings which include a boiler.[9] The average values in Table 3-16 show that the estimates in Table 3-15 for small buildings are reasonable.

Office Building Rental Rates

Office building annual rental rates vary over a wide range, from $10-60/square foot. Typical rental rates may be $15-30/square foot.[6,7,8] For this analysis, the selection of a relatively high rental rate will bias the economic analysis toward minimizing the cost impacts of pollution control costs. Therefore, a relatively low rental rate, $15/square foot, has been

TABLE 3-13. GENERIC BUILDINGS TYPICAL BOILER CONFIGURATIONS FOR WASHINGTON, D.C.[a]

Building Size Range (1000 sq.ft.)	Total Number of Boilers	Boiler Size of Each (MMBtu/hr)
1-25	1	1
26-50	1	3
51-100	2	2
101-200	2	4
201+	2	8

[a] Derived from Table 3-12.

TABLE 3-14. GENERIC BUILDINGS BOILER CONFIGURATIONS[a]

Building Size Range (1000 sq.ft.)	Washington, D.C. Number of Boilers	Washington, D.C. Boiler Size of Each (MMBtu/hr)	Boston, Massachusetts Number of Boilers	Boston, Massachusetts Boiler Size of Each (MMBtu/hr)
<25	1	1	1	3
25-50	1	3	1	5
51-100	2	2	2	5
101-200	2	4	2	6
>200	2	8	2	7

[a] See Tables 3-11 and 3-13.

TABLE 3-15. ESTIMATES OF GENERIC BUILDINGS ANNUAL FOSSIL FUEL CONSUMPTION IN BOILERS

Building Size Range (1,000 sq. ft.)	Washington, D.C.		Boston, Massachusetts	
	GJ/yr	(MMBtu/yr)	GJ/yr	(MMBtu/yr)
<25	1,160	(1,100)	1,320	(1,250)
25-50	2,560	(2,300)	3,340	(3,000)
51-100	2,954	(2,800)	4,220	(4,000)
101-200	3,480	(3,300)	5,275	(5,000)
>200	6,330	(6,000)	8,440	(8,000)

TABLE 3-16. ENERGY CONSUMPTION IN COMMERCIAL BUILDINGS IN 1983

Fuel Type	Northeast	North Central
Natural Gas[a]		
No. of Buildings[b]	113,000	212,000
Avg. Building Size (sq. ft.)[b]	15,700	22,500
Avg. Annual Gas Consumption per Building (MMBtu)[c]	1,168	2,055
Fuel Oil[d]		
No. of Buildings[e]	101,000	Q[f]
Avg. Building Size (sq. ft.)[e]	23,800	Q
Avg. Annual Fuel Oil Consumption per Building (MMBtu)[g]	1,389	Q

[a] Reference 9, p. 106, 109.

[b] Buildings which use natural gas to fire boilers.

[c] Includes natural gas consumption in boilers and other equipment.

[d] Reference 9, p. 119, 122.

[e] Buildings which use fuel oil only to fire boilers.

[f] Data withheld because the relative standard error was greater than 50% or fewer than 20 buildings were sampled.

[g] Includes fuel oil consumption in boilers and other equipment.

chosen in order that the cost impacts will not be understated for most office building tenants. The annual building rental cost estimates are summarized in Table 3-17.

3.3.3 Results of the Regulatory Analysis

Scope

The generic buildings economic impact analysis provides estimates of potential cost impacts of specific alternative air emissions standards for new commercial/institutional boilers in the five building size classes and two regions. The cost impacts are measured by comparing the annualized pollution control costs to estimates of the annual building rental costs.

The baseline is assumed to be high (3.0 percent) sulfur residual fuel oil. This is not an appropriate baseline assumption for many municipal areas. For example, New York City, Philadelphia and Boston require very low sulfur fuel oil. Therefore, this analysis overstates the potential cost impacts for buildings in these communities. This economic analysis also tends to be a "worst case" analysis of specific alternative air emissions standards. It is using a relatively low building rental rate which overstates the economic impacts of increased pollution control costs for many tenants. In addition, there is no significant cost impact for most generic buildings because most these buildings do not use boilers and many of the rest use natural gas (which is not subject to the cost impacts presented in this section).* Furthermore, this analysis assumes that there will be no boiler size cutoff; the alternative air emissions standards are assumed to be applicable to new boilers as small as 0.3 MW (1 MMBtu/hr). Finally, this analysis includes monitoring and testing costs which may not necessarily be part of the alternative air emission standard.

Cost Estimates

Two regulatory scenarios have been evaluated:

- a very low sulfur fuel standard, 129 ng SO_2/J (0.3 lb SO_2/MMBtu), with a $1,000 per year per boiler monitoring and testing cost assumption

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* See Appendix A.

TABLE 3-17. GENERIC BUILDINGS ANNUAL RENTAL COSTS

Building Size Range (1000 sq.ft.)	Representative Building Size (1000 sq.ft.)	Annual Rental Costs[a]
<25	12	$ 180,000
25-50	37	555,000
51-100	75	1,125,000
101-200	150	2,250,000
>200	380[b]	5,700,000

[a] Representative building size times $15/sq.ft.

[b] In 1983, there were 7,000 office buildings which were larger than 200,000 square feet with a total area of 2,671 million square feet; or an average of 2,671,000,000/7,000 or 380,000 square feet. Nonresidential Buildings Energy Consumption Survey: Characteristics of Commercial Buildings 1983. U.S. Department of Energy, Energy Information Administration. DOE/EIA-0246(83). July 1986. p.55,57.

- a flue gas desulfurization (FGD) or scrubber requirement with a $70,000 per year per boiler (see Table 3-7) monitoring and testing cost assumption

Table 3-18 shows the estimates of the total annualized pollution control costs for the very low sulfur fuel requirement. The sulfur premium is estimated to be $0.73/GJ or $0.77/MMBtu (1985 dollars) for 3.0 to 0.3 percent sulfur.[5,6]

Table 3-19 presents estimates of the total annualized pollution control costs for scrubbers. The monitoring and testing cost estimates are larger than the estimates used in Table 3-18. These total annualized pollution control cost estimates are summarized in Table 3-20.

Impacts on Building Rental Rates

The impacts of total annualized pollution control costs on building rental rates are summarized in Table 3-21. The range is large, 1-67 percent. Table 3-21 suggests significant economies of scale - the cost impacts are small for large buildings.

The cost impacts in Table 3-21 are relatively large for buildings smaller than 50,000 square feet for the scrubber scenario. It is important to note that the overwhelming share (88 percent)* of commercial buildings which have boiler installations were less than 50,000 square feet in size.

Table 3-22 presents estimates of the projected impacts of annualized pollution control costs (without monitoring and testing costs) on building rental rates. The impacts are negligible for the very low sulfur fuel standard.

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* See Table A-1 in Appendix A.

TABLE 3-18. DERIVATION OF ESTIMATES OF TOTAL ANNUALIZED POLLUTION CONTROL COSTS PER BUILDING FOR THE VERY LOW SULFUR FUEL STANDARD[a] (000$)

Building Size Range (000 sq. ft.)	Monitoring and Testing	Washington, D.C.		Boston, MA	
		Fuel Cost Increase[b]	Total[c]	Fuel Cost Increase[b]	Total[c]
<25	1	0.8	1.8	1.0	2.0
25-50	1	1.8	2.8	2.3	3.3
51-100	1	2.2	3.2	3.0	4.0
101-200	1	2.5	3.5	3.9	4.9
>200	1	4.6	5.6	6.2	7.2

[a] 129 ng SO_2/J (0.3 lb SO_2/MMBtu).

[b] Annual fuel consumption from Table 3-14 times $0.73/GJ or $0.77/MMBtu ($1985).

[c] Monitoring and testing costs plus fuel cost increase.

TABLE 3-19. DERIVATION OF ESTIMATES OF TOTAL ANNUALIZED POLLUTION CONTROL COSTS PER BUILDING FOR THE SCRUBBER REQUIREMENT[a] (000$)

Building Size Range (000 sq. ft.)	Monitoring and Testing[b]	Washington, D.C.		Boston, MA	
		Scrubber Cost[c]	Total[d]	Scrubber Cost[c]	Total[d]
<25	70	40	110	50	120
25-50	70	50	120	70	140
51-100	70	50	120	70	140
101-200	70	70	140	70	140
>200	70	80	150	75	145

[a] Scrubber is required.

[b] See Table 3-7.

[c] Estimates extrapolated from Reference 1 converted to 1985 dollars; assumes low capacity utilization rate and a 0.13147 capital recovery factor (10 percent interest and 15 years).

[d] Monitoring and testing plus scrubber costs.

TABLE 3-20. COMPARISON OF ESTIMATES OF TOTAL ANNUALIZED POLLUTION CONTROL COSTS PER BUILDING[a] (000$)

Building Size Range (1000 sq. ft.)	Washington, D.C.		Boston, Massachusetts	
	Very Low Sulfur	Scrubber	Very Low Sulfur	Scrubber
<25	1.8	110.0	2.0	120.0
25-50	2.8	120.0	3.3	140.0
51-100	3.2	120.0	4.0	140.0
101-200	3.5	140.0	4.9	140.0
>200	5.6	150.0	7.2	145.0

[a] See Tables 3-18 and 3-19. Includes monitoring and testing costs.

TABLE 3-21. IMPACTS OF TOTAL ANNUALIZED POLLUTION CONTROL COSTS ON RENTAL RATES (WITH MONITORING AND TESTING COSTS)[a] (percent increases)[b]

Building Size Range (1000 sq. ft.)	Washington, D.C.		Boston, Massachusetts	
	Very Low Sulfur	Scrubber	Very Low Sulfur	Scrubber
<25	1	61	1	67
25-50	c	22	1	25
51-100	c	11	c	12
101-200	c	6	c	6
>200	c	3	c	3

[a] Total annualized pollution control cost estimates from Table 3-20 divided by annual building rental costs in Table 3-17.

[b] Total annualized pollution control costs as a percent of annual building rental costs.

[c] Less than 0.5 percent.

TABLE 3-22. IMPACTS OF TOTAL ANNUALIZED POLLUTION CONTROL COSTS ON RENTAL RATES (WITHOUT MONITORING AND TESTING COSTS)[a] (percent increases)[b]

Building Size Range (1000 sq. ft.)	Washington, D.C.		Boston, Massachusetts	
	Very Low Sulfur	Scrubber	Very Low Sulfur	Scrubber
<25	c	22	c	28
25-50	c	9	c	13
51-100	c	4	c	6
101-200	c	3	c	3
>200	c	1	c	1

[a] Annualized pollution control cost estimates (excluding monitoring and testing) from Table 3-20 divided by annual building rental costs in Table 3-17.

[b] Annualized pollution control costs as a percent of annual building rental costs.

[c] Less than 0.5 percent.

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4. ECONOMIC IMPACTS: INDUSTRIAL SECTOR

This section summarizes the economic impact analyses for the industrial sector. Because the number of industries affected by the proposed standards is large, a two-fold approach has been used. The first component focuses on major steam using industries and the second component addresses smaller industrial groups.

4.1 MAJOR STEAM USERS

Boilers are used in all manufacturing groups. This section discusses trends in the financial and economic characteristics of a subset of manufacturing industries labeled "major steam users."

The major steam users consist of the following manufacturing groups:

- Food (SIC 20)
- Textiles (SIC 22)
- Paper (SIC 26)
- Chemicals (SIC 28)
- Petroleum (SIC 29)
- Primary metals (SIC 33)

These industries have been selected because:

- as a group, they account for most of the total number of industrial boilers and industrial boiler annual fuel consumption; and
- individually, they represent those industrial classes with the greatest number of boilers.

Table 4-1 shows that this group of major steam users accounted for 79 percent of the total number of large (greater than 14.7 MW or 50 MMBtu/hr) boilers, 90 percent of the total annual fuel consumption in large boilers, and 71 percent of the total number of boilers between 14.7 and 29.3 MW (50-99 MMBtu/hr) in the manufacturing sector in 1979.[1] Data are not available for boilers smaller than 14.7 MW (50 MMBtu/hr) by industry group.

This section also summarizes the projected short-term economic impacts on each of these major steam user groups of the alternative air emissions

TABLE 4-1. AN OVERVIEW OF THE USE OF BOILERS IN MANUFACTURING INDUSTRIES IN 1979[a]

Manufacturing Group (SIC Code)	>14.7 MW (>50 MMBtu/hr)[b] Number of Boilers	1979 Fuel Consumption PJ	(10^{12} Btu)	14.7-29.3 MW (50-99 MMBtu/hr)[c] Number of Boilers
Food and kindred products (20)	1,122	338.7	(321.0)	593
Textile mill products (22)	382	74.8	(70.9)	286
Paper and allied products (26)	1,239	1,661.9	(1,575.2)	331
Chemicals (28)	1,783	1,290.4	(1,223.1)	618
Petroleum (29)	653	493.1	(467.4)	241
Primary metals (33)	647	596.3	(565.2)	207
Subtotal for major steam users	5,826	4,455.3	(4,222.8)	2,276
Total manufacturing	7,408	4,928.4	(4,671.2)	3,203
Subtotal/total	79%	90%	90%	71%

[a] Unweighted data: includes only establishments which responded to the survey (Form EIA-463); does not include estimates for establishments which did not respond to the survey. Includes natural gas, coal, fuel oil, pulping liquor, blast furnace gas, coke oven gas, refinery off-gas, wood and miscellaneous other fuels.

[b] Reference 1, p. 5.

[c] Reference 1, p. 28.

standards for new small industrial fossil fuel-fired boilers. A "worst case" analysis has been conducted in order to delimit the magnitude of possible adverse economic impacts.

1

4.2.1 Economic Profiles

Overview. The six aforementioned major steam users accounted for 40 percent of total product shipments by the manufacturing sector in 1986.[3] They represent a collection of manufacturing industries which have experienced sharply different trends in output, profitability and general economic performance to date.

Figure 4-1 and Table 4-2 compare, for example, the growth in output for each of the six industries since 1977.[4] In general, output in the food, chemicals and paper industries grew relatively consistently at or above the industrial annual average of 2.6 percent over the past ten years. In 1987 the quantity of goods produced in these three sectors was up 38-44 percent over 1977 levels and 20-35 percent over the levels experienced during the 1982 economic recession. Output in the food sector, in particular, appeared to be relatively insensitive to economic recession.

In contrast, production in the textile, petroleum and primary metals industries fell 10-35 percent below 1977 levels during the recession of 1982. Although output for these three industries recovered in the post-1982 period, this group has lagged behind the food, chemicals and paper industries and has continued to experience problems. For instance, primary metal production dropped between 1984 and 1986 due to continued competition from steel imports and steel substitutes.

Figures 4-2 through 4-4 and Tables 4-3 through 4-5 review the profitability and the financial performance of each of the six major steam using sectors. Figure 4-2 measures trends in the after-tax rate of return which accrued to investors in each of the six industries during the eight quarters of 1985 and 1986. Investments in the food and kindred products (SIC 20) industry yielded the highest after-tax rates of return over these eight quarters -- a reflection of the strong growth in food production observed earlier in Figure 4-1. Rates of return on equity in the paper (SIC 26), chemicals (SIC 28) and textile (SIC 22) industries also exceeded the all manufacturing average in 1985 and 1986. In contrast, the primary metals (SIC 33)

FIGURE 4–1

Federal Reserve Board Index Of Industrial Production

INDEX BY MANUFACTURING GROUP
1977 = 100

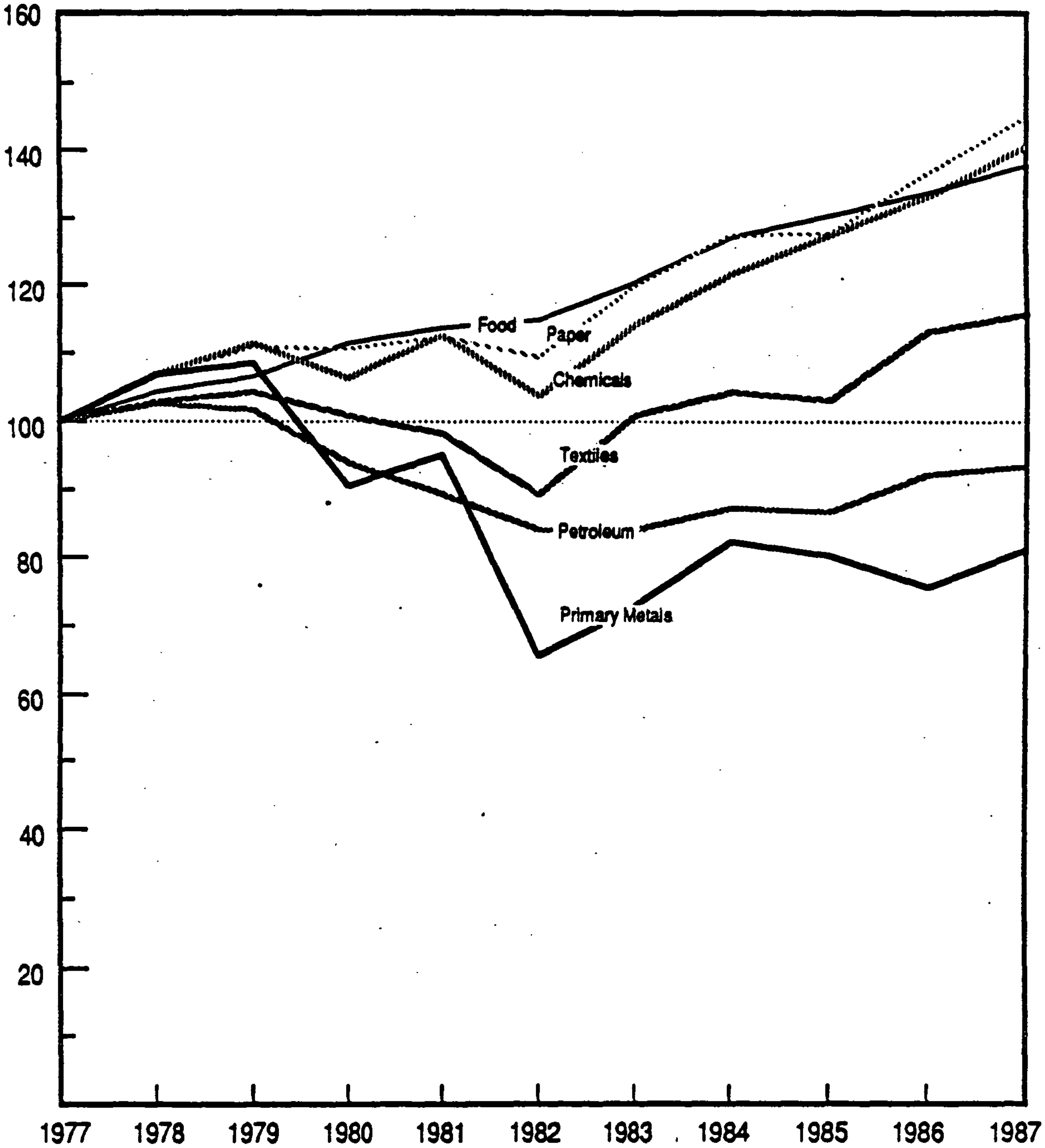

TABLE 4-2. FEDERAL RESERVE BOARD INDEX OF INDUSTRIAL PRODUCTION[a] (1977 = 100)

Year	Food	Textiles	Paper	Chemicals	Petroleum	Primary Metals	Total Industrial
1987	137.8	115.9	144.4	140.2	93.5	81.3	129.8
1986	134.4	109.2	136.5	132.0	92.7	75.1	125.1
1985	130.2	103.2	127.6	127.1	86.8	80.5	123.8
1984	126.9	104.2	127.2	121.6	87.4	82.3	121.4
1983	120.4	100.9	119.8	114.0	84.0	73.0	109.2
1982	114.9	89.2	109.4	103.8	84.2	65.8	103.1
1981	113.7	98.1	112.4	112.6	89.4	95.0	111.0
1980	111.4	100.8	110.6	106.4	94.0	90.4	108.6
1979	106.7	104.4	110.8	111.4	101.7	108.5	110.7
1978	104.3	102.8	106.8	106.8	102.5	107.0	106.5

[a] Reference 4. Also see Figure 4-1.

FIGURE 4-2

Rates Of After-Tax Profit On Stockholders' Equity

PERCENT BY INDUSTRY GROUP

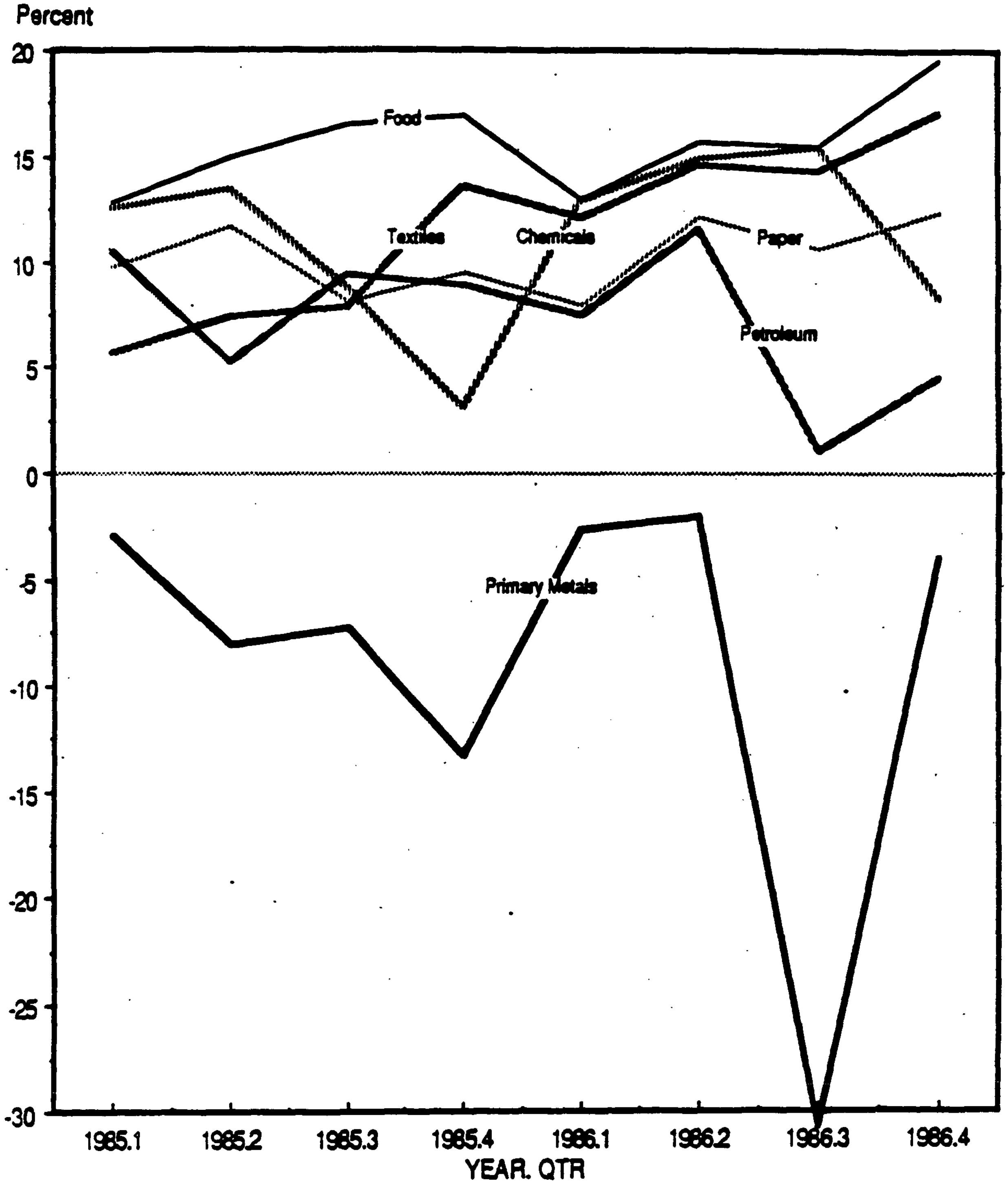

FIGURE 4-3

Rates Of After-Tax Profit On Total Assets

PERCENT BY INDUSTRY GROUP

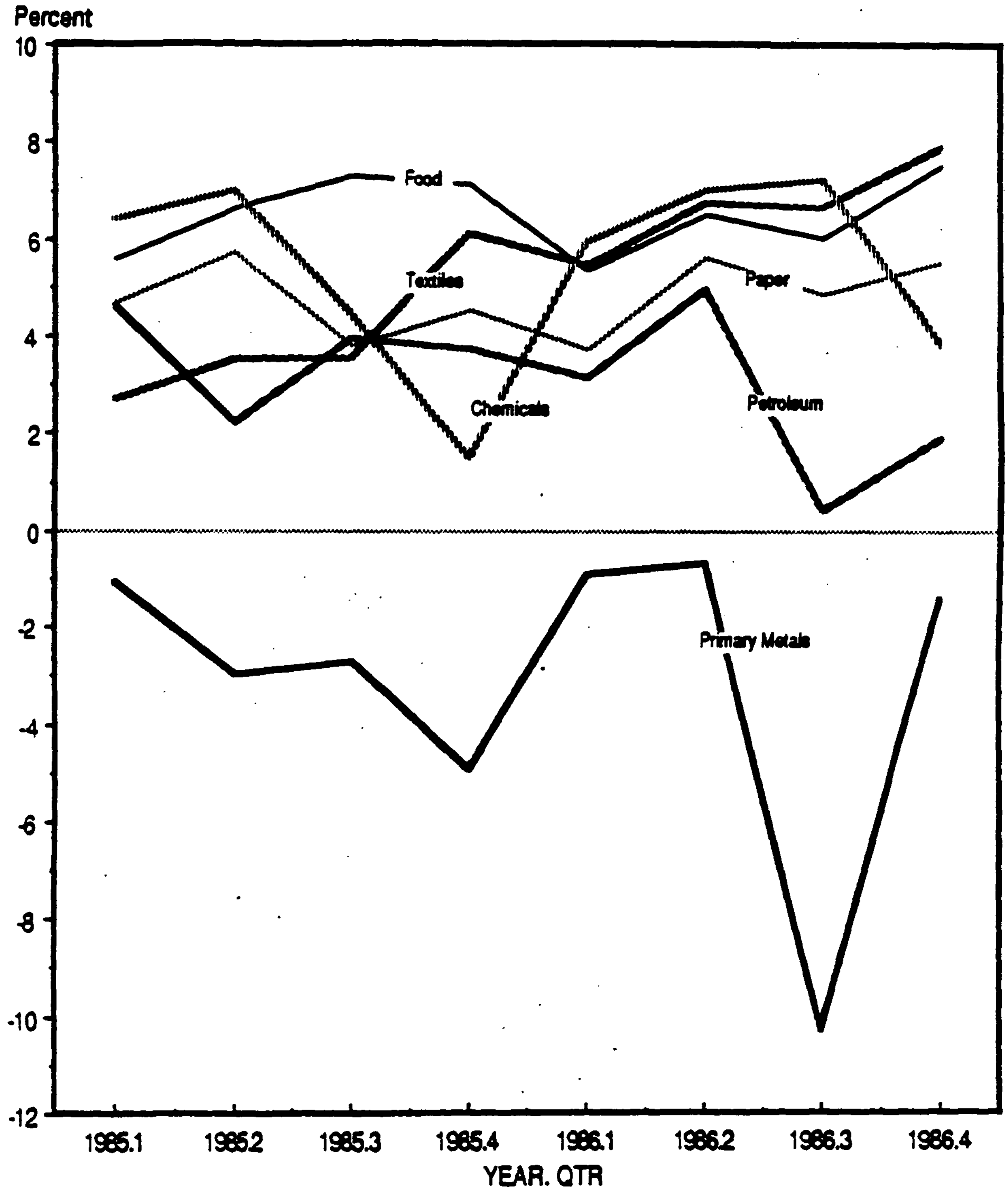

FIGURE 4-4

After-Tax Profits Per Dollar Of Sales

CENTS BY INDUSTRY GROUP

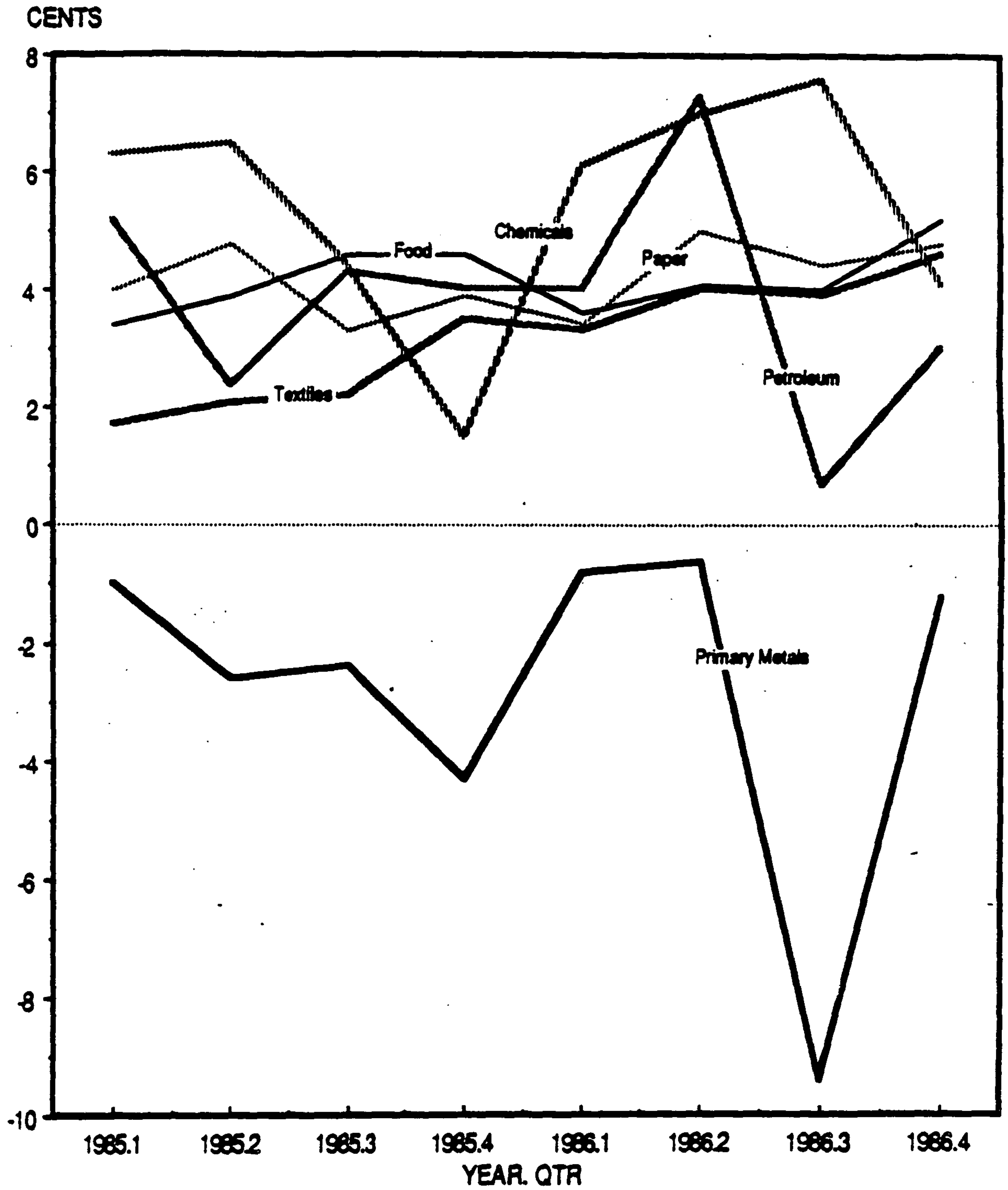

TABLE 4-3. AVERAGE RATES OF AFTER-TAX PROFIT ON STOCKHOLDERS' EQUITY BY INDUSTRY GROUP[a]
(Percent)

	Food & Kindred Products	Textile Mill Products	Paper & Allied Products	Chemicals & Allied Products	Petroleum & Coal Products	Primary Metals	All Manuf.
4Q 1986	19.6	17.0	12.3	8.2	4.5	- 4.0	8.6
3Q 1986	15.5	14.3	10.6	15.4	1.0	- 30.7	8.5
2Q 1986	15.7	14.6	12.1	14.9	11.5	- 2.0	12.2
1Q 1986	12.9	12.0	7.9	12.8	7.4	- 2.6	9.0
4Q 1985	16.9	13.5	9.4	3.1	8.8	- 13.3	9.3
3Q 1985	16.5	7.8	8.1	8.7	9.3	- 7.3	9.9
2Q 1985	15.0	7.4	11.7	13.4	5.2	- 8.1	10.9
1Q 1985	12.8	5.7	9.8	12.5	10.5	- 3.0	10.5

[a] Quarterly Financial Report for Manufacturing, Mining and Trade Corporations. U.S. Department of Commerce, Bureau of the Census. Various issues.

TABLE 4-4. AVERAGE RATES OF AFTER-TAX PROFIT ON TOTAL ASSETS BY INDUSTRY GROUP[a]
(Percent)

	Food & Kindred Products	Textile Mill Products	Paper & Allied Products	Chemicals & Allied Products	Petroleum & Coal Products	Primary Metals	All Manuf.
4Q 1986	7.5	7.9	5.5	3.8	1.9	- 1.4	3.8
3Q 1986	6.0	6.6	4.8	7.2	0.4	- 10.3	3.8
2Q 1986	6.5	6.7	5.6	7.0	4.9	- 0.7	5.5
1Q 1986	5.3	5.4	3.7	5.9	3.1	- 0.9	4.0
4Q 1985	7.1	6.1	4.5	1.5	3.7	- 4.9	4.2
3Q 1985	7.3	3.5	3.8	4.4	3.9	- 2.7	4.5
2Q 1985	6.6	3.5	5.7	7.0	2.2	- 3.0	5.0
1Q 1985	5.6	2.7	4.7	6.4	4.6	- 1.1	4.8

[a] Quarterly Financial Report for Manufacturing, Mining and Trade Corporations. U.S. Department of Commerce, Bureau of the Census. Various issues.

TABLE 4-5. AVERAGE AFTER-TAX PROFITS PER DOLLAR OF SALES BY INDUSTRY GROUP[a]
(Cents)

	Food & Kindred Products	Textile Mill Products	Paper & Allied Products	Chemicals & Allied Products	Petroleum & Coal Products	Primary Metals	All Manuf.
4Q 1986	5.2	4.6	4.8	4.1	3.0	-1.2	3.3
3Q 1986	4.0	3.9	4.4	7.6	0.7	-9.4	3.4
2Q 1986	4.1	4.0	5.0	7.0	7.3	-0.6	4.7
1Q 1986	3.6	3.3	3.4	6.1	4.0	-0.8	3.5
4Q 1985	4.6	3.5	3.9	1.5	4.0	-4.3	3.4
3Q 1985	4.6	2.2	3.3	4.4	4.3	-2.4	3.7
2Q 1985	3.9	2.1	4.8	6.5	2.4	-2.6	4.0
1Q 1985	3.4	1.7	4.0	6.3	5.2	-1.0	4.0

[a] Quarterly Financial Report for Manufacturing, Mining and Trade Corporations. U.S. Department of Commerce, Bureau of the Census. Various issues.

industry continued to be a poor investment with losses reported during each of the eight quarters in 1985/1986. Investments in the petroleum industry (SIC 29) also have suffered recently as a consequence of the slide in crude oil prices. The after-tax rate of profit on stockholders' equity in the petroleum sector fell from 11.5 percent in the second quarter of 1986 to 1.0 percent in the following quarter and then rose slightly to 4.5 percent by the end of the year.

Figure 4-3 illustrates trends in the productivity of assets in terms of producing income in each of the six major steam using sectors. As of the fourth quarter of 1986, both the textile mill products and the food and kindred products industries were the most productive in the use of assets. Rates of return in the two industries averaged 7.9 percent and 7.5 percent, respectively. Asset productivity also has remained strong in the paper and chemicals industries (except for a weak fourth quarter performance in the latter). Neither the petroleum nor the primary metals industries has performed well in relation to the other four. As shown in Figure 4-3, the after-tax profit rate on total assets in the petroleum industry fell to 0.4 percent in the third quarter of 1986 and the primary metals sector suffered a 10.3 percent loss during that same time period.

Data on the after-tax profits per dollar of sales paint a similar picture to that provided in the earlier figures. Figure 4-4 shows that, except for the fourth quarters, the chemicals industry has turned in the highest level of after-tax profits per dollar of sales (6-8 cents) in 1985/1986. Generally, the after-tax profits per dollar of sales have been roughly similar (3-5 cents) for the food, textile and paper industries especially during 1986.

In 1983 the food and kindred products industry employed the largest number of workers (1,635,000 laborers) and the petroleum and coal products sector employed the fewest (192,000) of the six manufacturing groups considered in this study. As shown in Table 4-6, this distribution is expected to continue through the mid-1990s with one exception: the number of jobs in the paper and allied products industry will exceed that in the textile industry in 1995 as the latter declines in importance. In addition, the

TABLE 4-6. EMPLOYMENT BY INDUSTRY GROUP[a]
(Thousands of Jobs)

	1983	1990	1995
Food and kindred products	1,635	1,663	1,646
Textile mill products	753	725	680
Paper and allied products	663	699	705
Chemicals and allied products	1,051	1,098	1,115
Petroleum and coal products	192	191	192
Primary metals industries	834	950	975

[a] Reference 5.

number of jobs in the food and kindred products industry also is projected to reach a peak in 1990 and then decline by 17,000 through 1995.[5]

In the remainder of this section, U.S. Department of Commerce data are summarized for the last ten years for each of the major steam users.[3,6,7] Data items of interest include trends in:

- value of shipments
- employment
- significance of imports and exports
- new plant and equipment expenditures

Food. The Food and Kindred Products industry (SIC 20) is a relatively large and diverse sector consisting of about 25 major sub-industries which process food and beverages for human and animal consumption. In 1986 this industry accounted for the second highest level of product shipments among 14 manufacturing industries classified by 2-digit SIC.[3]

As shown in Table 4-7, the real (1985 $) value of total shipments by the food industry stayed relatively constant in the late 1970s and then dropped about 11 percent to $301.6 billion in 1985 before picking up slightly in the following year.

Total employment in this sector also has been declining. From 1979 to 1985 the labor force dropped from 1,733,000 to 1,602,000 and then rose to 1,617,000 in 1986. Despite this drop in employment; labor productivity in the Food and Kindred Products industry has grown faster than the rest of the manufacturing industries due largely to significant technological improvements in food processing machinery.[8]

In recent years the U.S. has maintained a deficit in the balance of trade for food and kindred products. Nevertheless, this deficit has been declining. In 1986, U.S. exports of processed food and beverages rose over 5 percent to $10.8 billion while imports rose only 2.5 percent to $16.4 billion. As shown in Table 4-7, imports in recent years accounted for about 4 percent of the total volume of shipments of food and kindred products. The U.S. also has exported about 4 percent of the total supplies of food and kindred products.

TABLE 4-7. HISTORICAL TRENDS: FOOD AND KINDRED PRODUCTS (SIC 20)

	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
Value of Shipments ($\$10^9$)	192.9	216.0	236.0	256.2	272.1	280.5	287.1	300.0	301.6	314.5
(1985 $\$10^9$)	319.6	333.6	334.8	333.3	322.8	312.8	308.1	310.0	301.6	306.3
Total Employment (000)	1,711	1,724	1,733	1,708	1,671	1,636	1,615	1,619	1,602	1,617
Import/new supply ratio[a]	.03	.04	.04	.04	.04	.03	.03	.04	.04	.04
Export/shipment ratio[b]	.04	.04	.04	.05	.05	.04	.04	.04	.03	.04
New plant and equipment ($\$10^9$)	n/a	4.8	5.0	5.8	6.0	6.7	5.8	6.4	7.0	N.A.
(1985 $\$10^9$)	n/a	7.4	7.1	7.5	7.1	7.5	6.2	6.6	7.0	N.A.

[a] Value of imports/(value of imports plus domestic shipments).

[b] Value of exports divided by value of domestic shipments.

According to a recent study, the continuation of favorable consumer purchasing habits, increases in disposable income and changing demographics all point towards increased industry shipments in the future. In addition, the recent wave of mergers and acquisitions will provide benefits in terms of increased economies of scale and improved efficiency in this industry. These factors, in conjunction with favorable outcomes on food and agricultural issuesin multilateral trade negotiations, indicate continued economic health in the Food and Kindred Products industry.[9]

Textiles. Shipments by the textile mill industry (SIC 22) rose 2.4 percent between 1985 and 1986 after having dropped 4.0 percent below the preceding year. Despite the recent expansion in demand, domestic textile product shipments have tended towards a pattern of long term decline in real terms. Between 1977 and 1985, textile mill product shipments (measured in constant dollars) fell 21 percent. This was largely attributable to the intense competitive atmosphere generated by a rising volume of imports in recent years.[10] As shown in Table 4-8, the ratio of imports to the total new supply of textile products doubled over the 1977-1986 time frame. During the same time period, the ratio of textile exports to total shipments generally declined.

Industry restructuring, plant closings and consolidations in the wake of increased import competition made an impact on employment. As shown in Table 4-8, textile mill employment dropped 22 percent from 910,000 in 1977 to 705,000 workers in 1986.

Investments in new plant and equipment in the textile industry averaged $2.0 billion a year (in 1985 $) in the late 1970s. These capital expenditures dropped to $1.6-1.8 billion per year (in 1985 $) in the mid-1980s due to a downturn in profits.

Paper and Allied Products. The Paper and Allied Products industry (SIC 26) produces pulp, paper, paperboard and converted paper products. Primary paper products (pulp, paper and paper board) account for about 44 percent of the total output of this industry. Some of the primary product output is sent directly to end-users. However, most of it is sold to firms in the allied conversion sector for further processing into paper products. These firms,

TABLE 4-8. HISTORICAL TRENDS: TEXTILE MILL PRODUCTS (SIC 22)

	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
Value of Shipments ($\$10^9$)	40.6	42.3	45.1	47.2	50.1	47.5	53.4	55.5	53.3	54.6
(1985 $\$10^9$)	67.4	65.4	64.1	61.6	59.8	52.7	56.2	56.9	53.3	53.2
Total Employment (000)	910	899	885	848	823	749	741	746	702	705
Import/new supply ratio[a]	.04	.04	.04	.04	.05	.05	.05	.06	.07	.08
Export/shipment ratio[b]	.04	.04	.05	.06	.05	.04	.03	.03	.03	.03
New plant and equipment ($\$10^9$)	1.2	1.3	1.4	1.5	1.7	1.6	1.6	1.9	1.8	1.6
(1985 $\$10^9$)	2.0	2.0	2.0	2.0	2.0	1.7	1.7	2.0	1.8	1.6

[a] Value of imports/(value of imports plus domestic shipments).

[b] Value of exports divided by value of domestic shipments.

and those in the primary products sector, collectively operate more than 6,500 establishments nationwide. Establishments involved largely in the relatively capital-intensive primary products sector have increasingly concentrated in the South close to abundant timber reserves. Establishments in the more labor-intensive allied conversion industries have tended to be more widespread and closer to end-users.[11]

Except for the recession of 1982, the total value of shipments by the Paper and Allied Products sector increased steadily over the past 10 years. The total value of shipments more than doubled between 1977 and 1986 at an average annual rate of 8.0 percent. In real terms, the total value of shipments grew 1.7 percent per year over the 1977-1986 time period (see Table 4-9).

During this time period, total industry employment reached a peak of 707,000 workers in 1979 and then declined to 661,000 by 1983 as a result of economic recession in 1982 and the restructuring of firms through increased merger and acquisition activity. Total employment in this industry rose from 1983 to 1986 as a result of increased output and profitability. By 1986 employment stood at 674,000 workers or 1.8 percent above the level of 1983.

Imports of pulp (primarily from Canada) constituted a major, albeit declining, source of supply for this sector during the past 9 years. The import share of new pulp shipments held steady at about 31 percent in the late 1970s and then declined to 24 percent in 1986. Imports of paper and board also held steady at about 10 percent of total supply throughout the late 1970s and early 1980s and then jumped to 13 percent by 1985. The decline in the strength of the dollar has since caused imports of paper and board to drop back to 12 percent of total new supply.

Annual expenditures for new plant and equipment (measured in 1985 $) rose almost 47 percent between 1977 and 1979 and then fell 26 percent to $6.3 billion during the 1982 economic recession. Coincident with the growth in output and profits since the recession, annual new capital expenditures also rose and stood at $8.7 billion (in 1985 $) in 1986.

<u>Chemicals and Allied Products</u>. Firms in this manufacturing group produce basic materials and chemical feedstocks for use by other industries;

TABLE 4-9. HISTORICAL TRENDS: PAPER AND ALLIED PRODUCTS (SIC 26)

	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
Value of Shipments ($\$10^9$)	52.1	57.0	65.2	72.8	80.2	79.0	85.1	95.9	93.4	103.8
(1985 $\$10^9$)	86.5	88.2	92.6	94.8	95.3	88.2	91.6	99.1	93.4	101.1
Total Employment (000)	692	699	707	693	689	662	661	681	677	674
Pulp mills (SIC 2611)										
Import/new supply ratio[a]	0.33	0.31	0.33	0.31	0.31	0.29	0.29	0.31	0.27	0.24
Export/shipments ratio[b]	0.38	0.35	0.38	0.45	0.44	0.41	0.40	0.38	0.36	0.37
Paper and board (SIC 262,263,266)										
Import/new supply ratio[a]	0.10	0.11	0.11	0.10	0.10	0.10	0.10	0.11	0.13	0.12
Export/shipments ratio[b]	0.05	0.05	0.05	0.08	0.07	0.06	0.05	0.05	0.04	0.04
New plant and equipment ($\$10^9$)	3.5	3.8	5.2	6.5	6.1	5.6	5.9	7.2	8.6	8.9
(1985 $\$10^9$)	5.8	5.9	7.4	8.5	7.2	6.3	6.3	7.4	8.6	8.7

[a] Value of imports/(value of imports plus domestic shipments).

[b] Value of exports divided by value of domestic shipments.

they also manufacture consumer goods such as cosmetics, perfumes and drugs. The chemical industry ranks fifth in contribution to GNP among manufacturing industries. It is extremely diverse both in terms of the large number of chemical products and in terms of the firms producing the chemicals.[12]

Like the paper industry, the chemicals industry is its own best customer. Only 13 percent of industrial chemical shipments go to final customers; 46 percent go to other sectors of the chemical industry; and 41 percent go to the manufacturing industry.[13]

Measured in 1985 dollars, the total value of shipments by the chemicals industry increased at a 2.2 percent annual rate between 1977 and 1981. The 1982 economic recession took a toll on the chemicals industry as the real value of shipments dropped 10 percent in one year to 193.0 billion dollars -- a level lower than that of 1977 (see Table 4-10). The real value of shipments peaked again in 1984 at 218.8 billion dollars and then dropped to 193.1 billion dollars in 1986.

Total employment in the chemical and allied products sector reached a peak of 1,109,000 laborers in 1981. As a result of the 1982 economic recession, subsequent mergers and industry restructuring, the number of workers in the chemicals industry fell 7.8 percent below the 1981 peak to 1,022,000 by 1986.

The chemical and allied products industry has been a net exporter of chemicals to the rest of the world. As shown in Table 4-10, imports averaged about 5 percent of the total supply of chemicals in the late 1970s and early 1980s. Recently, however, the import share edged up to 7 percent in 1986. The export share of total shipments has dropped from 14 percent in 1980 to 11 percent in 1986.

Petroleum Refining. As shown in Table 4-11, the real value of petroleum and coal products shipments in the U.S. grew 13.2 percent per year between 1977 and 1981 --largely a reflection of the doubling in real crude oil prices which occurred in that time period. Between 1981 and 1985, the real value of shipments dropped 9.4 percent per year as a result of slackening demand. Shipments tumbled a further 30 percent from 1985 to 1986 due to the collapse in crude oil prices in that time frame.[14]

TABLE 4-10. HISTORICAL TRENDS: CHEMICALS AND ALLIED PRODUCTS (SIC 28)

	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
Value of Shipments ($\$10^9$)	118.2	129.4	147.7	162.5	180.5	170.7	183.2	198.2	197.3	198.3
(1985 $\$10^9$)	196.2	200.2	209.9	211.7	214.4	193.0	204.7	218.8	197.3	193.1
Total Employment (000)	1,074	1,096	1,109	1,107	1,109	1,075	1,043	1,049	1,044	1,022
Import/new supply ratio[a]	.04	.05	.05	.05	.05	.05	.05	.06	.06	.07
Export/shipment ratio[b]	0.10	0.10	0.13	0.14	0.13	0.12	0.10	0.11	0.10	0.11
New plant and equipment ($\$10^9$)	7.4	7.8	9.8	11.6	13.1	12.7	13.0	15.3	16.4	17.1
(1985 $\$10^9$)	12.3	12.1	13.9	15.1	15.5	14.2	14.0	15.8	16.4	16.7

[a] Value of imports/(value of imports plus domestic shipments).

[b] Value of exports divided by value of domestic shipments.

TABLE 4-11. HISTORICAL TRENDS: PETROLEUM AND COAL PRODUCTS (SIC 29)

	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
Value of Shipments ($\$10^9$)	97.5	103.9	148.4	198.7	224.1	206.4	191.6	200.6	179.1	129.3
(1985 $\$10^9$)	161.9	160.7	210.0	258.9	266.2	230.5	206.2	207.2	179.1	125.9
Total Employment (000)	202	208	210	198	214	201	196	189	179	168
Petroleum refining (SIC 2911)										
Import/new supply ratio[a]	0.09	0.07	0.07	0.07	0.07	0.07	0.09	0.11	--	--
Export/shipment ratio[b]	0.01	0.01	0.01	0.01	0.02	0.03	0.03	0.03	--	--
New plant and equipment ($\$10^9$)	11.8	13.2	15.2	19.6	26.0	26.4	23.1	25.5	26.7	18.7
(1985 $\$10^9$)	19.6	20.4	21.6	25.5	30.9	29.5	24.9	26.3	26.7	18.2

[a] Value of imports/(value of imports plus domestic shipments).

[b] Value of exports divided by value of domestic shipments.

Employment trends in the petroleum and coal products sector (SIC 29) have essentially mirrored the changes in shipments. Employment peaked in 1981 at 214,000 workers and then declined to 179,000 in 1985 at a compound annual rate decline of 4.5 percent. This rate of decline increased to 6.1 percent between 1985 and 1986 as a result of: 1) curtailments in oil and gas exploration brought on by the sharp decline in crude oil prices; and 2) industry retrenchment due to increased corporate merger and acquisition activity.

The drop in crude oil prices in 1985/1986 had a significant impact on new plant and equipment expenditures for the petroleum and coal products industry. Between 1981 and 1985, new plant and equipment expenditures (in $1985) generally dropped $3-5 billion below the 1981 peak of $30.9 billion. In 1986, capital expenditures plummeted 32 percent to $18.2 billion.

Iron and Steel. Since 1982, the iron and steel industry has been embedded in a long term slump due to slow growth in domestic demand coupled with world-wide market saturation and low productivity improvements.[15] Steel shipments in 1986 were $46.2 billion (in 1985$) or 44.5 percent below the 1981 level of $83.2 billion (see Table 4-12). Pig iron production in 1986 also was down 40 percent below 1981 levels.

Structural shifts in the pattern of steel consumption, aging capital stock and high labor costs have, in large part, been responsible for the steel industry plight. Even though the quantity of steel mill product shipments generally rose from 1982 through 1985, the industry permanently cut 12 percent of domestic steel making capacity and 20 percent of domestic iron making capacity over this time period. Despite these cuts, the industry still operated at less than two-thirds capacity in the mid 1980s.[16]

Higher levels of steel mill product imports also contributed to the industry's problems. Imports soared from 15 percent of total steel mill products supplied in 1979 to 26 percent in 1984 before falling slightly in 1985/1986 as a result of the President's Steel Import Restraint program.

The iron and steel industry slashed its work force by nearly 25 percent or 102,000 workers during the 1981/1982 economic recession. The labor force has continued to decline since that time period. In 1986 a total of 175,000

TABLE 4-12. HISTORICAL TRENDS: IRON AND STEEL INDUSTRY[a]

	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
Value of Shipments ($\$10^9$)	50.6	59.1	67.3	61.5	70.1	47.3	48.2	53.8	52.5	47.4
(1985 $\$10^9$)	83.8	91.3	95.5	80.0	83.2	52.7	51.7	55.6	52.5	46.2
Pig iron production (10^6 short tons)	81.3	87.7	87.0	68.7	73.6	43.3	48.7	51.9	50.4	44.0
Raw steel production (10^6 short tons)	125.3	137.0	136.3	111.8	120.8	74.6	84.6	92.5	88.3	81.6
Raw steel production capability utilization rate (%)[b]	78	87	88	73	78	48	56	68	66	64
Total steel mill products shipments (10^6 short tons)	91.1	97.9	100.3	83.9	88.5	61.6	67.6	73.7	73.0	70.3
Total Employment (000)	452	449	453	399	391	289	243	236	208	175
Market penetration of imported steel mill products (%)[c]	18	18	15	16	19	22	21	26	25	23

[a] American Iron and Steel Institute and U.S. Department of Commerce.

[b] Tonnage capability to produce raw steel for a full order book based on the current availability of raw materials, fuels and supplies, and of the industry's coke, iron, steelmaking, rolling and finishing facilities.2

[c] Imports/(imports plus domestic production); in terms of short tons.

TABLE 4-12. HISTORICAL TRENDS: IRON AND STEEL INDUSTRY[a]
(continued)

	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
Capital expenditures										
($\$10^9$)	n/a	n/a	2.5	2.7	2.4	2.3	1.9	1.2	1.6	0.9
(1985 $\$10^9$)	n/a	n/a	3.6	3.5	2.9	2.6	2.0	1.2	1.6	0.9
Net income ($\$10^9$)	n/a	n/a	0.8	0.7	1.7	-3.4	-2.2	0	-1.8	-4.1

[a] American Iron and Steel Institute and U.S. Department of Commerce.

laborers were employed in the iron and steel industry--down 61 percent from a 1979 high of 453,000 workers.

Operating losses have further frustrated the industry's attempt to modernize aging plant and equipment. As shown in Table 4-12, new capital expenditures (in 1985 $) averaged $1.2-1.7 billion in 1984-1985 and were concentrated largely on productivity and quality enhancing equipment such as continuous casters. Although these expenditures (in 1984/1985) were made in the face of continuing operating losses, they were nevertheless down more than 50 percent below the amounts expended in the late 1970s and early 1980s.

After five consecutive years of losses, total net income in 1987 was $1.0 billion. Production of raw steel and steel mill products increased in 1987 over 1986 levels and total employment declined in 1987. Raw steel production capability utilization rate rose to 80 percent in 1987.[17]

4.1.2 Projected Impacts on Product Prices

The economic impact analysis for the major steam user groups in the industrial sector focuses on presenting aggregate incremental annualized pollution control costs as a percent of 1985 average product prices. This analysis assumes full passthrough of pollution control costs.

The effect of a regulatory option on 1985 average product prices is calculated by finding the product of the change in the cost of new steam, the share of steam affected by the regulatory option and the amount of steam consumed per dollar of 1985 output (see Figure 4-5). The cost impacts are stated in real terms. The only real cost increase is assumed to be due to new boiler, pollution control and fuel costs. All other production costs are held constant in real terms at 1985 levels.

When regulatory options are applied, the first component of the product price calculation (the change in the cost of new steam) is affected. The cost of new steam changes due to an option's effect upon annualized boiler and pollution control capital costs, annualized non-fuel operating and maintenance (O&M) costs, and annualized fuel costs. When this new steam cost change is multiplied by the ratio of annual steam consumed (per unit of output) to annual dollar value of shipment (per unit output) a gross change in product price is derived. Because a certain percentage of the product is produced

FIGURE 4-5

Derivation Of Estimated Increase In National Average Industrial Product Prices Due To Pollution Control Costs

$$\Delta\,\text{Product Price} = \text{Steam Intensity Ratio} \times \text{\% Of Total Steam Affected By Alternative Control Level} \times \text{Maximum Cost Impact}$$

Where...

$$\textit{Steam Intensity Ratio} = \frac{\text{Industrial Boiler Total Fuel Consumption in 1985}}{\text{1985 Value Of Shipments}}$$

$$\textit{\% Of Total Steam Affected By Alternative Control Level} = \left(\frac{\text{New Small Industrial Boiler Total Fossil Fuel Consumption}}{\text{Total Fuel Consumption From All Boilers}}\right) \times 100$$

$$\textit{Maximum Cost Impact} = \frac{\text{Increase In Total Annualized Costs}}{\text{Total Fossil Fuel Consumption From New Small Industrial Boilers}}$$

$$\Delta\,\text{Product Price}\,(\%) = (\text{GJ}/\$) \times (\%) \times (\$/\text{GJ})$$

with steam generated from existing boilers, the cost estimate is reduced by the proportion of new boiler steam to total steam used within each industry group, which results in an average steam cost for the industry.

The ratio of annual total industrial boiler fuel consumed to annual dollar value of shipment by industry is assumed to remain constant over time. Ratios employed in this analysis are listed in Table 4-13. This table shows that the paper industry is a relatively steam-intensive group.

An analysis of average cost impacts would involve allocating the projected increases in total annualized costs in Section 2 by industry group (which is not available) and dividing by the consumption of all fuels in new small industrial boilers. This assumes full cost pass-through. Next, multiply by a small fraction which represents the amount of total steam requirements met by new small boilers. This type of analysis was conducted for the large (>29 MW, >100 MMBtu/hr) industrial boiler NSPS analysis and the average change in product price was estimated to be less than 0.1 percent for each of the major steam user groups.[2]

This analysis for small boilers focuses on the marginal, not average, costs. The marginal costs are the maximum, worst case annualized cost increases per unit of annual boiler fuel demand. The maximum, worst case annualized cost increase per unit of annual boiler fuel demand is derived from the national impacts analysis in Section 2. Table 4-14 presents the derivation of this parameter for coal and residual fuel oil. Because of the fabric filter requirement for PM emissions control, coal is expected to have a relatively larger average annualized cost impact per unit of annual fuel demand than residual fuel oil.

The "% of total steam affected by the alternative control level" is 100% if all of the boilers at the industrial facility are new, smaller than 29 MW (100 MMBtu/hr) and burn coal or residual fuel oil. Otherwise (and usually), this parameter is less than 100 percent because some portion of the total steam demand is met by larger and/or older boilers.

The worst case marginal cost impact analysis assumes the industry group with the largest steam intensity ratio in Table 4-13 (paper), the fuel type is coal and all of the boilers are new coal-fired units <29 MW (<100 MMBtu/hr) -

TABLE 4-13. STEAM-INTENSITY RATIOS

Industry	1985 Industrial boiler total fuel consumption[a] PJ	(10^{12} Btu)	1985 Value of shipments[b] (\$10^{9})	Industrial boiler total fuel consumption per \$ of value of shipments GJ	(10^{6} Btu)
Food	716	(679)	301.6	0.0024	(0.0023)
Textiles	176	(167)	53.3	0.0033	(0.0031)
Paper	2,027	(1,921)	93.4	0.0217	(0.0206)
Chemicals	1,382	(1,310)	197.3	0.0070	(0.0066)
Petroleum Ref.	589	(558)	179.1	0.0033	(0.0031)
Iron and Steel	398	(377)	52.5	0.0076	(0.0072)

[a] Includes natural gas, distillate and residual fuel oil, coal, wood, black liquor, LPG, refinery gas, blast furnace gas and coke oven gas. EEA estimates.

[b] U.S. Department of Commerce; reference Tables 4-7 through 4-12.

TABLE 4-14. NATIONAL IMPACTS[a]

Fuel Type	Annual Fuel Demand PJ	(10^2 Btu)	Annualized Cost Increase 10^6 \$1985	Average Annualized Cost Increase Per Unit of Annual Fuel Demand 1985 \$/GJ	(1985 \$/MMBtu)
Coal	8.65	(8.20)[b]	18.245[c]	2.11	(2.23)
Residual fuel oil	27.993	(26.532)[b]	29.248[d]	1.04	(1.10)

[a] Boiler size 3-29 MW (10-100 MMBtu/hr) in the fifth year following proposal of NSPS.

[b] Assumes a 26 percent average annual capacity utilization rate. A larger average annual capacity utilization rate would result in smaller marginal annualized cost impacts per unit of fuel demand.

[c] From Table 2-21, with monitoring and testing costs, $5.935 (4.113 + 1.822) million for SO_2 emissions control and $12.31 (8.67 + 3.64) million for complying with the 21 ng PM/J (0.05 lb PM/MMBtu) control level.

[d] From Table 2-29, with monitoring and testing costs for the 129 ng SO_2/J (0.3 lb SO_2/MMBtu) control level, $29.921 (7.255 + 22.666) million less $0.673 million for distillate fuel oil monitoring and testing costs, or $29.248 million.

so that 100% of the total steam demand is affected by the alternative control level. In this case, the expected change in product price is (0.0206 MMBtu/dollar) * 100% * ($2.23/MMBtu) = 4.6% (as outlined in Figure 4-5).

This is a worst case analysis for several reasons:

- The coal annualized cost impacts in Table 4-14 include the estimates for fabric filters for new boilers 3-9 MW (10-30 MMBtu/hr) and this is not required by the proposed coal PM NSPS.
- A steam plant composed of only small new coal-fired boilers (without any older and/or larger boilers) is not typical; less than 100 percent of total steam requirements is affected by the NSPS is more typical.
- The cost impacts in Table 4-14 may be overstated if local air emissions standards are more stringent than the baseline assumptions presented in Section 2.
- The cost impacts in Table 4-14 may include monitoring and testing costs which are not required by the proposed standards.
- The average annualized cost increase per unit of annual fuel demand is overstated for new boilers with average annual capacity utilization rates larger than 26 percent.
- Small coal boiler sales are much lower than oil or gas boiler sales (see Table 2-9); therefore, the pertinent marginal cost impacts for most affected facilities will be much smaller than $2.11/GJ ($2.23/MMBtu).

The marginal impact on product prices is smaller than 4.6% for other industry groups, other fuel types (residual fuel oil, distillate fuel oil, natural gas), and situations where less than 100 % of the total steam demand is affected by the alternative control level. For example, if the food industry is selected with residual fuel oil as the fuel type and only 20% of the total steam requirements at the plant are met by new units <29 MW (<100 MMBtu/hr), then the expected marginal product price impact is (0.0023 MMBtu/dollar) * 20% * ($1.10/MMBtu) = 0.05% (obviously much smaller than 4.6%).

Therefore, the marginal annual costs of compliance with the proposed standard are expected to increase product costs by less than five percent for each of the major steam user groups.

4.2 SELECTED INDUSTRIES

4.2.1 Introduction

The major steam users analysis focuses on aggregate two-digit SIC code industries (i.e., SIC 28, Chemicals). The selected industries analysis addresses several smaller groups at the four-digit SIC code[18] level.

Industries most likely to experience cost-related impacts are those with a high steam cost to production cost ratio. A high ratio usually stems from one of two factors: 1) the production process is steam-intensive or 2) the firm or industry has cyclic steam requirements, resulting in a low capacity utilization of the boiler equipment. Low capacity utilization causes the capital cost component of steam costs to rise, yielding high annualized costs per unit of steam.

Capital availability constraints occur when the cost of acquiring funds is so high that a firm considers a project to be uneconomic or financially unattractive. Capital availability is most often a problem for relatively small firms. Although some large firms may have excessive debt burdens, lack of access to organized capital markets is more often characteristic of small firms.

Three four-digit SIC code industries were evaluated:

- rubber reclaiming (SIC 3031)
- automobile manufacturing (SICs 3711, 3713 and 3714)
- liquor distilling (SIC 2085)

The economic analysis of selected industries focused on cost impacts, capital availability and profitability indicators.

4.2.2 Methodology

4.2.2.1 Cost and profitability impacts. The following three steps are used to estimate the cost impact of regulatory options on a selected industry:

- Step One -- Define a model plant for the selected industry.
- Step Two -- Evaluate the cost impacts for the model plant, assuming full cost absorption.
- Step Three -- Evaluate the impacts on the profitability of the model plant.

Each step is described below.

The selected industries analysis focuses on model plants to measure the economic impact of regulatory options on each industry. The model plant represents a typical plant for the segment of each industry that might be considering a boiler investment either as boiler expansion or replacement. A model plant is used since it is difficult to obtain precise details about the expansion and replacement plans of actual firms.

The following production characteristics for the model plant are estimated:

- Plant Output/Year -- average product output per year in those plants more likely to invest in new boilers.
- Price (Cost)/Unit of Output -- the historic, average selling price per unit
- Plant Sales/Year -- plant output per year multiplied by price per unit of output.
- Plant Earnings/Year -- plant sales per year multiplied by a derived profit margin (percent return on sales). The figure estimates the profitability of the model plant.

The effect of regulatory options on product cost is calculated by finding the product of the change in the cost of new steam, the share of steam affected by the new regulation, and the amount of steam consumed per dollar of output. The cost impacts are stated in real terms. The only real cost increase is due to new boiler and fuel costs; all other real production costs are held constant.

The additional costs due to a regulatory option will affect the profitability of an industry. This impact will be assessed by examining the following two financial indicators for the model plant:

- Net Profit After Taxes (Net Income). Profit after all costs and taxes have been deducted.
- Return on Assets. Net income divided by total assets, converted to a percent form.

The change in indicators due to regulatory options is a measure of the ability of the model plant to absorb the additional costs of a regulatory option.

Net income is calculated by subtracting expenses from total sales to derive gross profit and then taxes are subtracted from gross profit to equal net income. Regulatory options could affect the amount of expenses, which would alter net income. Return on assets is derived by dividing net income by total assets for the model plant and converting to a percent form. Alternative regulatory options could affect net income, resulting in a change in return on assets.

4.2.2.2 <u>Capital availability</u>. Capital availability constraints may result if regulatory options create a need for financing additional pollution control investments. The following two steps are used to evaluate whether capital availability will be a constraint on a selected industry:

- Step One -- Define financial indicators for a model firm.
- Step Two -- Evaluate the ability of a firm to finance pollution control investments.

The firm is the focus of the capital availability analysis because decisions involving large capital expenditures are made at the corporate level. Depending upon the state of corporate cash reserves and the relative costs of various financing tools, a firm will choose a combination of internal and external financing instruments to meet the additional investments required to comply with regulatory options.

The capital availability analysis focuses on the following two financial indicators, which measure each industry's financing ability:

- Coverage Ratio -- the number of times operating income (earnings before taxes and interest expenses) covers fixed obligations (annual interest on debt instruments and long-term leases).
- Debt/Equity Ratio -- a measure of the relative proportions of two types of external financing.

These two indicators are analyzed for both the base case and the regulatory options. The change in indicators due to regulatory options is analyzed to determine how difficult it will be for the firm to meet financial requirements for the pollution control equipment investment.

The cash flow coverage ratio is calculated by dividing operating income by fixed obligations, both of which could change as a result of alternative regulatory options. If the coverage ratio remains above the 3.0 standard benchmark, the cost of capital can be assumed to be above "acceptable" levels. However, as the coverage ratio falls, the cost of obtaining capital will rise.

The debt/equity ratio is calculated by dividing total debt by total equity of the firm (book values). The incremental debt incurred from financing the pollution control required by the regulatory options is added to the base debt; the incremental equity issued to finance the remainder of the investment is added to the base case equity. A new debt/equity ratio then is calculated and the change is analyzed to assess the effect of the regulatory options on the firm's capital structure.

To determine the coverage and debt/equity ratios under alternative regulatory options, five financing strategies, which differ by the percentages of the investment financed by debt versus equity, are considered. (Note that for the changes in coverage ratios and debt/equity ratios, 100 percent external financing is assumed.) The external financing scenarios are:

- zero percent new debt, 100 percent new equity
- 25 percent new debt, 75 percent new equity
- 50 percent new debt, 50 percent new equity
- 75 percent new debt, 25 percent new equity
- 100 percent new debt, zero percent new equity.

4.2.3 Model Plant Descriptions[19]

The typical rubber reclaiming industry plant has an annual output of 18,000 metric tons (20,000 short tons). The typical plant's boiler house contains three boilers that have a combined capacity of 62 MW (211 MMBtu/hr) and all boilers are assumed to operate at 45 percent of rated capacity. One 26 MW (87 MMBtu/hr) coal-fired boiler was assumed to be replaced.

The model automobile manufacturing plant is assumed to be part of a 26-plant firm. Total annual firm production is 2.3 million vehicles. The model plant boiler house consists of four coal-fired boilers with a total capacity of 102 MW (348 MMBtu/hr). It was assumed that a 26 MW (87 MMBtu/hr) boiler operated at a 25 percent average annual capacity utilization rate would be replaced.

The typical liquor distilling plant produces 17 million liters (4.5 million gallons) of distilled liquor annually. It was assumed that two older boilers would be replaced by a 26 MW (87 MMBtu/hr) coal-fired boiler and a 18 MW (62 MMBtu/hr) boiler, both operated at an average annual capacity utilization rate of 45 percent.

4.2.4 Regulatory Option

The three selected industry analyses all involve new coal-fired boilers 18-26 MW (60-90 MMBtu/hr). The regulatory option examined is a scrubber.

4.2.5 Summary of the Economic Impacts[20]

The change in product cost was estimated to be less than one percent for each of these three selected industries (assuming full cost pass-through). The expected change in return on assets is summarized in Table 4-15.

The analysis of capital availability examines the ability of the model firm to finance the new boiler investment. The coverage ratios and debt/equity ratios did not vary significantly due to the pollution control costs. It was concluded that these industries should be able to absorb additional financing of new boiler investments without undue weakening of the solvency position of the industries.

TABLE 4-15. ESTIMATED RETURN ON ASSETS FOR MODEL PLANTS[a] (percent)

Selected Industry	Base Case	Scrubber Requirement
Rubber reclaiming	4.1	1.0
Automobile manufacturing	8.1	8.0
Liquor distilling	1.3	0.5

[a] Reference 19, p. 9-33.

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APPENDIX A.
PROFILE OF BOILERS IN COMMERCIAL BUILDINGS

This appendix summarizes information on the number and location of boilers in commercial buildings. This information is significant because most commercial buildings in the United States do not include a boiler and, therefore, will not be subject to an economic impact due to a NSPS.

The U.S. Department of Energy/Energy Information Administration (Office of Energy Markets and End Use) has conducted the Nonresidential Buildings Energy Consumption Survey (NBECS) three times. The 1979 NBECS collected data during 1979 and 1980 from a statistical sample of 6,222 buildings. The 1983 NBECS collected data during 1983 for a statistical sample of 7,140 buildings: 5,845 from the 1979 NBECS and 1,295 new buildings constructed between 1979 and 1982. The 1986 NBECS collected data during 1987 for 9,189 buildings. The 1986 NBECS excluded buildings smaller than 1,000 square feet and those whose primary use is residential (the 1979 and 1983 NBECS did not). Commercial buildings in the 1979, 1983 and 1986 NBECS exclude buildings on military installations and exclude buildings in which industrial or agricultural activities occupied more of the total floor space than any other type of activity.

The 1983 NBECS estimated that 73,000 (plus or minus 21,000*) commercial buildings constructed before 1980 had new (replacement) boilers installed between January 1980 and July 1983.[1] The 1983 NBECS also estimated that there were an average of 1.38 boilers per building which included a boiler.[2] Therefore, about 100,000 (plus or minus 30,000) new (replacement) boilers were installed between January 1980 and July 1983 in commercial buildings constructed before 1980. The 1983 NBECS also estimated that 26,000 new boilers were installed in new commercial buildings constructed in the four-year period between 1980 and 1983.[2] The total average annual commercial/institutional new boiler sales level estimate is 100,000/3.5 years (or 28,600 annual replacements) plus 26,000/4 years (or 6,500 boilers per year in new buildings), or a total of about 35,000 new boilers per year for the 1980-1983 period.

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* This represents DOE/EIA's estimate of the 95 percent confidence interval.

The 1983 NBECS estimated that there were more than 1 million boilers in commercial buildings in 1983.* Less than 20 percent of the commercial buildings in the U.S. in 1983 had boilers (reference Table A-1). Natural gas is the primary commercial boiler fuel type in the North Central, South and West Census regions (see Figure A-1). However, fuel oil and natural gas have equal market shares in the Northeast Census region.

Larger commercial buildings are more likely to use a boiler for space heating in comparison with small buildings. Only 10 percent of the commercial buildings less than 5,000 square feet each include boilers. However, at least 40 percent of the commercial buildings larger than 25,000 square feet include boilers in 1983.

The average number of boilers per building is related to the building size. There is an average of three boilers per building for buildings larger than 200,000 square feet which use boilers (see Table A-1: 45,000 boilers in 14,000 buildings). The average number of boilers per building is less than 1.2 for buildings smaller than 10,000 square feet which use boilers (see Table A-1: 450,000 boilers in 385,000 buildings).

The categories with the largest total number of boilers in 1983 were mercantile/sales/personal services, offices, educational and assembly. The area with the largest number of boilers in commercial buildings in 1983 was the Northeast Census region (374,000 boilers), followed closely by the North Central region (325,000 boilers). Table A-1 also shows that 39 percent of the commercial buildings in the Northeast in 1983 used boilers versus 21 percent for the North Central, 14 percent for the West and 9 percent for the South.

Table A-2 summarizes estimates for 1986. The total number of buildings with boilers in 1986 (627,000) is smaller than the estimate for 1983 (733,000) because the 1986 estimates exclude residential buildings and buildings smaller than 1,000 square feet.

Table A-2 shows that very few new buildings use boilers. Less than 10 percent of the commercial buildings constructed after 1970 use boilers.

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* For comparison, PEDCo estimated that there were 1,295,130 commercial boilers in the U.S. in 1977.[3]

In 1986, 11 percent of the commercial buildings were not heated. Warm air furnaces were used in three times as many buildings as those with boilers. Individual space heaters or electric baseboards were used in more commercial buildings than were boilers. Other alternatives to boilers were packaged heating units, heat pumps and district heating.[4]

FIGURE A-1

U.S. Census Regions And Divisions

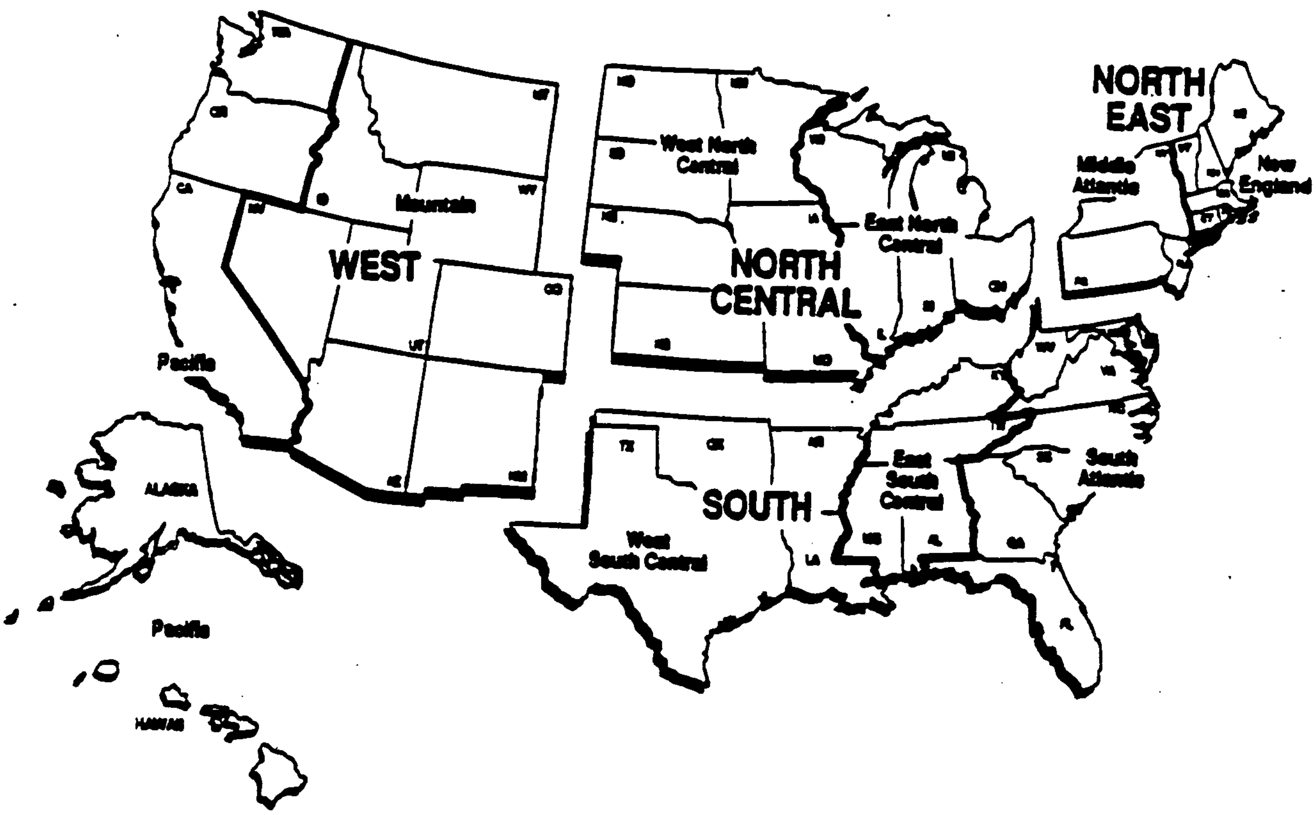

TABLE A-1. COMMERCIAL BUILDINGS IN 1983[a]

Characteristic	All bldgs. (10^3)	Bldgs. w/boilers (10^3)	Bldgs. w/boilers / All bldgs. (%)	No. of buildings (10^3) that fire boilers with Nat. Gas[b]	Fuel Oil[b]	Other[b]	Total no. of boilers (10^3)
All Buildings	3,948	733	19	497	216	48	1,015
Square Footage							
<5,000	2,248	227	10	159	50	Q[c]	267
5,001-10,000	725	158	22	105	56	Q	183
10,001-25,000	567	169	30	109	56	15	242
25,001-50,000	222	90	41	62	22	7	133
50,001-100,000	107	49	46	32	17	5	86
100,001-200,000	50	27	54	19	10	3	58
>200,000	29	14	48	11	5	1	45
Principal Activity							
Assembly	457	116	25	85	34	Q	146
Educational	177	83	47	60	26	8	157
Food sales/service	380	42	11	27	Q	Q	54
Health care	61	15	25	10	6	Q	29
Lodging	106	31	29	23	8	Q	50
Mercantile/personal	1,071	133	12	83	49	Q	175
Office	575	128	22	88	32	8	161
Residential[d]	236	87	37	59	26	Q	102
Warehouse	425	53	12	33	15	Q	74
Other	179	25	14	16	7	Q	40
Vacant	281	19	7	13	4	Q	26
Census Region							
Northeast	670	263	39	132	132	Q	374
North Central	1,211	251	21	222	23	8	325
South	1,493	138	9	79	46	17	213
West	574	82	14	64	Q	Q	103

[a] Reference 2.

[b] The sum of natural gas, fuel oil and other is larger than column 2, "buildings with boilers," because some buildings use more than one fuel type.

[c] Data withheld by DOE/EIA because the relative standard error was greater than 50 percent or because fewer than 20 buildings were sampled.

[d] Primarily residential, but with some evidence of a commercial establishment on-site.

TABLE A-2. COMMERCIAL BUILDINGS IN 1986[a]

	All buildings (10^3)	Buildings with boilers (10^3)	Buildings with boilers as % of all buildings
All buildings	4,154	627	15
Square footage			
1,001-5,000	2,220	151	7
5,001-10,000	931	173	19
10,001-25,000	557	133	24
25,001-50,000	242	91	38
50,001-100,000	123	40	33
100,001-200,000	52	22	42
200,001-500,000	23	12	52
>500,000	6	3	50
Census region			
Northeast	663	253	38
Midwest[b]	1,096	184	17
South	1,570	115	7
West	825	75	9
Principal building activity			
Assembly	575	118	21
Education	241	87	36
Food sales	102	Q[c]	--
Food services	201	19	9
Health care	52	12	23
Lodging	137	33	24
Mercantile and service	1,287	170	13
Office	614	98	16
Public order and safety	55	14	25
Warehouse	549	33	6
Other	103	13	13
Vacant	238	18	8

[a] Reference 4.

[b] Same as North Central in Table A-1 and Figure A-1.

[c] Data withheld because the relative standard error was greater than 50 percent, or fewer than 20 buildings were sampled.

TABLE A-2. COMMERCIAL BUILDINGS IN 1986[a] (continued)

	All buildings (10^3)	Buildings with boilers (10^3)	Buildings with boilers as % of all buildings
Year constructed			
1900 or before	188	62	33
1901-1920	255	71	28
1921-1945	629	120	19
1946-1960	878	147	17
1961-1970	730	115	16
1971-1973	243	22	9
1974-1979	572	41	7
1980-1983	350	28	8
1984-1986	309	20	6

[a] Reference 4.

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APPENDIX B.
HISTORICAL NEW BOILER SALES DATA

This appendix presents historical new boiler sales data for units smaller than 29.3 MW (100 MMBtu/hr).

There are three major types of boilers: cast iron, firetube, and watertube. Cast iron boilers produce hot water or low pressure steam. They are fired by gas or oil. Most of these units have firing rates which are smaller than 59 kW (200,000 Btu/hr). Table B-1 summarizes annual cast iron boiler sales data (provided to EPA by the Hydronics Institute, Berkeley Heights, New Jersey). Annual boiler sales have fluctuated over a wide range, from 155,400 units in 1975 to 347,900 units in 1980.

Cast iron boilers are used in houses, apartment buildings and commercial/institutional buildings. It was assumed that all boilers smaller than 59 kW (200,000 Btu/hr) were residential.[1] It was further assumed that about 75 percent of the boilers larger than 59 kW (200,000 Btu/hr) were in the commercial/institutional sector (see Table B-2).

Firetube boilers produce hot water and low and high pressure steam and are larger than cast iron boilers. They are fired primarily by gas or oil; however, a small number of coal and wood units have been sold. Firetube boiler sales data (provided to EPA by the American Boiler Manufacturers Association, Arlington, Virginia) are summarized in Table B-3. In the ten-year period presented in Table B-3, annual sales levels have ranged from a low of 5,878 units in 1982 to a high of 8,739 units in 1977.

Watertube boilers are available in many sizes (including units larger than 29.3 MW or 100 MMBtu/hr) and are fired by many fuel types. Table B-4 summarizes watertube boiler sales data for boilers smaller than 100,000 pounds of steam per hour capacity (provided to EPA by the American Boiler Manufacturers Association, Arlington, Virginia). Recent watertube boiler sales levels are less than half of the 1970's sales levels.

TABLE B-1. HISTORICAL CAST IRON BOILER SALES[a]
(Thousands of Units)

	kW (thousand Btu/hr capacity)					
Year	<59 (<200)	59-73 (200-250)	73-132 (250-450)	132-220 (450-950)	>220 (>950)	Total
1975	128.5	11.0	8.0	4.2	3.7	155.4
1976	160.7	14.5	10.1	5.4	4.0	194.6
1977	174.1	15.8	11.2	5.7	4.3	211.1
1978	184.5	16.4	11.1	5.1	4.2	221.3
1979	251.5	19.6	11.2	5.4	4.3	292.0
1980	297.4	21.3	19.2	5.3	4.7	347.9
1981	186.8	15.0	10.4	4.6	4.5	221.4
1982	174.4	13.5	10.1	3.9	4.3	206.0
1983	169.6	12.4	10.0	3.9	4.0	200.0
1984	205.7	13.5	10.3	4.0	4.4	237.9

[a] Hydronics Institute. Includes residential, commercial/institutional and industrial boilers.

TABLE B-2. HISTORICAL RESIDENTIAL/COMMERCIAL/INSTITUTIONAL CAST IRON BOILER SALES ESTIMATES (Thousands of Units)

	Residential[b]	Commercial/Institutional kW (thousand Btu/hr) 59-220[a] (200-950)	>220[a] (>950)	Total
1975	135.2	17.4	2.8	155.4
1976	169.2	22.4	3.0	194.6
1977	183.3	24.6	3.2	211.1
1978	193.7	24.4	3.2	221.3
1979	261.6	27.2	3.2	292.0
1980	310.0	34.4	3.5	347.9
1981	195.4	22.6	3.4	221.4
1982	182.3	20.5	3.2	206.0
1983	169.6	27.4	3.0	200.0
1984	213.7	20.9	3.3	237.9

[a] Estimates derived from Table B-1. Includes 75 percent of the boilers larger than 59 kW (200,000 Btu/hr).

[b] Estimates for single-family homes and apartment buildings. Derived from data presented in Table B-1. (Includes all boilers less than 59 kW [200,000 Btu/hr capacity] plus 25 percent of the boilers larger than 59 kW [200,000 Btu/hr capacity].)

TABLE B-3. HISTORICAL FIRETUBE BOILER SALES[a]
(Number of Units)

Year	Boiler Size MW(MMBtu/hr) <0.3 (<1)	0.3-1 (1-3)	1-12 (3-40)	Total
1975	1,533	2,317	3,360	7,210
1976	2,031	2,607	3,620	8,258
1977	2,062	2,798	3,879	8,739
1978	2,054	2,634	3,753	8,441
1979	2,112	2,860	3,729	8,701
1980	1,902	2,600	3,131	7,633
1981	1,377	2,408	2,922	6,707
1982	1,261	2,068	2,549	5,878
1983	1,470	2,165	2,755	6,390
1984	1,483	2,298	2,902	6,683

[a] American Boiler Manufacturers Association. Includes residential, commercial/institutional and industrial boilers. Includes firebox boilers. Includes hot water, low pressure steam and high pressure steam boilers.

TABLE B-4. HISTORICAL WATERTUBE BOILER SALES[a]

	Boiler Size (KPPH)[b]							
	10-25		25-50		50-100		Total	
Year	Units	KPPH	Units	KPPH	Units	KPPH	Units	KPPH
1975	107	2,033	150	5,691	102	7,716	359	15,440
1976	93	1,793	119	4,415	71	5,331	283	11,539
1977	110	2,101	140	5,144	100	7,435	350	14,680
1978	76	1,525	138	5,001	115	8,599	329	15,125
1979	67	1,264	153	5,811	95	6,595	315	13,670
1980	57	1,051	128	4,915	76	5,477	261	11,443
1981	64	1,159	98	3,660	72	5,081	234	9,900
1982	42	740	60	2,179	61	4,467	163	7,386
1983	37	663	55	2,121	47	3,620	139	6,404
1984	37	664	56	2,259	41	3,070	134	5,993

[a] American Boiler Manufacturers Association; stationary, industrial-type. Includes commercial/institutional and industrial boilers smaller than 100,000 pounds of steam per hour capacity.

[b] Thousand pounds of steam per hour capacity.

REFERENCES

1. Devitt, T. et al. Population and Characteristics of Industrial/Commercial Boilers in the U.S. PEDCo Environmental, Inc. Cincinnati, Ohio. EPA-600/7-79-178a. Prepared for the Industrial Environmental Research Laboratory, U.S. Environmental Protection Agency. August 1979.

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16. ABSTRACT

This report presents projected national environmental cost and energy impacts of alternative sulfur dioxide (SO_2) and particulate matter (PM) air emission standards for new small industrial-commercial-institutional steam generating units (small boilers) firing coal, oil, and natural gas. The analysis examines projected impacts in the fifth year following proposal of the standards. The report was prepared during development of proposed new source performance standards (NSPS) for small boilers.

17. KEY WORDS AND DOCUMENT ANALYSIS

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